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December 11, 2008

Re: Docket No. 2008-0273; In the Matter of Public Utilities Commission Instituting a Proceeding to Investigate the Implementation of Feed-in Tariffs

In the Order Initiating Investigation, filed on October 24, 2008 ("Order"), the Commission stated that it would be issuing a scoping paper on feed-in tariffs that the HECO Companies¹ and the Consumer Advocate should consider in developing their joint proposal on feed-in tariffs due on December 23, 2008. Consistent with the Order, enclosed is a paper titled "Feed-in Tariffs: Best Design Focusing Hawaii's Investigation" which was developed by the Commission's consultant, the National Regulatory Research Institute ("NRRI"). Any written comments on the NRRI paper should be provided to the Commission within twenty days of the date of this letter. In addition, the NRRI paper contains appendices, which include requests for information and questions. As recommended by NRRI, the Commission directs the parties to respond to the questions in Appendices A and C within forty-five days of the date of this letter (within thirty days, however, for the threshold legal questions in Appendix A).

Dec. 31
- Jan. 25
- Jan. 26
- Jan. 30
- Jan. 12

In addition, by letter dated and filed on December 8, 2008, the HECO Companies request an extension of time from December 8, 2008, to December 22, 2008, to file a stipulated protective order in this docket. According to the HECO Companies, they seek to have the deadline for a stipulated protective order coincide with the deadline for a stipulated procedural order to "allow the HECO Companies to discuss both potential filings simultaneously with the parties" to "increase the chances that the parties may come to agreement on both documents and avoid the need for separate filings." The Commission grants the request. The deadline to file a stipulated protective order is extended from December 8, 2008 to December 22, 2008.²

Sincerely,

Carlito P. Caliboso
Chairman

CPC:SKD:laa

Enclosure

¹Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Ltd. are collectively referred to as the "HECO Companies."

²Motions that do not involve the final determination of a proceeding may be determined by the chairperson or commissioner. See HAR § 6-61-41(e).



Feed-in Tariffs: Best Design Focusing Hawaii's Investigation¹

December 2008

¹ David Magnus Boonin, Principal of the National Regulatory Research Institute (NRRI), is this document's primary author. The Hawaii PUC has retained NRRI to assist the Commission in several areas relating to the Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and Hawaiian Electric Companies dated October 2008. The purpose of the present document is to provide additional focus to the Hawaii Public Utilities Commission's investigation into feed-in tariffs, create common language, and propose questions and issues that warrant consideration. Any recommendations are for the purpose of further discussion and do not necessarily represent the opinion of the Commission, NRRI, or any individual.

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I. Introduction

A. Feed-in tariffs: vocabulary and types

Feed-in tariffs set the price a utility pays for ~~certain types of non-utility~~ generation, such as renewable resources. There are several structures of feed-in tariffs:

- **Avoided-cost feed-in tariffs** have the utility pay for purchased power based upon the cost that the utility avoids. These tariffs reflect market conditions the utility faces, such as demand, need for additional capacity, and the price of displaced fuel. They can track hourly price changes or changes in seasonal or time-of-day costs. Avoided-cost tariffs were widely introduced in the United States in compliance with the Public Utilities Regulatory Policy Act of 1978. A price equal to the utility's avoided cost means that the ratepayer is indifferent to whether the utility buys from the non-utility generator, because the purchase cost will equal the cost the utility would have incurred absent the non-utility generator.
- **Premium tariffs** add a fixed premium to a utility's avoided cost. This is a type of feed-in tariff ~~used~~ in the Czech Republic, the Netherlands, Slovenia, and Spain.
- **Net metering** has the utility pay the customer's retail price for customer-provided or hosted "behind-the-meter" electricity production in excess of the customer's needs. The retail meter runs backwards or a second meter records the onsite generation. The second-meter metering is subtracted from the retail meter. Net metering is **usually** limited to smaller generating facilities (e.g., those producing less than 100 kW). In effect, the utility is paying the retail price for wholesale electricity.
- **Project-based feed-in tariffs** base the price on the typical cost of developing a specific type of a resource (e.g., large offshore wind) plus a reasonable profit. The tariff sets rates for individual technologies for an extended guaranteed period, such as 15 years. The goal of this type of tariff is to encourage the development of certain types of resources by creating a more bankable revenue stream for the developer. Ideally, this approach would not only encourage development but also reduce the cost of financing a project. Many nations in the European Union, as well as the states of Washington and (to a limited extent) Wisconsin, use this type of feed-in tariff (see Appendix B). ~~The purpose of an avoided-cost feed-in tariff is to ensure ratepayer indifference for the purchased power, while the purpose of a project-based feed-in tariff is to encourage project development.~~

There are methods for encouraging renewable energy other than feed-in tariffs, such as auctions, requests for proposals (RFPs), and Renewable Portfolio Standards (RPS). Each of these approaches presents opportunities and challenges. The costs

related to each of these approaches are normally included in retail rates. Per our assignment, this paper focuses only on feed-in tariffs and makes no assessment about the relative merits of these various approaches.

This report assumes the continued use of the term “renewable energy” as defined in Hawaii’s renewable portfolio standards legislation at section 269-91, which states:

“Renewable energy” means energy generated or produced utilizing the following sources:

1. Wind;
2. The sun;
3. Falling water;
4. Biogas, including landfill and sewage-based digester gas;
5. Geothermal;
6. Ocean water, currents, and waves;
7. Biomass, including biomass crops, agricultural and animal residues and wastes, and municipal solid waste;
8. Biofuels; and
9. Hydrogen produced from renewable resources.

B. Procedural background

Section 7 of the Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and Hawaiian Electric Companies dated October 2008 (the Agreement) addresses feed-in tariffs. Section 7 of the Agreement appears to focus on project-based tariffs when it states that

feed-in tariffs should be designed to cover the renewable energy producer’s costs of energy production plus some reasonable profit, and that the benefits to Hawaii from using a feed-in tariff to accelerate renewable energy development (from lowering oil imports, increasing energy security, and increasing both jobs and tax base for the state) exceed the potential incremental rents to be paid to the renewable providers in the short term.

The parties to the Agreement went on to

respectfully request that by March 2009, the Commission will conclude an investigative proceeding to determine the best design for feed-in tariffs for feed-in tariffs that support the Hawaii Clean Energy Initiative, considering such factors as categories of service, size or locational limits for projects qualifying for the feed-in tariff, how to manage and identify project development milestones relative to a queue of projects wishing to take the feed-in tariff term, what annual limits should apply to the amount of renewables allowed to take the feed-in tariff payments, and the terms and conditions and duration of the feed-in tariff that shall be offered to all qualifying renewable projects, and the continuing role of the Competitive bidding framework.

The parties also respectfully request “that by July 2009, the Commission adopt a set of feed-in tariffs and prices that implement the conclusions of the feed-in tariff investigation.”

C. Scope and structure of this document

The Agreement states that “the parties regard avoided energy cost based on fossil fuel prices for renewable energy contracts as a vestige of the past.” This requirement, coupled with the statement that “feed-in tariffs should be designed to cover the renewable energy producer’s costs of energy production plus some reasonable profit,” indicates the parties’ preference for feed-in tariffs that are production cost-based tariffs. This assessment does not address the issue of superiority between an avoided-cost and a project-cost feed-in tariff, but does raise the issue in the questions in Appendix C of this document. ~~Henceforth in this document, PBFiT shall mean a project-based feed-in tariff.~~

Net metering and avoided-cost contracts are addressed in the Agreement at sections 19 and 6, respectively. Except as they may intersect with PBFiTs, these other feed-in tariffs are beyond the scope of this investigation. Interconnection rules are also important for project development. This investigation will not address interconnection rules unless an interconnection issue is critical to the design of PBFiTs and not addressed in the Commission’s existing interconnection rules. Cost estimates should, however, include the interconnection costs.

The rest of this report includes sections on:

- Threshold issues about the need for and legality of PBFiTs.
- General issues relating to design of the PBFiT, such as: how many PBFiTs are needed, the underlying costs of a project, and the concept of capping PBFiT purchases;

- Specific PBFiT design issues such as the term of obligation, converting costs in price, rate design, and tariff eligibility; and
- Related issues.

There are also three appendices. The first is a set of tables with which parties can provide supporting cost information. The second is a recap of other PBFiTs from the European Union and other states in the USA. The third is a set of potential questions to help focus this investigation.

II. Threshold Issues

A. Legal issues

The PBFiTs established through this process have price levels determined independently of the utility's avoided cost. Those price levels, therefore, could exceed the utility's avoided costs, depending on the period during which transactions occur. This possibility raises several legal and policy questions under state and federal law, including the federal Public Utility Regulatory Policies Act (PURPA). We set forth these questions at Appendix C questions 1 to 3.

Because these threshold questions affect the lawfulness and feasibility of a PBFiT, we recommend that the Commission direct the parties to respond to these legal issues within 30 days of the issuance of this report.

B. Other incentives

Hawaii already has other mechanisms in place that are designed to encourage the development of renewable resources, including in part: a renewable portfolio standard, the requirement that utilities purchase electricity from qualifying facilities at avoided cost in compliance with PURPA, net metering for smaller renewable installations, high retail rates and competitive bidding programs for renewable resources. The Commission should require that the signatories to the Agreement and encourage all parties to explain how these other incentives will interact with a PBFiT and what a PBFiT will do that the other incentives will not accomplish. The Commission should also require that the parties suggest modifications to the current incentive mechanism that may be able to encourage the development of renewable resources in a similar amount as a PBFiT. Potential enhancements might include RPS carve outs for particular technologies, establishing predictable long-term avoided costs that are the basis for payments for an extended period, setting a floor price for competitive bids or easing the eligibility requirements of net metering.

III. General Project-Based Feed-in Tariff (PBFiT) issues

A project-based fixed-rate feed-in tariff encourages the development of specific renewable technologies by establishing a rate that allows developers to recover reasonable costs and earn a profit. A qualifying project remains on that tariff at the fixed rate for a prescribed number of years (e.g., 10 years). Unlike market-based avoided costs that vary with the price of fossil fuels, and unlike net metering where the rates are based upon the retail tariff and not wholesale costs from the utility's or the developer's perspective, a PBFiT focuses on the financial needs of a typical project. The Commission must receive from the parties, especially developers, and assess for accuracy estimates of the typical cost of each technology if capital is to be efficiently attracted and extra costs are not to be borne by consumers.

Policy makers use PBFiTs to encourage resource development by compensating developers in excess of a market-based avoided cost. Technologies that are still evolving often need a stimulus to reach commercial maturity. Policymakers often expect the PBFiT price for a technology to decrease as the technology matures. The PBFiT set today is likely to be higher than the price in subsequent PBFiTs for the same technology as the renewable market grows and becomes more knowledgeable and efficient. The trend of decreasing subsequent PBFiTs creates a link between higher costs and risks assumed by early adopters and the price they receive.

Regulators should consider the following issues in the general design of PBFiTs:

- How many different PBFiTs are needed and why? Are different PBFiTs needed for reasons such as different renewable technologies, different locations, and different-sized units?
- What are the costs and operating characteristics of the various technologies, including capital costs, life of the project, operating costs, and expected output, and the variation based upon factors such as project size and location?
- Should there be a cap on the amount of electricity purchased under the PBFiT? Should the caps differ by technology? What is the calculation basis for a cap?

The ensuing subsections address each of these questions.

A. How many PBFiTs?

Underlying factors such as technology, size, and location can affect the price needed to encourage the development of resources. Regulators establish individual PBFiTs for technologies when the underlying characteristics such as initial cost, operating costs, life expectancy, and annual output differ. Different technologies may have the same initial costs and operating costs, but one may produce more electricity

annually and have a longer service life than the other, thereby requiring a lower PBFiT price.

The Hawaii RPS lists many different technologies, including wind; the sun; falling water; biogas, including landfill and sewage-based digester gas; geothermal; ocean water, currents, and waves; biomass, including biomass crops, agricultural and animal residues and wastes, and municipal solid waste; biofuels; and hydrogen produced from renewable resources. Within each of these listed technologies, there may be subsets such as onshore wind versus offshore wind, biomass from varying feedstocks, or project size. A residential rooftop solar PV installation, for example, has a different cost structure than a large-scale solar PV installation. Location may influence the underlying costs of a project (e.g., public land on Oahu versus private land on Kauai). What is the cost and availability of real estate? What is the proximity to transmission and load? Are the underlying cost factors different on different islands for the same technology such as geothermal? These questions and others must inform tariff design.

With probably over a dozen different technologies, some of which require further segmentation by size or location, the number of PBFiTs needed is large. The Commission may wish to focus on PBFiTs that merit priority attention based upon the projects under consideration, or that might be more likely candidates for consideration based upon the existence of a reasonable PBFiT.

B. What are the key costs and operating characteristics?

~~In developing the cost support for a PBFiT, a regulator should examine typical costs and operating characteristics for that type of project, rather than the costs and characteristic of a single particular project using that technology.~~ PBFiTs are meant to encourage reasonable projects (i.e., those that are at least as cost-effective as the typical project) rather than any project regardless of its costs. All cost and operating estimations should, however, be Hawaii-specific to the extent that Hawaii's unique geography affects cost. The parties will need to identify a series of costs and characteristics that matter for the Commission. These include:

1. Installed capital costs

Installed capital costs comprise the total cost of bringing a resource on-line. The metric used here is \$/kW, recognizing that total cost may depend on the size of the project. Costs should include total pre-operational costs of development, including costs such as interest during construction, interconnection costs, and salvage costs (e.g., land sale or reuse, site reclamation, and scrap). How to convert these installed costs into a per-kWh price is discussed elsewhere in this document.

2. Expected service life

All else being equal, the longer the service life of a resource, the lower the PBFiT price. A longer service life allows for cost distribution over more kWh. Service life is

also important in determining the reasonableness of the term of obligation of the PBFiT. A term of obligation of 10 years, for example, does not encourage resource development if the resource's expected life is only 5 years.

3. Expected annual output

Annual output is a measure of the resource's productivity. This report measures annual production as full-time equivalent hours per kW. This metric emphasizes output regardless of project size. The full-time equivalent output on a per-kWh basis also deemphasizes the focus on capacity, as some of these renewable resources have intermittent output (e.g., solar PV is not available at night and wind power is not available when the wind is not blowing). PBFiTs used elsewhere pay developers for output rather than capacity. If a facility does not produce, the developer is not paid. If the resource produces more than what is expected, the developer stands to increase its profits. Uncertainty around production is a risk that PBFiTs leave with the developer. One way of mitigating this risk associated with output and profitability for both the developer and ratepayers is through stepped tariff design, discussed later in this document.

4. Fixed operating costs

There are ongoing fixed operating costs after a resource achieves commercial operation. These costs may include staffing, real estate taxes, and overhead. Fixed operating costs do not vary with output but may vary with the size of the project. These costs may change over time due to inflation.

5. Variable operating costs

Variable costs change with output. Some renewable resources, such as wind, have few or no variable costs. Other renewable resources, such as biofuels, have variable costs associated with the price of fuel, while others have variable net benefits associated with accepting waste streams as a fuel stock.

6. Reasonable profits

To establish a reasonable return on investment, the regulator needs to understand a typical project's financing. How highly leveraged (i.e., bearing how much debt compared to equity) are these projects? Does a PBFiT create a financing environment through a reliable revenue stream from the ratepayer to the investor, allowing for greater leverage and thus lower-cost financing than would be available under an avoided-cost tariff? If the PBFiTs are to encourage early development of resources, does the reasonable return need to be set higher for these early tariffs? Are there reasons other than encouraging early development to set the profit margin higher, such as risks associated with early implementation? Is this true across all project classes? Does the current "credit crunch" affect the financing costs including expected profits by equity

investors? To make effective decisions, the Commission will need the signatories to the Agreement, and developers, to provide detailed, verifiable responses to these questions.

C. How much electricity should the PBFiT obligate the utility to purchase?

The amount that the utility must purchase under a PBFiT can be open-ended (i.e., the PBFiT is available to all qualified electricity produced) or capped. A regulator can establish maximum amounts purchased under any of these tariffs. Capping a low-priced PBFiT may create development opportunities for higher-cost renewable resources. Capping a high-priced PBFiT still allows the technology a development opportunity while limiting the rate impact of purchasing high-priced resources.

Overall caps on the amount of electricity purchased under PBFiTs are reasonable to consider, as the above-market price paid for electricity under a PBFiT places upward pressure on the retail price for electricity. Is there a maximum acceptable level of rate increase that is acceptable? A regulator may want to consider the total impact the Clean Energy Infrastructure Surcharge (CEIS) has on retail rates, not just the impact of PBFiT purchases when setting a cap. Caps could be set so that when a utility meets its RPS goal, PBFiTs are not available to additional projects. Caps can also be placed on installed capacity, expected production, or rate impact (e.g., the difference between the purchased cost made under a PBFiT rate and an avoided-cost rate compared to total retail revenues).

Caps add importance to the timing of a project's eligibility for the open PBFiT. Without a cap, all resources that meet the established milestones are eligible for the PBFiT. A capped PBFiT only pays the PBFiT price to those resources that meet the eligibility milestone before reaching the cap. Caps have developers compete against each other for a place in line. The tighter the restriction, the greater the competition.

A regulator must also establish the terms for purchasing available renewable energy excluded by the cap. What price should utilities pay for renewable electricity that is not eligible for a PBFiT because of a cap? Auctions, requests for proposals, and avoided-cost purchases are some of the available options. Auctions and RFPs require administrative oversight but allow the market to influence the price. Avoided-cost pricing requires that the avoided-cost rate be updated periodically by a regulator and relies more on an administrative decision than market forces in setting the price.

D. Request for cost data

There are two forms attached to this document at Appendix A. The first form, PBFiT Supporting Cost Information, allows parties to the investigation an opportunity to provide detailed supporting cost information on multiple classes of projects. Parties should complete a separate form for each type of project (e.g., large solar PV on Oahu on public lands) for which they want to propose a PBFiT.

The second form is a summary table where the parties should summarize the information provided on the detailed forms. Parties should feel free to insert additional rows as needed. Both forms are in Microsoft Word and will automatically expand to accept however much information the respondent may wish to provide. Each form has a space to identify the responding entity (the organization rather than the individual).

Hawaii's geography, electricity infrastructure, retail electricity prices, and general economic conditions set it apart from any other state. The parties must always keep in mind challenges such as high retail electricity prices, the importance of preserving the environment, the lack of interconnectivity between the islands, and challenges concerning the location of generating resources and load when responding to the Commission in this investigation.

To remain on the schedule requested in the Agreement, while satisfying the Commission's obligation to make decisions based on substantial evidence, we suggest that the Commission: (a) require responses to Appendices A and C be due within 45 days (30 days for threshold legal questions in Appendix C) of the issuance of this report; (b) make clear to all parties that without credible cost and operating data for a technology, the Commission cannot responsibly establish a PBFiT for that technology.

IV. Specific Tariff Design Issues

A. Term of obligation

Regulators must determine based upon information provided by the parties, especially developers, the term of a PBFiT before it is possible to determine the PBFiT's price. A straightforward approach is to link the obligation period to the expected useful life of the project. Assuming that the PBFiT calculations depreciate the asset over the expected useful life of the plant, setting the obligation period longer than the useful life will provide developers who can extend plant life with a potential windfall. Setting the period shorter than the expected life of the plant will leave the investor at risk of not recovering the entire investment, depending on what happens after term expiration.

A related issue is what happens once the obligation lapses and the plant still produces electricity. The PBFiT design allows for the recovery of the total investment plus profit, making the continued use of a PBFiT price unwarranted. Options include auctions, RFPs, and avoided-cost purchases of the production from a plant with extended life.

B. Conversion of project costs to PBFiT rates

The first step in determining a PBFiT's price is to convert the total installed cost of the project into an ongoing (annual) revenue requirement. This PBFiT price will be in place for the term of obligation, as discussed at section III.A. To accomplish this step,

tariff designers “levelize” the installed costs². This levelization approach assumes regular annual output over the expected life of the plant. Levelization converts a capital cost into equal payments over the project’s life, similarly to the way in which a mortgage converts the purchase price of a house into monthly payments. Just as a mortgage retires the principal of and pays the interest on a loan, levelization funds depreciation and the cost of capital including a profit.

Assume that the total cost of a project is \$100,000 and that the project’s useful life is 20 years with a 5% straight-line depreciation per year. Also, assume that the tax-adjusted return is 16%. The 16% includes the underlying capital structure, the cost of borrowing, and a reasonable profit adjusted for income taxes. A \$100,000 “mortgage” at 16% for 20 years would require monthly payments of \$1,391.26 or an annual payment of \$16,695.12. Over 20 years, that yields \$333,902.40, \$100,000 of which represents the return of the initial investment.

The second step adds the fixed operating costs to the levelized capital costs. This total represents the typical project’s annual fixed costs. Divide the total of the levelized capital cost and the fixed operating cost by the expected output in kWh of the typical project. This produces \$/kWh. Next, add to this any variable cost in \$/kWh, and the PBFiT is calculated. The PBFiT may need further refinement to address the issues of output degradation or inflation discussed below.

C. Adjustments to the price calculation

1. Declining of output

The output from even well maintained plants sometimes declines over the life of a facility. Expected output is a key assumption in setting the PBFiT. Adjusting for declining output will be necessary in situations when the decline is significant. Adjust the calculation of the PBFiT price for declining output by using the average annual expected output over the expected life of the project, rather than the initial expected output. Under the levelization approach, which assumes constant production and payments over the life of the project, the use of average annual expected output provides developers with a benefit, as they will be recovering their costs earlier. If a severe decline in output is expected, replace the standard mortgage model with a present-value assessment that produces the same results but with declining annual payments tied to the expected production schedule over the expected life of the project.

² Installed costs include total pre-commercial costs of development, including costs such as interest during construction, interconnection costs, and salvage costs (e.g., land sale or reuse, site reclamation, scrap, etc.)

2. Inflation adjustments

Inflation can affect both the cost of development (installed capital cost) and the cost of operating a plant. Inflation estimates are usually included in the development costs. There is no need to adjust further the PBFiT for inflationary pressures on installed capital costs unless there is a prolonged period of development or the period between the a regulator's reviews of the appropriateness of the PBFiT is long. A regulator should set a routine review period (e.g., three years).

PBFiTs may be in place for long periods (e.g., 10 to 20 years). Operating costs, both fixed and variable, may increase because of inflation over this period. An inflation adjustment removes the guesswork from presetting the rates to reflect unknown inflation and has ratepayers pay for these variable costs in current dollars. The PBFiT therefore can identify the operating costs that warrant an inflation adjustment. These costs are the "base" costs. With a base established, the next issue is to determine a reasonable inflationary index. The adjustment should reflect the driving cost element (e.g., the cost of fuel or the cost of labor). A regulator's oversight is administrative once it establishes a base and index. Insignificant operating costs negate the need for an inflation adjustment.

D. Rate design

1. Time-of-day vs. around-the-clock rates

Some technologies run intermittently. As a result, the utility cannot coordinate their output with customer demand (e.g., solar PV, wind, runoff from the river, hydro, and waves), while other technologies' output is under the control of the operator (e.g., biomass and biofuels). Some tariff designers criticize PBFiTs for not tracking market conditions, such as the utility's daily demand curve. Intermittent resources run "as available," and it is in the operator's best interest to have a facility operate "whenever the sun shines." An around-the-clock kWh charge is a reasonable rate design for these technologies. A time-differentiated rate does not have much value when a typical plant for a technology operates around the clock (e.g., a base load plant) rather than tracks load.

Regulators should consider a time-differentiated rate that encourages on-peak production for technologies that can follow load. The time-differentiated approach provides additional benefit to customers by encouraging the resource to produce when avoided costs are relatively high. A pitfall is setting the time-of-day differential greater than the avoided-cost differential, as this will increase the total cost to ratepayers. There may also be legal issue that would prohibit a feed-in tariff in excess of avoided cost in Hawaii, as discussed in section II.

2. Stepped design

Stepped design for PBFiT sets more than one price for a technology's output. Location, fuel mix, size, and output are all potential reasons for a stepped design³. A stepped design for location occurs when the cost of developing a project in one location differs from the cost in another location. Different interconnection costs could drive the price differential. Fuel mix differences can occur when the plant uses more than one fuel type. A typical project's cost for some technologies can vary with its size. Typically, the larger the size, the lower the average cost of each kW. One option is to create separate PBFiTs for different circumstances. Another approach is to include within a single PBFiT price differentials to reflect these differences. Parties to this investigation should submit information at Appendix A that would identify needs for price differentiation based upon location, fuel mix, and size.

Variations in production are another reason for a stepped tariff. A wide range in the potential output from a project causes a wide range in the potential revenue at a set price. A low single rate guards against excess profits but also deters investments in less productive projects. A high single rate encourages more projects but creates an opportunity for high profits. One way to balance these two extremes is a stepped tariff that pays the developer a higher amount for the first step of production and a lower amount for subsequent output. The output step could be set monthly, annually, or over the entire useful life of the project. A stepped tariff based upon output can operate similarly to a demand ratchet, with the first amount of output associated with a plant's nominal capacity receiving higher payments than subsequent output. The Commission should direct the parties to this investigation to submit information at Appendix A that will identify needs for price differentiation based upon output.

3. Payment for net or gross output

Renewable resources are sometimes located behind the utility's meter. The net-versus-gross debate focuses on whether a developer must use its power for its own (or its host's) electricity needs first and sell only the excess under the PBFiT, or whether the developer has the right to sell all its electricity to the utility under the PBFiT. (Under net metering, the output from the renewable resource turns the meter backwards after the host meets its local needs for electricity). The author knows of no rule that would require a developer to sell its output to the utility before using some of the output for its own purpose, so that case is not considered.

The goal of the PBFiT is to encourage the development of certain resources. Imposing a net purchase requirement (i.e., the developer or its host must use its power internally first at a lower de facto compensation than the PBFiT) would diminish this

³ Stepped retail tariffs charge different prices for different levels of consumption.

encouragement by the difference between the retail price and the PBFiT price. In cases when the PBFiT price is lower than the retail price, developers who have retail electricity needs can elect to use their own production for their own use.

E. Eligibility

1. Queue milestones

Milestones determine a project's eligibility for a PBFiT. Should a project be eligible for a PBFiT when it makes an administrative filing, reaches some permitting threshold, breaks ground, is 50% or some other percentage complete, or starts producing electricity? Should a single milestone (e.g., commercial operation) or multiple milestones (e.g., permitting and 50% complete) be used? The tariff could state that "any eligible project that starts producing electricity for the first time between the dates of X and Y will be paid in accordance with the prices set forth in this tariff and for twelve years" (assuming a twelve-year term obligation). In the sample language above, other milestones could replace the production milestone.

As a general premise, developers want to lock in their place in a queue as early as possible, while regulators concerned about seeing production may lean towards a production milestone. A production milestone is administratively straightforward and ensures production. The definition of a production milestone is important to avoid gaming or misuse (e.g., by demonstrating minimal production to reserve significant production under the PBFiT).

A cap on the amount of electricity eligible for purchase under a particular PBFiT (see section II.C) makes the chosen milestones even more important. Developers are striving not only to reach the established milestone(s) in time, but also to achieve the milestone before others fill the capped amount.

2. Affiliated interests

Utilities may have deregulated subsidiaries that generate electricity and sell that electricity to the utility under terms consistent with the state's affiliated interest rules. Given the following reasons, should a utility's affiliates be eligible for compensation under the PBFiT?

- Utilities should be developing their own renewable resources under standard ratemaking and not require extra incentives afforded by PBFiTs.
- Utility affiliates paid through PBFiTs can displace independent developers if a cap is in place.

V. Related Issues

A. Treatment of other governmental incentives

Other governmental incentives exist to encourage the development of renewable resources, including in part renewable energy tax credits, renewable energy credits, and carbon credits. These credits are constantly changing and are difficult to predict. These credits have real value and usually belong to the developer. If these incentives are not reflected in the determination of the typical project cost for the PBFiT price, the PBFiT is providing too high an incentive to developers (and is too expensive for the ratepayers). ~~regulator could require that PBFiTs require the energy provider to assign any credits associated with the energy to the purchasing utility.~~ The utility could sell these credits if there is a market, with all or part of the proceeds used as an offset against the Clean Energy Infrastructure Surcharge.

B. PBFiTs and access to capital

PBFiTs encourage the development of renewable resources by making the price paid for electricity more predictable, as well as compatible with a project's costs. Revenues that are more dependable make financing easier and less costly, especially when those revenues arrive predictably through the ratepayer's monthly payments. Regulators should consider payment structures that improve the dependability of paying developers (or their investors) from the dollars paid by ratepayers for the renewable electricity. This can include dedicating PBFiT-related utility revenues for payment to developers.

C. Encouraging utilities to purchase renewable energy

The Agreement calls for including 10% of the utility's purchases under the feed-in tariff in rate base through January 2015. Utilities and regulators face the challenge of balancing the build-versus-buy bias that can exist in rate-base, rate-of-return regulation. The incentive included in the Agreement is redundant given that the PBFiTs require utilities to purchase qualifying electricity under the tariff's terms. The parties to the Agreement need to demonstrate that the inclusion of these costs in the rate base accurately addresses an actual cost incurred by utilities associated with purchasing this power (e.g., imputed debt).

VI. Information about Other PBFiTs

Appendix B provides a table that summarizes the price and term of obligation of PBFiTs in the European Union. Appendix B also includes a summary of the terms of Washington State's and Wisconsin's PBFiTs. There is almost universally a large difference between the PBFiT price for solar PV and other technologies.

VII. Request of Parties to Investigation

The Commission should direct the parties to this investigation to provide comments on this document. In particular, the Commission should direct the parties to this investigation to:

1. Complete the tables provided at Appendix A.
2. Respond to the questions listed at Appendix C.

Appendix A: Cost Data Forms

(Responses are due in 45 days.)

PBFiT Supporting Cost Information

(Submitted by _____)

Responses should reflect typical costs and operations for projects of the stated class and not those for a specific project. All costs should be in 2009 dollars and reflect the unique cost characteristics of developing projects in Hawaii.

Eligible Projects

Technology: _____

Restrictions (if any):

Size (kW) Location Other Factor(s)

Installed Capital Cost (\$/kW)⁴: _____ (Provide range and expected cost).

Please provide a complete explanation of the stated costs, including references and a discussion of the impact of the size or location of the plant.

Expected Service Life (months): _____ (Provide range and expected service life).

Please provide a complete explanation of the stated service life, including references, and discuss whether service life would change with variations in output.

¹ Costs include total pre-commercial costs of development, including costs such as interest during construction, interconnection costs, and salvage costs (e.g., land sale or reuse, site reclamation, scrap, etc.)

Expected Annual Output per kW (kWh): _____ (Provide range and expected out)

Please provide a complete explanation of the annual output, including references and discuss whether output is expected to degrade over the project's service life (please quantify expected degradation, if any).

Fixed Operating Costs (\$/year): _____ (Provide range and expected costs)

Please provide a complete explanation of the fixed operating costs, including references and a discussion about whether the costs should be expected to vary with project size (please quantify any expected variation). Discuss any inflationary adjustments that may be appropriate.

Variable Operating Costs (cents/kWh): _____ (Provide range and expected costs)

Please provide a complete explanation of the variable operating costs, including references and a discussion about any inflation adjustments that may be required and adjustments for renewable or environmental credits.

Reasonable Profits (%)⁵: _____

Please describe how this figure was determined, including capital structure, cost of debt and equity, tax rates, and the benefits or lack thereof of PBFITs on access to capital markets compared to avoided-cost purchase rates. Please provide references or citations.

² Please assume that there is a mechanism directing the payment to the developer of revenues collected from the customer for renewable electricity.

Summary Table of Cost Data⁶

Presented by: _____

Project Definition	Capital Costs (\$/kW)	Expected Life (Years)	Annual Output per kW (kWh)	Fixed Operating Costs (\$/year)	Variable Operating Costs (cents/kWh)	Profit (%)
Wind - Onshore						
Wind - Offshore						
Solar PV - Large						
Solar PV - Small						
Falling Water						

⁶ Please insert the data used in the detailed sheets, using the preferred value and not the ranges. Insert additional lines as needed.

Appendix B: Other PBFiTs

Tariff Level and Duration of Feed-in Tariffs in the European Union

Washington State Feed-in Tariff Summary

Wisconsin Feed-in Tariff Summary

Price and Term of Duration for Plants Commissioned in 2006							
	Tariff level in 2006 expressed in Euro cents/kWh.						
Country/State	Small Hydro	Wind Onshore	Wind Offshore	Solid Biomass	Biogas	Solar PV	Geothermal
Austria	3.8-6.3 13 years	7.8 13 years		10.2-16.0 13 years	3.0-16.5 13 years	47.60 13 years	7.0 13 years
Cyprus	6.5 no limit	9.5 15 years	9.5 15 years	6.5 no limit	6.5 no limit	21.1-39.3 15 years	
Czech Rep – fixed	8.1 15 years	8.5 15 years		7.9-10.2 15 years	7.7-10.3 15 years	45.5 15 years	15.5 15 years
Czech Rep – premium	10.5 15 years	12.5 15 years		10.0-12.0 15 years	9.9-12.5 15 years	49.0 15 years	18.0 15 years
Denmark		7.2 20 years		8.0 20 years	8.0 20 years	8.0 20 years	6.9 20 years
Estonia	5.2 7 years	5.2 12 years	5.2 12 years	5.2 7 years	5.2 12 years	5.2 12 years	5.2 12 years
France	5.5-7.6 20 years	8.2 15 years	13.0 20 years	4.9-6.1 15 years	4.5-14.0 15 years	30.0-55.0 20 years	12.0-15.0 15 years
Germany	6.7-9.7 30 years	8.4 20 years	9.1 20 years	3.8-21.2 20 years	6.5-21.2 20 years	40.6-56.8 20 years	7.2-15.0 20 years
Greece	7.3-8.5 12 years	7.3-8.5 12 years	9.0 12 years	7.3-8.5 12 years	7.3-8.5 12 years	40.0-50.0 12 years	7.3-8.5 12 years
Hungary	9.4 No limit	9.4 No limit		9.4 No limit	9.4 No limit	9.4 No limit	9.4 No limit
Ireland	7.2 15 years	5.7-5.9 15 years	5.7-5.9 15 years	7.2 15 years	7.0-7.2 15 years		

Italy						44.5-49.0	
						20 years	
Lithuania	5.8	6.4	6.4	5.8	5.8		
	10 years	10 years	10 years	10 years	10 years		
Luxembourg	7.9-10.3	7.9-10.3		10.4-12.8	10.4-12.8	28.0-56.0	
	10 years	10 years		10 years	10 years	10 years	
The Netherlands	14.7	12.7	14.7	12.0-14.7	7.1-14.7	14.7	
	10 years	10 years	10 years	10 years	10 years	10 years	
Portugal	7.5	7.4	7.4	11.0	10.2	31-45	
	15 years	15 years	15 years	15 years	15 years	15 years	
Slovakia	6.1	7.4		7.2-8.0	6.6	21.2	9.3
	1 year	1 year		1 year	1 year	1 year	1 year
Slovenia - fixed	6.0-6.2	5.9-6.1		6.8-7.0	5.0-12.1	6.5-37.5	5.9
	10 years	10 years		10 years	10 years	10 years	10 years
Slovenia - premium	8.2-8.4	8.1-8.3		9.0-9.2	6.7-14.3	8.7-39.7	8.1
	10 years	10 years		10 years	10 years	10 years	10 years
Spain-fixed	6.1-6.9	6.9	6.9	6.1-6.9	6.1-6.9	23.0-44.0	6.9
	No limit	No limit	No limit	No limit	No limit	No limit	No limit
Spain - premium	8.6-9.4	9.4	9.4	8.6-9.4	9.4	25.5	9.4
	No limit	No limit	No limit	No limit	No limit	No limit	No limit
Source: Evaluation of different feed-in tariff design options – Best practice paper for the International Feed-In Cooperation, Energy Economics Group							

Washington State

Solar PV built in the state: \$0.59/kWh, 7 years

Wind: \$0.17/kWh; 7 years

Wisconsin

Wisconsin Electric Solar PV: \$0.225/kWh; 10 years

Wisconsin Electric Biogas: \$0.08/kWh on-peak, \$0.049/kWh off-peak, 10 years

Madison Gas & Electric Wind: \$0.061/kWh

Appendix C: Questions

The Commission should direct the parties to respond to the following questions. Please provide detailed responses including supporting calculations and assumptions, underlying reasoning, and supportive citations. Responses to the threshold legal issues are due within 30 days. Responses to all other questions are due in 45 days.

Threshold Issues (Legal)

1. If the price associated with a feed-in tariff exceeds the utility's avoided cost, then by definition the utility's customers will incur higher costs than they would in the absence of the feed-in tariff. Please comment on the legal implications of this result. For example:
 - a) Is this result permissible under current Hawaii statutes?
 - b) Does HRS § 269-27.2 create a ceiling on the feed-in tariff price?
 - c) If so, how do the signatories to the Energy Agreement (or other parties to this proceeding) propose to demonstrate that each feed-in tariff price does not violate the statute?

2. As with any administrative agency decision, a Commission decision approving a feed-in tariff must be supported with substantial evidence.
 - a) Focusing on the price term, what evidence is legally necessary? Consider these options, among others:
 - i) evidence of actual costs to develop similar projects in Hawaii
 - ii) generic (i.e., non-Hawaii) evidence of costs associated with each particular technology
 - iii) evidence that the tariff price results in costs equal to or below the utility's avoided cost
 - b) By what process do the signatories (and other parties to this proceeding) propose to gather this evidence and present it the Commission, under the procedural schedule proposed by the signatories?

3. Assume the Commission does create feed-in tariffs, which entitle the seller to sell to the utility at the tariff price.
 - a) If the tariff price exceeds the utility's avoided cost, is there a violation of PURPA, provided the seller is relying on a state law right to sell rather than a PURPA right to sell?

- b) If the tariff price exceeds the utility's avoided cost (as calculated prior to the existence of the tariff), could a seller assert a PURPA right to a sale at the tariff price, on the grounds that the utility now has a new "avoided cost" equal to cost it would have incurred under the state-mandated feed-in tariff?
- c) If the price associated with a feed-in tariff is less than the utility's avoided cost, what benefit does the tariff offer the developer that is not already available under PURPA?
- d) Please offer any other comments concerning the legal and practical relationship between the feed-in tariff and existing PURPA rights and obligations.

Other Threshold Issues

- 4. Feed-in tariffs, if approved by the Commission, would join an array of legislative and regulatory initiatives to boost production of renewables in Hawaii. Those initiatives include PURPA, the renewable portfolio standard, net metering and various distributed generation actions. Are there overlaps, redundancies, gaps among these multiple initiatives? What is the independent purpose of each of these, in relation to the others?

Process and General Feed-in Tariff Issues

- 5. Please explain the criticality of completing the "best-design" phase of this investigation by March 2009 and having project-based FiTs in place by July 2009 as called for in the Agreement.
- 6. Please explain why project-based FiTs are superior to other methods that require a utility to purchase renewable electricity.
- 7. Please quantify the costs over avoided costs of an open-ended PBFiT program assuming the utility meets the RPS goals set forth in the Agreement.
- 8. Please quantify the benefits of lowering oil imports, increasing energy security, and increasing both jobs and tax base for the state mentioned in the Agreement.
- 9. Is the goal to encourage as much use of renewable resources as possible as soon as possible, or is it to encourage the orderly introduction of renewable resources based upon cost effectiveness?
- 10. How long a period should exist between mandatory Commission reviews of the PBFiTs?

PBFiT General Design Issues

11. Do each of the technologies listed as a renewable resource in the RPS legislation require a PBFiT?
12. Should PBFiTs for certain technologies be established now while others are deferred?
13. Should the Commission cap purchases under PBFiTs? If yes, what is the maximum amount? Should individual caps be set for each technology? What period should the cap cover? What is the measurement for the cap (e.g., dollars, percent of sales, kW, or kWh)?
14. What limitations exist for integrating renewable resources onto the grid? Should these limits affect the PBFiT design or caps, or are they just another cost that developers must consider?

Specific Tariff Design Issues

15. How long should the Commission set for the PBFiT's term of obligation? Should it be different for different technologies? Is there a common basis (e.g., a conservative estimate of expected useful life) for establishing the term of obligation? On what basis should a utility pay for electricity after the term expires?
16. Should PBFiTs require the utility to purchase the project's gross or net output at the PBFiT price?
17. How should the utility determine the price paid for renewable energy not covered by a PBFiT (e.g., purchases above the cap or beyond the term of obligation)?
18. What inflation adjustment, if any, should the PBFiT include, using what base and indexes?
19. What milestones (e.g., commercial operations) should the Commission set to determine eligibility for the PBFiT? Are Hawaii's RPS statute requirements an eligibility requirement? Should utility affiliates be eligible to receive the PBFiT price?
20. Please comment on the need for stepped tariffs based upon location, size, fuel mix, and output.
21. Under what circumstances should the PBFiT price be time-differentiated?
22. How highly leveraged (i.e., bearing how much debt compared to equity) are these projects?

23. Does a PBFiT create a financing environment through a reliable revenue stream from the ratepayer to the investor, allowing for greater leverage and thus lower cost financing than would be available under an avoided-cost tariff?
24. If the PBFiTs are to encourage early development of resources, does the reasonable return need to be set higher for these early tariffs? Are there reasons other than encouraging early development to set the profit margin higher, such as risks associated with early implementation? Is this true across all project classes?
25. Does the current "credit crunch" affect the financing costs, including expected profits by equity investors?

Related Issues

26. Please provide a quantitative analysis demonstrating the public interest aspect of the concept that 10% of the utility's purchases under the feed-in tariff PPA should be included in the utility's rate base through 2015. In addition to the overall prudence of the rate base recommendation, please address the 10% and 2015 date included in the Agreement.
27. What is the appropriate rate of return for the PBFiT portion of rate base that consists of a mandated purchase with guaranteed recovery and no capital outlay?
28. Are there preferable utility incentives, other than putting PBFiT revenues into the rate base, to encourage the development of renewable resources?
29. Should the PBFiT require developers to assign credits (e.g., investment tax credits, renewable energy credits, and carbon credits) earned from a project to the purchasing utility as a condition of receiving payments under the PBFiT? If not, how should these credits be included in the estimation of a typical project's cost?