BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application	)	
of PacifiCorp for Approval	)	Docket No. 03-035-14
of an IRP Based Avoided Cost	)	
Methodology for QF Projects	)	Direct Testimony of
Larger than 1 Megawatt	)	Bruce W. Griswold
	)	

May 2005

Q. Please state your name, business address and position with PacifiCorp dba Utah Power & Light Company (the Company).

A. My name is Bruce W. Griswold. My business address is 825 N. E. Multnomah, Suite 600, Portland, Oregon 97232. I am a Manager in the Origination section of the Company's Commercial and Trading Department.

Qualifications

Q. Please briefly describe your education and business experience.

A. I have a B.S. and M.S. degree in Agricultural Engineering from Montana State and Oregon State, respectively. I have been employed with PacifiCorp over eighteen years in various positions of responsibility in retail energy services, engineering, marketing and wholesale energy services. I have also worked in private industry and with an environmental firm as a project engineer. I currently work in the Commercial and Trading Business unit of PacifiCorp. My responsibilities are wholesale, qualifying facility and large retail transactions including the negotiation and management of the non-tariff power supply and resource acquisition agreements with PacifiCorp's largest retail customers.

Q. Have you previously appeared in any regulatory proceedings?

A. Yes. I have appeared in proceedings in Utah and Idaho.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with an overview of the Company's case, to discuss the way the avoided cost prices discussed by Company witness Duvall are utilized in the calculation of prices for individual qualifying facilities ("QFs") from 3 to 99 MW, to describe the Company's proposal for purchases from QFs 100 MWs or larger in size and to address renewable QF issues.

Q. Please provide an overview of the background of this proceeding.

A. Since 2002, the parties have participated in working groups, task forces and litigated cases in an effort to identify and resolve avoided cost, contract, accounting and related issues regarding purchases from QFs. While that effort led to a better understanding of the issues by the parties, and resulted in a stipulation which provided the basis for several hundred MWs of new QF development, ultimately parties were unable to reach consensus on the QF issues, including a preferred avoided cost method to recommend to the Commission. As a result, there was a need, as the Commission recognized in its April 1, 2005 Order in this docket, for the Commission to initiate this proceeding to provide direction on QF issues.

Q. What is the Company's position regarding the methodology that should be adopted by the Commission for determining avoided costs?

A. The Company's preferred method for determining avoided costs for QFs from 3 to 99 MWs is the differential revenue requirement ("DRR") methodology, as described in Mr. Duvall's testimony, with adjustments based on QF project-specific characteristics. For very large QFs, those 100 MW or greater in size, that are requesting a contract term greater than ten (10) years, the Company proposes to use the competitive bidding process adopted in the Energy Resource Procurement Act, U.C.A. §54-17-101 et seq., (the "Act"). If those QFs want to receive a capacity payment, they would have to be the winning bidder in the competitive bidding process established by the Act. If the QF doesn't want a capacity payment, or is unsuccessful in the bidding process, it would still receive energy payments calculated using the GRID model and based on its operating characteristics.

Q. Has the Company's position on the appropriate avoided cost standard changed during this multi-year process?

A. No. The Company has supported and continues to support the "ratepayer indifference" standard as a principal consideration in developing an avoided cost methodology.

Q. You mentioned adjustments for individual QF projects based on their specific operating characteristics, what adjustments should be considered?

A. My direct testimony in Docket 03-035-14 outlined a number of QF project specific adjustments to be considered when finalizing the avoided cost prices. These factors include:

a. *The type of power being delivered to the utility by the QF project.* One of the key factors affecting the prices paid to the QF is the type of power delivered to PacifiCorp. Rates for purchases should reflect the duration and firmness of the energy and capacity provided. When the QF has contractually committed to make capacity and energy available on a firm basis, the QF is entitled to capacity and energy payments that reflect the energy and capacity costs it allows the Company to avoid. If the QF will only agree to make power available on a non-firm basis, it is entitled to only an energy payment. This means, in instances where the QF decides when the Company is to receive energy, the Company is unable to count on the QF for planning purposes. Under the proposed DRR methodology using the GRID model, the energy price will reflect whether or not the QF will provide operating reserves. If it does not, the energy price will be discounted, in the model, to reflect the cost that the source control area incurs for carrying operating reserves as a control area obligation.

b. *The QF's availability during daily and seasonal peak periods.* The Company's standard avoided cost prices assume that energy and capacity from a QF will be available during the Company's daily and seasonal peak periods. If the large QF cannot or will not commit to provide energy and capacity during peak periods, then no capacity payments should be made to the QF project for those months when the QF is not providing capacity and energy during the peak periods.

c. *The ability of the utility to dispatch the QF.* The ability of a utility to schedule or dispatch QF generation on demand (as the avoided resources described in Mr. Duvall's testimony would allow the utility to do) is a key consideration that should be taken into account when establishing project specific avoided costs. Any QF that offers to sell PacifiCorp capacity and energy must meet the availability of the avoided resource to receive the full avoided costs including a capacity payment. For example, in the May 2004 Stipulation, the QF project had to meet a monthly availability of eighty-five (85) percent to receive a monthly capacity payment. If the QF does not achieve the 85% then they would not receive a capacity payment in that month. The proposed GRID model has the capability to model the specific QF project as a dispatchable or must-run generation plant; therefore this factor is incorporated into the GRID model as opposed to being an adjustment outside the model. Adherence to meeting its proposed availability would be based on actual measured output of the QF each month and the power purchase agreement would include terms and conditions for non-performance. Since this analysis is resource specific, it can only be applied on a case by case basis.

d. *The reliability of the QF*. The specific rates paid to the QF should be adjusted to reflect the actual, or valid operator estimate, of the facility's operating reliability and capacity production capability (such as due to heat rate or capacity degradation over time) as compared to the avoided resource. This adjustment is an adjustment to the standard avoided cost capacity payment because it affects the extent to which PacifiCorp can rely on the QF resource for planning purposes.

e. *The type of generation technology and fuel source.* The type of generation and fuel source can also affect avoided cost prices. For example, wind resources are dependent upon wind for fuel and therefore considered an intermittent resource. I will discuss factors associated with wind later in my testimony.

These factors were applied to the QF power purchase agreements that were signed under the May 2004 Stipulation Order and the Company proposes to continue to apply these factors for purchases from QFs in the future.

Q. Are there additional factors that should be considered with the proposed DRR methodology in determining final avoided cost prices for a QF over 3MW?

A. Yes. As the Company's witnesses originally testified in Docket 03-035-14, there are accounting standards that should be considered in determining the avoided cost price for an individual QF. These applicable accounting standards are based on Emerging Issues Task Force ("EITF") 01-08, *Determining Whether an Arrangement Contains a Lease,* and Financial Accounting Standard ("FAS") 13, *Accounting for Leases*. EITF 01-08 addresses an issue commonly known as "off balance sheet financing." Under EITF 01-08, the Company is required to review contracts executed or modified after July 1, 2003 to determine whether or not they contain a lease. If it is determined that a lease exists, the EITF 01-08 states that an evaluation must be performed under FAS 13 to determine if the lease is capital or operating. If, after reviewing the contract under the FAS 13 criteria, it is designated to be a capital lease then PacifiCorp would be required to record the contract as debt on its balance sheet with a corresponding capital lease asset on the balance sheet. The additional debt may result in an adverse impact on the Company's credit quality which in turn could impose additional costs on the Company and therefore its customers. In addition, to offset the additional debt on the balance sheet and return the Company's debt/equity ratio to the ratio that existed prior to the contract, the Company would have to infuse equity. Equity has a cost and if the cost associated with the added debt is not taken into account then the indifference standard is not met. Since these debt calculations must be done on an agreement by agreement basis, it is appropriate for the implicit debt cost to be addressed separately from the avoided cost pricing process and included in the power purchase agreement as a monthly line-item adjustment to the QF payment. Currently, all QF power purchase agreements regardless of size go through a screening process to determine if the accounting standards apply.

Q. If EITF 01-08 does not result in debt being added directly to PacifiCorp's balance sheet, do credit rating agencies consider contractual resources as debt-like?

A. Yes. Major credit rating agencies and other members of the financial community view contractual resources as being debt-like and, as a result, will impute or infer debt on the purchaser's financial statements. These adjustments will then be used in ratio calculations and for ratings purposes. As in the case of debt being added directly to PacifiCorp's balance sheet, equity must be infused in order to offset the effects of this inferred debt. Likewise, this equity has a cost associated with it. PacifiCorp needs to take this cost into account when considering QF agreements. Company witnesses Larson and Shah discuss the accounting issues and the impact to the Company in greater detail in their testimony.

Q. Please comment on any contractual issues with QFs from 3 to 99 MWs.

A. The Company is relying on the QF resource to serve its network load and as such the contract should contain other payment adjustments to address the contractual arrangement between PacifiCorp and the QF project. Under PURPA regulations, there are a number of issues that affect the overall payment for purchases from QFs that may be reflected in the non-price provisions of the contract with the QF. These adjustments are mainly for non-compliance with meeting agreed milestones such as the commercial operation date, credit and security requirements in the event of project default, and performance variance from scheduled power deliveries. PacifiCorp feels that these issues are adequately captured in the power purchase agreement template that the Company utilizes for QF agreements from 3 to 99 MWs. In fact, the Company has completed four (4) QF contracts under the Stipulation Order containing provisions that address these issues as they apply to the specific QF project.

RENEWABLE ISSUES

Q. What are Green Tags?

A. A "Green Tag" has been defined to represent the separable bundle of non-energy attributes (environmental, economic and social) associated with the generation of renewable power. Green Tags are also called green tickets, renewable certificates, and Renewable Electricity Certificates or Credits ("RECs"). Green Tags are generally sold separately from their associated energy or as bundled products in wholesale markets. The definition of what constitutes a valid Green Tag or REC is expected to be defined on a state by state basis. In retail markets, they may be sold separately as an independent "product" and/or may be combined with energy to provide a renewable product. Green Tags are also used as a tool to measure and track renewable generation for states that are required to demonstrate compliance with state mandates and other energy programs such as Renewable Portfolio Standards ("RPS").

Q. How are Green Tags associated with renewable QF projects?

A. Green Tags associated with the energy generated are an inherent part of a renewable QF. If a resource project is developed and deemed to be a renewable resource, it has the attributes that allow it to declare Green Tags associated with the project. If the renewable project then certifies with FERC as a QF, because it meets the PURPA standards, then it becomes a renewable QF with Green Tags. Those Green Tags may or may not have value depending on the State's definition of what constitutes a valid Green Tag or REC.

Q. What is FERC's view on Green Tags?

A. FERC held in an Order in late 2003 that Green Tags or RECs were a recent development by the states and that determination of the control and ownership of a QF's Green Tags should be made by the individual state.

Q. What is the Company's position on Green Tag ownership?

A. The Company believes that its ratepayers are paying for the delivered capacity and associated energy from all PURPA contracts, renewable or not and therefore are the ultimate end-use customer of the Green Tags from renewable QF projects. Therefore, in the Company's view, the Green Tags are the property of the ratepayers through the vehicle of the power purchase agreement between the QF and the Company and the QF facility owner should not have the right to sell the Green Tags during the term of the power purchase agreement. In the event the QF contract ends or is terminated, the Green Tags revert to the QF project until the QF developer sells or transfers the Green Tags to another purchaser. Phrased differently, for any QF project over three (3) MW in Utah, the Company would retain the Green Tags for the benefit of the Company's ratepayers without any additional payment when it buys power from the QF resource. California, which is the only state in the Company's service territory that has decided the ownership issue, also takes the position that Green Tags associated with QF facilities are transferred to the utility with the obligation to purchase the QF power.

Q. What factors should be considered in determining the avoided cost price paid to an individual renewable QF project?

A. The factors I discussed above with respect to QFs generally also apply to renewable QF projects. For example, with respect to a wind project, performance is based on mechanical turbine availability as well as wind performance (speed and variability). The probability that the wind resource may not be available when needed to meet peak load is significant. As a result, a separate calculation of planning reserve contribution is required and should reflect the variability of wind generation during the system peak. Several factors drive the measure of wind's capacity contribution to PacifiCorp's system. The first of these factors is site performance. For example, wind speed and duration are characteristics which directly impact site generation and the capacity factor of a particular wind site. Second, seasonal and time-of-day patterns determine wind contribution during peak hours. Third, the composition of the existing resource mix as well as volatility in system loads and resources affect how wind's capacity contributes to the Company's system.

Q. How should the avoided cost for an intermittent resource such as wind QF be determined?

A. As a result of the May 2004 Stipulation Order, the Company agreed to participate in a renewable QF sub-task force of the Large QF Task Force. As an active participant in that sub-taskforce, the Company prepared and distributed in January 2005, an adjustment procedure for calculating the project avoided cost, which I have attached as Exhibit UP&L _____(BWG-1) and a spreadsheet example, which I have attached as Exhibit UP&L _______(BWG-2) for a generic wind project. At the time that the procedure and examples were prepared for the sub-taskforce, the avoided cost methodology for QFs over 3MW had not been determined and therefore the Company used Schedule 37 published prices to illustrate the adjustments for a wind resource. Nevertheless, the procedure and examples outline the adjustments and how they would be made to the DRR avoided cost prices to determine the specific prices for a wind QF project.

Q. How should capacity payments be determined and structured for wind QF projects?

A. Under the Company's proposal, the Company will pay twenty (20) percent of the avoided capacity costs as determined using the Commission approved avoided cost methodology for QF projects over 3 MW. This position is consistent with the Commission determination in the Schedule 37 docket for wind QF projects up to 3 MW. The twenty percent capacity payment covers capacity only and does not include other costs or adjustments. The Company proposes that a wind QF resource receive a volumetric price structured as on-peak and off-peak prices where the 20% capacity payment would be included only within on-peak hours. In order for the wind QF to receive the full 20% capacity payment in the on-peak energy price, it would need to maintain a 35% wind capacity factor. A 35% wind capacity factor was selected as a reasonable estimate of the annual on-peak capacity factor of a proxy wind resource. A wind plant is "fueled" by the wind, which blows steadily sometimes and not at all other times. While utility-scale wind turbines are now designed to operate 65% to 80% of the time, they often run at less than full capacity. Therefore, a wind capacity factor of 25% to 40% is not uncommon and this range has been documented throughout the wind industry. Therefore, a wind resource that maintained a 35% annual on-peak capacity factor would get exactly a 20% capacity payment. A resource that demonstrates it historically generates above 35% on-peak would get more than 20% and a resource that generates below 35% would get less.

Q. What other adjustments or factors are appropriate for consideration in pricing for wind QF projects?

A. There are a number of other adjustments and factors that need to be considered for wind QF projects that I will now explain. The first is wind integration costs. Avoided costs need to be reduced by the Company's cost to integrate the wind energy delivered into its system. Because of the implications for reliability and the Company's role as control area service provider, the Company undertook to define methods of assessing and estimating wind integration costs given the characteristics of the Company's control areas. These costs include the cost of holding incremental operating reserves to accommodate wind generation on the system, and the expected higher operating costs due to the variable and relatively uncontrollable nature of wind generation. A second factor is the extent to which the wind resource is "firmed-up." In order to receive full avoided costs, a QF resource must provide firm service equivalent to the avoided resource. In the case of a wind resource, that would require firming of the resource by the developer using, for example, something like the BPA wind firming

Q. Is a renewable QF project subject to the same contractual obligations as any other QF project?

A. Yes. As the PURPA regulations note, there are a number of issues that affect the overall payment for purchases from QFs that are reflected in the non-price provisions of the contract with the QF. A QF contract should contain other cost adjustments to address the specific contractual arrangement between PacifiCorp and the QF project. These adjustments are mainly for non-compliance, credit requirements, insurance, and performance variance. The renewable QF is also subject to the same accounting treatment as has been described by Messrs. Larson and Shah in their testimony and credit rating agencies still view the QF contract as debt like.

<u>QF Projects 100 MW or Greater</u>

Q. How does the Company propose to determine prices for QFs 100 MW or larger that are requesting a contract term of ten years or longer?

A. As I mentioned earlier, under the Company's proposal, the terms, conditions and price for capacity purchases from QFs of 100 megawatts or greater with contract terms of ten years or longer would be determined by the all source competitive bidding process established under the Act. In order to be eligible for a capacity payment, the QF would be required to submit a proposal in that competitive bidding process and any contract for purchases of capacity from the QF would be contingent upon selection of the QF as the winning bidder in that process. PacifiCorp would not be required to accept offers for QF capacity that were made outside of the bidding process, or from QFs that were not selected through the competitive bidding process. However, PacifiCorp would be required to accept offers for QF energy at prices determined using the GRID model, as described in Mr. Duvall's testimony.

Q. Why is the Company proposing that the Act's competitive bidding process be used to determine the terms, conditions and prices for capacity purchases from this category of large QFs?

A. I will mention only three reasons. The first is that competitive bidding is the method recognized under Utah Code Ann. § 54-12-2 (2) for determining the rates, terms and conditions for purchases from QFs and, since the Commission is now preparing to implement, pursuant to the Act, a bidding process for resource acquisition, it is time to apply that bidding process to purchases from QFs.

A second reason is that a competitive bidding approach would provide the Commission, the customers, the Company and QF developers with the best available determination of the Company's "avoided costs" and, as a result, would best meet the ratepayer indifference standard. Administratively determined avoided costs have become, in this and other jurisdictions, a seemingly endless debate over what resources can actually be avoided by the utility and, as Mr. Collins recently testified, have not always resulted in rates that meet the ratepayer indifference standard. Under a competitive bidding approach, that debate would be replaced by a process in which avoided costs would be determined directly and simply from the bid submitted by the winning supplier. In addition, because bidding provides, especially under the framework created by the Act, a mechanism for identifying potential alternative sources of supply, it would increase the chances that the Company's resource needs would be met by the more efficient and reliable supplier, thus increasing the chances of meeting the ratepayer indifference standard.

A third reason is that the failure to require those large long-term QFs to participate in the Act's bidding process could effectively cripple that process. Under the Act, the Company is required to use a Commission monitored competitive bidding process to acquire significant energy resources. In the context of a power purchase agreement, a significant energy resource is defined as a contract with a term of ten or more years and not less than 100 MW. Based on that legislative requirement, the Company is currently planning to issue, by September 2005, an RFP seeking an additional 525 MWs of resources. As the Commission knows, two of the disappointed bidders from the last RFP (2003-A), with a combined total of approximately 900 MWs of uncontracted capacity, have declared themselves to be QFs. If those QFs were allowed to proceed outside the bid process, they alone would eliminate, hypothetically, the need for the bid process. Under those circumstances, it is difficult to see how the Company could use the Act's bidding process as a viable resource acquisition method.

Introduction of Witnesses

Q. Please list the other Company witnesses providing testimony in this docket and provide a brief description of their subject matter.

A. The other Company witnesses providing direct testimony are:

Gregory N. Duvall, Managing Director, Planning Major Projects, presents PacifiCorp's proposed avoided cost methodology for QFs from 3 to 99 megawatts.

Matthew S. Larson, Principle Consultant, Commercial & Trading, will explain the impact on the Company's financial statements of power purchase agreements with QFs as a result of accounting standards.

Mahendra B. Shah, Director, Treasury, discusses the accounting standard and rating agency related additional costs imposed on the Company and its customers as a result of power purchase agreements with QFs.

Q. Does this conclude your testimony?

A. Yes it does.