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July 23, 2008

Via Electronic and US Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PACIFICORP 2009 Renewable Energy Adjustment Clause
Docket No. UE 200

Dear Filing Center:

Enclosed please find an original and five copies of the Confidential Testimony and Exhibits of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities ("ICNU") in the above-referenced docket. The confidential pages and exhibits are inserted in separate envelopes and sealed pursuant to the protective order in this proceeding. Also enclosed is a complete Redacted Version of the testimony.

Thank you for your assistance and please do not hesitate to give me a call if you have any additional questions.

Sincerely yours,

/s/ Brendan E. Levenick
Brendan E. Levenick

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Confidential Testimony and Exhibits of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities upon the parties, on the official service list shown below for UE 199, via U.S. Mail. A Redacted Version of the testimony and exhibits was served via electronic mail.

Dated at Portland, Oregon, this 23rd day of July, 2008.

/s/ Brendan E. Levenick
Brendan E. Levenick

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 200

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
RAC 2009	)
	)

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

July 23, 2008

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350.

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a utility regulatory consultant and President of RFI Consulting, Inc. ("RFI"). I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services related to electric utility system planning, energy cost recovery issues, revenue requirements, cost of service, and rate design.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit ICNU/101. I have participated in and filed testimony in numerous cases involving PacifiCorp's (or the "Company") net power cost issues over the past ten years.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses PacifiCorp's Renewable Adjustment Clause ("RAC"), Schedule 202, proposal for the projected test year ended December 31, 2009.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have identified four adjustments to the Company's proposed Schedule 202:

<u>2009 Sales Forecast Adjustment</u>

1. The Company proposes to use projected 2007 billing units from UE 179 to compute the Schedule 202 charges. However, Oregon sales have grown since 2007 and are expected to continue to grow. To properly recover costs during the rate effective period, sales levels used in the RAC should match the expected sales during the period. Eliminating this problem produces a reduction to Schedule 202 charges of approximately 4.2%, or $1.96 million.

<u>Rolling Hills Prudence</u>

2. The Rolling Hills project fails to meet the prudence standard. The wind potential data supporting the project was characterized by its authors as only a [redacted] This hardly represents the quality of information necessary to support a $200 million investment.

3. Unless the Oregon Public Utility Commission (the "Commission" or "OPUC") adopts the Staff proposed capacity factor adjustment in UE 199, I recommend removal of the Rolling Hills project from the RAC with an offsetting increase in the Transitional Adjustment Mechanism ("TAM"). This adjustment reduces Schedule 202 by $7.75 million. However, there would be an offsetting increase of $3.45 million to Schedule 200 that should be applied in the TAM.

<u>99 MW Wind Projects</u>

4. The Company includes three 99 Megawatt ("MW") wind projects (Seven Mile Hill, Glenrock and Rolling Hills) in the test year. These 99 MW projects were acquired without a competitively bid Request for Proposal ("RFP"), and were sized to circumvent the RFP process. I recommend a pricing adjustment intended to discourage the Company from such behavior in the future. This disallowance would amount to a $1.00 to $2.66 million reduction to Schedule 202, depending on the determination of Rolling Hills prudence.

<u>Renewable Energy Credits</u>

5. The Company proposes to bank Renewable Energy Credits ("RECs") rather than selling them. I recommend the Company be required to establish a regulatory liability in the amount of the current REC market value and deduct it from ratebase. This results in a reduction to Schedule 202 revenue requirements of $232,000. This approach is necessary because there is nothing to prevent the Company from selling the RECs later and retaining the benefits.

Goodnoe Liquidated Damages

6. The Goodnoe project was delayed beyond its originally planned completion date. The Company has a liquidated damages clause in the Goodnoe construction contract. While the final amount of the liquidated damages offset is as yet unknown, the Commission should require the Company to offset its current estimate of the amount and use it as a reduction to ratebase for the project or use it to offset net power costs in UE 199. A deferral and true up should be used to account for the final award. This adjustment reduces the RAC by $122,000.

2009 Sales Forecast Adjustment

Q. WHAT TEST YEAR IS THE COMPANY USING IN THIS CASE?

A. The Company proposes to compute the Schedule 202 revenue requirement on the basis of a test year ending December 31, 2009. The costs included in the test year are calendar year 2009 costs.

Q. IN DEVELOPING THE CHARGES FOR SCHEDULE 202, DID THE COMPANY USE A 2009 BILLING UNIT FORECAST?

A. No. The Company unitized the charges under schedule 202 using the 2007 *forecasted* sales and billing units from UE 179.

Q. WHAT ARE THE PROPER SALES LEVELS TO USE FOR THE TEST YEAR?

A. Even though this proceeding is an automatic adjustment clause, the Company still should use a complete and consistent test year as the basis for developing Schedule 202. Sales data from 2009 must be used because rates should provide the best forecast of conditions during the rate effective period of 2009. Otherwise, the Company will collect more revenue in 2009 than costs incurred, based on the Company's latest forecasts. Use of 2009 sales data is also required to properly match revenue recovery with revenue requirements. This is a fundamental tenet of ratemaking.

Q. HAS THE COMPANY CONSISTENTLY USED THE UE 179 PROJECTED 2007 MWH LEVELS IN OTHER CURRENT OR RECENT CASES?

A. No. In UE 191 and UE 199, the Company substantially increased Net Variable Power Costs ("NVPC") at a system level to recognize the increase in sales occurring in 2008 and 2009. While much of the increase in loads is occurring in other states, between 2007 (the UE 179 test year) and 2009 (the UE 199 and UE 200 test year) Oregon sales were projected to increase by 78 MW on average, or more than 5%. Increases in load are ultimately the main driver of increases to net power costs. As a result, the Company has been quite willing to reflect increased *costs* related to sales growth in the TAM. However, in both the TAM, and in this case, the Company has not done the same for billing units.

Q. HAS THE COMPANY REFLECTED HIGHER SALES LEVELS IN ANY OTHER WAY IN THIS CASE?

A. Yes. In computing the SG jurisdictional allocation factor, the Company used 2009 test year figures for peak demand and energy. As a result, the Company has been willing to directly reflect load changes in computing at least one element of the 2009 test year costs.

In a very general sense, the costs of the resources included in this case can also be directly tied to increased demands on the system. As there is no RPS requirement for 2009, there was no requirement under the RPS statute to bring these resources on line during the test year. However, the Company has a substantial amount of renewable generation included in its preferred Integrated Resource Plan ("IRP") portfolio, and load growth was at least part of the justification for the addition of these resources at the present time. Consequently, the costs of these resources are at least partially a result of load growth. It is not logical for the Company to reflect sales growth in some aspects of its filing, but not to reflect sales growth in the development of the final rates.

Q. HAS THE COMPANY ATTEMPTED TO JUSTIFY THIS MISMATCH BETWEEN SALES REVENUES AND COSTS IN GRID?

A. Yes. The same issue arose in UE 199. In the response to ICNU Data Request ("DR") 6.1 in UE 199, the Company stated that it didn't believe it was appropriate to change billing units outside of the context of a full rate case. ICNU/102, Falkenberg/1. This argument has little merit because the Company has already included 2009 costs and load data for other aspects of its filings.

Q. ACTUAL 2009 SALES LEVELS ARE NOT YET AVAILABLE. IS IT A PROBLEM TO USE <u>PROJECTED</u> 2009 SALES LEVELS INSTEAD OF 2007 DATA?

A. No. The Commission has used projected billing units and sales forecasts in rate case test years for many years now. Further, the 2007 (UE 179) billing units and sales were forecasts as well, and are now obviously out of date and largely irrelevant. Now that actual data is available, use of 2007 projected billing units is simply nonsensical. There is no justification for using this outdated and clearly irrelevant data.

Q. HAS THE COMPANY DEVELOPED FORECASTED BILLING UNITS FOR THE 2009 TEST YEAR?

A. No. In its answer to ICNU DR 5.1, the Company stated it did not have a projection of 2009 billing units. ICNU/102, Falkenberg/2. However, the Company provided a projection of Oregon 2009 sales for major customer categories. From this data, I developed projected billing units. I used these to compute my proposed Schedule 202 charges based on the Company's requested revenue requirement. Exhibit ICNU/103 provides the results of my analysis in the same format as Exhibit PPL/401.

Q. DOES THIS ADJUSTMENT REDUCE THE COMPANY'S REVENUE REQUIREMENT IN ANY WAY?

A. No. It will serve to reduce revenues collected by the amount necessary to properly match revenue requirements with revenues collected. It has approximately the same effect, however, as a revenue requirement reduction of $1.96 million. In other words, without this adjustment, the Company could expect to over-collect by $1.96 million under Schedule 202. By adopting this sales forecast adjustment, this problem is avoided.

Q. IS YOUR PROPOSAL CONSISTENT WITH ICNU'S AND STAFF'S CUSTOMER GROWTH PROPOSALS IN UE 199?

A. Yes. In UE 199, both Staff and ICNU proposed to reflect the impact of increased sales on the final rate levels.

Q. IS THIS PROPOSAL CONSISTENT WITH THE STIPULATION AND FINAL ORDER IN DOCKET UM 1330?

A. Yes.

Order No. 07-572 states as follows:

> Pursuant to paragraph 6 b of the stipulation, the Joint Parties agree that the RAC schedules will recover the actual and forecasted revenue requirement associated with prudently incurred costs of resources (including associated transmission) that are: (1) eligible under SB 838; (2) in service as of the date of the proposed rate change; and (3) approved by the Commission. The revenue requirement includes:
>
> - The return of and on capital costs of the renewable energy source and associated transmission;
> - Forecasted operation and maintenance costs;
> - Forecasted property taxes;
> - Forecasted energy tax credits; and
> - Other forecasted costs and cost offsets authorized by SB 838 and not captured in the Utility's annual power cost update.
>
> All costs in the RAC schedules will be updated annually. The annual RAC updates also will include:

- An update to gross revenues, net revenues, and total income tax expense for the calculation of "taxes authorized to be collected in rates" under OAR 860-022-0041; and
- An update to the forecasted inter-jurisdiction allocation factors from the then-current methodology approved by the Commission based on the same 12-month period used in Pacific Power's power cost update filing.

Re Investigation of Automatic Adjustment Clause pursuant to SB 838, OPUC Docket No. UM 1330, Order No. 07-572 at 3 (Dec. 19, 2007).

Clearly, the composition of the RAC contemplates extensive use of forecasted costs as shown above. Indeed, use of a fully forward test year (2009 in this case) contemplates use of forecasted data of all types. Also, the passage above references use of "forecast costs and cost offsets." Sales growth produces additional revenues which is, *per se*, a cost offset. Further, the last two items listed above (the gross revenue update and forecasted inter-jurisdictional allocation factors) rely on forecasted loads. The Commission's order contemplates reliance on forecasted costs and forecasted loads.

Finally, the rate design/rate spread methodology used by the Stipulation and adopted in the order clearly states "costs recovered through the RAC will be allocated across customer classes using forecasted energy . . . ." Id. at 4. Thus, the Commission recognized the use of forecasted energy in the rate spread language as well.

Rolling Hills Prudence

Q. PLEASE DESCRIBE THE ROLLING HILLS PROJECT.

A. This project is being developed adjacent to the Glenrock site 25 miles east of Casper, Wyoming. The project has 66 General Electric Company (“GE”) 1.5 MW wind turbines, for a total installed capacity of 99 MW. The project size is significant for reasons I will discuss later.

Q. PLEASE PROVIDE A BRIEF HISTORY OF THE PROJECT’S DEVELOPMENT.

A. PacifiCorp had originally ordered wind turbines for development at a different site. However, in the response to ICNU DR 1.1, in Attachment 1.1-7, the Company states that the original site ([redacted]) was rejected in favor of the Rolling Hills site because the capacity factor was “[redacted].” ICNU/102, Falkenberg/12. Instead, the Company chose to develop the Rolling Hills site based on an expected capacity factor of [redacted]. Id. As a result, the Company was able to use the turbines it had available at Rolling Hills rather than the original site. [redacted] ICNU/102, Falkenberg/3.

Q. DID THE COMPANY EVALUATE THE ECONOMICS OF THE ROLLING HILLS PROJECT PRIOR TO THE COMMITMENT DECISION?

A. Yes. The Company shows the results of this analysis in Exhibit PPL/202 (Confidential). [redacted]. PPL/200 Tallman/9-10. In other words, unless the additional value of compliance with the RPS exceeds [redacted] Indeed, shown on PPL/202 are other complying resources that appear to have more favorable economics. [redacted]. Rolling Hills is a questionable resource addition based on the Company's analysis of the project's economics.

As a result, there is no real evidence that Rolling Hills was the best way to comply with future RPS requirements. As there is no Oregon RPS requirement for 2009, the economic Rolling Hills analysis presented in PPL/202 is not compelling and by itself raises questions about the project.

Q. IS THE EXPECTED CAPACITY FACTOR OF A WIND RESOURCE A SIGNFICANT DRIVER OF PROJECT ECONOMICS?

A. Yes, there is no question about that. Central to the expected economics of the project, and indeed any wind project, is the expected annual generation, or capacity factor. Considering that a [redacted] reduction in capacity factor assumptions was sufficient for the Company to abandon the [redacted] project, it should be clear that the capacity factor assumptions are crucial to the economics of Rolling Hills. In order to make an intelligent investment decision (amounting to over $200 million), the Company should want to have excellent information concerning the expected capacity factor of the project.

Q. DESCRIBE THE INFORMATION USED BY THE COMPANY TO ESTIMATE THE EXPECTED CAPACITY FACTOR FOR ROLLING HILLS.

A. The Company used a questionable analysis described as nothing more than a "[redacted]" by the study authors. ICNU/102, Falkenberg/23. In ICNU DR 10.1, I asked for copies of the studies used to support the wind resource capacity factor assumptions used in the board presentations provided in the response to ICNU DR 1.1. ICNU/102, Falkenberg/22. Confidential Attachment 10.1-10 provides excerpts from the analysis performed for Rolling Hills. The 15 page document was prepared by the Company's consultants, [redacted] and apparently constitutes the entirety of the information used by the Company to evaluate the Rolling Hills capacity factor.

Q. DISCUSS THE FINDINGS OF THIS REPORT.

A. The report states that: [redacted]. ICNU/102, Falkenberg/23.

Q. EXPLAIN WHAT IS MEANT BY [redacted].

A. The decision to develop Rolling Hills was made in late December 2007.[1/] Given perceived time constraints, the Company did not undertake the ordinary process used to develop accurate estimates of capacity factors for a wind project. For the Company's other projects, the process used normally involved construction of several test towers with wind measuring equipment, and collection of several years' worth of data. This was the process used in other wind projects developed by the Company.[2/] In discovery, the Company provided a number of studies prepared to evaluate the wind energy potential of other sites it was involved with. In some cases, multiple consultants' studies were provided and, in most cases, a there were multiple wind metering towers measured. The table below provides an analysis of the number of towers used for the various projects, and the number of years of data collected for each sites. As the confidential table below shows, the data used for Rolling Hills was far less detailed and appears inadequate compared to other sites.

1/ See ICNU/102, Falkenberg/3.

2/ [redacted]

[redacted]

It should be pointed out that not all of the towers were used in all of the projections of wind potential. However, the presence of multiple towers at a site allowed for exclusion of towers that produced questionable data, or were only available for a limited period of time.

Q. EXPLAIN THE SIGNIFICANCE OF THE COMPARISON TOWER.

A. The use of a comparison tower is important, because long term studies required more data than a short sample period (5 years or less) might provide. The process normally followed was to correlate wind data obtained for a shorter period at a site, with data from an observation point with a longer history of data being available. This was done to provide evaluations of wind potential spanning many years of data. [redacted] ICNU/102, Falkenberg/29.

Q. WHAT WIND DATA WAS USED TO DEVELOP THE ROLLING HILLS ESTIMATES?

A. The Company used only one year's worth of data from two towers at the adjacent Glenrock site. Given the close proximity of the two sites, use of the Glenrock data may not by itself have been an overwhelming problem. However, there are some important differences between the two sites. [redacted] ICNU/102, Falkenberg/26-28.

Q. WHAT WERE SOME OF THE KEY FINDINGS IN THE ROLLING HILLS WIND POTENTIAL REPORT?

A. The report makes the following statements:

[redacted]

ICNU/102, Falkenberg/29.

Q. PLEASE EXPLAIN STATEMENT 1 ABOVE.

A. [redacted]

Q. PLEASE EXPLAIN STATEMENT 2 ABOVE.

A. [redacted] ICNU/102, Falkenberg/29.

Q. EXPLAIN THE SIGNIFICANCE OF TOWER HEIGHTS MENTIONED IN STATEMENTS 3 AND 4.

A. [redacted]

[redacted]

Q. WERE THERE OTHER PROBLEMS WITH THE DEVLEOPMENT OF THE ROLLING HILLS SITE NOTED BY THE COMPANY?

A. Yes. Based on Confidential Attachment to ICNU DR 1.1-6, the [redacted] ICNU/102, Falkenberg/36. While the Glenrock wind potential study projected an annual capacity factor of [redacted] the Company assumed only a 38.5% capacity factor in GRID, a much larger than expected difference. See ICNU/102, Falkenberg/36, 54. Whether this is merely an error in the GRID study, or occurred for other reasons is unclear.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE DEVELOPMENT OF THE ROLLING HILLS SITE?

A. With respect to the prudence of the project, there are a number of "red flags," particularly with respect to the wind data used to evaluate the economics of the resource. The consultants' report relied upon by the Company was nothing more than a [redacted] The report specifically called for [redacted] Despite all of this, the Company told its board and executives that [redacted] ICNU/102, Falkenberg/36. [redacted]

Q. PLEASE RELATE THIS TO THE PRUDENCE STANDARD.

A. Prudence is normally defined in terms of the "reasonable person standard." This holds that actions would be considered to be prudent if they are consistent with those of a reasonable person who possessed the qualifications and experience necessary to make the decision and who acted with a standard of care consistent with the importance of the problem at the time. The Company's decision to pursue the Rolling Hills project was not prudent based on this standard.

Q. PLEASE EXPLAIN.

A. The Rolling Hills project represented an investment with an assumed life of 25 years costing more than $200 million. The staggering sum of this investment (nearly two thirds the cost of the Currant Creek and Lakeside projects) meant it was a very important decision. A reasonable person would not decide to spend $200 million on a [redacted] particularly when the person's paid advisor recommended [redacted] As such, the Rolling Hills project fails under the prudence standard based on the evidence currently available at that time.

Q. HOW SHOULD THE COMMISSION ADDRESS THIS ISSUE?

A. In UE 199, the Staff has proposed a capacity factor adjustment for the Rolling Hills project and ICNU plans to support that adjustment. If the Commission adopts a capacity factor adjustment, it may be a good compromise and avoid a prudence disallowance. Regardless, the Commission should still make an adjustment related to the issue of the 99 MW sizing of the project. However, if the Commission decides not to implement the

Staff capacity factor adjustment, the issue of prudence must be addressed in this proceeding. If the Commission does not adopt Staff's capacity factor in UE 199, I recommend that the Commission remove the Rolling Hills project from rates in this case.

Q. WHAT DISALLOWANCE DO YOU RECOMMEND?

A. Based on Mr. Dalley's Exhibit PPL/301, Rolling Hills produces a revenue requirement during the test year of $25.56 million on a total Company basis. The Oregon jurisdicational allocation amounts to $7.75 million. However, removing the project from rate base should be accompanied by its concurrent removal from GRID in the TAM. Based on the response to ICNU DR 1.12, this would result in a total Company increase to the TAM of $13.30 million or an Oregon Jurisdictional increase of $3.45 million.

<u>Policy Issues Concerning the 99 MW Wind Projects</u>

Q. ARE THERE OTHER POLICY ISSUES REGARDING THE COMPANY'S OTHER WIND PROJECTS.

A. Yes. The Company has included three 99 MW wind projects in the test year. The sizing of these projects raises important policy concerns.

Q. WHAT 99 MW WIND PROJECTS ARE INCLUDED IN THE TEST YEAR?

A. There are two other 99 MW projects in the test year: Glenrock and Seven Mile Hill. As stated previously, the Rolling Hills project is also sized at 99 MW.

Q. WHAT IS THE SIGNIFICANCE OF THE SELECTION OF A 99 MW SIZE FOR THESE PROJECTS?

A. Oregon's rules require competitive bidding for projects 100 MW or larger. Utah rules also required competitive bidding for projects 100 MW or larger. As a result, by sizing these projects smaller than 100 MW, the competitive bidding process was avoided by the Company.

Q. COULD THESE PROJECTS HAVE BEEN SIZED LARGER THAN 99 MW?

A. Yes. Wind projects are made up of many small (1.5-2.0 MW) wind turbines. Presuming a large enough site, by adding a specific number of turbines at the site, one could always develop a project 99 MW or larger. In the response to ICNU DR 1.6, the Company admitted it is now planning to add additional wind turbines to increase the output of the Glenrock and Seven Mile Hill sites. ICNU/102, Falkenberg/41. Further, the Company did not identify any reason why it could not have developed the Glenrock and Rolling Hills projects as a single 198 MW project, except for the fact that Glenrock was already committed before Rolling Hills was added to the resource plan. ICNU/102, Falkenberg/42. As discussed above, and as can be seen from ICNU/104 (a map of the two projects), Glenrock and Rolling Hills are at adjacent sites which run parallel to each other. The delineation between Glenrock and Rolling Hills appears somewhat arbitrary from this map.[3/] Thus, it might be viewed as one project or two projects. Indeed, I understand from Staff testimony in UE 199 that the Commission would treat these as a single project based on Order No. 06-586. Re PacifiCorp, OPUC Docket No. UE 199, Staff/200, Schwartz/6 (June 23, 2008). If so, then the Company violated the Commission's policies, and there should be some consequence for so doing.

In the end, there is really no reason why Glenrock and Rolling Hills could not have been a single project larger than 200 MW. Likewise, there is no reason why Seven Mile Hill could not have been developed as single project larger than 100 MW, given the

[3/] Based on the surface topography provided in ICNU DR 10.1-10, it is apparent that Rolling Hills is at a lower elevation, and has been characterized by the Company as an inferior location at a recent Commission meeting. Given the inferiority of the Rolling Hills projects and its detrimental impact on Glenrock project, the question remains as to whether it should have been developed at all.

plans to expand the project in the future. Naturally, this discussion does not address, the issues surrounding the unproven wind characteristics of the Rolling Hills project.

Q. WHY DOES THE COMPANY SAY IT IS BUILDING 99 MW WIND PROJECTS RATHER THAN LARGER PROJECTS?

A. I asked about this recently in the Wyoming rate case. It was also the subject of OPUC DR 2. Exhibit ICNU/102 also contains a copy of the answers to OPUC DR 2 and WIEC DRs 18.3 and 18.4 from Wyoming Docket No. 20000-277-ER-07. ICNU/102, Falkenberg/43-45. In WIEC DR 18.4, the Company suggested that if it was required to undergo a competitive bidding process as required under Utah regulation for projects over 100 MW, it could not have expected to complete the projects in time to obtain the Federal Production Tax Credit ("PTC"). These were scheduled to expire at the end of 2008.

Q. DO YOU HAVE ANY DOUBTS ABOUT THESE EXPLANATIONS?

A. Yes. In DR ICNU 1.1, we requested materials presented to the Company executives and/or Board regarding the recommendations to proceed with these projects. Various confidential documents were provided. [redacted] Given that these projects are supposed to come on line in December 2008, this seems to be a critical timing issue. Had the project been delayed for unforeseen reasons, the PTC may not have been available if the credits were not extended. This would certainly raise doubt regarding the overall viability of the projects since a December 31, 2008 completion date left no margin for error.

4/ The documents did present some financial results with and without the PTCs, but there was no other discussion of the issue.

Further, in the past the PTCs have been scheduled to expire and they have subsequently been reinstated by Congress. It is interesting that in the attachments to ICNU DR 1.1, the Company frequently mentioned expected actions of Congress (in terms of passing a national RPS) as part of the justification for the decision. Thus, the Company certainly did not hesitate to speculate about actions of Congress as regards justification for renewable projects. In any case, the Company stated in responses to ICNU DR 9.1 that it did not rely on any analysis of the likelihood of Congress extending the PTC and provided no analysis of any particular bills dealing with the issue. ICNU/102, Falkenberg/46. This by itself was of questionable prudence, as one undertaking development of wind projects costing hundreds of millions of dollars should have carefully monitored Congressional actions impacting the project economics.

Q. HAS THE COMPANY RECENTLY ADDRESSED THE PTC ISSUE IN TESTIMONY?

A. Yes. In the current Utah rate case, Mr. Tallman discussed the PTC issue in his rebuttal testimony.[5/] Mr. Tallman put the issue of expiring PTCs in context by stating as follows:

> The Company is pursuing these wind projects with the specific intent of meeting our renewable resource commitments and for the long-term benefit of customers. Acceptance of Mr. Brubaker's recommendation by the Commission would have a chilling effect upon the Company's renewable resource acquisition activities and essentially result in little or no renewable acquisition activity unless Congress guaranteed the PTC to be in place for several years at a time. *History has shown that Congress is unlikely to take such multi-year actions.*
>
> * * *
>
> Q. Is it possible PTCs will be applicable to wind turbines that are placed in service during 2009?

5/ In that case, one of the witnesses proposed that the Commission impute PTCs to the cost of wind projects even if the credits were not available.

> A. Yes; both the House and Senate have passed versions of legislation that would extend PTCs to wind turbines placed in service during 2009.
>
> Q. Is it likely that the federal government will impose a renewable portfolio standard applicable to the Company's load service obligation in Utah?
>
> A. Yes. As referenced later in my testimony, the House of Representatives passed legislation during 2007 that would implement such a RPS requirement. This legislation did not become law during 2007 but it is reasonable to expect that federal RPS legislation will indeed become law within the foreseeable future.

Re PacifiCorp, Utah PSC Docket No. 07-035-93, Rebuttal Testimony of Mark Tallman, at 12, 14 (emphasis added).

Mr. Tallman seems to be suggesting that it is reasonable to assume PTCs will be extended beyond 2008 given passage of such bills by both the House and Senate, since he believed it was reasonable to assume an RPS will be enacted when only the House had passed such a bill.

As Mr. Tallman noted, history has shown that PTCs have not been authorized in multi-year increments by Congress. Yet the Company apparently now believes it is reasonable to assume that the PTCs will be extended.

Q. WHAT IS YOUR CONCLUSION REGARDING THE PTC ISSUE?

A. This justification strikes me as more of a rationalization than anything else. In any case, the recent Chehalis project activities clearly show that the Company could request a waiver from competitive bidding rules if there was a valid reason for doing so.

Q. IS THERE A POLICY ISSUE AT STAKE HERE FOR THE COMMISSION?

A. Yes. Because wind projects can be sized in small increments and built in multiple stages, the size of a single project is inherently arbitrary. For example, the Company could obtain a 500 MW site, and build five 99 MW projects. Under this approach, the

Company might avoid bidding requirements completely simply by naming the projects New Wind Farms 1 through 5, and filing five sets of permits. This is a situation unlike thermal units where economies of scale might result in excessive costs if the Company were to follow such an approach. Given the Company's above stated observation that Congress is unlikely to extend PTCs for long periods of time, it would always be possible to time the development process to create a "time sensitive" opportunity.

Further, given the recent Chehalis acquisition, it seems fairly clear that the trend is for the Company to avoid competitive bidding. In the end, the Commission needs to decide if this is a healthy trend, or whether, as the Company might suggest, it was just the result of odd, unrelated circumstances. (In the case of Chehalis, a "time limited opportunity" much like the possible termination PTCs leading to the rapid development of the 99 MW wind projects.)

Q. IS THIS REALLY A PROBLEM CREATED BY TIMING CONCERNS?

A. No. The Company has had a commitment to build more renewable energy resources for quite some time. I see no reason why the Company could not have arranged to implement an RFP in time to conduct a bidding process for a December 2008 in service date for comparable resources. Just as the Company could always size wind projects to come under the 100 MW threshold, it can also always create time constraints by dragging its feet until the last minute.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Commission has adopted various rules and policies to implement competitive bidding requirements. I presume this is to ensure ratepayers get the lowest cost resources available. In this case, the Commission needs to decide whether the Company was justified in its decision to circumvent the process. In the end, the Company has violated the Commission's policies.

In my view, competitive bidding rules are a sham if it is up to the Company to follow them on a case by case basis. I recommend the Commission take steps to penalize the Company for its choices in this case. There are a number of ways the Commission might do so. My recommendation would be for the Commission to implement an adjustment designed to reduce the cost of the 99 MW wind projects to the cost of competitive projects. For the Rolling Hills project, this would be an alternative to prudence disallowance discussed above. If the Commission adopts the Rolling Hills prudence disallowance, I'm satisfied it would drive home the message to the Company that it should follow, rather than circumvent, the Commission's rules and policies. However, if the Rolling Hills capacity factor adjustment is adopted, then it would eliminate the need for the prudence disallowance, and reduce the value of this adjustment.

Q. PLEASE EXPLAIN YOUR PROPOSAL FOR GLENROCK.

A. Exhibit ICNU/105 shows my recommended disallowance for Glenrock and for Rolling Hills, depending on the Commission's prudence determination.[6/] In 2008 the Company obtained three new wind resources via Power Purchase Agreement ("PPA") arrangements – Mountain Wind I, Mountain Wind II, and Spanish Fork II. Based on data contained in the UE 199 GRID study, the average cost for 2009 for these projects was $60.25/MWh. This is less than the cost of Glenrock and Rolling Hills, which are $73.24 and $95.68/mWh respectively. In this proposal, the cost of the 99 MW projects should be

[6/] If the Commission invokes the prudence disallowance, then Rolling Hills would not be included in this analysis. Otherwise, it should be.

limited to the cost of the competitive options. My recommended adjustment in this case amounts to $1.00 to $2.66 million on an Oregon basis for the 2009 Test Year.[7/]

Q. IS THIS A REASONABLE DISALLOWANCE TO INVOKE?

A. Yes. This disallowance results in the Company obtaining an Return on Equity ("ROE") on these projects in excess of 6.5%. While less than the 10% allowed in UE 179, it still exceeds the Company's cost of debt and preferred stock. Consequently, the investors are allowed to recover all of the costs invested in the projects and all of the taxes and operating expenses, but do not obtain the equity risk premium. As a result, this level of disallowance should be viewed as removing any "profit motive" from this sort of behavior in the future.

Q. GIVEN THE CONTEXT OF OREGON ADOPTING AN RPS LAW, IS IT APPROPRIATE TO INVOKE DISALLOWANCES RELATED TO THE COMPANY'S COMPLIANCE STRATEGIES?

A. Yes. I assume Oregon implemented the RPS because it believed there were important policy reasons to do so. If utilities comply with the law through poorly thought out projects that end up costing more than necessary, or which fail to perform adequately, it will defeat the purpose of the RPS statute. It would give renewable energy a "black eye" if utilities profit from unsuccessful projects that fail to deliver renewable energy in a cost effective manner. By adopting my proposals above, the OPUC can establish that it will both require compliance with the RPS and ensure that utilities to do so in a reasonable and prudent manner. This is critical to protect the integrity of the RPS.

[7/] Seven Mile Hill has a cost comparable to the competitive projects. Including it in the total would result in a modest reduction to the adjustment. However, I don't believe the Company should be rewarded for its decision to not use competitive bidding.

Renewable Energy Credits

Q. DO RENEWABLE RESOURCES GENERATE RENEWABLE ENERGY CREDITS?

A. Yes. Ordinarily, these can be sold at market prices. At present they appeal to individuals and industries that wish to show their support for renewable energy.

Q. CAN RECS THAT HAVE BEEN SOLD COUNT TOWARDS OREGON'S RPS?

A. No. However, mandatory compliance with the RPS does not begin until 2011. As a result, RECs generated by the Company's resources in 2009 could be sold at market prices. In fact, the Company assumed in the recent Utah rate case that it would makes sales of RECs not allocated to Oregon.

Q. IS THERE AN ESTIMATE OF THE CURRENT MARKET PRICE FOR RECS?

A. Yes. In the current Utah rate proceeding, the Company estimated a market value of \$3.5/MWh for RECs.

Q. WILL THE COMPANY SELL ITS RECS IN 2009?

A. It is not known yet. The company stated in responses to ICNU DRs 5.11 and 5.12 that it plans to "bank" the Oregon allocated RECs for future compliance requirements. ICNU/102, Falkenberg/47. The Company cites expectations of future price escalation and reduced price risk as advantages of this strategy. ICNU/102, Falkenberg/48. We have no assurance that the Company won't simply sell the Oregon allocated RECs next year. The Company could easily claim that it expected market prices to drop thus, sold the RECs because it was not earning a high enough rate of return, for example.

Q. ASSUMING THE COMPANY CAN SHOW ITS BANKING STRATEGY IS PRUDENT, WHAT IS YOUR RECOMMENDATION?

A. In order to prevent the Company from selling these RECs later without benefiting Oregon ratepayers, I recommend the Company be required to establish a regulatory liability equal to the current market value of the RECs. This amount should then be deducted from rate base in computing charges under schedule 202 for the 2009 test year. As RECs are later used, the regulatory liability would be reduced. For the test year, this approach would reduce Schedule 202 revenue requirements by approximately $232,000. <u>See</u> Exhibit ICNU/106.

<u>Goodnoe Liquidated Damages</u>

Q. WAS THE GOODNOE WIND PROJECT COMPLETED ON TIME?

A. No. The project was originally scheduled to come on line in November 2007. It has now been delayed substantially, and was on line by June 2008. Based on the response to OPUC DR 44, the Company has a liquidated damages clause in the Goodnoe contract. ICNU/102, Falkenberg/49-50.

Q. IS THE COMPANY PRESSING A CLAIM AGAINST THE PROJECT DEVELOPER RELATED TO THIS DELAY?

A. Yes. Based on the response to OPUC DR 44, the Company believes the damages clause applies. However, the Company and the developer have not reached any agreement concerning the amount of these damages. The Company has not reflected any estimate of the amounts applicable for application against the RAC.

Q. WHAT IS YOUR RECOMMENDATION?

A. In OPUC DRs 60 and 61, the Company estimated the liquidated damages award to be at most $4.1 million in total to the Company. ICNU/102, Falkenberg/51-53. I recommend the Commission require the Company deduct this amount against the installed cost of Goodnoe or require it to be passed through to ratepayers in UE 199. Further, I recommend the Commission require the Company to defer any difference between the estimated damages and the final damages awarded for later true up. This would result in a reduction in this case of $122,000.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 200

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
RAC 2009	)
	)

ICNU/101
QUALIFICATIONS OF RANDALL J. FALKENBERG

July 23, 2008

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies, and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley	Pennsylvania Power Committee	Phase-in of nuclear unit. Power & Light Co.
2/85 cancellation of	I-840381	PA	Phila. Area Ind. Energy Users' Group	Electric Co.	Philadelphia Economics of nuclear generating units.
3/85	Case No.	KY	Kentucky Industrial	Louisville Gas	Economics of cancelling fossil

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
	9243		Utility Consumers	& Electric Co.	generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General & Georgia Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7-Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86	9437/613	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of gas sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Policy Issues.
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.

**Expert Testimony Appearances
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Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT Plant	CCS	PacifiCorp	Certification of Peaking
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling
7/05	UE-172	OR	ICNU	Portland General	Power Cost Modeling
08/05	UE-173	OR	ICNU	PacifiCorp	Power Cost Adjustment
8/05	UE-050482	WA	ICNU	Avista	Power Cost modeling, Energy Recovery Mechanism
8/05	31056	TX	OPC	AEP Texas Central	Stranded cost true-up.
11/05	UE-05684	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation, PCA

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
2/06	05-116-U	AR	AEEC	Entergy Arkansas	Fuel Cost Recovery
4/06	UE-060181	WA	ICNU	Avista	Energy Cost Recovery Mechanism
5/06	22403-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
6/06	UM 1234	OR	ICNU	Portland General	Deferral of outage costs
6/06	UE 179	OR	ICNU	PacifiCorp	Power Costs, PCAM
7/06	UE 180	OR	ICNU	Portland General	Power Cost Modeling, PCAM
12/06	32766	TX	OPC	SPS	Fuel Reconciliation
1/07	23540-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
2/07	06-101-U	AR	AEEC	Entergy Arkansas	Cost Allocation and Recovery
2/07	UE-061546	WA	ICNU/Public Counsel	PacifiCorp	Power Cost Modeling, Jurisdictional Allocation, PCA
2/07	32710	TX	OPC	EGSI	Fuel Reconciliation
6/07	UE 188	OR	ICNU	Portland General	Wind Generator Rate Surcharge
6/07	UE 191	OR	ICNU	PacifiCorp	Power Cost Modeling
6/07	UE 192	OR	ICNU	Portland General	Power Cost Modeling
9/07	UM 1330	OR	ICNU	PGE, PacifiCorp	Renewable Resource Tariff
10/07	06-152-U	AR	AEEC	EAI	CA Rider, Plant Acquisition
10/07	07-129-U	AR	AEEC	EAI	Annual Earnings Review Tariff
10/07	06-152-U	AR	AEEC	EAI	Purchase of combined cycle power plant.
04/08	26794	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Case

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 200

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
RAC 2009	)
	)

ICNU/102
EXCERPTS OF PACIFICORP DATA RESPONSES

REDACTED

July 23, 2008

UE-199/PacifiCorp
June 4, 2008
ICNU 6th Set Data Request 6.1

ICNU Data Request 6.1

Please refer to PPL/201. Please explain why the Company is using year 2007 forecasted sales for development of Schedule 200 rather than Year 2009 projected sales.

Response to ICNU Data Request 6.1

The Company used the billing determinants from its most recently approved general rate case, Docket UE-179, to develop the proposed TAM adjustment in this case. This is consistent with the prior TAM filing approved in UE-191. The Company did not consider it appropriate to use billing determinants from a test period that has not been reviewed or approved under the context of a general rate case.

UE-200/PacifiCorp
June 5, 2008
ICNU 5th Set Data Request 5.1

ICNU Data Request 5.1

Please refer to Exhibit PPL/402. Please provide the most recent forecast of billing units for the 12 months ended 2009 for each rate schedule shown on the exhibit.

Response to ICNU Data Request 5.1

Please refer to Attachment ICNU 5.1. The Company has not prepared the forecast by the rate schedules listed in Exhibit PPL/402.

UE-200/PacifiCorp
April 22, 2008
ICNU 1st Set Data Request 1.6

ICNU Data Request 1.6

Does the Company have the flexibility at Glenrock, Seven Mile Hill or Rolling Hills to add additional wind turbines to increase the energy available from these resources to an amount more than 99 mW?

Response to ICNU Data Request 1.6

The Company is exploring the potential to add additional wind turbines to the Glenrock and Seven Mile Hill sites beyond the projects currently planned for those sites. The Company is currently planning to add 13 wind turbines at the Seven Mile Hill site via the Seven Mile Hill II project and an additional 26 wind turbines via the Glenrock III project.

UE-200/PacifiCorp
April 22, 2008
ICNU 1st Set Data Request 1.5

ICNU Data Request 1.5

Is there any reason why the Rolling Hills and Glenrock wind resources couldn't have been built as a single wind resource of 198 mW? If so, explain.

Response to ICNU Data Request 1.5

The decision to add the Rolling Hills resource to the portfolio had not been made at the time the decision was made to add the Glenrock resource to the portfolio. In addition, the wind turbines being utilized for the Rolling Hills project were procured for use at another wind project site located in another state. The decision to add the Rolling Hills resource to the portfolio was made after the Company determined that the anticipated capacity factor for the other project was undesirable. Subsequently, the Company made the decision to add the Rolling Hills resource to the portfolio based on information known to it at that time.

UE-200/PacifiCorp
April 17, 2008
OPUC Data Request 2

OPUC Data Request 2

Please explain how PacifiCorp determined that 99 MW was the optimal size for three of the recently acquired projects: Glenrock, Rolling Hills and Seven Mile Hill.

Response to OPUC Data Request 2

The decision to size certain wind projects at the 99 MW level was made due to the combination of wind turbine availability and the reasonable expectation that purchased turbines could be incorporated into a wind project prior to the expiration of the federal production tax credit at the end of 2008. Constructing a wind project prior to the expiration of the federal production tax credit is inherently preferable and more economical than constructing a wind project after expiration of the tax credit.

20000-277-ER-07/Rocky Mountain Power
December 31, 2007
WIEC 18th Set Data Request 18.3

WIEC Data Request 18.3

Explain why the Company is building 99 MW wind farms at that particular size. Does the Company have any evidence or analysis that shows this is a preferable, or more economical size for such projects? If so, provide.

Response to WIEC Data Request 18.3

The decision to size certain wind projects at the 99 MW level was made due to the combination of wind turbine availability and the reasonable expectation that purchased turbines could be incorporated into a wind project prior to the expiration of the federal production tax credit at the end of 2008. Constructing a wind project prior to the expiration of the federal production tax credit is inherently preferable and more economical than constructing a wind project after expiration of the tax credit.

20000-277-ER-07/Rocky Mountain Power
December 31, 2007
WIEC 18th Set Data Request 18.4

WIEC Data Request 18.4

Is it correct that Utah law requires competitive bidding for any new resource of 100 MW or larger? If so, does the Company agree that the 99 MW units are sized merely to avoid the competitive bidding process? Explain and justify your answer.

Response to WIEC Data Request 18.4

The Company objects to this request on the grounds that it calls for a legal opinion. Nonetheless, subject to and without waiving this objection, the Company provides the following response.

The Company interprets Utah law as currently requiring a specified resource procurement process for each significant energy resource (SER) of 100 MW or larger. The Company does not agree that any 99 MW wind project was sized merely to avoid the competitive bidding process. The Company's interpretation is that a 99 MW resource is not subject to Utah law with respect to a SER. The Company further states that it is reasonable to expect that a SER procurement process would result in sufficient delays such that the wind turbines made available to the Company would not have remained available to the Company and/or that each 99 MW wind project could not practically have been planned for construction prior to the expiration of the federal production tax credit at the end of 2008.

UE-200/PacifiCorp
July 3, 2008
ICNU 9th Set Data Request 9.1

ICNU Data Request 9.1

In the response to WIEC Data Request ("DR") 18.3 in the recent Wyoming rate case, the Company stated that the decision to build the 99 mW wind farms in Wyoming was driven, at least in part, by expectations concerning the expiration of the Federal production tax credit at the end of 2008. Please provide documentation concerning the Company's expectations regarding the expiration of the production tax credit. Please include any analyses of bills then before congress that dealt with continuation of the tax credits, and any internal documents assessing the likelihood of continuation of the credits.

Response to ICNU Data Request 9.1

The independent decisions to advance the Seven Mile Hill, Glenrock, and Rolling Hills 99 MW projects were made on: January 31, 2007; May 31, 2007; and December 20, 2007, respectively.

The Company relied upon no specific studies or analyses regarding an assessment of the likelihood and terms of an extension of the Federal production tax credit (PTC) applicable to wind projects. Then-current federal law clearly extended the PTC only to units placed in-service by December 31, 2008. It is general industry knowledge, requiring no study or analyses, that extension of expiring PTCs and the terms of such extension have historically been uncertain and the subject of numerous bills that have not been enacted.

UE-200/PacifiCorp
June 5, 2008
ICNU 5th Set Data Request 5.11

ICNU Data Request 5.11

Please explain why the Company has not included sales of Renewable Energy Credits ("RECs") as a credit against revenue requirements for the test year.

Response to ICNU Data Request 5.11

At this time, the Company is banking the Oregon-allocated RECs from eligible facilities for future RPS compliance.

UE-200/PacifiCorp
June 5, 2008
ICNU 5th Set Data Request 5.12

ICNU Data Request 5.12

If the answer to ICNU DR 5.11 is that the Company is "banking" the REC's for future use in compliance with the Oregon RPS, please provide an explanation and analysis as to why this is a lower cost strategy than simply selling the REC's now, and buying RECs in the future as needed or acquiring more renewable resources.

Response to ICNU Data Request 5.12

Banking RECs for future compliance is a lower cost/risk strategy that benefits customers for the following reasons:

- Banking RECs reduces price risk because RECs can reasonably be expected to have a higher value in the future when federal renewable portfolio standards (RPS) are applicable and/or RPS mandates from one or more states in the WECC are potentially adjusted upward;
- Oregon's RPS has no limit on the use of bundled RECs, which is what PacifiCorp is currently banking for future use;
- It is reasonable to expect that bundled RECs sold now would likely be replaced with unbundled RECs; which have an inherent legal constraint on their use; and
- Having the banked RECs gives the Company the ability to better manage annual compliance obligations. For example, without having banked RECs, the Company may be in the position of non-compliance, absent declaring force majeure on resources if unanticipated delays are experienced.

UE-200/PacifiCorp
June 17, 2008
OPUC Data Request 44

OPUC Data Request 44

For each project included in the 2009 RAC filing, please provide:

a. A description of vendor guarantees related to pricing and milestones/ deadlines in each contract PacifiCorp entered into for project development, equipment, materials, construction, other labor and other major cost items
b. A description of any missed milestones/deadlines related to PacifiCorp's contracts with the vendors in item a, above
c. A description of damages provisions in contracts under item a, above
d. The amount of any damages collected by PacifiCorp in relation to contracts for each project
e. If PacifiCorp has collected any revenues related to item d, above, an explanation of how these revenues are accounted for in the RAC filing or in any other Oregon proceeding

Response to OPUC Data Request 44

a. Each project included in the 2009 RAC filing has an associated contract or contracts with vendors who supply project development, equipment, materials, construction, other labor and/or other major cost items. For the projects currently under construction, it is impossible to list all such vendors until such time as those projects are completed as some non-material vendors are yet unknown. With respect to the projects in the 2009 RAC filing, the following constitutes a description of vendor guarantees for the material vendor contracts:
    i. Leaning Juniper 1 – Project completion agreement with associated delay liquidated damages;
    ii. Marengo – Balance of plant and turbine supply agreements with associated delay liquidated damages;
    iii. 7 Mile Hill - Balance of plant and turbine supply agreements with associated delay liquidated damages;
    iv. Marengo II - Balance of plant and turbine supply agreements with associated delay liquidated damages;
    v. Goodnoe Hills – Engineer, procure, construct (EPC) agreement with associated delay liquidated damages;
    vi. Glenrock - Balance of plant and turbine supply agreements with associated delay liquidated damages;
    vii. Rolling Hills - Balance of plant and turbine supply agreements with associated delay liquidated damages.
    viii. Blundell Bottoming Cycle – Engineer, procure, construct agreement with associated delay liquidated damages.

UE-200/PacifiCorp
June 17, 2008
OPUC Data Request 44

b. To date, and with respect to completed projects, the Goodnoe Hills EPC agreement represents the only agreement wherein milestone dates were missed and the Company believes damages apply. With respect to projects under construction, it is undetermined if milestone dates have been missed per the terms of the contracts.

c. Damages provisions are typically represented on a $/day or $/turbine/day basis.

d. The Company has yet to determine final damages associated with the Goodnoe Hills EPC agreement as the parties are currently not in agreement as to the magnitude of such damages.

e. Please refer to "d." above. No damage revenues have been collected to date because both parties are not in agreement as to the magnitude of the amount. As a result, the potential for damage revenues has not been included in the RAC filing.

UE-200/PacifiCorp
July 17, 2008
OPUC Data Request 60

OPUC Data Request 60

In reference to PacifiCorp response to OPUC DR #44 (d), and (e), please provide the company estimate for liquidated damages associated with the Goodnoe Hills EPC agreement.

Response to OPUC Data Request 60

The Company's current calculation places the potential level of liquidated damages to be a maximum of approximately $4.1 million. The Company is unable to estimate the actual liquidated damages as the contractor has submitted claims, or is expected to submit claims, that if valid, would erase a significant portion of the potential liquidated damages. The Company is in the process of reviewing the contractor's claims as compared to the terms of the EPC agreement.

UE-200/PacifiCorp
July 17, 2008
OPUC Data Request 61

OPUC Data Request 61

Following up Staff Data Request No. 44:

a. Regarding revenues related to liquidated damages arising from the Goodnoe Hills EPC agreement: Does PacifiCorp expect to reach settlement in time to include the additional revenues in its UE 200 update filing due December 1, 2008? If not, when does the company expect negotiations to conclude? When does PacifiCorp expect to update the revenue requirement to account for those revenues?

b. For r esources still under construction: At what point after construction is completed does PacifiCorp expect to be able to determine if liquidated damages apply?

c. Do the contracts that include a provision for liquidated damages include a specified process for settlement? If so, please explain the process and specify where in each contract that process is included. If the contracts do not specify a settlement process, please explain why.

d. Does the company propose to update the revenue requirement for revenues related to liquidated damages as a reduction to O&M or to rate base? Please explain the pros and cons of both methods and include how the reduction would be calculated, using a theoretical dollar amount.

Response to OPUC Data Request 61

a. Please refer to the Company's response to OPUC Data Request 60. The Company is currently unable to estimate when liquidated damage claims may be settled with respect to the Goodnoe Hills EPC agreement.

b. The Company is unable to specify in advance when liquidated damages will be determined as contractors are typically not prevented from making claims during or after construction where such claims may have the effect, if valid, of reducing the contractor's exposure to liquidated damages.

c. Contracts that include a provision for liquidated damages typically do not include a specific settlement process just for liquidated damages. Liquidated damage disputes are typically settled pursuant to the terms of law or, if applicable, the contract specific dispute resolution process (e.g., arbitration) applicable to all contractual provisions.

d. If a final settlement for liquidated damages with respect to the Goodnoe Hills EPC agreement is reached prior to date of the Company's rebuttal testimony in the proceeding (currently set for August 22, 2008), it is the Company's intent to update the revenue requirement by reflecting the settlement as a reduction to rate base. The Company views this as the most appropriate method for recording such items since they generally are associated with the cost of the plant rather than a reduction in operating expenses. If the final settlement is reached after the final round of testimony in the proceeding, then the cost differences to the plant associated with the settlement will be reflected in either the December 1, 2008 update or through deferred accounting, as provided by Sections 6(e) and (f) in the Stipulation in UM 1330.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 200

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
RAC 2009	)
	)

ICNU/103
DEVELOPMENT OF RAC ADJUSTMENT FOR JANUARY 1, 2009

July 23, 2008

PACIFIC POWER & LIGHT COMPANY
DEVELOPMENT OF RAC ADJUSTMENT FOR JANUARY 1, 2009
FORECAST 12 MONTHS ENDED DECEMBER 31, 2009

Line No.	Description	Sch No.	kWh	Sch 200 Present Revenue	RAC Adjustment Revenue	RAC Adjustment Cents\kWh
	(1)	(2)	(3)	(4)	(5)	(6) (5)/(3)
	Residential					
1	Residential	4	5,500,858,427	$220,453,212	$15,965,501	0.290
2	**Total Residential**		5,500,858,427	$220,453,212	$15,965,501	
	Commercial & Industrial					
3	Gen. Svc. < 31 kW	23	1,244,814,968	$48,204,878	$3,491,058	0.280
4	Gen. Svc. 31 - 200 kW	28	2,235,589,080	$84,718,823	$6,135,445	0.274
5	Gen. Svc. 201 - 999 kW	30	1,434,298,853	$52,818,281	$3,825,167	0.267
6	Large General Service >= 1,000 kW	48	3,355,047,387	$115,674,985	$8,377,329	0.250
7	Partial Req. Svc. >= 1,000 kW	47	224,778,394	$7,633,718	$552,844	0.246
8	Agricultural Pumping Service	41	116,486,439	$4,401,683	$318,775	0.274
9	Klamath Basin Irrigation[1]	33	114,982,019		$315,036	0.274
10	**Total Commercial & Industrial**		8,725,997,140	$313,452,368	$23,015,654	
					$22,700,618	
	Lighting					
11	Outdoor Area Lighting Service	15	10,012,681	$258,675	$18,734	0.187
12	Street Lighting Service	50	9,883,968	$212,366	$15,380	0.156
13	Street Lighting Service HPS	51	13,496,578	$457,778	$33,153	0.246
14	Street Lighting Service	52	1,583,931	$41,173	$2,982	0.188
15	Street Lighting Service	53	7,330,279	$81,405	$5,895	0.080
16	Recreational Field Lighting	54	724,804	$13,855	$1,003	0.138
17	**Total Public Street Lighting**		43,032,241	$1,065,252	$77,147	
18	**Total Sales to Ultimate Consumers**		14,154,905,788	$534,970,832	$39,058,302	
19	**Employee Discount**			($225,855)	($16,357)	
20	**Total Sales with Employee Discount**		13,470,753,833	$534,744,977	$39,041,945	

[1] Schedule 33 rate set equal to Schedule 41 rate.

BEFORE THE PUBLIC UTILITY COMMISSION

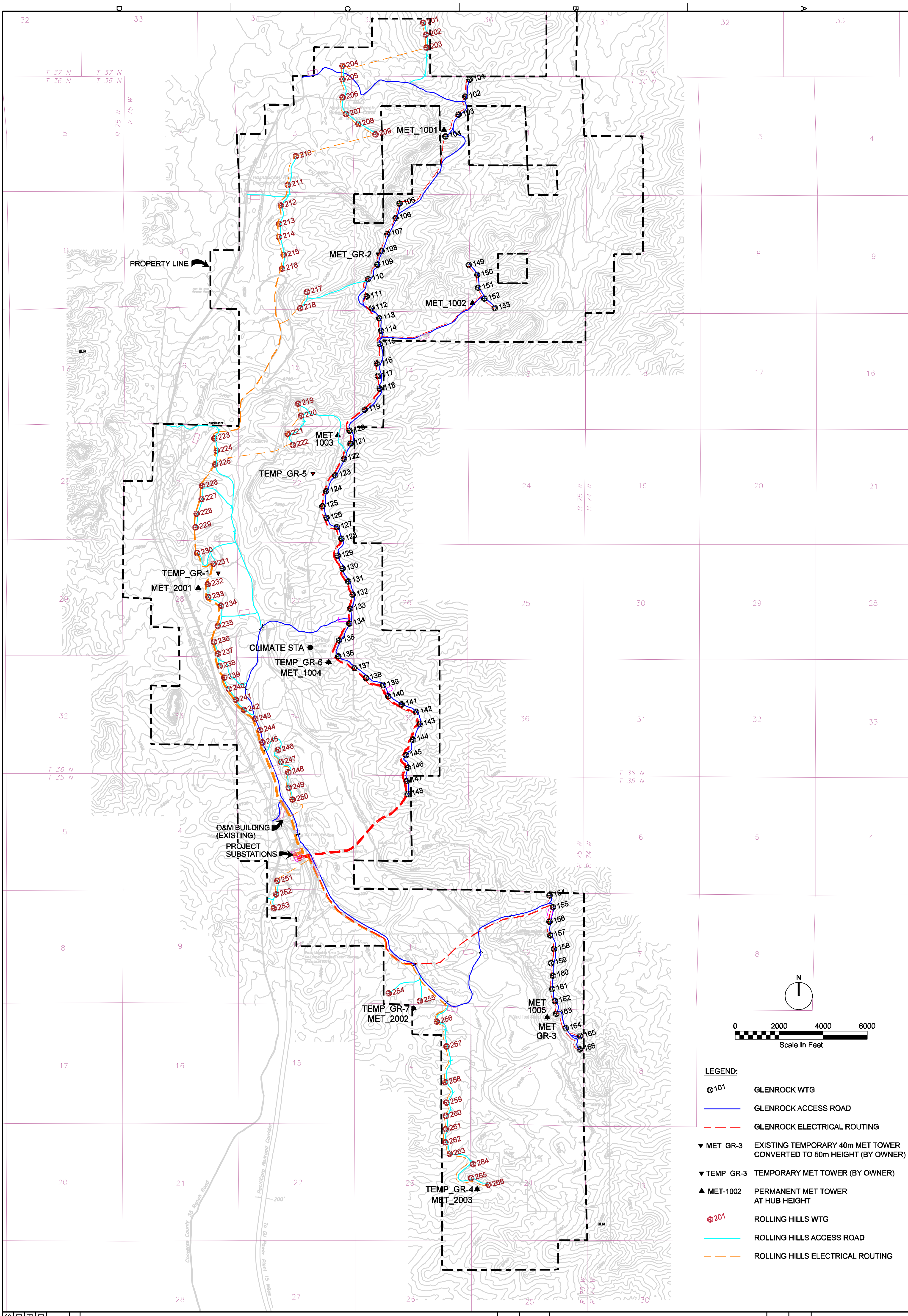
OF OREGON

UE 200

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
RAC 2009	)
	)

ICNU/104
GLENROCK / ROLLING HILLS
FACILITY LAYOUT, REV. 4.3

July 23, 2008



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PLOT DATE: 12/28/2007

PLOT TIME: 1:23:21 PM

CH2MHILL

GLENROCK / ROLLING HILLS
FACILITY LAYOUT, REV 4.3
REV 4.3

PACIFICORP ENERGY
SALT LAKE CITY, UTAH
WIND PROJECTS
CONVERSE COUNTY, WYOMING

VERIFY SCALE
BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

DATE	DEC 2007
PROJ	356172
DWG	FIGURE
SHEET	

NO.	DATE	REVISION	BY	APVD
DSGN	DR	CHK	APVD	

PRELIMINARY

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 200

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
RAC 2009	)
	)

ICNU/105
GLENROCK / ROLLING HILLS
CALCULATIONS

July 23, 2008

	Glenrock	Rolling Hills	Total
Electric Plant In Service	210,292,077	206,460,230	416,752,307
Depreciation Reserve	-4,556,328	-4,473,305	-9,029,633
Accumulated DIT Balance	-27,001,688	-26,509,676	-53,511,364
Net Rate Base	178,734,060	175,477,249	354,211,309
	11.26%	11.26%	11.26%
Pre-Tax Return on Rate Base	20,119,164	19,752,562	39,871,726
Operation & Maintenance	4,395,966	3,862,750	8,258,716
Depreciation	8,411,683	8,258,409	16,670,092
Property Taxes	1,561,213	1,532,765	3,093,978
Federal Renewable Energy Tax Credit	-10,763,254	-8,610,991	-19,374,245
Oregon/Utah State Energy Tax Credits	0	0	0
Rev. Reqt. Before Franchise Tax & Bad Debt	23,724,772	24,795,495	48,520,267
Franchise Taxes	572,280	598,107	1,170,387
Bad Debt Expense	159,338	166,529	325,867
Total Revenue Requirement	24,456,390	25,560,131	50,016,521
Total mWh	333,925	267,152	601,076
CF	38.50%	30.80%	
$/mWh	73.24	95.68	83.21
Alternative Wind Resources	60.25	60.25	60.25
Adjustment $/mWh	-12.99	-35.42	-22.96
Adjustment	-4,336,307	-9,463,339	-13,799,646
Capacity Factor Adjustment in TAM	567,220	3,176,574	3,743,794
Net Adjustment	-3,769,087	-6,286,765	-10,055,852
Oregon Adjustment	-995,470	-1,660,425	-2,655,894

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 200

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
RAC 2009	)
	)

ICNU/106
RAC TOTAL REVENUE REQUIREMENT

July 23, 2008

ICNU/106
Falkenberg/1

Pacific Power
Oregon
Renewable Adjustment Clause
Total Revenue Requirement

	CY 2009											
	Leaning Juniper	Marengo	Blundell Bottoming Cycle	Goodnoe Hills	Marengo II	Glenrock	Seven Mile Hill	Rolling Hills	Total	Factor	Factor %	Oregon Allocated
Electric Plant In Service	175,714,195	246,087,156	23,237,159	196,642,063	135,784,147	210,292,077	201,359,265	206,460,230	1,395,576,291	SG	26.4114%	368,591,655
Depreciation Reserve	(20,044,173)	(18,408,667)	(1,186,054)	(8,193,419)	(4,752,445)	(4,556,328)	(4,362,784)	(4,473,305)	(65,977,176)	SG	26.4114%	(17,425,516)
Accumulated DIT Balance	(43,695,706)	(50,543,529)	(4,982,221)	(23,756,462)	(16,747,719)	(27,001,688)	(25,854,707)	(26,509,676)	(219,091,708)	SG	26.4114%	(57,865,253)
2009 mWh	307,253	594,902	87,898	280,244		333,925	361,360	267,152	2,232,733	SG	26.4114%	589,697
Offset @ 3.5 $/mWh*	1,075,384	2,082,155	307,645	980,855	-	1,168,736	1,264,761	935,031	7,814,567	SG	26.4114%	2,063,939
Net Rate Base	110,898,931	175,052,804	16,761,240	163,711,327	114,283,983	177,565,324	169,877,013	174,542,218	1,102,692,840			291,236,947
	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%			11.26%
Pre-Tax Return on Rate Base	12,483,316	19,704,784	1,886,726	18,428,133	12,864,354	19,987,606	19,122,172	19,647,310	124,124,402			32,783,029
Operation & Maintenance	3,351,019	4,866,477	540,000	3,195,887	2,321,109	4,395,966	3,551,906	3,862,750	26,085,114	SG	26.4114%	6,889,452
Depreciation	7,028,568	9,843,486	729,879	7,865,683	5,431,366	8,411,683	8,054,371	8,258,409	55,623,444	SG	26.4114%	14,690,947
Property Taxes	100,000	1,547,245	149,094	1,438,559	998,252	1,561,213	1,494,895	1,532,765	8,822,023	GPS	28.4419%	2,509,155
Federal Renewable Energy Tax Cred	(9,903,548)	(12,783,479)	(2,833,194)	(9,033,001)	(6,391,739)	(10,763,254)	(11,647,576)	(8,610,991)	(71,966,781)	SG	26.4114%	(19,007,456)
Oregon/Utah State Energy Tax Cred	(523,780)	-	(322,276)	-	-	-	-	-	(846,055)	SG	26.4114%	(223,455)
Rev. Reqt. Before Franchise Tax & B	12,535,575	23,178,514	150,229	21,895,261	15,223,341	23,593,214	20,575,769	24,690,244	141,842,146			37,641,671
Franchise Taxes	305,298	564,756	4,459	530,812	367,211	572,280	499,755	598,107	3,442,678			913,582
Bad Debt Expense	85,003	157,244	1,242	147,792	102,242	159,338	139,145	166,529	958,535			254,366
Total Revenue Requirement	**12,925,876**	**23,900,514**	**155,929**	**22,573,866**	**15,692,794**	**24,324,831**	**21,214,669**	**25,454,880**	**146,243,360**			**38,809,619**
									Company Revenue Requirement			**39,041,946**
											Adjustment	232,327

* - Offset from sales shows the revenue for Oregon Allocated REC's for 2009.