Q. Please state your name, business address and present position with Rocky Mountain Power (the Company).

A. My name is Mark R. Tallman. My business address is PacifiCorp, 825 NE Multnomah, Suite 2000, Portland, Oregon 97232, and my present position is Vice President, Renewable Resource Development. My position reports to the President of PacifiCorp Energy. Both Rocky Mountain Power and PacifiCorp Energy are divisions of PacifiCorp (the "Company").

Qualifications

Q. Mr. Tallman, please briefly describe your education and business experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from Oregon State University and a Masters of Business Administration from City University. I am also a Registered Professional Engineer in the states of Oregon and Washington. I have been the Vice President of Renewable Resource Acquisition since December 2007. Prior to that, I was Managing Director of Renewable Resource Acquisition from April 2006 to December 2007. I have worked at the Company for more than 22 years in a variety of positions of increasing responsibility, including the commercial and trading organization; the Company's engineering organization; the retail distribution organization; and five years as a District Manager.

Q. Please describe your present duties.

A. My present duties include the acquisition of renewable resource assets from third parties, the acquisition of major equipment purchases (such as wind turbines) and a variety of other duties intended to ensure that the Company successfully adds renewable resources to its portfolio, meets its renewable resource commitments, and meets its compliance obligation with respect to renewable portfolio standards (RPS).

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. My testimony rebuts the testimony by Ms. Donna DeRonne on behalf of the Utah Committee of Consumer Services (CCS) with respect to operation and maintenance (O&M) costs for the Leaning Juniper 1 wind plant and testimony submitted by Mr. Kevin Higgins on behalf of the Utah Association of Energy Users (UAE) Intervention Group and Wal-Mart Stores Inc. with respect to O&M costs for the Marengo and Marengo II wind plants. In addition, my testimony rebuts the testimony of Mr. Maurice Brubaker for the Utah Industrial Energy Consumers (UIEC) with respect to: (1) wind project capacity factors; (2) production tax credits (PTCs); and (3) renewable energy credits (RECs) associated with the Goodnoe Hills wind project. Finally, I rebut the testimony of Mr. Randall Falkenberg on behalf of the CCS with respect to wind resource integration costs.

O&M – Leaning Juniper 1

Q. What is the adjustment Ms. DeRonne is proposing to the Leaning Juniper 1 Wind Plant O&M expense?

A. Ms. DeRonne proposes an adjustment to remove a portion of the Leaning Juniper 1 expense associated with a two-year warranty agreement that was included in Leaning Juniper 1's O&M expense. Since the warranty agreement expires in

September 2008, Ms. DeRonne proposes to remove 25 percent (3 months) worth of costs. This results in a total Company reduction of $217,750 and reduces revenue requirement in Utah by $92,276.

Q. Does the Company agree with Ms. DeRonne's adjustment?

A. No.

Q. When the warranty agreement expires in September 2008 does the Company expect to continue incurring similar costs on the Leaning Juniper 1 Plant?

A. Yes. While the warranty agreement ends in September, the costs that are currently covered by the warranty expense will not. Based on the operational history of the units, the Company believes it can expect to incur a similar rate of costs. Since there will no longer be a warranty agreement in place, the Company expects that a similar level of costs will be incurred due to unscheduled maintenance costs incurred on a post-warranty basis. Instead of having the warranty cost, the Company will incur the direct cost associated with replacing or repairing defective equipment and performing unscheduled maintenance on the turbines. Such work includes providing any necessary manpower, tools and equipment.

Ms. DeRonne fails to recognize that the Company will continue to have a need to repair or replace equipment at the Leaning Juniper 1 wind plant. As an expense that is validly expected to be incurred to cover the costs of replacing or repairing defective equipment in the future (similar to what the warranty expense covered), the Company does not agree with Ms. DeRonne's adjustment and recommends that the Commission reject it as invalid.

Wind O&M – Marengo

Q. Please explain the adjustment Mr. Higgins is proposing to the Marengo II O&M expense.

A. Mr. Higgins proposes an adjustment to remove $621,607 total Company from the Marengo II operation and maintenance expense. This would reduce revenue requirement in Utah by $263,418. Mr. Higgins proposes this adjustment as he does not feel that the reduced period of operation of the Marengo II project is reflected in the December 2008 test period.

Q. How does Mr. Higgins arrive at the $621,607 total Company adjustment?

A. In this adjustment Mr. Higgins starts with the June 2009 Marengo/Marengo II operation and maintenance expense. He then estimates what portion should be attributable to Marengo and Marengo II, removes six months of inflation and then estimates the O&M expense based on the months in service in 2008. Mr. Higgins makes his adjustment on the basis of megawatt (MW) proration.

Q. Does the Company agree with this adjustment?

A. No.

Q. Is the reduced period of operation of the Marengo II project reflected in the December 2008 O&M expense?

A. Yes, the reduced period of operation of the Marengo II project is reflected in the December 2008 figure.

Q. What are the components that make up the $5,540,118 figure that is in the December 2008 test period?

A. As stated in Data Request Response DPU 38.3, the portion of O&M expense attributable to Marengo II is $1,053,572. The portion attributable to Marengo I is $4,486,546.

Q. Is Mr. Higgins' adjustment warranted?

A. No. There is no reason for Mr. Higgins to arbitrarily proportion the Marengo/Marengo II O&M expense based on MW as shown in UAE Adjustment 1.4. In response to DPU 38.3, the Company provided the portion of expenses that relate to the Marengo II project. The Company's forecast takes into account many components such as account service & maintenance agreements, substation & relay maintenance, environmental compliance costs, road maintenance & snow removal, weed control costs, and materials and facilities costs. Furthermore, many of these forecasted costs are based on contractual obligations. As stated in Data Request Response DPU 38.3, the portion of O&M expense attributable to Marengo II is $1,053,572. The portion attributable to Marengo I is $4,486,546.

Q. What is the flaw with the way Mr. Higgins prorates the Marengo O&M expense?

A. Mr. Higgins prorates the Marengo operation and maintenance expense between the Marengo and Marengo II plant solely using MW. His calculation does not take into account any other factors that may affect the forecasted O&M expense. For example, the Marengo service and maintenance agreement has a cost that is higher on a per turbine per year basis than that of Marengo II. In addition, the Company negotiated that the lower cost applicable to Marengo II will also apply to Marengo when the Marengo II plant is operational. The costs per turbine per year for the Marengo and Marengo II projects are shown in confidential Exhibit

RMP___(MRT-1R-RR). In the Company's O&M expense forecast, the contractually obligated service and maintenance agreement costs represents approximately seventy five percent of the projected Marengo/Marengo II O&M expenses in the December 2008 test period. Therefore, it is inappropriate to prorate the Marengo/Marengo II O&M expense costs based solely on MW. To capture the impact of Marengo II coming on line midway through the test year, actual cost projections are required.

Q. What does the Company recommend to the Commission with respect to the adjustment proposed by Mr. Higgins?

A. Since Mr. Higgins attempts to prorate the Marengo/Marengo II O&M costs based on MW, and ignores the contractually obligated service and maintenance agreements which the Company has used to align the O&M expense to the test period, the Company recommends that the Commission reject the proposed adjustment.

Wind Capacity Factors

Q. What recommendation does UIEC's witness (Mr. Maurice Brubaker) make with respect to actual generation from wind projects?

A. Mr. Brubaker recommends that the Company be required to track, and file periodically with the Commission, with appropriate access for the Committee and customers, the actual generation from each wind project.

Q. Does Mr. Brubaker recommend a revenue requirement adjustment?

A. No.

Q. Does the Company agree with Mr. Brubaker's reporting recommendation?

A. No. The Company currently files semi-annual results of operation reports with the Committee, Division and the Commission. This process provides ample opportunity for parties to have reasonable access to actual generation information and there is no reason for the Commission to place additional reporting burdens on the Company.

Q. What reason does Mr. Brubaker's testimony give as being the need for such actual wind project generation?

A. Mr. Brubaker contends that such information will enable the Commission to determine in the future if a revenue requirement adjustment is warranted based on actual generation versus the generation estimated at the time the decision to pursue the project was made. Specifically, Mr. Brubaker suggests that the Commission may want to impute additional generation if the actual generation is below expected.

Q. Does Mr. Brubaker recommend that the Commission impute less generation if the actual generation is above expected?

A. No. Mr. Brubaker's recommendation is not symmetrical. It only envisions penalizing the Company and not rewarding the Company.

Q. How does generation from wind projects get included in proceedings involving net power cost?

A. The Company includes a production profile in the GRID model for each wind resource.

Q. What is the basis for the production profile?

A. The Company utilizes the best information available to it at the time. This typically includes the results of previous wind studies and/or, if the resource is in service, historical actual generation data.

Q. Is the historical actual generation level of each resource provided to each party applicable in the proceedings?

A. Yes. If requested, the Company provides the historical actual production of each resource contained in the GRID model, including wind resources.

Q. Is it typical for the Company to receive a data request for historical actual generation levels?

A. Yes. Such a request is common.

Q. Is the output from wind projects dependent on the weather?

A. Yes. Weather patterns play a large role in determining the actual production of a wind project during any given year or twelve month period.

Q. Will the output from wind projects vary from year to year?

A. Yes. The studies performed by the Company’s consultants recognize that the projected annual energy production for a wind project will vary from year to year. For this reason, it is common for wind project production to be estimated over long periods of time, thus taking into account annual variations.

Q. What other weather dependent resources are similarly placed in the GRID model using an assumed profile?

A. Stream flows for hydro resources are normalized in the GRID model. Similar to wind resources, hydro resources are dependent on the weather during a given year to determine their actual generation output. Because of the variability in both wind and stream flows from year to year, the GRID model calculates net power costs using normalized inputs for both wind and hydro resources.

Q. Does the Company agree with Mr. Brubaker's imputation theory?

A. No. The Company believes Mr. Brubaker is essentially recommending that the Commission revisit the prudence of the Company's decision to pursue the resource during a future rate proceeding. This is inappropriate and does not recognize that the Company is asking the Commission to determine prudence in this docket with respect to the subject wind resources.

Q. Does Mr. Brubaker question the prudence of the Company's renewable resource decisions.

A. No. Mr. Brubaker does not question the prudence of the Company's renewable resource decisions in this Docket.

Q. When the Company makes a decision to construct a wind project, is it using the best information available to it at the time with respect to estimated energy production?

A. Yes.

Q. Is there a broader implication to Mr. Brubaker's recommendation to the Commission?

A. Yes. While Mr. Brubaker does not question the prudence of the Company's decisions, his testimony is in effect saying that he believes the Commission should revisit each such decision in the future and impute a penalty upon the Company if the actual performance of the asset is different than expected when the decision was taken (based on information the Company knew at the time). Mr. Brubaker's recommendation has far reaching implications. First, aside from the fact that his suggestion lacks symmetry, Mr. Brubaker's suggested policy fundamentally alters the premise that decisions by the Company shall be judged by the Commission on the basis of what the Company knew at the time. Mr. Brubaker's recommendation is in effect a new form of regulation for which there is no sound basis. Finally, there is no reason to believe that parties to a future rate proceeding would limit themselves to challenging only wind resource capacity factor. Mr. Brubaker's recommendation opens the door for every past decision to be re-assessed (i.e., not just resource decisions but transmission, distribution, or any other decision impacting rates) and, as Mr. Brubaker suggests, subject the Company to imputed penalties if a future Commission is not in agreement with a prudence ruling by a previous Commission.

Q. What does the Company recommend to the Commission with respect to Mr. Brubaker's imputation recommendation?

A. The Company recommends that the Commission reject Mr. Brubaker's recommendation. It is an inappropriate adjustment that has no sound foundation as an established or reasonable regulatory principle, it is not symmetrical, and it would significantly increase the Company's risk profile related to rate base investments and/or other decisions including, but not limited to, non rate base resource acquisition decisions.

Wind Project Production Tax Credits

Q. What recommendation does Mr. Brubaker make with respect to the in-service date for wind projects?

A. Mr. Brubaker contends that federal Production Tax Credits (PTC) are absolutely critical to making a wind project economical and beneficial to customers. Mr. Brubaker then recommends that the Commission impute PTC benefit into the revenue requirement impacts for any wind project that is not in-service by the end of the 2008 calendar year.

Q. Does the Company agree with Mr. Brubaker's recommendation?

A. No. Mr. Brubaker's recommendation violates fundamental rate making principles on two levels. First, Mr. Brubaker recommends that the Commission implement retroactive rate making by, in the future, looking back to determine if a wind project does not achieve commercial operation during 2008 and, if so, implement a retroactive rate making decision. Second, Mr. Brubaker's recommendation violates the principal of generation costs going into rates at cost.

Q. What reason does Mr. Brubaker give for such actions on the part of the Commission?

A. Mr. Brubaker contends that it is the Company who is exclusively in charge of and responsible for each project, its construction, and its timely completion. As such, Mr. Brubaker contends that the Company should bear the burden for any failure to meet the criteria required to achieve PTCs for a project.

Q. Is the Company entirely in control of when each component of a wind project becomes used and useful?

A. No. There are a number of factors beyond the Company's control that can impact construction schedules. Factors which may include: delays due to weather or transportation; equipment breakage; or other events where contractors or suppliers either fail to perform or otherwise claim Force Majeure.

Q. Mr. Brubaker contends that each wind project must be placed in service by the end of 2008 to qualify for PTCs. Is this correct?

A. No. Each wind turbine is declared eligible for PTCs when that individual wind turbine is placed in service.

Q. Is it reasonable that the Company entirely bear these risks?

A. No. 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. How do third parties account for such risks?

A. Third parties are able to charge whatever the market will bear and, as such, are able to hedge their risk by charging a premium.

Q. Does Mr. Brubaker recommend that the Company receive a risk premium for the risk that Mr. Brubaker recommends the Company bears?

A. No. Mr. Brubaker recommends asymmetrical rate making wherein the Company bears all the downside risk but receives no additional upside associated with Mr. Brubaker's version of a new regulatory compact that is not based on cost of service regulation.

Q. Is the cost to acquire renewable resources escalating faster than inflation?

A. Yes. The cost to acquire renewable resources continues to escalate at multiples of the annual inflation rate due to continued increases in major equipment supply (wind turbines for example), the cost of raw materials (steel for example), transportation (fuel for example), currency exchange rates (euro to dollar exchange rate for example), and labor.

Q. If the Commission were to accept Mr. Brubaker's recommendation, does Mr. Brubaker also recommend to the Commission that the Company be allowed to adjust the revenue requirement upward (for the subject resources) as the market for renewable resources escalates higher than cost?

A. No. Again, Mr. Brubaker fails to make such a symmetrical recommendation. This lack of symmetry and parity again points toward Mr. Brubaker recommending that the Commission apply asymmetrical rate making upon the Company without any consideration to compensating the Company for the risk of acquiring resources in the near-term for the long-term benefit of customers.

Q. At the time the Company decided to pursue each wind project, based on what the Company knew at the time, did the Company have a reasonable expectation that each wind project would reach commercial operation during 2008?

A. Yes.

Q. Is the Company still predicting that each wind project will achieve commercial operation during 2008?

A. Yes; current project schedules indicate that commercial operation will be achieved during 2008.

Q. Is it possible PTCs will be applicable to wind turbines that are placed in service during 2009?

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.

Q. What effect could federal RPS law have upon the market for renewable resources?

A. Such federal RPS law would extend the amount of load across the nation subject to RPS requirements, increase the demand for renewable resources and, therefore, increase the cost of renewable resources.

Q. How many states have RPS laws?

A. At present, there are twenty seven (27) states in the United States with RPS laws, eight (8) states in the Western Electricity Coordinating Council (WECC) with RPS laws, and three (3) jurisdictions that regulate retail electric service by the Company with RPS laws. In addition, Utah has passed a carbon reduction initiative law (SB-202). The Company's two electric control areas reside in the WECC.

Q. What is the market price referent in California?

A. The state of California has an RPS law and the California Public Utility Commission has set a market price referent wherein cost recovery is assured if renewable resources are acquired at or below the referent price. The current referent price is nearly $100/MWh.

Q. For the resources that Mr. Brubaker recommends that the Company bear asymmetrical PTC risk for, what is the cost of these resources without the PTC?

A. It varies by resource, but in each instance the levelized expected net delivered cost is less than $100/MWh.

RECs associated with the Goodnoe Hills wind project

Q. What recommendation does Mr. Brubaker make with respect to RECs associated with the Goodnoe Hills wind project?

A. Mr. Brubaker makes a recommendation that the Company's revenue requirement should be reduced by $290,000.

Q. What is Mr. Brubaker's revenue requirement reduction based on?

A. The $290,000 reduction is based on Mr. Brubaker's assessment that the Goodnoe Hills RECs should be carved out from the RECs in the case from other renewable resources and separately assigned a value of $6.05/MWh. The value for all RECs included in the case is $3.50/MWh for 75 percent of the RECs allocated to Utah.

Q. Did the Company assume that RECs from the Goodnoe Hills project are worth $6.05/MWh?

A. No. The Company determined that the differential present value revenue requirement for the project was $0 on a total project basis (inclusive of avoided market purchases) if the value of green tags or the cost of compliance with renewable portfolio standards rise to approximately $6.37/MWh during each year of the project's life. The $6.37/MWh represents a nominal levelized amount during the life of the project and is not intended to represent the exact value of RECs from the Goodnoe Hills project to customers over the life of the project or in a given year.

Q. Is it reasonable to expect that the value of RECs to customers will fluctuate over the life of the Goodnoe Hills project and that the cost of compliance with current or future RPS is or will be above $6.37/MWh?

A. Yes.

Q. What could influence the value of RECs from the Goodnoe Hills as allocated to Utah customers?

A. The overall market value of RECs from new wind projects could certainly influence the value of RECs from the Goodnoe Hills project. In addition, a formalized agreement under the multi-state process (MSP) for inter-jurisdictional allocation of RECs could have a direct impact of REC value for Utah customers as well as the enactment of a RPS by the federal government.

Q. Is it reasonable to expect that a RPS law enacted by the federal government will have a non-compliance cost above $6.37/MWh?

A. Yes. The Company believes the cost for non-compliance under a federal RPS could easily be $20/MWh. While the cost of non-compliance is $50.00/MWh in some states, the $20.00/MWh level is conservative relative to federal legislation passed by the U.S. House of Representatives.[1]

Q. Will the Company sell all RECs at a price of $3.50/MWh?

A. No, Some RECs will be sold above that price, and some will be sold below that price. Also included in the portfolio of RECs available for sale are RECs from the Foote Creek, Rock River, Glenrock, Leaning Juniper 1, Seven Mile Hill, and Marengo wind projects. RECs from Goodnoe Hills represent about 15 percent of

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[1] See H.R. 3221. This legislation did not become law during 2007. **H.R. 3221 (2007),** Subtitle H--Federal Renewable Portfolio Standard, Section. 9611. Federal Renewable Portfolio Standard, (a) In General- Title VI of the Public Utility Regulatory Policies Act of 1978 is amended by adding at the end the following:

> *SEC. 610. FEDERAL RENEWABLE PORTFOLIO STANDARD.*
>
> *(j) Enforcement- A retail electric supplier that does not comply with subsection (b) shall be liable for the payment of a civil penalty. That penalty shall be calculated on the basis of the number of kilowatt-hours represented by the retail electric supplier's failure to comply with subsection (b), multiplied by the lesser of 4.5 cents (adjusted for inflation for such calendar year, based on the Gross Domestic Product Implicit Price Deflator) or 300 percent of the average market value of Federal renewable energy credits and energy efficiency credits for the compliance period. Any such penalty shall be due and payable without demand to the Secretary as provided in the regulations issued under subsection (e).*
>
> *(k) Alternative Compliance Payments- The Secretary shall accept payment equal to 200 percent of the average market value of Federal renewable energy credits and Federal energy efficiency credits for the applicable compliance period or 3.0 cents per kilowatt hour adjusted on January 1 of each year following calendar year 2006 based on the Gross Domestic Product Implicit Price Deflator, as a means of compliance under subsection (b)(4).*

the total RECs included in the Company’s filing. Therefore, isolating just the Goodnoe Hills RECs should not be done unless there is a specific reason to do so. The Company currently markets its REC portfolio on both a bundled and unbundled basis to obtain maximum value, not on a project priority basis.

Q. Does Mr. Brubaker recommend to the Commission that the Company retain all REC revenues from Goodnoe Hills sold at higher than his referenced $6.05/MWh during the life of the Goodnoe Hills project?

A. No. Mr. Brubaker only recommends that the Company bear the downside risk of his proposed revenue imputation with no symmetrical upside adjustment proposal. Mr. Brubaker’s recommendation neglects to recognize that the value of RECs from the project can reasonably be expected to rise over the life of the project.

Q. What is the cost for non-compliance under the RPS laws in the Company’s service area?

A. In Washington, the penalty is $50.00 for each MWh the Company fails to not include as an adequate level of energy from renewable resources in its portfolio. In California, the penalty is five (5) cents per KWh (or $50 per MWh), up to $25 million per year, if the Company fails to meet procurement targets for renewable energy. In Oregon, the penalty is not defined by the law; Senate Bill 838 states that the Commission may impose a penalty against the Company in an amount determined by the Public Utility Commission of Oregon if the Company fails to comply with the standard.

Q. What Utah allocation of RECs from the Goodnoe Hills Project is the Company proposing in this case?

A. The Company has included RECs at a level based on Utah's allocated share based on the "Revised Protocol." This is 42.377 percent under the "SG" factor.

Q. Did the Energy Trust of Oregon Inc., an Oregon non profit corporation, (the "Trust") fund any portion of the Goodnoe Hills Project?

A. Yes. The Trust funded $4.5 million toward the project pursuant to the agreement contained in confidential Exhibit RMP___(MRT-2R-RR).

Q. What is the purpose of the Trust agreement?

A. The purpose of the agreement is for the Trust to invest in a utility scale wind project for the benefit of Oregon customers. In return for its investment, the Trust expects that the Company will allocate RECs for the benefit of Oregon customers (as outlined in the Trust agreement) and maximize the value of Oregon's allocated RECs based on the then-current status of compliance with Oregon's RPS.

Q. Does the Trust agreement reflect that other jurisdictions may wish to make a similar investment?

A. Yes. The Trust funding agreement recognizes that each jurisdiction should be offered the opportunity to implement a funding mechanism that effectively displaces a portion of the Trust's funding. For example, Utah has the opportunity to provide up to 42.377 percent (per the SG factor) of the $4.5 million ($1,906,965) in funding via some mechanism which could include the outcome from this Docket.

Q. What distinct time periods does the Trust agreement contain with respect to the allocation of RECs to each jurisdiction?

A. Under the agreement, the allocation of RECs for 5-years after the date of commercial operation for Goodnoe Hills is done pursuant to the methodology contained in the Trust agreement which is based on system-wide REC allocation. After the 5-year period, the REC allocation is determined by additionally examining the level that each jurisdiction chooses to displace a portion of the $4.5 million Trust grant. The intent is that no jurisdiction would have the opportunity to fund more than their Revised Protocol share.

Q. What happens to Oregon's allocated RECs if all jurisdictions elect to fund a share of the $4.5 million based on the Revised Protocol percentages.

A. In this instance, Oregon's allocated share would remain at a level very near Oregon's Revised Protocol percentage, after taking into account the effects of the Bonneville Power Administration (BPA) Conservation Rate Credit (CRC) program for jurisdictions in the Pacific Northwest. Under the example contained in the Trust Agreement, Oregon's share of RECs would be 33.6 percent.

Q. What happens to Oregon's allocated RECs if no jurisdictions elect to fund a share of the $4.5 million based on the Revised Protocol percentages.

A. In that instance, Oregon's allocated share of RECs would be higher than what Oregon would otherwise receive if all jurisdictions opt to fund a portion of the $4.5 million amount. Under the example contained in the Trust Agreement, Oregon's share of RECs would increase to 57.2 percent.

Q. Under the Trust agreement, what factors go into determining the allocation of RECs to each jurisdiction?

A. Key factors include the Revised Protocol percentages and other factors including actual project cost, the level of BPA CRC received and contributions from other jurisdictions to displace a portion of the Trust funding. These factors would apply to determining REC allocations applicable to the time period after the project has been in commercial operation for 5 years.

Q. In this case, Docket No. 07-035-93, has the Company accounted for the funding provided by the Trust for the Goodnoe Hills wind plant?

A. Yes.

Q. How has the Company accounted for this funding in the rate case?

A. The funding was included as a reduction to operating expense in the O&M section of the rate case. The funding has been factored into the Incremental Generation Operation and Maintenance adjustment 4.12 in Exhibit RMP___(SRM-1S). In this adjustment, the funding has been netted against the administrative line. On back-up page 4.12.1 a bullet note revealed that all credits were included in the administrative line of the adjustment.

Q. What was the amount of funding included in the current case?

A. The amount of funding included in the current case and netted against the administrative line is $846,779 total company, or $358,840 on a Utah basis. Please see Mr. McDougal's rebuttal testimony Exhibit RMP__(SRM-1R-RR) page 11.2.1 which includes the backup for this adjustment. If Utah elects to displace the Trust's funding associated with the test period, then $358,840 will need to be added to the revenue requirement in this case.

Q. Is there a reason the Company accounted for this funding in the O&M portion of the case and, if so, why?

A. Yes. When this funding is received from the Trust, the Company will apply the funding against the Goodnoe Hills wind plant O&M expense as allowed pursuant to the Project Funding Agreement.

Q. What does the Company recommend to the Commission with respect to Mr. Brubaker's $290,000 revenue requirement reduction?

A. The Company recommends that the Commission reject Mr. Brubaker's recommendation. To do otherwise establishes a precedent that the Commission would rather take the risk that future REC values are lower than $6.37/MWh over the life of the Goodnoe Hills project. Should that be the case, then the Company should be free to sell RECs from the Goodnoe Hills project during its life, keep the revenues, and buy RECs from a future then-current market for allocation to Utah at cost.

Q. What does the Company recommend to the Commission with respect to the Trust's $4.5 million in funding?

A. The Company recommends that the Commission affirmatively declare that it wishes to displace a portion of the Trust's $4.5 million in funding towards the Goodnoe Hills project and that the Company's revenue requirement in this docket be increased by $358,840.

Wind Resource Integration Cost

Q. What adjustment does Mr. Falkenberg make with respect to wind integration costs?

A. Mr. Falkenberg recommends that net power costs be reduced by approximately $1.7 million on the basis that, as Mr. Falkenberg contends, the Company will have far less than 1,000 MW of wind capacity installed during the test year. Mr. Falkenberg believes, on this basis, that the $1.14/MWh rate used by the Company for integration costs, which is based on the 2007 Integrated Resource Plan (IRP), is overstated since the Company has yet to reach the level of 2,000 MW of installed wind capacity targeted in the 2007 IRP.

Q. How many MW of installed wind capacity will be in the Company's system during the test year?

A. Approximately 1,200 MW. This includes wind projects for which the Company provides integration, storage, and return services, as well as qualifying facility contracts from wind projects.

Q. What conceptual problem is there with Mr. Falkenberg's reasoning?

A. The $1.14/MWh from Appendix J of the 2007 IRP was developed to support a 2,000 megawatt portfolio of wind resources. It was never designed to be parsed out to individual projects as Mr. Falkenberg has attempted to do in his testimony. The Company has used, and continues to use, integration cost assumptions that are consistent with the then-current IRP. Using Mr. Falkenberg's method leads to unrealistic results. For example, the first half of the 2,000 megawatt portfolio would be assessed a one percent increase in their spinning reserve requirement whereas the second half of the portfolio would be assessed a three percent increase in their spinning reserve requirement for exactly the same service. When the portfolio is completely in place by 2013, then, under Mr. Falkenberg's reasoning, half of the wind plants would require reserves of six percent, while the other half would require reserves of eight percent. This is non-sensical, does not represent the way the Company actually operates its system, and should be seen as an ill-founded proposal by Mr. Falkenberg to shift legitimate costs out of the test period to some future time.

Q. If wind integration costs are to be revisited at this point in the general rate case, what other considerations should the Commission take into consideration?

A. It should be noted that the Bonneville Power Administration (BPA) has recently added a wind integration charge of $0.68 per kilowatt month for interconnected wind projects. This represents approximately $2.82/MWh for a wind plant with a capacity factor of thirty three (33) percent; more than double the Company's assumed rate of $1.14/MWh. This new charge by BPA will increase net power costs for the Company in 2008 by $396,780. This cost is not included in the case, but if wind integration costs are to be revisited at this point of the general rate case, then these new charges from BPA should be included. In addition, the Company failed to include integration costs associated with the Rock River, Combine Hills, Wolverine Creek, Mountain Wind I, and Mountain Wind II wind resources.

Q. If the BPA tariff increase and the integration costs associated with the above mentioned wind plants is added, what would be the resulting integration cost?

A. Assuming that the five wind plants produce at an annual capacity factor of at least 30 percent, approximately $885,000 for integration costs associated with the five mentioned wind plants and an additional $396,780 for the BPA tariff increase; increasing the Company filed cost for integration from $1.9 million to approximately $3.2 million in integration costs.

Q. In addition to the conceptual flaws mentioned above, are there computational errors in Mr. Falkenberg's wind reserve adjustment?

A. Yes. There are two problems with Mr. Falkenberg's calculations. First, he calculates 42 MW as being about two percent of 2,000 MW of nameplate wind capability and then assumes that one percent of nameplate rating is the same as one percent for purposes of calculating spinning reserves. This is incorrect since reserves are calculated on the amount of plant running during each hour, which is about a third of nameplate for wind. Thus, the conversion is not one for one; rather it is over three to one. Second, he incorrectly assumes that the additional reserve is half spinning and half non-spinning. The correct assumption is that it is all spinning.

Q. What integration cost did the Company include in the rate case and how does it compare to what Mr. Falkenberg is recommending?

A. Based on the 2007 IRP, the Company included approximately $1.9 million in integration costs. Mr. Falkenberg's adjustment results in integration costs of approximately $200,000 or just 10.5 percent of that included by the Company. This fact alone demonstrates that Mr. Falkenberg’s methodology is fundamentally flawed.

Q. What should the Commission do with Mr. Falkenberg's adjustment to the wind integration costs?

A. The Commission should reject Mr. Falkenberg's adjustment. As described above, it is both conceptually and computationally flawed.

Q. Does this conclude your testimony?

A. Yes.