Q. Please state your name and business address with Rocky Mountain Power (the Company), a division of PacifiCorp.

A. My name is Brian S. Dickman and my business address is 201 South Main, Suite 2300, Salt Lake City, Utah, 84111.

Qualifications

Q. What is your current position at the Company and what is your employment history?

A. I am currently employed as the manager of revenue requirement for the Company. I have been employed by the Company since 2003 including positions in revenue requirement and regulatory affairs. Prior to joining the Company, I was employed as an analyst for Duke Energy Trading and Marketing.

Q. What are your responsibilities as manager of revenue requirement?

A. My primary responsibilities include the calculation and reporting of the Company's regulated earnings or revenue requirement, application of the inter-jurisdictional cost allocation methodology, and the explanation of those calculations to regulators in the jurisdictions in which the Company operates.

Q. What is your educational background?

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance in 2002 and a Bachelor of Science degree in accounting from Utah State University in 2001. I completed the Utility Management Certificate Program at Willamette University and I have also attended various educational, professional and electric industry-related seminars.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified before the Idaho Public Utilities Commission and the Wyoming Public Service Commission.

Purpose of Testimony

Q. What is the purpose of your direct testimony?

A. My direct testimony explains and supports the Company's application to recover the increased revenue requirement of $39.0 million for two major plant additions, namely, the Populus to Ben Lomond transmission line and the Dunlap I wind project. I explain the Company's proposal to adjust rates effective January 1, 2011, to begin collecting the price increases related to this filing and the Company's first major plant addition filing in Docket No. 10-035-13, and I explain the Company's proposal to begin amortizing and collecting the balance of revenue requirement deferred between July 1 and December 31, 2010, related to Docket No. 10-035-13. In addition to my testimony, several Company witnesses provide testimony supporting the development of the projects included in this filing, along with the expected costs and benefits. I will identify these Company witnesses and the subject of their respective testimony.

Q. Please explain the circumstances that gave rise to this filing.

A. In the Company's most recent general rate case, Docket No. 09-035-23, the Company and intervening parties reached an agreement May 14, 2009, that specified a filing schedule for major plant addition cases in 2010 and the Company's next general rate case in 2011. The settlement agreement was approved by the Public Service Commission of Utah ("the Commission") June 1, 2009. Paragraph 10(a) of that agreement states:

> 10. Single Item Rate Cases.
>
> a. Ben Lomond to Terminal Transmission Line Segment and Dave Johnston Scrubber Projects. The Company anticipates that (i) the capital additions of scrubbers to the Dave Johnston Power Station will be completed by May 2010 and (ii) the Ben Lomond to Terminal Transmission Line Segment will be completed by June 2010. No projected costs or revenues associated with the foregoing projects will be included in the Company's 2009 General Rate Case. The Company intends to file an application on or after February 1, 2010 for single item rate recovery of the foregoing capital projects pursuant to Utah Code Anno. § 54-7-13.4 (the "Act"). The Parties agree not to oppose the Company's right to file or time of filing (assuming consistency with the 90 and/or 150 days stated in the Act) of the Company's application for approval of rate recovery for the foregoing projects. All Parties reserve and retain the right to take or make any and all substantive positions, claims or objections going to the merits, prudency (if a prudency review has not already been made under the Energy Resource Procurement Act) or amount of recovery in connection with such filings.
>
> b. Ben Lomond to Populus Transmission Line Segment and 2009R RFP Resource Selection Process. The Company anticipates that (i) the Ben Lomond to Populus Transmission Line Segment will be completed by December 2010, and (ii) a resource selection will have been made and implemented in the 2009R RFP resource selection process by November 2010. The Company intends to file an application on or after August 3, 2010 for single item rate recovery of the foregoing capital projects pursuant to the Act assuming, with respect to the later project, that the 2009R RFP resource selection process results in a capital project to be included in rate base. The Parties agree not to oppose the Company's right to file or time of filing (assuming consistency with the 90 and/or 150 days stated in the Act) of the Company's application for approval of rate recovery for the foregoing projects. All Parties reserve and retain the right to take or make any and all substantive positions, claims or objections going to the merits, prudency (if a prudency review has not already been made under the Energy Resource Procurement Act) or amount of recovery in connection with such filings.

Consistent with that agreement, in February 2010, the Company filed an application to address the cost recovery of the costs associated with pollution control equipment at Dave Johnston Unit 3 and the Ben Lomond to Terminal transmission line. On June 15, 2010, the Commission issued an order approving the stipulation allowing for the deferral of an annual amount of $30.8 million. The Company's current application is the second of the major plant additions filings planned for 2010 and addresses the costs related to the Populus to Ben Lomond transmission line and the Dunlap I wind project.

Q. Do the investments in this application qualify for alternative cost recovery for major plant additions as outlined in Utah Code Section 54-7-13.4?

A. Yes. One percent of the Company's Utah rate base approved by the Commission in Docket No. 09-035-23 is $46.3 million and each of the plant additions exceeds this threshold. Additionally, the filing is being made within eighteen months of final order in Docket No. 09-035-23 as required by the statute.

Revenue Requirement

Q. What is the revenue requirement related to the two major plant additions addressed in this application?

A. The following table summarizes the overall requested revenue requirement for each of the projects, allocated to Utah:

$ *millions*

Populus to Ben Lomond Transmission Line	$ 31.4
Dunlap I Wind Plant	$ 7.6
Total Revenue Requirement	$ 39.0

Q. Please explain how the revenue requirement of the plant additions was prepared.

A. The revenue requirement of each plant addition was calculated using the same model and methods employed by the Company in its general rate cases. Each plant addition was treated as an incremental adjustment to a "base case" revenue requirement for the Company's Utah jurisdiction. The Company utilized the Jurisdictional Allocation Model ("JAM") to allocate the various individual revenue requirement components to the state of Utah and compute the net increase in revenue requirement for each project. The working model used to prepare these pages has been included in folder D.1 of the Filing Requirements CD.

Q. What is the return on equity ("ROE") used in this application?

A. The cost of capital included in this filing is consistent with the outcome approved by the Commission in Docket No. 09-035-23, which includes an ROE of 10.6%.

Q. What is the method currently approved for allocating total Company revenue requirement to Utah?

A. Total Company revenue requirement components are allocated among the Company's jurisdictions using the Revised Protocol allocation method, as approved by the Commission in Docket No. 02-035-04. However, pursuant to the stipulation reached between the Company and participants in the Multi-State Process, and approved by the Commission, Utah rates are currently limited to the lesser of the amount derived using the Revised Protocol method or the amount derived using the Rolled-In method multiplied by 101 percent (the Rate Mitigation Cap).[1] The rate change in Docket No. 09-035-23 was calculated using the capped revenue requirement based on the Rolled-In allocation multiplied by 101 percent.

Q. What method of cost allocation was used to determine the incremental impact of the major plant additions in this filing?

A. I have computed the incremental revenue requirement related to the major plant

[1] According to the stipulation rates will be set on the lesser of: (i) Rolled-In multiplied by 101.00 percent, or (ii) Revised Protocol, plus a rate mitigation premium of 100.25 percent if applicable. Currently Utah revenue requirement on Rolled-In is less than Revised Protocol and is limited by the Rate Mitigation Cap.

additions in this filing on a Rolled-In basis. This calculation is done using Rolled-In for two reasons. First, rates set in Docket No. 09-035-23 were based on Rolled-In allocation plus the Rate Mitigation Cap so computing the incremental revenue requirement in this filing using Rolled-In is consistent with the previous general rate case as well as the subsequent major plant addition filing in Docket No. 10-035-13. In addition, the Rolled-In methodology is not impacted by the Embedded Cost Differential component of the Revised Protocol which is currently under review by interested parties in Utah and the Company's other impacted jurisdictions as I explain later in my testimony.

Second, the incremental electric plant in service included in this filing is allocated on a system generation ("SG") factor, and the vast majority of the remaining revenue requirement components are also allocated on either the SG factor or the system energy ("SE") factor. Both of these factors are the same under both the Revised Protocol and Rolled-In allocation methodologies, and the incremental revenue requirement directly related to the two projects in this filing is similar under either method. Exhibit RMP___(BSD-1) provides further numerical details supporting the Utah-allocated revenue requirement of each project.

Q. Does the revenue increase requested in this filing include the additional one percent related to the Rate Mitigation Cap?

A. No. I have calculated the incremental revenue requirement using the Rolled-In allocation with no adder related to the Rate Mitigation Cap. This approach results in an appropriate level of incremental revenue requirement directly related to these individual projects, and is also consistent with the approach taken in the settlement of the Company's previous major plant filing in Docket No. 10-035-13.

Q. Is the Revised Protocol allocation method currently under review?

A. Yes. The Revised Protocol agreement established a committee (the "Standing Committee") for the purpose of continued monitoring and maintenance of the Revised Protocol method. Representatives from the staff of the respective Commissions that approved the Revised Protocol are members of the Standing Committee and they work with the Company and other interested parties to address issues that arise which may have an impact on the allocation methodology. During 2009, the Company and the Standing Committee began work to answer questions from interested commissioners regarding the continued relevance of the Revised Protocol. Then, on November 9, 2009, the Utah Commission issued an order in Docket No. 09-035-23 stating its intent that inter-jurisdictional allocation issues be addressed and the reasonableness of any allocation established prior to their approval of any future change in the Company's rates. At the time of filing this application the Company continues to work with the Standing Committee and other interested parties, including participants from Utah, to determine a course of action related to the future of inter-jurisdictional allocations.

Q. Please describe Exhibit RMP___(BSD-1).

A. Exhibit RMP___(BSD-1) contains the numerical details and calculations supporting the revenue requirement of each project and the allocation to Utah.

Page 1.0 is a summary by project of the net incremental revenue requirement. The first column on page 1.0 ties to the Utah Rolled-In results from Docket No. 09-035-23. The next two columns show the impact of the settlement agreement reached in the Company's first major plant addition case, followed by the cumulative revenue requirement as a result of that case. The next two columns show the incremental impact of the two major plant additions included in this case, and the far right column contains the cumulative revenue requirement after both major plant addition filings are layered onto the general rate case results.

Pages 2.0 through 2.5 contain the detailed numerical calculations for the Populus to Ben Lomond transmission line, and pages 3.0 through 3.6 contain the same details for the Dunlap I wind project. Pages 4.1 through 4.4 contain the inter-jurisdictional allocation factors used to allocate revenue requirement components to Utah.

Q. What did the Company use for the "base case" mentioned above?

A. The starting point in this case is the cumulative result of the Commission ordered outcome in Docket No. 09-035-23 and the approved settlement of the first major plant additions filing in Docket No. 10-035-13. This base scenario is needed as the starting point from which to calculate the incremental impacts of the two individual plant additions addressed in this filing.

Q. How were the two major plant additions in this filing incorporated into the "base case" results?

A. Each project in this case was treated as an incremental adjustment to the "base case" and entered into the JAM similar to adjustments in past Company filings.

Adjustment lead sheets and supporting calculations are provided on pages 2.0 through 2.5 and pages 3.0 through 3.6 of Exhibit RMP___(BSD-1). Each adjustment includes the incremental change to rate base, depreciation expense, operation and maintenance expenses (including any impact on system net power costs), and other items such as property taxes, miscellaneous revenue, and income taxes. Incremental rate base was computed using average balances, with electric plant in service and accumulated depreciation reserve on a 13-month average.

Q. Do your calculations include the impact on overall revenue requirement of any changes in inter-jurisdictional allocation factors resulting from these plant additions?

A. Yes. Consistent with Filing Requirement C.5 of Utah Code Section 54-7-13.4, allocation factors were allowed to remain dynamic in the JAM and were updated to reflect the impact of each plant addition in the JAM. Load based allocation factors, such as the SG and SE factors previously mentioned, are the same as those used and approved in Docket No. 09-035-23. Page 4.4 of Exhibit RMP___(BSD-1) details the change in allocation factors compared to the base case.

Q. Did you encounter any irregular results related to the dynamic allocation factors?

A. Yes. Because this filing includes updates to a limited set of revenue requirement components, the Income Before Taxes ("IBT") factor is disproportionately impacted by the adjustments for the major plant additions. According to both the Rolled-In and Revised Protocol allocation methods the IBT factor is used to allocate state income taxes. In this case, if state taxes are left to be computed and allocated in this manner the Utah-allocated revenue requirement impact of the major plant additions would be higher than it otherwise should be.

Q. What did you do to address this issue?

A. For each major plant addition added in this case the IBT factor is allowed to remain dynamic and allocate state income taxes computed within the JAM model; however, each lead sheet also includes a line item adjustment to state income taxes that results in the Utah-allocated state income taxes being included at the Company's statutory rate of 4.54%. This rate is consistent with how the Company computes tax related entries on its books and is the same method used to compute the state taxes on revenue increases in general rate cases. The net result of the adjustments to state income taxes for the two projects in this filing is a reduction to Utah allocated revenue requirement of approximately $1 million.

Populus to Ben Lomond Transmission Line

Q. Please describe the various components comprising the revenue requirement calculation for the Populus to Ben Lomond transmission line.

A. The following data inputs (on a total Company basis) were used in calculating the revenue requirement for the Populus to Ben Lomond transmission line segment investment:

- Capital additions totaling $548.1 million are scheduled to be placed in service on or before November 16, 2010.
- Annual depreciation expense totaling $10.9 million is included in results by applying a transmission-specific composite depreciation rate

of 2.03 percent to projected net capital additions.

- Depreciation reserve totaling $7.1 million is included on a 13-month average basis consistent with net capital additions. An additional $0.5 million of removal costs are included as an offset to depreciation reserve.
- Incremental O&M expense is included in results totaling $140,000. These expenses represent incremental costs the Company will incur during the first year of operation, including aerial safety patrols, ground patrols, and minor corrections of conditions found.
- A reduction in net power costs totaling $1.4 million is included based on the additional transmission capacity of the Populus to Terminal line. Please see the direct testimony of Dr. Hui Shu for a more detailed discussion regarding net power costs.
- Incremental wheeling revenue of $0.1 million is included based on the ability of the line to provide additional short term wheeling for third parties.
- Property tax expense totaling $4.3 million is included in results by taking into account the anticipated increase in assessed value and tax expense for the 2011 assessment year. Property tax expense was estimated by applying jurisdictional specific tax rates and assessment ratios to each project's total capital costs.
- Tax entries to include the capital additions and the related book and tax depreciation adjustments were calculated consistent with the

methodology used in Utah Docket No. 09-035-23. State income taxes were adjusted such that the state income tax expense impact of the incremental plant additions is at the statutory rate of 4.54%

Dunlap I Wind Project

Q. Please describe the various components comprising the revenue requirement calculation for the Dunlap I wind project investment.

A. The following data inputs (on a total Company basis) were used to calculate the revenue requirement for the Dunlap I wind project:

- Capital additions totaling $264.5 million are scheduled to be placed in service by September 30, 2010.
- Annual depreciation expense totaling $10.3 million is included in results by applying a composite depreciation rate of 4.06 percent to projected wind capital additions and 2.03 percent to projected transmission capital additions.
- Depreciation reserve totaling $7.4 million is also included on a 13-month average basis consistent with net capital additions.
- Incremental O&M expense totaling $2.5 million is included in results for the first year of operation. These expenses represent incremental costs the Company will incur during the first year to operate the wind project and newly installed transmission interconnection, including materials, contracts, preventative maintenance, and other miscellaneous operation and maintenance costs.

- A reduction in net power costs totaling $8.0 million is included based on the additional generating capacity of the plant. Please see the direct testimony of Dr. Shu for a more detailed discussion regarding net power costs.
- Incremental revenue totaling $1.3 million from the sale of renewable energy credits (“RECs”) is included based on the annual generation output of the plant. This revenue is allocated to Utah consistent with the methodology used in Docket No. 09-035-23. Please see the direct testimony of Mr. Stefan Bird for further discussion related to REC sales.
- Property tax expense totaling $1.2 million is included in results by taking into account the anticipated increase in assessed value and tax expense for the 2011 assessment year. Property tax expense was estimated by applying jurisdictional specific tax rates and assessment ratios to each project’s total capital costs.
- Tax entries to include the capital additions and the related book and tax depreciation adjustments were calculated consistent with the methodology used in Utah Docket No. 09-035-23.

Method of Cost Recovery

Q. Is the Company requesting approval to change retail rates as a result of this application?

A. Yes. The Company is requesting authority to adjust rates effective January 1, 2011, to begin to recover both the $39.0 million for projects included in this case as well as the $30.8 million for projects included in the Company's previous major plant addition case, Docket No. 10-035-13. In addition, the Company requests approval to begin collection of the amount deferred as a result of the stipulation in Docket No. 10-035-13. As of December 31, 2010, this balance is expected to be approximately $15.7 million.

Q. Please explain the Company's proposal to recover the balance of costs previously deferred.

A. As approved by the Commission in Docket No. 10-035-13 the Company began deferring the incremental revenue requirement of the major plant items in that case effective July 1, 2010. According to the stipulation in that docket, beginning on the later of July 1, 2010, or the date that the projects are both in service[2], the Company is to record a monthly entry of $2,566,667 in a regulatory asset until rates are adjusted to begin collecting the deferred balance from customers. The deferred balance accrues a monthly carrying charge of 0.695 percent (8.34 percent divided by twelve). By December 31, 2010, the accumulated balance in the regulatory asset will be $15,724,521 as shown in the following table.

Docket No. 10-035-13 Deferral

Monthly Carrying Charge 0.695%

	Deferral	Interest	Ending Balance
Jul-10	$ 2,566,667	$ 8,919	$ 2,575,586
Aug-10	$ 2,566,667	$ 26,819	$ 5,169,072
Sep-10	$ 2,566,667	$ 44,844	$ 7,780,583
Oct-10	$ 2,566,667	$ 62,994	$ 10,410,244
Nov-10	$ 2,566,667	$ 81,270	$ 13,058,181

[2] The Dave Johnston Unit 3 pollution control equipment was placed into service May 27, 2010, and the various segments of the Ben Lomond to Terminal transmission line were all placed into service by April 2010.

Dec-10	$ 2,566,667	$ 99,674	$ 15,724,521

The Company proposes to begin collecting the $15.7 million plus ongoing carrying charges from customers effective January 1, 2011, over an approximate eight month period until the balance is collected. This treatment will closely align the completion of the deferral recovery with the implementation of new rates in the Company's next general rate case. Mr. Bill Griffith addresses the specifics of the deferral recovery in his testimony. Currently the Company expects to file its next general rate case by mid-January 2011 with new rates effective mid-September 2011.

Witnesses

Q. Please identify the other Company witnesses in this application and the purpose of their direct testimony.

A. The following Company personnel have provided direct testimony addressing various issues in this application:

- Mr. John A. Cupparo, vice president of transmission for PacifiCorp, provides an overview of the Populus to Ben Lomond transmission line and demonstrates how the line is beneficial to customers.
- Mr. Darrell T. Gerrard, vice president of transmission system planning for PacifiCorp, provides additional details and technical information on the construction of the line.
- Mr. Stefan A. Bird, senior vice president of commercial and trading for PacifiCorp Energy, provides information on the Dunlap I wind project.
- Mr. Bruce N. Williams, vice president and treasurer of PacifiCorp,

describes how the Company financed the construction of the major plant additions.

- Dr. Hui Shu, manager of net power costs, presents the net power cost impact of the major plant additions.
- Mr. C. Craig Paice, regulatory consultant for cost of service, presents the class cost of service impacts related this filing and the Company's previous major plant addition case in Docket No. 10-035-13.
- Mr. William R. Griffith, director of cost of service and pricing, provides the rate spread and rate design proposed to collect the incremental impact of both major plant addition cases and the tariff rider proposed to collect the deferred balance from Docket No. 10-035-13.

Q. Does this conclude your direct testimony?

A. Yes.