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

A. My name is Brian S. Dickman. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

Q. Are you the same Brian S. Dickman who submitted direct testimony on behalf of the Company in this proceeding?

A. Yes.

Q. What is the purpose of your response testimony?

A. My testimony responds to certain issues raised by the Utah Division of Public Utilities ("DPU") in its energy balancing account ("EBA") Audit Report and by La Capra Associates, Inc. ("La Capra"), on behalf of the DPU, in its Technical Report. I first present an updated calculation of the EBA deferral, supporting deferral and recovery of $28.4 million from customers through the EBA for the 12-month period from January 1 through December 31, 2013 ("Deferral Period"). The updated EBA calculation reflects corrections identified since the Company's original filing and one adjustment related to an invoice issue raised by the DPU. Next, I respond to specific issues raised by the DPU and La Capra.

Q. Has the Company provided exhibits and workpapers supporting its updated EBA deferral calculation?

A. Yes. Exhibit RMP___(BSD-1AR) contains the updated calculation of the EBA deferral, and supporting workpapers are provided with the Company's filing. The identified adjustments to the EBA increase the Utah-allocated deferral amount by $51,046 compared to the original filing. Details regarding the individual changes are provided later in my testimony.

Q. Please summarize the Company's response to the specific adjustments proposed by the DPU that are addressed in your testimony.

A. My testimony responds to eight specific issues raised by the DPU as listed below:

1. Corrections to the EBA Calculation - The Company agrees with two corrections identified by the DPU. The first corrects the calculation of the scalar used to determine Utah-allocated net power costs ("NPC") during the Deferral Period, and the other corrects an adjustment to monthly coal costs that was inadvertently omitted from the filing. However, the Company does not agree that an adjustment is required to the booked amount for deal number 1226654 as recommended by the DPU.
2. Black Hills Power ("BHP") Damages - The Company agrees that the EBA calculation should not include amounts billed by [redacted] should be removed from the EBA.
3. Buy-Through Adjustments - The Company disagrees with the DPU's adjustment to impute a reduction to the EBA due to a lack of supporting detail for buy-through expenses. The Company's updated filing reflects a correction to the amount of buy-through during the Deferral Period, and no additional reduction should be made. The Company provided summary information through responses to data requests ("DRs") supporting the monthly buy-through amounts, and indicated that detailed information contained customer-specific information that could not be provided until consent from the affected customers was obtained. The Company has now obtained such permission and provided the detailed customer-specific information as a supplemental DR response.
4. Black Cap Adjustment - Contrary to claims made by the DPU, the Company provided all necessary information, through the original filing requirements and responses to DRs, for the DPU to verify the adjustment to actual NPC related to the Black Cap solar resource. Disallowing the Company's Black Cap adjustment is inappropriate.
5. Double Counted Pipeline Fees - The Company provided the necessary information through a response to a DR for the DPU to verify the double counted pipeline fees were correctly removed from the EBA. Adopting the DPU's adjustment would reduce the deferral twice for the same amount.
6. Plant Outages - Company witness Dana Ralston provides testimony describing the Company's disagreement with the proposed adjustments related to plant outages. However, if the Commission determines that an adjustment is warranted, the calculation of replacement power costs made by La Capra should

be corrected to reflect that the plants were not expected to run at nameplate capacity during the outages.

7. Bridger Coal Costs - The Company disagrees with each of the proposed adjustments to Bridger Coal Company costs. The Company has provided the necessary information for the DPU to validate the Bridger Coal Company invoices and royalty calculations. Further, the loss on disposal of a fixed asset occurred despite the Company's prudent mine operations, and the cost should not be removed from the EBA.
8. Clay Basin - The Company disagrees with the Clay Basin accounting adjustment and has provided a reconciliation of the injection cost for January 2013 showing the cost was booked correctly.

Q. Do any other Company witnesses also provide testimony in response to issues raised by the DPU and La Capra?

A. Yes. Company witness Mr. Dana M. Ralston provides testimony concerning plant outages, and Company witness Mr. John A. Apperson provides testimony concerning the trading transactions.

Corrections to the EBA Calculation

Q. What corrections to the EBA calculation are proposed by the DPU?

A. The DPU proposes three corrections to the EBA calculation. First, the DPU determined the Company inadvertently used the scalar from the prior year's filing in place of the scalar calculated for the Deferral Period. Second, due to a formula error, the Company did not include the monthly inventory adjustment for coal costs at the Jim Bridger plant. Third, the DPU could not tie the invoice for deal number 1226654 to the accounting entry and proposed a correction, increasing the Utah-calculation $4,625.

Q. Does the Company agree with the corrections to the EBA calculation?

A. The Company agrees with the corrections to the scalar and the Jim Bridger coal cost adjustments, which will increase the Utah-allocated deferral by amounts of

$75,827[1] and $11,230, respectively.

The Company disagrees with changing the accounting entry for deal number 1226654 booked in July 2013. The DPU proposes a correction for this deal on the basis that it doesn't tie to the supporting invoice. However, in October 2013, the Company made an adjusting entry on its books to correct deal 1226654 and another transaction, deal 1242774. As seen in Table 1 below, when the correcting entry is considered, the total booked for deals 1226654 and 1242774 matches the amount invoiced and no further adjustment to the EBA is required.

Table 1
Deal 1226654 Reconciliation

FR 6.2 Row	Deal Number	Month	Amount
20662	1226654	July 2013	$ 275,580
20730	1242774	July 2013	165,943
31049	7123	October 2013	16,077
			$ 457,600
		Deal Number	**Invoice Amount**
		1226654	$ 288,000
		1242774	169,600
			$ 457,600

Black Hills Power Damages

[redacted]

[redacted]

[1] The Company calculated EBA increase caused by correcting the scalar differs from the DPU because the Company updated the scalar after including adjustments for coal costs, buy-through, and BHP Damages.

[redacted]

[2] Wyoming Public Service Commission, Addendum to Stipulation, dated January 20, 2006. Docket No. 20000-EA-05-226 / Record No. 10015.

[redacted]

[redacted] The resulting adjustment reduces the Utah-allocated deferral amount by $17,223.

Q. Should the expense in question be included in the Deferral Period even though the invoice was not paid until 2014?

A. Yes. Per Generally Accepted Accounting Principles ("GAAP"), expenses are booked in the period incurred regardless of when the expense is paid. The Company received an invoice from BHP before closing the books for the month of December and, in accordance with GAAP, the Company accounted for the impact in December 2013.

Buy-Through Adjustment

Q. What adjustment does the DPU propose for buy-through energy?

A. The Company adjusts actual NPC to remove the impact related to buy-through of economic curtailment by interruptible industrial customers. As this adjustment reduces NPC, the DPU suggests increasing the adjustment by 25 percent citing a lack of supporting detail being provided. The DPU's adjustment reduces the Utah-allocated deferral by $395,016.

Q. Does the Company agree with the proposed DPU adjustment for the buy-through energy?

A. No. The Company provided a summary of the buy-through dollar amounts in additional filing requirement ("AFR") 15 and a summary of the buy-through MWh in DR 20.1. Data request DPU 20.1 requested customer invoices, and the Company responded that customer invoices cannot be provided without the consent of the customer, but once consent was received the Company would provide invoices. On August 13 and 15, following receipt of customer consent, the Company provided supplemental DR responses that included detailed information supporting the buy-through amounts removed from the EBA.

The adjustment proposed by the DPU is merely a penalty sought by the DPU based on an arbitrary percentage applied to a line item that reduces the EBA. The DPU's rationale is that it couldn't verify the buy-through amounts because the Company failed to provide support. As indicated above, the Company has now provided the detailed information after receiving consent from the individual customers. Furthermore, the DPU has reviewed the buy-through adjustment in previous EBA filings. While similar timing constraints were encountered relating to obtaining customer consent to provide detailed information, the DPU did not conclude further adjustments were required in those filings.

Q. Is the Company adjusting its procedures to ensure this customer-specific information for interruptible industrial customers is available in a timely manner in the future?

A. Yes. The Company is currently working with its interruptible industrial customers to gain consent to provide this customer-specific information in future requests by the DPU. This will allow the Company to provide the requested information without having to seek customer consent with each request.

Q. Does the Company propose any corrections to its original buy-through adjustment?

A. Yes. In its original response to DR DPU 20.1 the Company identified that a correction needed to be made to the buy through amounts in June and July. Upon review of the detailed support for the buy-through amounts provided in a supplemental response to DPU 20.1 the Company found that two customer invoices did not match the adjustment included in the EBA. The final corrected amounts were identified in the supplemental response to DPU 20.1, resulting in a reduction of $123,013 to total company NPC during the Deferral Period. The Company has corrected the EBA to reflect the updated information, including the impact to allocation factors, reducing the Utah-allocated deferral by $18,788.

Black Cap Adjustment

Q. What is the DPU's proposed adjustment for the Black Cap solar resource?

A. The DPU proposed a complete disallowance of the Company's Black Cap solar adjustment, reducing the Utah-allocated deferral by $47,672. Consistent with the 2010 Protocol, the costs and benefits of the Black Cap solar facility are situsassigned to Oregon because it was acquired pursuant to an Oregon state-specific initiative. In the EBA filing, the zero-cost energy output from Black Cap is initially included in system-wide NPC and would be allocated to all states. This zero-cost energy is removed from system-wide NPC by marking it to market, i.e. applying the market price of electricity to the Black Cap output. The DPU supports the allocation treatment of Black Cap as calculated by the Company, but claims the Company has not provided sufficient information to validate the mark-to-market calculation.

Q. Has the Company provided the necessary information to DPU to verify the mark-to-market adjustment for Black Cap solar?

A. Yes. The Company provided the following information prior to the issuance of the DPU audit report:

- AFR 15 included the Black Cap hourly generation for the entire year and the mark-to-market calculation performed by the Company;
- Filing Requirement ("FR") 6 provided the detailed monthly historic market prices used in the mark-to-market calculation; and
- DR DPU 20.2 provided the documentation for the intra-hour and inter-hour integration costs used in the mark-to-market calculation.

All necessary information to validate the mark-to-market calculation has been provided. The Company does not agree with the disallowance of the Black Cap solar adjustment.

Q. Has the DPU indicated what information it thought was missing?

A. In response to DR RMP 1.2 the DPU indicated the Company did not provide documentation that verified the market prices. As noted above, historical market prices were provided in FR 6 by month and by heavy- and light-load-hour periods. The monthly average prices are simply aggregates of daily market prices provided by Intercontinental Exchange, Inc. ("ICE"). Despite indicating the market prices could not be verified, the DPU has used the market prices from FR 6 in other areas of its review, including calculating the replacement power cost of plant outages as noted later in testimony.

Double Counted Pipeline Fees

Q. Please explain the DPU proposed adjustment for double counted pipeline fees.

A. Certain pipeline fees were double booked during the prior deferral period (January 2012 - December 2012) for $133,063. The Company reversed the double counted expenses on its books in January 2013. The DPU indicates it could not find the specific accounting entries removing the double counted fees, but "should additional information be provided by the Company this adjustment may be removed." The proposed adjustment reduces the Utah-allocated deferral by $42,976.

Q. Has the Company identified the specific accounting entries for the DPU?

A. Yes. In response to DR DPU 31.1, which was not due until after the DPU audit report was issued, the Company identified the line items comprising the correcting entry in AFR 17, supporting that the double-counted fees have been properly removed from the EBA. Therefore, this adjustment should be removed as stated by the DPU.

Plant Outages

Q. Please describe the proposed adjustment for plant outages.

A. La Capra, on behalf of the DPU, suggests plant outages at the Chehalis gas plant and the Craig coal plant were avoidable and therefore the replacement power costs should not be included in the EBA.

Q. Does the Company agree the replacement power for plant outages should be excluded from the EBA?

A. No. Company witness Mr. Ralston provides detailed testimony concerning the identified plant outages.

Q. Does the Company agree with La Capra's calculation of the replacement power cost?

A. No. To determine the cost of replacement power, La Capra calculated the difference between the market price for electricity and the fuel cost at each unit, applied to an estimate of lost MWh during the outage. First, the Company found several errors in the formulas referencing the market prices, causing the overall impact of La Capra's adjustments to be overstated. Second, the estimated lost MWh are simply the nameplate capacity of the unit multiplied by the duration of the outage event. In other words, the replacement costs are calculated assuming the unit would have generated at its full nameplate capacity for the entire outage.

Instead of assuming the unit would have generated at its nameplate capacity during all hours of the outage, the lost MWh should align with the monthly capacity factors used to determine NPC in rates. Base NPC was set in Docket No. 11-035-200, and includes a monthly capacity factor for each generation unit. This methodology is consistent with the structure of the EBA as it excludes the replacement power cost for only the generation included in Base NPC and all other costs are trued-up in the EBA calculation as normal. The Company would also adjust the market prices based on actual light load hours and heavy load hours in place of using an average. Making these corrections reduces the impact of the adjustments proposed by La Capra to the Utah-allocated deferral to approximately $570,000 for Chehalis and $970,000 for Craig. However, as stated in Mr. Ralston's response testimony, the Company's position is that no adjustment should be made.

Bridger Coal Costs

Q. Please describe the DPU-proposed adjustments to the Bridger Coal Company costs.

A. The DPU proposes three separate adjustments concerning the Bridger Coal Company costs:

- Pacific Minerals Incorporated ("PMI") Invoices/Non Supporting Documentation - The DPU was unable to tie the invoices for certain costs to the booked amounts (Table 3 of DPU Exhibit 1.2). This proposed adjustment reduces the Utah-allocated deferral by $43,241, and includes imputing an arbitrary 25 percent disallowance related to one line item.
- PMI Royalty Accrual - The DPU was unable to verify the August 2013 federal royalty accrual to the Bureau of Land Management ("BLM"). The DPU proposes an adjustment reducing the Utah-allocated deferral by $440,586.
- PMI Loss on Disposal of Asset - A loss on disposal of an asset occurred despite the Company's prudent mine operations. The DPU proposes to exclude the entire loss, reducing the Utah-allocated deferral by $221,322.

Q. Please explain the DPU's adjustment for PMI Invoices/Non Supporting Documentation.

A. The DPU proposes an adjustment for certain booked costs which it was unable to tie to invoices. These costs are noted in Table 3 of DPU Exhibit 1.2. Included in the DPU's review was a reversal of a Caterpillar Global Mining invoice which was double booked in October 2013. The DPU was unable to tie out the reversal and therefore added 25 percent to the item, further reducing Bridger Coal costs.

Q. Does the Company agree with the DPU's proposed adjustment for PMI Invoices/Non Supporting Documentation?

A. No. The differences noted in Table 3 of DPU Exhibit 1.2 are a result of self-accrued sales and use tax. Bridger Coal Company obtained a direct pay permit from the Wyoming Department of Revenue that authorized Bridger Coal Company, as of January 1, 2013, to accrue for sales and use tax and remit such tax directly to the state rather than to the vendor/supplier. A supplemental response to DR DPU 26.1 has been provided and includes the sales and use tax information accrued and remitted by Bridger Coal Company to the Wyoming Department of Revenue.

Q. Does the Company agree with the DPU's proposed correction of the duplicate entry for the Caterpillar Global Mining invoice recorded in October 2013 and the arbitrary 25 percent adjustment to NPC?

A. No. In October 2013, Bridger Coal Company recorded a duplicate entry for Caterpillar Global Mining - Invoice Number 91259360 for $369,825, but the Company reversed the double entry in December 2013. The Company provided the documentation reflecting the reversal of the double entry in DR DPU 34.1. The Company disagrees that an adjustment is required for this entry, and is opposed to the DPU proposing a penalty by adding an arbitrary percentage to a line item that reduces the EBA.

Q. Please explain the DPU's adjustment to the August 2013 PMI royalty accrual.

A. The DPU recalculated the Company's August 2013 federal royalty accrual using Bridger Coal Company's average operating costs for August 2013. The DPU used a cost of [redacted] per ton, derived from the Company's fuel supply report provided in AFR 13. The [redacted] per ton value is the weighted average cost of Bridger Coal Company deliveries to the Jim Bridger plant included in the EBA for August 2013. However, the royalty valuation for coal being produced from the federal and state leases in 2013 requires a separate calculation.

Q. Please explain the royalty obligations for coal mined at Bridger Coal Company.

A. Bridger Coal Company is the lease holder of federal, state, and private coal leases. Royalty rates for the private leases are based on a negotiated rate per ton. Federal and state lease royalty rates are 12.5 percent for surface-mined coal and 8.0 percent for underground-mined coal. The ad valorem rates are applied to the gross proceeds accruing to the lease holder for the federal and state leases.

Q. Please explain the royalty valuation used for the federal and state leases.

A. Bridger Coal Company is a captive mining operation that supplies coal to the Jim Bridger plant pursuant to a non-arm's length agreement. Gross proceeds for these leases are valued in accordance with regulations for non-arm's length sales transactions per the Code of Federal Register (CFR 30). Specifically, Bridger Coal Company is required to determine the value of gross proceeds pursuant to a 1994 settlement agreement with the Department of Interior's Minerals Management Service. Gross proceeds include all costs incurred to place the coal in marketable condition which is equivalent to Bridger Coal Company's operating costs, plus the Company's actual allowed rate of return on the net capital investment of the mine.

Separate royalty valuations are required for the surface mine and the underground mine. The Company prepares preliminary valuations at the beginning of each calendar year based on expected operating costs and projected coal deliveries. The valuations are adjusted during the year if material changes in costs or production are forecasted. Calculation of the final valuations and subsequent true-ups typically occurs during July to September time period of the following year.

Q. What is the basis for the royalty valuation estimates utilized by Bridger Coal Company in the August 2013 federal royalty accrual?

A. The royalty valuation initially prepared in January 2013 assumed the surface mine would deliver 390,000 tons of coal in 2013 with a federal and state coal lease royalty valuation of [redacted] per ton. For the underground mine the Company assumed 5,210,000 tons of coal would be delivered with a federal and state coal lease royalty valuation of [redacted] per ton. The lower coal deliveries of the surface mine was a significant factor in the higher royalty valuation.

Q. Did the Company make adjustments to these royalty valuations during 2013?

A. Yes. The Company updated the surface and underground mines' royalty valuations in September 2013; surface mine deliveries increased to 837,000 tons and underground mine deliveries decreased to 4,639,000 tons. Based on these delivery projections and updated costs, the estimated surface mine valuation decreased to [redacted] per ton and the underground mine valuation increased to [redacted] per ton.

Additionally, an adjustment was made to royalty expense in September 2013, to reflect the revised valuation for Bridger coal delivered during the January 2013 through August 2013 period. The Company expects to finalize 2013 royalty valuations in August/September 2014 and the resulting true-up will be captured in the 2015 EBA.

Q. Please explain the DPU adjustment for the loss on disposal of a fixed asset.

A. In DR DPU 25.4, the DPU asked the Company to "please explain why a loss on disposal of fixed assets was incurred" and to "provide supporting workpapers showing how this amount was calculated." The Company responded that during the moving of a long wall mining unit the underground mine experienced a roof failure trapping the long wall face shields which were unable to be safely retrieved. The Company also provided supporting workpapers detailing the loss incurred on the net book value of the assets. However, because the Company did not provide a root cause analysis or documentation to show prudence in maintaining the mine roof in its response, the DPU has proposed the loss on disposal of a fixed asset be excluded from the EBA, reducing the Utah-allocated deferral by $221,322.

Q. Has the DPU requested a root cause analysis for the roof collapse and documentation showing prudence in maintaining the roof?

A. Yes. The information was requested in DPU 32.2, but a response was not due from the Company until after the DPU audit report was issued.

Q. Does the Company agree with the exclusion of the loss on disposal of asset?

A. No. In addition to the fact that a roof collapse is an inherent risk in underground mining, the U.S. Department of Labor, Mine Safety and Health Administration ("MSHA") was on-site and conducted a review of the event, and no fines or citations were issued by the agency. As MSHA, the federal agency with mining operation expertise, did not fault the Company for this incident, the Company disagrees with the DPU adjustment. The MSHA report was provided as part of the Company's response to DR DPU 32.2.

Clay Basin

Q. Please explain the adjustment related to the Clay Basin accounting.

A. La Capra proposes an adjustment to remove an accounting entry related to natural gas injections at Clay Basin. In January 2013, the Company injected 11,669 MMBtu of natural gas at Clay Basin and included net injection costs of $30,888. Dividing $30,888 by 11,669 MMBtu results in a unit cost of $2.65 per MMBtu, but the invoice for the purchased gas showed a unit cost of $3.235 per MMBtu. La Capra proposes an adjustment to change the January booked costs based on $3.235 per MMBtu, resulting in a reduction of $6,861 to the Utah-allocated deferral.

Q. What caused the difference between the recorded injection cost and the cost per the invoice?

A. The total injection costs booked each month include an accrual for the current month and a true up of the prior month's accrual. Consequently, comparing the net costs booked for the month to the volume injected will not provide an accurate comparison of the unit cost of gas to the amount invoiced. For example, injection costs booked in January 2013 include the current month accrual and the true-up of December 2012 injection costs. Table 2 below illustrates the specific components of the January costs.

Table 2

Clay Basin Accounting - January 2013			
1 January Injection MMBtu			11,669
2 January Injection Accrual		$	38,654
3 Adjustment to True-Up December Injection		$	(7,766)
4 January Injection Cost Booked	(Line 3 + Line 4)	$	30,888
5 Adjustment to True-Up January Injection		$	(844)
6 Actual January Injection Cost	(Line 2 + Line 5)	$	37,810
7 January Unit Cost	(Line 6 / Line 1)	$	3.24

In February 2013 an adjustment was also made to true-up the accrual for the January injection costs. Taking the true-up entries into consideration the January 2013 injection was booked at a unit cost of $3.24 per MMBtu, which is the actual cost per the invoice.

Other

Q. Do you have any other comments concerning the DPU and La Capra audit reports?

A. Yes. Both DPU and La Capra repeatedly suggest the Company has intentionally failed to provide sufficient information and/or delayed responses to DRs. This notion is particularly concerning because the Company feels it has made a good faith effort to cooperate with the DPU as evident by supplying 20 filing requirements, responding to approximately 140 DRs, and providing more than

2,300 documents in response those DRs. In addition, filing requirements and DRs can sometimes have up to 10 or more subquestions. However, as it relates to some of the adjustments proposed in this case the Company was unaware the DPU was lacking information needed to complete its review of the EBA.

While the DPU notes it does not expect the Company to anticipate every question the DPU may have, the Company can only respond to questions as asked. Audit issues are rarely settled with one question, and responses to questions typically spark further questions. Resolution of an issue may require many rounds of questions and answers. The Company recognizes the complexity of its operations and continues to be willing to spend time with DPU to answer any follow-up questions or to give further explanation of the information provided.

Q. Does this conclude your testimony?

A. Yes.