P U B L I C

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Utility Service Schedules and Electric Service Regulations	))))))))))	**DOCKET NO. 09-035-23** **Exhibit No. DPU 7.0** **Direct Testimony and Exhibits** **Matthew Croft**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Testimony of

Matthew Croft

October 8, 2009

Q. Please state your name and occupation?

A. My name is Matthew Allen Croft. I am employed by the Utah Division of Public Utilities ("Division") as a Utility Analyst.

Q. What is your business address?

A. Heber M. Wells Office Building, 160 East 300 South, Salt Lake City, Utah, 84114.

Q. On whose behalf are you testifying?

A. The Division.

Q. Please describe your education and work experience.

A. I graduated in December of 2007 from the University of Utah with a Bachelor of Arts degree in Accounting. I am currently enrolled in the Masters of Accounting program at the University of Utah. I began working for the Division in July of 2007.

Q. Have you previously testified before the Commission?

A. Yes. I testified concerning various revenue requirement adjustments in Dockets 07-035-93 and 08-035-38.

Q. What is the purpose of the testimony that you are now filing?

A. The purpose of my testimony is to propose and explain adjustments to Rocky Mountain Power's ("Company") filed Utah Revenue Requirement.

Q. Can you please identify your adjustments and the corresponding effect on Utah's revenue requirement?

A. Yes. My adjustments are summarized in the table below with the approximate revenue requirement impact.

Adjustment	Approximate Utah Revenue Requirement Effect
Remove Washington Public Utility Tax	(3,851,132)
Revise Rate Base Templates with Actual Plant Additions	(35,386)
Trapper and Bridger Mines Rate Base	100,891
Apply Test Year Revenues and Expenses to Lead Lag Study	(95,000)
Reduction to Business Unit Target	(950,197)
Total	(4,830,824)

Q. **Can you please explain your adjustment concerning the Washington Public Utility tax (WPUT)?**

A. Yes. In 2008, the Company paid $9.3 million for the WPUT and has assumed the same amount for the test year. The Company has included this amount in FERC account 408 and applied an SO allocation factor in the Jurisdictional Allocation Model (JAM) which results in Utah being responsible for an allocated cost of $3.9 million. This tax only relates to Washington and so I propose that the WPUT be assigned 100% to Washington. This change not only reduces Utah's allocated expenses by $3.9[1] million, but there is also a secondary effect on the lead lag study which will be discussed later in my testimony.

Q. What is the WPUT?

A. The WPUT is basically a tax on revenue earned from Washington customers. The Revised Code of Washington[2] states the tax base for the WPUT to be:

> Gross income[3] derived from operation of public and privately owned utilities, including the general categories of transportation, communications, and the supply of energy and water…Unlike the B&O tax which pyramids (i.e. different

[1] See DPU Exhibit 7.2
[2] RCW 82.16. http://dor.wa.gov/docs/reports/2007/Tax_Reference_2007/27publicutility.pdf
[3] "Gross income" is defined in RCW 82.16.010 as the "value proceeding or accruing from the performance of the particular public service or transportation business involved, including operations incidental thereto, but without any deduction on account of the cost of the commodity furnished or sold, the cost of materials used, labor costs, interest, discount, delivery costs, taxes, or any other expense whatsoever paid or accrued and without any deduction on account of losses."

> firms may be taxable on income derived from the same product), the public utility tax applies only on sales to consumers.

This tax base[4] is multiplied by 3.873% to arrive at the WPUT owed. Backing out the 3.873% from the $9.3 million tax included in the base and test year yields a tax base amount of $240.7 million. The general business revenues allocated to Washington[5] in this case are approximately $284 million. It is therefore assumed that the $240 million tax base is solely from Washington customers.

Q. What is the WPUT used for?

A. According to the Washington Department of Revenue website,

> The majority of the funds are distributed into the state general fund. A portion, however, provides financial assistance to local governments for maintenance of public works facilities.[6]

The WPUT is a tax on Washington related income that goes directly to the benefit of the people of Washington. This is a tax that Utah ratepayers should not have to pay for as it is based on revenue from Washington customers and only benefits the people of Washington.

Q. Why has the Company allocated the WPUT using an SO factor?

A. In response to DPU 13.12 the Company stated that:

> Other taxes are allocated as prescribed under the Revised Protocol methodology. This allocation was properly reflected in the lead lag study and in this general rate case proceeding. Please refer to Docket 02-035-04 for information regarding the Revised Protocol methodology.

I reviewed Docket No. 02-035-04 for information regarding the allocation of other taxes (which would include the WPUT) but I could only find one instance when other taxes were mentioned. Exhibit B of the stipulation in that docket is a spread sheet that indicates each

[4] See RCW 82.16. There are certain deductions that can be taken from gross income.
[5] See the UTCR tab in the Company's JAM model.
[6] http://dor.wa.gov/content/FindTaxesAndRates/OtherTaxes/tax_pubutil.aspx

FERC account and associated allocation factors under revised protocol and rolled-in methodologies. Exhibit B shows FERC 408 (Taxes Other than Income) as including the same five factors under rolled-in and revised protocol. These factors include S (Situs-Direct assigned), GPS (Property), SO (General Payroll Taxes), SE (Misc Energy), and SG (Misc Production). The Company has assigned an SO (General Payroll Taxes) factor to WPUT. The WPUT however is not at all related to general payroll taxes. As explained previously, the WPUT is a tax on the Company's Washington related gross income. Under Exhibit B of the Commission's approved stipulation under Docket No. 02-035-04 the situs factor was one of the factors included under FERC account 408. I have therefore assigned the WPUT on a situs basis to Washington. As mentioned previously, this reduces Utah's revenue requirement by approximately $3.9 million.

Q. **Can you please explain your adjustment concerning plant additions?**

A. Yes. My adjustment concerning plant additions and the corresponding effects on depreciation, depreciation reserve and retirements reduce Utah's revenue requirement by only about $35,000. The specific plant additions adjustment can be divided into four areas. First, I adjusted the January 2009 through August 2009 plant addition forecast with information on the actual plant additions received from the Company. Secondly, I adjusted the September 2009 through June 2010 forecast for plant additions that were partially or fully placed into service early (i.e., during the January 2009 through August 2009 time frame). For example, the "Snyderville Add 2nd Transformer" project was scheduled to go into service in October 2009 at a total project cost of $6.2 million but $1.2 million was already placed into service through August 2009. Third, I have also adjusted for projects that were forecasted to be placed in service before September 2009 but are now anticipated to be placed into service later during the test period. For example, the “Hurricane Twin Cities 69kV Ln Purchase” project was expected to be placed in service by July 2009 at a cost of $3.2 million. According to the Company’s supplemental response to DPU 5.3(c), this project will not be placed into service until September 2009 but will remain at the original forecasted cost. I therefore increased the September 2009 plant addition forecast by $3.2 million. The fourth part of this adjustment accounts for a few projects with in-service dates and or dollar amounts that have shifted within or after the September 2009 through June 2010 time frame. For example, the High Plains wind plant was forecasted to be placed into service in October 2009 at $245.5 million but was placed into service on September 13th 2009[7] and the costs are expected to be approximately $236.4million[8]. The Blundell 3 Project Development and Well Integration project is now scheduled to be placed into service in July 2010 and has therefore been removed from rate base because it falls outside the test period. Since there are more than 40 individual adjustments to the Company’s plant additions I will not discuss each one. DPU Exhibit 2.6 shows all of these individual plant addition adjustments in the “Adjustment Breakdown” tab. I also adjusted the retirements’ template for actual retirements incurred by the Company through August 2009. The combination of the change in forecasted plant additions and forecasted retirements has been carried through the depreciation template and so corresponding adjustments to both depreciation expense and the depreciation reserve have been made. These adjustments have the following effect on Utah’s revenue requirement:

[7] See RMP response to DPU 29.24
[8] See RMP response to DPU 42.6

	Total Company Adjustment to Rate Base (13 Mo Avg)	Utah Revenue Requirement Effect
Rate Base		
Plant Additions	(40,832,146)	334,501
Retirements	(30,230,997)	(872,401)
Depreciation Reserve	31,714,070	966,205
		428,305
	Total Company Adjustment to Expense	**Utah Revenue Requirement Effect**
Expense		
Depreciation	(2,414,995)	(463,690)
Total		(35,386)

Q. **Can you please explain how a $40 million total Company decrease to plant additions results in a slight increase to Utah's revenue requirement?**

A. Yes. The $40 million decrease is the net result on a total Company basis. Utah's allocated share of that adjustment is very different. For example, the actual distribution additions for Utah that are situs assigned were approximately $10.5 million higher (13 month average) then those that were included in the filing. Transmission additions, which are allocated on an SG factor (41%) were approximately $20 million (13 month average) higher than what was included in the filing. These increases were offset by other items that mostly get allocated on an SG factor. These offsetting items include steam, wind, and hydro additions, which were a combined $63 million (13 month average) lower than what was included in the filing. These items combined with several others resulted in the slight increase to Utah's revenue requirement.

Q. **Can you please explain what significant and specific plant addition projects contributed to this slight increase?**

A. Yes. Although there are several adjustments that offset each other, there are a few items that should be mentioned. First, it appears there was a shift in distribution projects from Oregon to Utah. Oregon's actual capital addition projects (through August 2009) related to distribution were approximately $16.7 million (total, not average) less than the forecast included in the filing. Although I have accepted the Company's actual distribution additions for now, I have issued a data request (DPU 50) concerning this shift in distribution projects. This adjustment may change depending on the response to this data request. A second item is the change of the in-service date for High Plains. High Plains was placed into service on September 13th, approximately one month earlier than expected. In addition, approximately $15.6 million of the $236.4 million forecasted cost was placed into service through August 2009. Due to the Company's use of a thirteen month average, the dollars placed into service earlier get weighted heavier than projects that go into service later and therefore increase the revenue requirement. Although the full in-service date for the "Oquirrh New 345-138kV Substation" has been pushed back by six months (from June 2009 to December 2009), the cost has increased from $26.9 million to $49.8 million. When considering the 13 month averaging method, the change from June 2009 to December 2009, and the increase in total costs related to this project, Electric Plant In Service (EPIS) increases about $8.7 million. Although I have accepted this increase in cost and change of in-service date for now, I have issued a data request concerning this matter. This adjustment may change depending on the response to this data request.

Q. **Where there any assumptions used in making your adjustments to the Company's forecasted plant additions?**

A. Yes. In making my rate base adjustments there were a few assumptions I had to use. First, if a project was going into service in a particular month, I assumed that the entire associated dollar amount was also placed into service in that month[9]. Based on the Company's response to DPU 6.2 however, it appears that some projects have dollar amounts going into service in other months besides the specific months stated on pages 8.10.5 through 8.10.15 of Company Exhibit SRM-2. I have issued a data request (DPU 50.2) asking the Company to provide the forecasted in-service dollar amounts by month for each project listed on pages 8.10.5 through 8.10.15 of SRM-2. Once I receive this response I will revise my adjustment if necessary for these timing issues so that nothing is double counted. Second, I assumed that McFadden Ridge will be placed into service on September 30th as indicated by the Company. This project was originally forecast to be placed into service in October, was later changed to November and now is anticipated to be September 30th. I have issued a data request (DPU 49.3) to the Company concerning this matter and reserve the right to change the McFadden Ridge in-service date depending on the Company's response.

Q. **Are there any other adjustments related to plant additions that need to be made?**

A. Yes. In addition to providing the actual plant additions, the Company also provided updates of Unclassified Plant (FERC 106).

Q. **Can you please explain what Unclassified Plant (FERC 106) is and how it relates to plant additions?**

A. Yes. FERC 106 consists of plant additions that are providing benefit to customers but have not technically been transferred to FERC 101 (EPIS). The dollars associated with capital addition projects move from Construction Work in Progress (CWIP) to FERC 106 and then

[9] One major exception is the McFadden Ridge project. See DPU Exhibit 2.6.

to EPIS. FERC 106 is therefore somewhat of a holding account that goes up and down throughout the year as projects move from CWIP to EPIS. The dollars in FERC 106 are providing service and benefit to rate payers and are therefore recoverable through the Company's return on rate base. Because of the constant fluctuation however, it is nearly impossible to predict what will be in this account and when.

Q. **How has the Company chosen to forecast FERC 106?**

A. The Company assumed a test year amount equal to the December 2008 level. At the end of December 2008 approximately $362 million ($300. 4 million related to Chehalis) resided in FERC 106. This amount is then carried through the test year. Each month, that same $362 million gets depreciated. In reality however, FERC 106 would be constantly changing each month as dollars move in from CWIP and out to EPIS.

Q. **How have you chosen to adjust FERC 106?**

A. The first part of my adjustment assumes the same method as the Company with the exception that June 2009 through August 2009 incorporates the actual movement of FERC 106. This information was provided to the Division in the initial and supplemental responses to DPU 5.3(b). My adjustment includes the actuals for those three months. My adjustment will change once I receive the actual FERC 106 balances from January 2009 through May 2009[10]. My calculations can be seen in the electronic DPU Exhibit 2.5 under the "Adjustments Breakdown" and "FERC 106 Adj" tab. They are also in DPU Exhibit 7.5. I have included the actual movement for these amounts so as not to double count items that might be in the actual EPIS additions that have also been provided by the Company. In addition, the Company's thirteen month averaging methodology for EPIS includes the months of June

[10] DPU Data Request 54 is still pending.

2009 through August 2009. By making this adjustment, the August 2009 amount ($352 million) in FERC 106 is carried through to the end of the test year rather than the Company's December 2008 amount ($362 million).

Q. **Which of these two amounts ($352 million and $362 million) is more likely to be representative of the September 2009 through June 2010 time frame?**

A. We know that the amount related to Chehalis ($300.4 million) will carry through to the end of the test year whether it's in FERC 106 or EPIS. The variable portion of FERC 106 ($51 million at August 2009, $61 million at December 2008) is with the other components which consist of steam, transmission, distribution, and general plant. I have looked at past history to see how FERC 106 has fluctuated on a total Company basis. As DPU Exhibit 7.5 shows, the three year average from 2006 to 2008 was approximately $45 million. If I include 2006 to August 2009 data, the average is about $47 million. Based on these data I believe the variable portion of FERC 106 for August 2009 ($51 million) would be a reasonable balance to carry forward through the test year rather than the Company's $61 million.

Q. **What is the net effect of all your adjustments related to plant additions and their corresponding effect on depreciation, depreciation reserve and retirements?**

A. As explained previously, the net effect on Utah's revenue requirement is a reduction of $35,386.

Q. **Do you have other rate base adjustments concerning the actual information received from the Company?**

A. The Company also provided actual information through August 2009 for the Bridger and Trapper Mines. By updating the Trapper and Bridger Mines through August 2009 I also had to change the subsequent September 2009 through June 2010 forecast. I assumed the same equipment additions as were originally forecast for those months. This adjustment (Trapper and Bridger combined) increases total Company rate base by $2,116,661 and increases Utah's revenue requirement by approximately $100,844.

Q. **Can you please explain your adjustment concerning the Lead Lag study?**

A. Yes. My adjustment to the lead lag study is composed of two parts. The first is to remove the WPUT component from the Other Taxes lag day calculation. The second part applies the revenue and expense lag day components on page 2.1 of the study to the Commission approved test year revenues and expenses[11].

Q. Can you please explain why you have removed the WPUT component from the Other Taxes lag day calculation?

A. Yes. As explained earlier in my testimony, the WPUT only pertains to the Company's Washington income and the benefits of the tax go just to the people of Washington. Removing the WPUT increases the expense lag associated with other taxes from 41.07 days to 65.28 days.

Q. Can you please explain why you have applied test year revenues and expenses to the lead lag study?

A. Yes. I will first provide an explanation for what I am proposing compared to what was filed by the Company. The schedule below is a very simplified version of page 2.1 of the lead lag study and is used for the purpose of explaining my adjustment.

[11] DPU Exhibit 2.5 (JAM) currently includes the Division's revised revenues and expenses.

RMP - As Filed

2007 Lag Day Components
2007 Revenues/Expenses

(2007 Rev Lag Days - 2007 Exp Lag Days)
x (2007 Exp/365 Days)
Cash Working Capital Balance

DPU Proposed

2007 Lag Day Components
June 2010 Revenues/Expenses

(07/Jun 10 Rev Lag Days - 07/Jun 10 Exp Lag Days)
x (**June 2010** Exp/365 Days)
Cash Working Capital Balance

The lead lag study used by the Company in this case applies revenue and expense lag day components (calculated from calendar year 2007 data) to calendar year 2007 revenues and expenses. Since the Company has chosen a forecasted test year, I believe the lead lag study should reflect to the extent possible that forecast year and incorporate the Commission approved test year revenues and expenses.

Q. Since the revenue and expense lag day components are based off of 2007 data, wouldn't it be more appropriate and consistent to apply them to 2007 revenues and expenses as the Company has done?

A. My adjustment using test year revenues and expenses does create an inconsistency in that the revenue and expense lag day components were based on conditions during 2007, not the 12 months ended June 2010. This rate case however is based on a June 2010 test period and so either method has some kind of inconsistency. The essence of the lead lag study is to help calculate the cash working capital needed by the Company. Cash working capital is basically the funds needed from investors to sustain daily operations during the time between when expenses are paid and revenues received. Since the Company has used a June 2010 test year, the funds required by investors during the test year should be based as much as possible on the conditions during the test year. Using test year revenues and expenses brings the lead lag study closer to the conditions during the test year. Page 1.1 of the lead lag study explains guidelines that were used by the Company that are "consistent with Robert Hahne's text 'Accounting for Public Utilities.'" "Accounting for Public Utilities" states the following:

> The lead-lag study requires comprehensive analysis of the <u>test year</u> transactions to determine "net lag days" for:
>
> 1) The time lag between services rendered and the receipt of revenues for such services; and
> 2) the time lag between the recording of labor, materials, etc., costs and the payment of such costs.[12]

The text goes on to say that, "The net lag days are multiplied by the average daily operating expenses for the <u>test year</u> to produce cash working capital used in maintaining daily operations." Although we can't determine the revenue and expense lag day components for the Company's chosen test year without a new lead lag study, the reasonable revenues and expenses for the test year will be determined by the Commission. If the Commission decides that the 2007 revenues and expenses would be more appropriately applied to the 2007 revenue and expense lag day components, I would propose that at least the overall net lag

[12] <u>Accounting for Public Utilities.</u> Hahne. Matthew Bender & Company, Inc., member of LexusNexis Group. Publication 16, Release 25, October 2008. Page 5-8. Section 5.04[2].

days be multiplied by the "average daily operating expenses for the test year," as stated in "Accounting for Public Utilities.[13]"

Q. Will you please summarize why you have included test year revenues and expenses in the lead lag study?

A. Yes. My adjustment to include test year revenues and expenses essentially takes the Company's lead lag study one step further to best reflect the test period and to be consistent with Mr. Hahne's "Accounting for Public Utilities." In either method there are inconsistencies with using 12 months ending June 2010 and calendar year 2007 data. My adjustment brings as much of the test year into the lead lag study as possible to get a more accurate reflection of the test year period. The inclusion of the DPU revised test year expenses and revenues as well as the exclusion of the WPUT results in a net revenue lag of 5.26 days (under Rolled-In) which is .34 days less then that proposed by the Company. This reduction reduces the Company's cash working capital from $18,147,356 to $16,517,320. This adjustment reduces Utah's revenue requirement by approximately $95,000.

Q. Will you please explain how you have modeled this adjustment?

A. Yes. I have created a new tab in the Company's JAM model (DPU2.5) that represents Page 2.1 of the lead lag study. This new tab pulls in the test year (under Rolled-In) revenues (with the price increase) and expenses from other tabs in the JAM. This does create an additional circularity but the JAM compensates for this circularity. I placed the overall lead lag adjustment in the JAM last.[14]

[13] Ibid, Pp. 5-8. Section 5.04[2].
[14] Subsequent to this adjustment being placed in the JAM, a slight revision was made to the LLS 2.1 Tab in the JAM. This revision was combined with the QF adjustment which was technically the last adjustment run in the JAM.

Q. Will you please explain your other outstanding issues?

A. Yes. In response to DPU 5.2 the Company stated:

> In the relicensing process, PacifiCorp has proposed removing the Keno development from the Klamath Hydroelectric Project since it does not generate power and does not significantly benefit downstream generating facilities.

It is not entirely clear that the Keno Development is providing benefit to rate payers and should be recovered in rates. I have issued a data request (DPU 47.1) concerning this matter and an adjustment may be warranted once I receive the Company's response. I have also issued a data request (DPU 45) concerning the Cline Falls hydro facility which is no longer being operated by the Company. If there are costs associated with this facility in the test year, there may be an adjustment in this area as well. It was recently reported that the Company is no longer seeking to relicense the Klamath hydroelectric system. The Company's 2008 10K filing states that $57 million is included in CWIP for this relicensing. I am assuming for the time being that since the $57 million is in CWIP, it is not included the Company's filing. I have issued a data request (DPU 52) concerning this matter and an adjustment may be warranted, depending on the Company's response.

Q. Will you please explain your adjustment to the Company's Business Unit Target (Adjustment 4.19) ?

A. Yes. I will first explain adjustment 4.19 in general terms and more specifically how the Company calculated the adjustment. For a "reasonableness check,"[15] the Company decided to compare the "Adjusted 12 Month Ending June 2010 non- net power cost O&M" (JAM O&M) to the "Business Unit Target 12 Months Ending June

[15] DPU Data Request 18.6-1

2010" (Budget O&M). In calculating Adjustment 4.19, the Company started out with their total non-net power cost operation and maintenance expense (Total OMAG) from their 2009 and 2010 budgets. To make these budget amounts more comparable to the JAM O&M, the Company made subsequent adjustments to the 2009 and 2010 Total OMAG amounts. The Company then took the average of the 2009 and 2010 Total OMAG and subsequent adjustments. This average ($1.014 billion) is the Company's Budget O&M. Upon comparing the Budget O&M to the JAM O&M, it was found that the Budget O&M was approximately $8.8 million lower on a total Company basis. The Company then decided to lower the JAM O&M by that same amount. The Company used a proration methodology based on the JAM O&M to spread the $8.8 million to five specific FERC accounts. After spreading this adjustment to these five FERC accounts Utah's revenue requirement is reduced by $3.8 million. By averaging the 2009 and 2010 Budget O&M, the Company's methodology uses information outside of the test year. In response to DPU 18.8(2) the Company provided their 2009 and 2010 budget by month. [redacted]

Q. Has the Company provided an explanation for why they took an average of the two years as opposed to adding up the months of the test year?

A. Yes. In response to DPU 20.3 the Company stated:

> The Company used total budget numbers to insure no inaccuracy was introduced into the Business Unit Target by budget items that are accurate in total but simply included in the wrong month.

There are a few issues I have with this statement. First, since the Company budgets by month, I do not see how using the exact months of the test period would include items in the wrong month. Second, by including the two years in total OMAG, the Company is including things that are outside of the test year. For example, there are $33.4 million of budgeted overhaul costs for the first six months of 2009[16]. The last six months which are part of the test year only have $5.9 million budgeted for overhaul costs. The first six months of 2010 have $27.5 million budgeted while the last six months have $13 million budgeted. Third, many of the 2010 OMAG components have escalation factors built into them. Included in total OMAG for example are 2010 budgeted O&M costs for wind generation that are then applied to an escalation factor of 1.7%.

Q. Page 4.19.3 of SRM-2 contains subsequent adjustments to the total OMAG number to arrive at the business unit target. These subsequent adjustments are averages of calendar year 2009 and 2010. Have you changed these adjustments to match the exact months of the test year?

A. To be consistent with my OMAG adjustment above, I wanted to get many of these subsequent adjustments on page 4.19.3 by month but the Company responded in DPU 40.1 by saying that, "The amounts are all prepared on an annual basis. The Company uses the average of the budget for 2009 and 2010 to get the budget for the 12 months ended June 2010." With the exception of the "Remove Overhaul" adjustment, the Company has not provided month by month numbers. I have therefore used the Company's method of averaging these adjustments to arrive at the Business Unit Target. All these subsequent adjustments to Total OMAG are in DPU Exhibit 7.3.3. I have also issued a data request

[16] See DPU 7.3.3

concerning the “Remove Insurance” adjustment on page 4.19.3 that has not yet been answered. If the Company provides the insurance costs by month I will account for them the same way I have accounted for the “Remove Overhaul” adjustment.

Q. What is the overall effect of using the exact test year months as opposed to using an average of 2009 and 2010?

A. In applying my adjustment to recalculate adjustment 4.19, I also took into consideration the overhaul and payroll tax adjustments by DPU witnesses Salter and Thomson. This combination results in a total Company reduction to the Business Unit Target of $2,179,258. Once the proration methodology is applied to that amount, Utah’s revenue requirement is reduced by $950,197.

Q. Does this conclude your testimony?

A. Yes.