Witness OCS – 3R

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	**)**	**Docket No. 13-035-184**
Rocky Mountain Power for Authority to	**)**	
Increase Its Retail Electric Utility Service	**)**	**Rebuttal Testimony**
Rates In Utah and for Approval of Its	**)**	**of Donna Ramas**
Proposed Electric Service Schedules	**)**	**For the Office of**
And Electric Service Regulations	**)**	**Consumer Services**
	)	

June 4, 2014

Contents

INTRODUCTION 1

SUPPORTIVE REBUTTAL TESTIMONY ON SELECT ISSUES 2

Expired Amortization of Regulatory Asset..2

Special Contract Rate Increases 4

Naughton Unit 3 Extended Coal Operations 4

Unclassified Plant – Account 106 Adjustment..6

City Creek Project – CIAC 8

WOOD HOLLOW WILDFIRE COSTS..11

GENERATION OVERHAUL EXPENSE..12

NET PENSION & POST-RETIREMENT WELFARE PLAN PREPAID ASSET..16

JURISDICTIONAL ALLOCATION FACTORS 25

INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Donna Ramas. I am a Certified Public Accountant licensed in the State of Michigan and Principal at Ramas Regulatory Consulting, LLC, with offices at 4654 Driftwood Drive, Commerce Township, Michigan 48382.

Q. ARE YOU THE SAME DONNA RAMAS THAT SUBMITTED PREFILED DIRECT TESTIMONY IN THIS PROCEEDING ON MAY 1, 2014?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I first address several recommendations that I am supportive of which are presented in the direct testimonies of The Federal Executive Agencies ("FEA") witness Greg R. Meyer; UAE Intervention Group ("UAE") witness Kevin C. Higgins; and Division of Public Utilities ("DPU" or "Division") witnesses Matthew Croft and Richard S. Hahn.

I then briefly address the direct testimony of DPU witness David T. Thomson as it pertains to costs associated with the Wood Hollow wildfire.

I next address two issues discussed in the direct testimony of Artie Powell on behalf of the DPU. Specifically, as I have done in several prior cases, I address Dr. Powell's position that the actual historical generation overhaul expense amounts used in normalizing the amount of generation overhaul expense to include in base rates should be escalated to test year dollars prior to averaging. I again respectfully disagree with Dr. Powell's recommendations and conclusions on this issue. I also discuss several aspects of Dr. Powell's testimony addressing RMP's request to include the net prepaid pension asset in rate base.

Finally, I provide the impact of the updated line-loss factors on the jurisdictional allocation factors that include system load in determining the allocation percentage between the states. DPU witness George Evans and OCS witness Philip Hayet both recommend that the line-loss factors in the GRID model be updated. The line-loss factor updates result in a reduction of the system energy requirements. In his direct testimony, Mr. Hayet updated the system loss factor and applied the impact equally to all jurisdictional load. In his rebuttal testimony, Mr. Hayet refines his calculations by developing individual loss factor adjustments for each state.

SUPPORTIVE REBUTTAL TESTIMONY ON SELECT ISSUES

Expired Amortization of Regulatory Asset

Q. ARE THERE ANY ISSUES PRESENTED IN THE DIRECT TESTIMONY OF FEA WITNESS GREG R. MEYERS FOR WHICH THE COMMISSION HAS PROVIDED FURTHER GUIDANCE OR DIRECTIVES?

A. Yes. At page 15 of his direct testimony, Mr. Meyers indicates that the regulatory asset associated with the tax impact of healthcare reform changes to the deductibility of Medicare retiree drug subsidies will be fully amortized in September 2014. Thus, he recommends that the amortization expense be removed from the test year. The response to FEA Data Request 1.3, Attachment FEA 1.3 shows that $1,237,799 remains in test year expenses for the amortization on a total Company basis.

In its September 13, 2010 Order in Docket No. 10-035-38, at page 8, the Commission specifically addressed the amortization and the expiration thereof as follows:

> Based upon the above-described findings and conclusions, we issue an accounting order authorizing PacifiCorp to record a regulatory asset in the amount of $6.284 million. The asset shall be amortized over a four year period beginning October 1, 2010 and ending September 30, 2014. No return on rate base is authorized for any unamortized portion of the asset. PacifiCorp shall remove the amortization from rates in the Company's general or single item rate case anticipated to be filed in 2014, effective October 1, 2014.

Thus, under the Commission's Order, PacifiCorp is to remove the amortization expense associated with the tax impact of healthcare reform changes to the deductibility of Medicare retiree drug subsidies in this rate case. In searching through RMP's filing, I was unable to locate an adjustment removing the amortization expense. If the Company is unable to clearly demonstrate in its rebuttal testimony that the amortization expense has been excluded from test year expenses, then Mr. Meyer's adjustment should be made.

Special Contract Rate Increases

Q. UAE WITNESS KEVIN HIGGINS INDICATES THAT RMP HAS NOT ACCOUNTED FOR A PERCENTAGE BASE RATE INCREASE FOR A SPECIAL CONTRACT CUSTOMER THAT IS EFFECTIVE JANUARY 1, 2015 PER THE CONTRACT TERMS. DO YOU AGREE THAT AN ADJUSTMENT SHOULD BE MADE TO THE TEST YEAR TO REFLECT CONTRACTUAL RATE INCREASE?

A. Yes. I am not personally familiar with the special contract specifically discussed by Mr. Higgins in his testimony. However, if his assertion that the contract calls for a percentage rate increase effective January 1, 2015 is accurate, then I agree that an adjustment should be made to reflect the impact on the test year ending June 30, 2015. UAE Exhibit RR 1.2 shows that reflecting the increase for the six months of the test year that it would be effective results in a $268,772 increase in Utah revenues, which reduces the revenue requirements in this case by $269,085.

Naughton Unit 3 Extended Coal Operations

Q. WHAT ASSUMPTIONS DID RMP INCORPORATE IN ITS FILING REGARDING THE OPERATION OF NAUGHTON UNIT 3?

A. RMP prepared its filing under the assumption that Naughton Unit 3 will cease operations as a base load coal-fired generating unit in December 2014 and be converted to a gas-fired peaking unit by May 2015. RMP has requested approval to extend the operation of the unit as a coal-fired unit until December 31, 2017. The Direct Testimony of Steven R. McDougal, at page 44, indicates that the Company will update the revenue requirement in its rebuttal filing if it receives authorization for the extension prior to its rebuttal filing. He also indicates that the estimated reduction to the revenue requirements filed in this case resulting from such extension is approximately $5.2 million.

In its April 10, 2014 Net Power Cost ("NPC") Update filing in this case, RMP indicated that the extension of the operation of Naughton Unit 3 as a coal-fired resource until December 31, 2017 is now contingent on the Wyoming Department of Environmental Quality granting an amendment to the unit's Wyoming Regional Haze Best Available Control Technology ("BART") permit. The NPC Update filing indicated that if Wyoming grants the amendment to the BART permit prior to the rebuttal testimony due date, RMP will update the revenue requirements in its rebuttal position to reflect the impacts of the amendment. The NPC Update also indicates that if Wyoming's decision to modify the BART permit is issued after the rebuttal testimony due date, "…the Company will measure and defer any cost savings from continued Naughton Unit 3 coal operations past December 2014 for future rate making treatment."

Q. DID THE OCS OPPOSE THIS APPROACH IN ITS DIRECT TESTIMONIES?

A. No. The OCS did not find RMP's proposed approach to this issue unreasonable. Thus, I did not address RMP's approach in my direct testimony.

Q. DID ANY PARTIES PRESENT AN ALTERNATIVE APPROACH?

A. Yes. UAE Witness Kevin Higgins recommends that the revenue requirements in this case be calculated based on the Company's planned extension of the Naughton Unit 3 operations as a coal-fired unit, reducing the Utah revenue requirement by $5.2 million. He indicates on page 45 of his direct testimony that if the Company's proposed extension is rejected, "…the incremental costs attributed to that rejection can be deferred for future ratemaking treatment." This is the inverse of the Company's approach.

Q. IS MR. HIGGINS' ALTERNATIVE APPROACH ALSO REASONABLE?

A. Yes, it is. While the OCS does not find RMP's approach to be unreasonable, the approach proposed by Mr. Higgins would also be an acceptable alternative. Both approaches would provide protection to ratepayers and shareholders should the outcome of the requested extension of Naughton Unit 3 as a coal-fired unit differ from the assumption used in setting the revenue requirements adopted by the Commission in this case.

Unclassified Plant – Account 106 Adjustment

Q. IN HIS DIRECT TESTIMONY, DPU WITNESS MATTHEW CROFT REMOVES UNCLASSIFIED PLANT FROM TEST YEAR RATE BASE.

COULD YOU PLEASE BRIEFLY SUMMARIZE YOUR UNDERSTANDING OF HIS RECOMMENDATION REGARDING UNCLASSIFIED PLANT?

A. Yes. Exhibit RMP__(SRM-3), pages 2.21 through 2.30, show that the amount included in the average test year for the various unclassified plant accounts is based on the historic base year average balances. For example, page 2.25, lines 1636 through 1638 demonstrate that the "Unclassified Trans Plant – Account 300" balance for both the average base year and the average test year is $68,298,685 ($29,114,580 Utah). FERC Account 106 includes Completed Construction Not Classified, or "Unclassified Plant". At page 10 of his Direct Testimony, Mr. Croft explains that what he identifies as "Unclassified Plant (Account 106)" consists of three different FERC accounts, including FERC Account 106. At that same page of his testimony, Mr. Croft indicates that he removes all Unclassified Plant (Account 106) amounts from rate base in the JAM model because the underlying capital additions and retirement estimates that give rise to the balances are already accounted for in the plant in service accounts, FERC account 101, subaccounts 301 to 399, in the future test year. Thus, the unclassified plant balances included in the future test year by RMP need to be removed as they are already included in the classified plant balances (i.e., Account 101, subaccounts 301 through 399).

Q. DO YOU FIND MERIT IN MR. CROFT'S ADJUSTMENT TO REMOVE THE UNCLASSIFIED PLANT BALANCES FROM TEST YEAR RATE BASE?

A. Yes, I do find merit in Mr. Croft's discussion on this issue. However, I did not independently trace the items included in FERC account 106 – Completed Construction Not Classified in the base year to the Account 101 – Plant in Service balances at the beginning of the test year to ensure that there is in fact a double count for each of the individual plant items. Unless RMP is able to clearly demonstrate in its rebuttal testimony that there is no double-counting of the unclassified plant balances in the test year, Mr. Croft's adjustment should be adopted.

<u>City Creek Project – CIAC</u>

Q. DO YOU WISH TO COMMENT IN YOUR REBUTTAL TESTIMONY ON ANY OF THE ISSUES RAISED IN THE DIRECT TESTIMONY OF DPU WITNESS RICHARD S. HAHN?

A. Yes. In his direct testimony, at pages 55-60, Mr. Hahn addresses the City Creek project, which is a mixed residential and commercial development in downtown Salt Lake City. Property Reserve Inc. is the developer of the project. In both this rate case and the prior general rate case, Mr. Hahn contends that the Company failed to require the developer of the City Creek project to pay a reasonable amount of Contributions in Aid of Construction ("CIAC") on the project and that the determination of the CIAC was not consistent with RMP's line extension policy described in

Regulation 12. In the current proceeding, at page 60 of his direct testimony, Mr. Hahn indicates that the proper CIAC on the project that RMP should have collected is $17.85 million, RMP collected $7 million, and that the under-collection is $10.85 million. He recommends that plant in service be reduced by the $10.85 million that he contends should have been collected from the developer of the project.

Q. WHY SHOULD RMP PURSUE THE RECOVERY OF CIAC WHEN ALLOWED UNDER THE RULES AND REGULATIONS?

A. Any CIAC collected from developers and/or new customers connecting to RMP's system reduces the amount of plant costs to be recovered from the existing customer base. If a reasonable amount of CIAC is not collected from new customers to help cover the cost of connecting to RMP's system, this shifts costs of serving new customers to the existing customers.

Q. DO YOU SHARE ANY OF MR. HAHN'S CONCERNS REGARDING THE LEVEL OF CIAC COLLECTED BY RMP FROM THE DEVELOPER OF THE CITY CREEK PROJECT?

A. I have several concerns regarding the determination of the amount of CIAC to be collected on the City Creek Project. My first concern is that Mr. Hahn indicates at page 56 of his testimony that in response to DPU Data Request 31.2 in Docket No. 11-035-200, RMP stated it did not perform an estimate of a CIAC payment for the City Creek project. The response to DPU Data Request 20.10(c) in this case identifies the total cost for phases 1 and 2 of the City Creek Project as $32.6 million. Given the high amount of capital cost to RMP caused by the City Creek project, I find it surprising that an estimate of the appropriate CIAC payment was not performed or pursued by RMP.

Additionally, DPU Data Request 20.10(d) asked RMP to "Provide all supporting documentation for the CIAC payments made and demonstrate how these payments comply with Company policy regarding customer contributions." The response provided by RMP stated:

> No CIAC payments were made by Property Reserve Inc. (PRI), however, PRI provided value to the project in the form of trenching, ducts and vaults. That value was estimated at $1.45 million after work had been completed and is shown on the attached file "Attachment DPU 20.10-2". The cost associated with trenching, ducts and vaults is a non-allowable cost in accordance with Rocky Mountain Power Line Extension Policy, Regulation 12 in Utah.

In my opinion, this response does not adequately explain why CIAC was not pursed on the project and does not demonstrate that the Company's policy regarding customer contributions was complied with.

Q. YOU INDICATED ABOVE THAT MR. HAHN'S ADJUSTMENT TO REDUCE PLANT IN SERVICE BY $10.85 MILLION INCLUDED THE ASSUMPTION THAT RMP COLLECTED $7 MILLION OF CIAC ON THE PROJECT. THE RESPONSE TO DPU DATA REQUEST 20.10(D) QUOTED ABOVE INDICATES THAT NO CIAC PAYMENTS WERE MADE BY PROPERTY RESERVE INC. ON THE PROJECT. CAN YOU EXPLAIN THIS DISCREPANCY?

A. No. Mr. Hahn’s testimony, at pages 56 – 57, indicates that the developer constructed certain distribution facilities at its expense of $5.55 million and made a payment of $1.45 million, bringing the total cash and contributions to $7.0 million. However, RMP’s response to DPU 20.10(d) indicates that the value provided by Property Reserve Inc. on the project was only $1.45 million. Thus, Mr. Hahn’s recommended adjustment may be understated by the difference.

Q. ARE YOU RECOMMENDING THAT PLANT IN SERVICE ASSOCIATED WITH THE CITY CREEK PROJECT BE REDUCED AT THIS TIME FOR RMP’S FAILURE TO COLLECT CIAC FROM THE DEVELOPER?

A. Not at this time. I assume that RMP will offer rebuttal to Mr. Hahn’s recommendation. If RMP fails to adequately explain and justify its decision to not pursue or collect CIAC from the developer in its rebuttal position, then I would agree with Mr. Hahn’s position that a CIAC adjustment should be imputed to protect the existing ratepayers from the higher capital costs associated with the project.

<u>WOOD HOLLOW WILDFIRE COSTS</u>

Q. ARE THERE ANY ISSUES DISCUSSED IN THE DIRECT TESTIMONY OF DPU WITNESS DAVID T. THOMSON THAT YOU WISH TO ADDRESS?

A. Yes. In addressing the costs incurred by the Company associated with the Wood Hollow wildfire, at page 10 of his testimony, Mr. Thomson states: “The Division believes as stated above that the legal costs <u>and</u>

any other directly related costs of the Wood Hollow fire should be normalized in this general rate case." (Emphasis added) Based on the public portion of the Company's response to DPU 21.3, the Company adjusted certain fire and other damage costs out of base period costs, and they are not included in the future test period for the rate case. The public portion of the response to OCS Data Request 9.9 indicates that the injuries and damages expense included in the filing is based on average cash payments over three years. The response also indicates cash payments made on a particular item that was included in the injuries and damages expense on the Company's books was removed by the Company from the filing. It is not clear from the response if the cash costs removed by the Company were associated with the Wood Hollow wildfire. To the degree any cash payments associated with the Wood Hollow wildfire were removed by RMP such that RMP is not seeking recovery from Utah ratepayers of the costs, then such costs should not be "…normalized in this general rate case."

GENERATION OVERHAUL EXPENSE

Q. WOULD YOU PLEASE BRIEFLY SUMMARIZE THE ISSUE OF CONTENTION INVOLVING THE NORMALIZATION OF GENERATION OVERHAUL EXPENSES?

A. As previously indicated in my direct testimony, generation overhaul expenses are included in rates based on a four year average level. The reason for using a four-year average in normalizing the generation overhaul expenses is because the amount of expense incurred by RMP for the overhaul of generation facilities vary significantly from year to year and from generation unit to generation unit. The amount of overhaul costs capitalized versus expensed varies from overhaul to overhaul and between units depending upon the work performed in the overhaul. Many factors impact the overhaul expenses incurred each year. The costs to be included in rates are normalized based on a four-year average level in order to ensure that base rates are not set to include either an abnormally high or an abnormally low level of generation overhaul expense.

The Company, OCS and DPU all agree that the costs should be normalized based on a four-year average level. Where the parties differ is in regards to whether or not the historic costs should be inflated prior to determining the average test year expense level. It has consistently been the position of the OCS that the costs should not be escalated prior to determining the normalized expense. The Commission has agreed with the OCS' position that the historic costs should not be inflated prior to determining the normalized four-year average expense level in all cases in which it has addressed the issue in an order, specifically in its August 11, 2008 Order issued in Docket No. 07-035-93 and in its February 18, 2010 Order issued in Docket No. 09-035-23. In this case, Company witness Steven R. McDougal and DPU Witness Artie Powell continue to recommend that the historic costs be escalated prior to determining the four-year average expense.

Q. DID YOU ADDRESS THIS ISSUE IN YOUR DIRECT TESTIMONY?

A. Yes, I did. In my direct testimony, I addressed Mr. McDougal's recommendation that the costs be escalated prior to averaging. In this testimony, I address the information provided in DPU Witness Powell's direct testimony relevant to the issue.

Q. HAS DR. POWELL PRESENTED ANY NEW EVIDENCE IN THIS CASE SUPPORTING THE ESCALATION OF THE HISTORICAL BALANCES IN DERIVING THE NORMALIZED GENERATION OVERHAUL EXPENSE LEVEL THAT WAS NOT PREVIOUSLY CONSIDERED BY THE COMMISSION IN THE LAST FULLY LITIGATED RMP RATE CASE PROCEEDING?

A. In my opinion, no. Although he states at page 6 of his Direct Testimony that the Division presented additional or new evidence and information in several prior cases and in this case that had not been considered in Docket Nos. 07-035-93 and 09-035-23, similar information had been presented to the Commission with Dr. Powell's surrebuttal testimony in Docket No. 09-035-23 and was considered by the Commission. In his testimony in the current case, Dr. Powell presents a discussion comparing Method 1 and Method 2 of forecasting generation overhaul expenses. The information presented in Dr. Powell's testimony comparing his "Method 1" (i.e., inflation of the average of four historical values) and

"Method 2" (i.e., averaging of the inflated historical values) and arguments regarding why he feels Method 2 is superior to Method 1 was previously presented to the Commission in his surrebuttal testimony in Docket No. 09-035-23. A comparison of Method 1 to Method 2 and various model simulations and statistical comparisons under either Method 1 or Method 2 was presented to the Commission for consideration in Docket No. 09-035-23. While Dr. Powell has expanded his explanations from that provided in his Surrebuttal Testimony in Docket No. 09-035-23, he is still comparing the two methods.

In explaining his position that it is preferable to escalate the actual historical costs prior to determining the normalized average cost level, Dr. Powell presents several formulas in this case that may not have been fully included in Docket No. 09-035-23. He also discusses some economic theory and statistical theory. However I find nothing persuasive that would cause me to change my long-standing belief that generation overhaul expenses should not be escalated or inflated prior to averaging. It is my opinion that there is nothing new presented in this case that should lead to the conclusion that the historical costs should be escalated in determining the normalized cost level. I recommend that the Commission again re-affirm that the historical generation overhaul expenses should not be escalated for purposes of normalizing generation overhaul expense to include in base rates.

Q. ARE THERE ANY KEY POINTS THAT YOU FEEL ARE NOT CONSIDERED IN DR. POWELL'S ANALYSIS AND IN THE METHOD 1 AND METHOD 2 COMPARISONS HE PRESENTS AND EVALUATES?

A. Yes. Dr. Powell's hypothetical examples, calculations and discussion focus on the pressures of inflation on costs. While the hypothetical examples compare different methods of escalating costs, the analysis is not specific to the overhaul expense realized by RMP. It does not factor in the productivity offsets that have been and will continue to be realized by the Company in overhauling the generation units. This is addressed in further detail at pages 30 – 31 of my direct testimony.

<u>NET PENSION & POST-RETIREMENT WELFARE PLAN PREPAID ASSET</u>

Q. DR. POWELL PRESENTS THE DIVISION'S POSITION ON RMP'S REQUEST TO INCLUDE THE NET PREPAID PENSION ASSET IN RATE BASE. ARE THERE ANY SPECIFIC AREAS IN DR. POWELL'S DISCUSSION OF THE NET PREPAID PENSION ASSET THAT YOU WISH TO ADDRESS?

A. Yes. The issue of whether or not PacifiCorp's prepaid pension asset and accrued other post-retirement benefit liability, net of accumulated deferred income taxes, should be included in rate base was addressed at length at pages 60 through 71 of my Direct Testimony. In this rebuttal testimony, I will refer to this rate base issue as either the "net prepaid asset" or the "net accrued liability" for ease of discussion. At page 13 his Direct Testimony, lines 254 through 256, Dr. Powel states that: "Conceptually, the Division supports the inclusion in rate base of such prepaid costs that the Company incurs in providing service to its customers." Similarly, beginning at page 15, Dr. Powell explains the basis of his "general support" for the recovery of the net prepaid pension asset from ratepayers. While Dr. Powell does express the Division's conceptual support or general support for the recovery from ratepayers, he indicates at page 13 of his testimony that the Division does not believe that the Company has demonstrated the reasonableness of its proposal and has not provided adequate proof for the Commission to justify the inclusion at this time. For the reasons identified in my direct testimony, I do not agree with Dr. Powell's or the Division's "conceptual" or "general" support of inclusion of the net prepaid asset in rate base to earn a return.

Q. WHAT DOES DR. POWELL OFFER AS THE BASIS OF HIS "GENERAL SUPPORT" FOR THE RECOVERY OF THE NET PREPAID PENSION ASSET COSTS FROM RATEPAYERS?

A. At page 15 of his direct testimony, he initially indicates that other prepaid assets are included in rate base. He then states that "…the FERC appears to allow, 'as a general matter,' prepaid pension assets in rate base as part of a utility's OATT". Dr. Powell then provides several citations from a FERC Order on Tariff Filing issued March 10, 2008 in Docket Nos. ER08-129-000 and ER08-129-001, involving Southern Company Services, Inc. In that docket, Southern Company Services, Inc. was acting as agent for Alabama Power Company, Georgia Power

Company, Gulf Power Company, Mississippi Power Company and Savannah Electric and Power Company (collectively referred to as "Southern Companies").

Q. IS THE SITUATION ADDRESSED BY FERC IN THE SOUTHERN COMPANY SERVICES, INC. CASE SIMILAR OR CONSISTENT WITH RMP'S SITUATION AS IT PERTAINS TO THE NET PREPAID ASSET?

A. No, there are several significant differences. For example, Southern Companies' OATT rates were converted to comprehensive formula rates effective May 1, 2003 as a result of a settlement. Since that time, the amount of pension expense included in the OATT rates was trued-up each and every year to the actual costs for that year. Thus, the amount of pension expense recovered in the OATT rates equaled the amount of booked pension expense. This has not been the case for RMP in Utah as there is no true-up of the pension expense in rates and rates are not re-set annually. Additionally, Southern Company, Inc. asserted that the prepaid pensions were included in the prepayments in rate base in the 2003 settlement that resulted in the comprehensive formula rates. In the Order cited by Dr. Powell, FERC allowed Southern Companies to include in the OATT formula rates the jurisdictional portion of the prepaid pension asset accrued <u>after</u> the formula rates went into effect, offset by corresponding amounts of working capital reductions and deferred income taxes. FERC excluded over two-thirds of the amount of prepaid pension asset that Southern Company, Inc. sought to include in rate base. FERC specifically found that it was "…not just and reasonable for Southern Companies to include any amounts related to prepaid pension accumulated prior to May 2003 in rate base under Southern Companies' OATT." This is clearly different than the issue at hand involving RMP. In fact, if any weight were to be given to the FERC Order cited by Dr. Powell, it would be consistent with the alternative recommendation presented in my direct testimony.

Q. PLEASE EXPLAIN HOW THE FERC ORDER WOULD BE CONSISTENT WITH YOUR ALTERNATIVE RECOMMENDATION.

A. In my direct testimony, starting at page 70, I indicated that if the Commission determines that rate base treatment should be considered for the cash contributions made to the pension plan, it should be considered on a <u>prospective</u> basis only. In the FERC Order, the pension asset was only allowed in rate base in determining the formula rates to the extent that it was applicable to the period formula rates were effective. This would be the period in which the pension expense included in the formula rates was trued-up to actual amounts on an annual basis. At page 71 of my direct testimony, I indicated as follows:

> Starting with the test year in this case, one could consider the difference between the amount of cash funding into the pension plan that is applicable to electric operation employees (in other words exclusive of mining operations) and the amount of pension expense that is factored into the revenue requirements that are collected from customers. The amount of cash funding and the amount of expenses factored into the revenue requirement as a result of general rate cases could be tracked going forward and only the cumulative difference between these two amounts applicable to the Utah jurisdiction should be considered for rate base treatment. This would ensure that the calculation is in fact only based on the electric operations, only based on the Utah

jurisdictional amounts, and based on the amount actually being recovered in rates charged to Utah customers. While I do not recommend this approach, it is far more reasonable than the approach proposed by PacifiCorp in this case which is based on many, many years of past accounting entries that differ from the amounts included in electric rates charged to Utah ratepayers.

Q. IS THE NET PREPAID ASSET INCLUDED IN PACIFICORP'S TRANSMISSION RATES?

A. No. In response to DPU Data Request 39.15, the Company indicated that it does not include the net prepaid asset as part of its formula model for calculating transmission rates as the accounts containing the net prepaid pension asset are not included in the Company's transmission rate formula. DPU Data Request 39.14 asked the Company if FERC allows prepaid pension assets in rate base and to provide any orders indicating such allowance that the Company is aware of. In response, RMP indicated that it "…is currently evaluating FERC precedent regarding treatment of prepaid pension asset in rate base." In searching the FERC website, the only case I was able to find that specifically addressed the inclusion of the prepaid pension asset in OATT formula-based rates was the case cited by Dr. Powell.

Q. BEGINNING AT PAGE 18 OF HIS TESTIMONY, DR. POWELL DISCUSSES WHETHER OR NOT THE COMPANY HAS "…PROVIDED ANY EVIDENCE THAT INCOME FROM THE PENSION HAS REDUCED ITS PENSION EXPENSE." CAN YOU BRIEFLY DISCUSS THE IMPACT

OF EARNINGS ON THE PENSION PLAN ASSETS ON PENSION EXPENSE?

A. Yes. The expected return on pension plan assets is <u>always</u> an offset in calculating the pension expense. Under Accounting Standards Codification 715 (sometimes referred to as FAS 87), the following components make up the net periodic benefit cost (or pension expense): service cost, interest cost on projected benefit obligation, expected return on assets, amortization of prior service costs, amortization of transition obligation (if any remaining), and amortization of net (gain)/loss. The expected return on assets, which is a negative amount or reduction to the expense in the calculation, is based on the expected long-term rate of return on plan assets applied to the market-related value of plan assets. Since the qualified pension plan is required to be funded, there is always an offset in the pension expense calculation for the expected return on plan assets, which Dr. Powell refers to in his testimony as "income from the pension."

Q. SINCE THERE IS ALWAYS AN OFFSET IN THE PENSION EXPENSE CALCULATION FOR THE EXPECTED RETURN ON PLAN ASSETS, DOES THAT MEAN THAT SHAREHOLDER CONTRIBUTIONS CAUSED THE FULL AMOUNT OF THE EXPECTED RETURN?

A. No, definitely not. The expected return on plan assets (or "income from pension" as referred to in Dr. Powell's testimony), is based on the market value of the plan assets. The amount of plan assets considered in determining the expected return on plan assets are impacted by factors such as contributions to the pension plan, pension payments made out of the pension plan assets, and the prior earnings realized on the pension plan investments. The prepaid pension asset that RMP is seeking to include in rate base is the cumulative difference between the cash contributions to the pension plan assets and the actuarially determined pension expense. This differs from the market value of plan assets that is used in calculating the expected return on plan asset that is a component of the pension expense calculation. However, that being said, contributions to the pension plan increase the expected return on plan assets, which reduces pension expense over time.

Q. IN HIS DIRECT TESTIMONY, DR. POWELL INDICATES THAT IF THE COMMISSION ALLOWS THE INCLUSION OF THE NET PENSION ASSET IN RATE BASE, THE DIVISION RECOMMENDS THE REVENUE REQUIREMENT IMPACT BE REDUCED BY A ONE-TIME OFFSET OF $4.2 MILLION ON A UTAH BASIS. COULD YOU PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE DIVISION'S RECOMMENDED OFFSET AND THE PURPOSE OF THE OFFSET?

A. Dr. Powell indicates at lines 456 through 460 that the one-time offset would recognize the fact that the current net prepaid asset is the cumulative difference in cash contributions and expenses, and that from 1993 through 2007 the balance was negative. Apparently the Division views its proposed one-time offset as somehow alleviating the fact that the rate base was not reduced over the extended period in which the cumulative pension expense exceeded the cash contributions to the pension fund (ie., period of net accrued liability).

A review of DPU Exhibit 2.4 DIR-RR shows that the offset is based on first calculating what the revenue requirement impact would have been in each of the years, 1993 through August 2014, if the net prepaid asset or accrued liability that existed in each year had been included in the revenue requirements. For example, the exhibit shows that as of 1996, the difference between the cumulative pension and post-retirement welfare plan cash contributions and the cumulative pension and post-retirement welfare plan expense was a net accrued liability of $11.9 million before taxes and $7.4 million net of the associated accumulated deferred income taxes. The exhibit then applies the Commission authorized rate of return that was effective in 1996 of 13.81% to determine the purported “revenue requirement” impact, which is a reduction to revenue requirement of $1.1 million. The Division then applies CPI to determine the CPI adjusted revenue requirements. The $4.2 million one-time offset proposed by the Division in the event the Commission includes the net prepaid asset in rate base in this case is the total cumulative “CPI-adjusted revenue requirement” it calculated for each year, 1993 through August 2014.

Q. DO YOU AGREE THAT THE PROPOSED ONE-TIME OFFSET OFFERED BY THE DIVISION IS AN APPROPRIATE MEANS OF ALLEVIATING THE FACT THAT THE NET ACCRUED LIABILITY DID NOT OFFSET RATE BASE IN THE MANY PAST YEARS THAT THE CUMULATIVE EXPENSE EXCEEDED THE CUMULATIVE CASH CONTRIBUTIONS?

A. No, I do not. First, it is my opinion that the $4.2 million offset would constitute retroactive ratemaking. The determination of the $4.2 million is based on calculating revenue requirement impacts in past years under a methodology that differs from what was actually used in setting rates in Utah and capturing that difference to essentially flow it back to ratepayers in a current period. It is not appropriate to retroactively calculate what the revenue requirements would have been had a different scenario or method been used in calculating rates (i.e., as if the accrued liability or net asset been included in rate base) and flow those impacts into future periods.

Additionally, Utah revenue requirements were not reset in each of the years considered in the calculation of the $4.2 million. The calculation appears to be premised on the impacts if rates had been reset annually. This is not the case.

Finally, the adjustment does not factor in the numerous reasons discussed in my direct testimony regarding why the net prepaid asset should not be included in rate base, such as the fact that the net prepaid balance may not have been fully funded by shareholders and includes amounts not associated with the electric operations. The issues raised in my direct testimony would also apply to the $4.2 million one-time offset.

JURISDICTIONAL ALLOCATION FACTORS

Q. ARE YOU RECOMMENDING ANY ADDITIONAL ADJUSTMENTS IN THIS REBUTTAL TESTIMONY?

A. Yes. In his direct testimony filed on May 1, 2014, OCS witness Philip Hayet recommended that the line loss factors in the GRID model be updated to reflect a more recent five-year period. While use of the updated five-year average line losses reduces the system energy requirements, it also impacts the jurisdictional allocation factors that include system load in determining the allocation percentages between states. In his rebuttal testimony, Mr. Hayet refines his adjustment by developing individual loss factor adjustments for each state. In my direct testimony, I did not include the impact of the updated line-loss factors on the system energy requirements used in determining the jurisdictional allocation factors in the model. This rebuttal testimony presents the impacts of the updated line-loss amounts on the jurisdictional allocation factors and on the overall revenue requirement recommended by the OCS.

Q. WOULD YOU PLEASE DESCRIBE THE LINE LOSS FACTOR ADJUSTMENT AND EXPLAIN WHY IT IMPACTS THE JURISDICTIONAL ALLOCATION FACTORS?

A. Yes. In determining the line loss factors in the GRID model, RMP used a simple five-year average of line losses based on data for the period January 1, 2008 through December 31, 2012. OCS witness Philip Hayet recommends in his direct testimony that the data be updated for a more recent five-year period using 2009 through 2013 data. Use of the updated five-year average reduces the system energy requirements presented by the Company. Mr. Hayet's recommended power cost adjustments incorporate the impact of this update. His recommended adjustment is further refined in his rebuttal testimony. As use of the updated five-year average line losses reduces the system energy requirements, it also impacts the jurisdictional allocation factors that include system load in determining the allocation percentages between states.

Q. WHAT IMPACT DOES CHANGING THE LINE LOSS HAVE ON TEST YEAR ENERGY REQUIREMENTS?

A. Exhibit OCS 3.2R provides the impact on the energy requirements for Jurisdictional Allocation by using the more recent five-year average for each jurisdiction. Total system energy requirements decrease by 32,177 MWh, or 0.05%. The Utah energy requirements decrease by 64,059 MWh or 0.26%. Since the Utah energy requirements are declining at a greater percentage than the system as a whole when updated to a more recent five-year average line loss factor, the impact is a reduction in several of the jurisdictional allocation factors for the percentage allocated to the Utah jurisdiction.

Using the amounts presented in Exhibit OCS 3.2R, I incorporated the revised loads for jurisdictional allocation in the Jurisdictional Allocation Model in this case. Exhibit OCS 3.1R presents the OCS recommended revenue requirement, as revised to include the impact of the updated loads. The update to the loads is the only change made to the Jurisdictional Allocation Model when compared to Exhibit OCS 3.1D presented with my direct testimony. After reviewing RMP's rebuttal testimony, I will present the OCS's final revenue requirement position in my surrebuttal testimony.

Q. WHAT IMPACT DID THE CHANGE IN LOADS HAVE ON THE PERCENTAGE ALLOCATIONS TO UTAH?

A. Several allocation factors changed as a result of the change in loads. For example, the System Generation (SG) factor for Utah declined from 42.6283% in RMP's model to 42.6069% in the revised Jurisdictional Allocation Model. Similarly, the System Energy (SE) factor declined from 41.9717% to 41.8860%, and the System Overhead (SO) factor declined from 42.4703% to 42.4534%.

Q. DID YOU NEED TO MAKE ANY FURTHER MODIFICATIONS TO THE AMOUNTS PRESENTED ON OCS 3.2R PRIOR TO INPUTTING THE ADJUSTMENT IN THE JURISDICTIONAL ALLOCATION MODEL?

A. Yes. The information provided by the Company for energy sales and system load in response to OCS Data Request 2.52 and the 1st Supplemental Response to OCS 2.53 included the Wyoming jurisdiction on a combined basis, whereas the Jurisdictional Allocation Model separates the Pacific Power and Rocky Mountain Power Wyoming jurisdictions in the model. Since the breakdown between each of the Wyoming jurisdictions was not provided, I allocated the resulting Wyoming load presented on Exhibit OCS 3.2R between the Pacific Power and the RMP jurisdiction on the ratio of load between those two jurisdictions contained in the Company's model.

Q. WHAT IMPACT DOES THE ABOVE DESCRIBED CHANGES IN LOAD HAVE ON REVENUE REQUIREMENTS?

A. I entered the change in loads impacting the jurisdictional allocation factors after all other OCS recommended adjustments presented in the direct testimonies were input into the Jurisdictional Allocation Model. The resulting change in allocation factors, based on the incorporation of all other OCS direct testimony adjustments, resulted in the OCS recommendation changing from a decrease in revenues of $4,646,097 presented in my direct testimony to a decrease of $6,266,233. The decrease of $6,266,233 is shown in Exhibit OCS 3.1R. Thus, the resulting change in the jurisdictional allocation factors caused a $1,620,136 reduction in revenue requirements. The impact from the change in the allocation factors will vary depending on what adjustments are ultimately adopted by the Commission in this case.

Q. DOES THIS COMPLETE YOUR PREFILED REBUTTAL TESTIMONY?

A. Yes.