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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	**Docket No. 08-035-38**

PREFILED DIRECT TESTIMONY OF KEVIN C. HIGGINS

[REVENUE REQUIREMENT]

The UAE Intervention Group (UAE) and Wal-Mart Stores, Inc. ("Wal-Mart") hereby submit the Prefiled Direct Testimony of Kevin C. Higgins on revenue requirement issues.

DATED this 12th day of February, 2009.

/s/______________________________
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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 12th day of February, 2009, on the following:

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BEFORE

THE PUBLIC SERVICE COMMISSION OF UTAH

Direct Testimony of Kevin C. Higgins

on behalf of

UAE and Wal-Mart

Docket No. 08-035-38

[Revenue Requirement]

February 12, 2009

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being jointly sponsored by the Utah Association of Energy Users ("UAE") Intervention Group and Wal-Mart Stores, Inc. (jointly, "UAE-WM"). Wal-Mart Stores, Inc. is a member of UAE that has intervened separately in this proceeding.

Q, Are you the same Kevin C. Higgins who previously testified in the Test Period phase of this proceeding?

A. Yes, I am. I described my qualifications in the pre-filed direct testimony I submitted in that phase of the case. I also provided a more detailed description of my qualifications in Attachment A, attached to that direct testimony.

<u>Overview and Conclusions</u>

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses several revenue requirement issues in the Rocky Mountain Power ("RMP" or, in certain contexts, "PacifiCorp") general rate case filing. In this testimony I recommend several adjustments to the Company's proposed revenue requirement in support of a just and reasonable outcome. My recommended adjustments are concentrated on a limited number of issues. Absence of comment on my part regarding a particular revenue issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue.

Q. What are your primary conclusions and recommendations?

A. I am recommending the following adjustments to RMP's Utah revenue requirement:

(1) Net power cost should be re-calculated with the following changes:

(a) Application of RMP's most recent forward price curve, dated December 31, 2008.

(b) Removal of the Company's wind integration charge of $1.16/MWh for wind integration costs, replaced by an additional 26 MW of incremental reserves for wind integration.

(c) Increase of the Rolling Hills wind facility capacity factor from 33.7 percent to 37.3 percent, which is the capacity factor for the adjacent wind facility, Glenrock.

(d) Increase of the capacity factor for Marengo II wind facility, making it equivalent to that of Marengo, which is how these units were treated in GRID in Docket No. 07-035-93. This requires a capacity factor adjustment for Marengo II from 30.5 percent to 32.5 percent.

(e) Removal of startup costs associated with the use of "manual workaround" for the Lake Side and Currant Creek generating units.

(f) Adjustment of the energy production from the Rolling Hills and Glenrock III wind facilities to comport with changes to their scheduled operational dates.

The estimated impact of these adjustments to net power costs is to reduce Utah revenue requirement by approximately $8,303,293.

(2) Rate base should be adjusted to reflect cancellations or delays of the in-service dates of certain major projects. The estimated net impact of this adjustment is to reduce Utah revenue requirement by approximately $968,129, exclusive of net power costs (included in 1(f) above) and a small impact on interest synchronization expense.

(3) Projected wage and benefit expense should be reduced by $13,185,000 (Company-wide). This is one-half of the Company's proposed increase in this expense relative to the actual expense incurred for the year ending June 2008. The estimated impact of this adjustment is to reduce Utah revenue requirement by approximately $5,354,094.

Q. Please summarize the impact of your proposed adjustments to RMP's revenue increase.

A. Taken all together, my recommended adjustments reduce RMP's proposed Utah revenue increase of $116,723,779 by $14,625,516. These results are summarized in Table KCH-1, below.

Table KCH-1

Summary of UAE-WM Recommended Adjustments

Description	Est. Utah Revenue Impact	Cumulative Impact
Net Power Costs		
New forward price curve	$(2,377,844)	$(2,377,844)
Wind integration	$ (481,213)	$(2,859,057)
Rolling Hills cap. factor	$ (425,045)	$(3,284,103)
Marengo II cap. factor	$ (212,192)	$(3,496,295)
Startup cost removal	$(5,146,616)	$(8,642,911)
Delay in wind plants	$ 339,618	$(8,303,293)
Adjust rate base for delays	$ (968,129)	$(9,271,422)
Adjust wage and benefit expense	$(5,354,094)	$(14,625,516)
Total	$(14,625,516)	

<u>Net Power Costs</u>

Q. What issues do you address with respect to RMP's net power costs?

A. I present an update to net power costs using RMP's most recent forward price curve, dated December 31, 2008. In addition, I make adjustments in RMP's GRID model for: (1) wind integration costs; (2) Rolling Hills capacity factor; (3) Marengo II capacity factor; and (4) gas plant startup costs. In addition, I make adjustments to conform to certain plant-in-service timing changes discussed later in my testimony. The combined impact of these adjustments is summarized in UAE-WM Exhibit RR 1.1 (KCH-1), page 1. The output of the Net Power Cost study incorporating these adjustments is presented in UAE-WM Exhibit RR 1.2 (KCH-2). This summary report is comparable to the report presented in the direct testimony of RMP witness Gregory N. Duvall, Exhibit RMP (GND-1SS).

I will discuss each of my net power cost adjustments in sequence. The estimated revenue impact associated with each adjustment is calculated in the sequence of presentation, with each adjustment cumulatively incorporated into the calculation of net power costs.

Q. Please explain the purpose of presenting an updated net power cost result using RMP's most recent forward price curve.

A. RMP's Second Supplemental Filing projected net power costs using forward price curves for November 2, 2008. Since that time, forward energy prices for 2009 have fallen significantly. To better understand the impact of falling energy prices on RMP's net power costs, I requested that RMP provide an updated GRID run using the Company's most recent forward price curve. RMP provided this information in its Response to UAE 2.1 through 2.3.

Q. What observations do you have concerning this updated GRID run?

A. The fuel cost for RMP's gas generating units has fallen dramatically since the Company made its Second Supplemental filing. Indeed, the projected fuel burn expense for these units in the updated GRID run is approximately $77 million less than in RMP's filed case. However, despite this sizable reduction in fuel cost, projected net power costs fall by only $5.9 million to $1.047 billion in the updated run.

Q. Do you have any explanations for why the reduction in net power cost is so much smaller than the reduction in fuel cost?

A. For the most part, it appears that the reduction in fuel burn expense was offset by an increase in gas swap costs, i.e., RMP's fuel prices had already been largely locked in financially at higher prices.

Q. What is the cost of the gas swaps in the updated GRID run?

A. The cost of the gas swaps is approximately $155 million, up from $80 million in the filed case.

Q. Are you recommending any adjustments to the gas swap costs?

A. No. While the amount, timing, and cost of hedging activities are appropriate prudence issues, I have not reviewed the details of the underlying transactions, and therefore, cannot offer an opinion as to their prudence. I believe, though, that as a general proposition, utilities should implement carefully-designed hedging programs to manage the risk of their fuel supply costs. This practice can protect the utility and its customers from the harmful impacts of price spikes. Other times, however, the hedging party foregoes the cost savings that would otherwise occur when prices fall unexpectedly, as has occurred in this case. In general, it would not be reasonable to accept the benefits of a reasonable and prudent hedging program without also accepting the costs.

Q. What is your recommendation to the Commission?

A, I recommend using the December 31 forward price information in GRID to determine net power cost. As I indicated above, this reduces net power cost by $5,884,599. This results in an estimated reduction in Utah revenue requirement of $2,377,844. This adjustment is included (along with my other net power costs adjustments) in UAE-WM Exhibit RR 1.1 (KCH-1), page 1, and in the study results presented in UAE-WM Exhibit RR 1.2 (KCH-2). The individual impact of each of my net power cost adjustments is tabulated in UAE-WM Exhibit RR 1.1 (KCH-1), page 3.

Q. In making this recommendation, do you have any concern with the time frame of the analysis changing from the Company's filed case?

A. No. The use of an updated net power cost calculation does not change the fundamental time frame of the analysis: it remains Calendar Year 2009. RMP presented its direct case using the forward price curves available to the Company at the time it filed its case. Similarly, it is reasonable for UAE-WM to present its direct case using the most current information available at this time.

Q. Please explain your recommended adjustment for wind integration costs.

A. The integration of wind facilities into a control area's operations requires the incurrence of certain additional costs relative to the cost of integrating generating resources with less variable output. The question for purposes of determining net power costs is how to best reflect these projected costs in GRID. In this proceeding, RMP has imported an external calculation of wind integration costs discussed in the Company's 2007 IRP, Appendix J. This calculation is based on the cost of incremental reserves for load following necessary to integrate a specific amount of wind generation capacity (2,000 MW).

For a utility that self-supplies its ancillary services, such as RMP, the capacity cost associated with incremental reserves is already recovered in rate base. However, there is an opportunity cost of foregone wholesales sales (or increased purchases) associated with the incremental reserves held back from the market. The cost associated with holding back reserves is obviously a function of market conditions. As such, I believe it is more appropriate to estimate this cost within GRID rather than import it from an external calculation.

Q. How did you make this calculation within GRID?

A. In GRID, RMP assumes wind integration for approximately 1,200 MW of wind generation capacity. (For two of its wind facilities, Leaning Juniper and Goodnoe Hills, RMP purchases wind integration service from BPA.) In recent testimony provided in Oregon Docket No. UE-199, PacifiCorp presented information indicating that the Company requires 23 MW of incremental reserves to integrate 1,100 MW of wind capacity and 29 MW of incremental reserves to integrate 1,400 MW of wind capacity. Based on this representation, I have removed the Company's wind integration charge of $1.16/MWh for the self-supplied wind integration service in GRID and (conservatively) added 26 MW of incremental reserves to RMP's reserve requirement for wind integration. The net impact of this adjustment in GRID is to reduce net power cost by $1,190,889. This adjustment is presented in UAE-WM Exhibit RR 1.1 (KCH-1), page 3. It results in an estimated reduction in Utah revenue requirement of $481,213.

Q. Why are you recommending a capacity factor adjustment for the Rolling Hills facility?

A. The Rolling Hills wind project is a 99 MW wind generation facility that has been constructed on RMP property adjacent to the Company's Glenrock wind facilities in Converse County, Wyoming. At the time of the Company's filing, the facility's projected operational date was December 31, 2008. The actual in-service date occurred on January 17, 2009. RMP has included $206.5 million in projected plant costs for Rolling Hills in its Application.

The Rolling Hills project has engendered a fair amount of controversy. Its expected capacity factor of 31.0 percent at the time of project approval is low by Wyoming standards, raising questions as to the prudence of the investment. Indeed, in Order 08-058 issued November 11, 2008, the Oregon Public Utilities Commission found that the Company failed to prove that it was prudent when it developed the Rolling Hills project, and ordered that the costs related to this project be excluded from rates.[1] The Oregon Commission also found that the Company developed the project with a capacity of 99 MW size to avoid that Commission's Major Resource Acquisition Guidelines.[2] The Oregon Commission went on to state that the cost disallowance applied only to the recovery of Rolling Hills costs in the Renewable Adjustment Clause being decided and stated that the "future ratemaking treatment of the Rolling Hills project will be taken up as appropriate."[3]

In addition, the Oregon Commission made the following determinations:[4]

[1] Public Utility Commission of Oregon, Docket No. UE-200, Order No. 08-548 at 20. Nov. 14, 2008.
[2] Order at 22.
[3] Order at 20-21.
[4] Order at 19-20.

Pacific Power's Rolling Hills project's specifications are markedly inferior, compared to either Glenrock or Seven Mile Hill, or other Wyoming wind projects in general. Without the objective evidence that would otherwise be provided by the competitive bidding process, Pacific Power must establish that it was prudent for the Company to develop the project at this time and at this location.

According to Pacific Power, the estimated capacity factor at the time of project approval was 41.3 percent for Seven Mile Hill, 38.6 percent for Glenrock, and 31 percent for Rolling Hills. The estimated capacity factor at the time of project approval is the crucial factor in deciding whether the project was prudently acquired.

To overcome the weight of the evidence about the relatively poor capacity factor for Rolling Hills, Pacific Power argues that external considerations were crucial factors contributing to its decision to proceed with the project. One of these factors was the availability of the wind turbines.

Pacific Power states that its choice was not between Rolling Hills and another project, but between Rolling Hills and no project, because the Company would not have been able to hold the turbines made available to it for the duration of the RFP process. That rationale is inconsistent with other statements by the Company explaining its decision to proceed with Rolling Hills.

Pacific Power originally planned to develop another site in Idaho and acquired the turbines for that site. The Company has failed to prove that it could not have stored the turbines or that it could not have negotiated with the manufacturer to resell them if it had no immediate use for them.

Pacific Power disputes the availability of other sites at the time it decided to proceed with Rolling Hills. However, Staff rightly argued that the Company conducted no discovery for alternate sites. The public record (such as siting approval applications filed in Wyoming) does not provide an exhaustive inventory of sites that may be available, both within and outside the Company's service territory. Again, the failure to solicit competitive bids is a factor that undermines the weight of the Company's evidence.

Pacific Power cites the possible expiration of the federal production tax credits as a factor in its decision to proceed with Rolling Hills. Without regard to the probability that the tax credits would expire, the Company failed to prove that the availability of the credits was a material factor in its decision to proceed with the project. Further, the Company did not

> make a strong case that it needed to act to meet Renewable Portfolio Standard targets or other commitments.
>
> Nor are we persuaded by evidence comparing the Rolling Hills project to other projects in other regions. Pacific Power's burden was to prove that it prudently acquired the Rolling Hills project. The relevant alternatives are other wind projects in Wyoming that might have been – or may be – available.

Q. How does the information have a bearing on setting rates in Utah in this proceeding?

A. PacifiCorp has elected to size three wind projects at 99 MW that were developed by the Company: Glenrock, Seven Mile Hill, and Rolling Hills. Collectively, these projects cost more than $615 million, which RMP intends to recover from ratepayers. While Utah no longer requires that renewable projects sized 100 MW or greater be competitively bid, Oregon does. It is clear that the Company's sizing of these projects is intended to avoid the Oregon major resources acquisition requirements. On its face, the avoidance of an Oregon requirement might not, in and of itself, cause concern in Utah. However, as PacifiCorp has embarked on a major resource development program using a strategy that sidestepped competitive bidding requirements for these three projects, there is a valid concern for Utah with respect to the quality of projects and benefits to customers emerging from such a process. The Rolling Hills project, sized 1 MW below the Oregon competitive bidding threshold, with its relatively low (for Wyoming) capacity factor, should receive especially careful scrutiny.

I anticipate, based on the above-cited proceeding in Oregon and as well as an ongoing RMP rate proceeding in Wyoming, that the prudence of Rolling Hills will be an issue in Utah. In deliberating the appropriate course of action, I believe that one reasonable way for the Commission to deal with this issue is to adjust the capacity factor in GRID for the Rolling Hills facility in the calculation of net power costs. Such an adjustment should be structured to provide customers with energy benefits that are reasonably equivalent to the energy benefits more typical of a Wyoming wind site. Capacity factors for wind projects in Wyoming are estimated to be in the range of 38 percent to 45 percent.[5] In my opinion, an appropriate, but conservative, adjustment for this purpose is to set the capacity factor in GRID for Rolling Hills equal to 37.3 percent, which is the capacity factor for the adjacent wind facility, Glenrock. This adjustment is an increase from the 33.7 percent capacity factor used by RMP for Rolling Hills in GRID. This adjustment reduces net power cost by $1,051,886. This adjustment is presented in UAE-WM Exhibit RR 1.1 (KCH-1), page 3. It results in an estimated reduction in Utah revenue requirement of $425,045.

Q. Are you also recommending adjustments to the value of Renewable Energy Tax Credits or Renewable Energy Credits (“RECs”) credited to customers?

[5] Oregon Staff estimated a typical capacity factor for a Wyoming wind project of 38 percent. This figure also appears as representative of Wyoming wind capacity factors on page 28 of PacifiCorp’s 2008 IRP Public Meeting presentation, dated May 2, 2008. According to the Wyoming Infrastructure Authority, “Typically, Wyoming’s wind capacity factor is eight (8) to ten (10) points higher than that of surrounding states (42% to 45% is common).” www.wyia.org/wci/why.html.

A. No. While I believe that such adjustments could be reasonably extended to these credits, I am limiting my adjustment to the calculation of net power cost in GRID.

Q. Please explain your proposed adjustment to the capacity factor for the Marengo II wind facility.

A. In RMP's filing in Docket No. 07-035-93, in which Marengo II was brought into rate base, the project's capacity factor in GRID was represented to be 32.5 percent. In this proceeding, RMP uses a capacity factor for Marengo II of 30.5 percent. While I recognize that wind capacity factors for facilities not yet operational are projections and subject to change, I am concerned about the degradation of wind facility capacity factors in rate proceedings following their acceptance into rate base. To address this concern, I recommend adjusting the capacity factor in GRID for Marengo II to be equivalent to that of Marengo, which is how these units were treated in GRID in Docket No. 07-035-93. This requires a capacity factor adjustment for Marengo II from 30.5 percent to 32.5 percent. This adjustment reduces net power cost by $525,126. This adjustment is presented in UAE-WM Exhibit RR 1.1 (KCH-1), page 3. It results in an estimated reduction in Utah revenue requirement of $212,192.

Q. In Docket No. 07-035-93, you recommended an adjustment to GRID to accommodate a minimum operating level of 115 MW for Currant Creek, consistent with RMP's representation during the Currant Creek certification

proceeding that this facility would have operational flexibility to operate at this level. Have you made such an adjustment in this proceeding?

A. No, I have not. I continue to believe that net power costs should be calculated in such a way that incorporates the operational flexibility at Currant Creek that the Company advertised during the certification proceeding for the facility. This is particularly important given that the GRID model has a propensity to dispatch Currant Creek (and Lake Side) uneconomically, as discussed at some length in the prior rate case. Allowing Currant Creek to operate in GRID at lower output levels than the current minimum output level of 340 MW would reduce the amount of uneconomic dispatch charged to customers in net power costs. However, the Commission did not accept my minimum operating level adjustment in the prior proceeding because the GRID model does not have the capability of simultaneously running the Currant Creek units in the one-by-one mode necessary to accommodate a minimum operating level of 115 MW, and then switching back to the two-by-one mode used for typical operation.

The “manual workaround” that RMP has applied to the Currant Creek commitment logic addresses a portion of the concern I have with the minimum operating level of the facility in GRID. As I have not developed a technical “fix” that addresses the limitations of the model to accommodate more than one operating mode at a time for Currant Creek, I am not proposing a minimum operating adjustment at this time. However, I believe that this issue should remain open for resolution at a later date.

Q. Please explain the basis for your adjustment to gas facility startup costs.

A. I disagree with RMP's treatment of gas facility startup costs in GRID. At a fundamental level, it is troubling that RMP does not provide any recognition for the energy produced by a gas facility during startup. The Company's treatment is explained in its Response to CCS 21.14.

> Question: NPC: Does the Company agree or disagree that in its methodology used for computing additional start up costs and start up fuel costs that the Company does not consider the value of power produced during the start up sequence of the Currant Creek, Lake Side and Chehalis plants? Please provide an explanation of the answer.
>
> Response: The energy produced during start up has much less value than energy produced during steady state operations. The plants must follow a prescribed startup procedure and time line. This time line does not match the Company's requirements, e.g., the startup does not match an increase in loads. Therefore, another plant that is already on line must be backed off temporarily while the plant is ramping up to full load. Often times the online plant being backed off has a lower cost (e.g., coal) [than] the plant being ramped up (gas) resulting in a temporary net increase in net power costs. As such the power has limited value and is not included in the start up calculation.

In my opinion, this explanation does not hold together very well. First, it strikes me as incongruous to maintain that the energy produced by a unit throughout its startup has zero net economic value, but then suddenly becomes economical at the moment it reaches its planned operating level. Second, even if more economical units are being backed off to accommodate the startup, there is no reason not to credit the savings associated with the backed-off units against the cost of the startup. The failure to recognize such a credit overstates net power costs.

This problem is exacerbated in GRID by the manual workaround or "screen" that is applied to the Lake Side, Currant Creek, and to a lesser extent, Chehalis, units. As noted above, it has been determined in prior cases that GRID has a propensity to dispatch the Lake Side and Currant Creek plants at times when it is uneconomic to do so. To partially mitigate this problem with the commitment logic of GRID, RMP has proposed a manual workaround that "shuts down" these units (in the model) during certain periods of lower-cost energy (e.g., overnight). This "fix" may be a reasonable way, at least temporarily, to work around the commitment logic problem with the model. However, RMP is also assigning start up costs in GRID for each Currant Creek and Lake Side startup that is attributable to the manual workaround. So, not only is RMP not providing any credit for the energy that is produced during startup, the Company is also including startup costs for the numerous times that Lake Side and Currant Creek have to be "restarted" after "tricking" GRID into not dispatching these plants uneconomically. While there are real costs associated with turning a power plant on and off, there is no real-world wear and tear attributable to inserting a screen in GRID. Customers should not be required to pay for incremental startup costs because it is necessary to override the GRID model's commitment logic to keep it from dispatching plants uneconomically.

Q. What adjustment have you made for the treatment of startup costs?

A. I have adjusted net power costs to remove the Lake Side and Currant Creek startup costs associated with the use of the screen. While I also believe the remaining start up costs should be reduced by the savings from backed-off energy, I have not calculated the value of this savings at this time. This adjustment is presented in UAE-WM Exhibit RR 1.1 (KCH-1), page 3.

Q. What is the impact of this adjustment on net power cost?

A. This adjustment reduces net power cost by $12,736,651. It reduces Utah revenue requirement by approximately $5,146,616.

Q. Please explain the adjustments you made in GRID to conform to other adjustments recommended later in your testimony.

A. In the testimony that follows, I recommend adjusting rate base to account for certain schedule changes for major plant coming into service. These changes affect the timing of the Rolling Hills and Glenrock III facilities. I have adjusted the energy production from these facilities in GRID to comport with the changes in their scheduled operational dates. This results in an increase in net power costs of $840,473 and an estimated increase in Utah revenue requirement of $339,618. This adjustment is presented in UAE-WM Exhibit RR 1.1 (KCH-1), page 3.

Q. What is the combined impact of the adjustments to net power costs that you are recommending?

A. The combined impact of the adjustments I am recommending is a reduction in net power costs of $20,548,678. The estimated impact on Utah revenue requirement is a reduction of $8,303,293. This adjustment is presented in UAE-WM Exhibit RR 1.1 (KCH-1), pages 1-2. As I noted above, the outputs for the Net Power Cost Study incorporating these adjustments are presented in UAE-WM Exhibit RR 1.2 (KCH-2).

Adjustments to Rate Base

Q. What adjustments to rate base are you recommending?

A. The projected in-service date for several major facilities has changed since the filing of the Company's direct case. A summary of the delayed projects is presented in RMP's Response to CCS 27.61. I have adjusted rate base to reflect a one-month delay in the in-service dates of three major projects listed in this data response as well the cancellation of a fourth project. I have also reflected a corresponding reduction in the Renewable Energy Tax Credit and REC revenue associated with the delay in the in-service date of Rolling Hills and Glenrock III wind plants. The estimated impact on Utah revenue requirement is a reduction of $968,129, exclusive of a minor increase in interest synchronization expense, and exclusive of changes to net power costs. This adjustment is presented in UAE-WM Exhibit RR 1.3 (KCH-3). The reduction in energy production from the Rolling Hills and Glenrock III wind plants is incorporated in my net power cost adjustment, discussed above.

Wage and Benefit Expense

Q. What adjustment are you recommending to wage and benefit expense?

A. I am recommending a reduction in projected wage and benefit expense of $13,185,000 (Company-wide). This is one-half the Company's proposed increase in this expense relative to the actual expense incurred for the year ending June 2008.

Q. Please explain the basis for your recommendation.

A. My recommended adjustment is to wage and benefit expense as a whole, although it is influenced by my review of specific categories of expense. My recommendation is also influenced by the overall economic situation in the national economy, as well as in the Company's service territory.

As of the end of January 2009, the United States had lost about 3.6 million jobs in the deepening recession. In the current economic environment, which is widely viewed as the most serious world economic crisis since the Great Depression, I do not believe a "business as usual" approach to utility compensation is reasonable. That does not mean that I believe that utility employees should be singled out to bear an unfair burden in coping with current economic conditions. What is required is a test of reasonableness under the circumstances. Utah customers are being asked to absorb a new round of utility rate increases in a year in which statewide unemployment is projected to increase by 2.3 percent, and in which the state legislature has taken action to cut the budget for state government. Moreover, the RMP rate increases are coming at a time in which load growth has slowed, providing fewer sales units over which to recover the cost of the increased plant in service. Further, the one bright spot for consumers in the current economic crisis, the reduction in energy commodity costs, is a non-factor in this case because RMP's fuel costs were locked in when prices were higher.

Against this backdrop, I offer the following observations:

- PacifiCorp has over-budgeted for benefits and overhead expenses each of the past three years. In the past two years, this amount has been fairly pronounced: $26.6 million in 2008 and $21.9 million in 2007 (total Company).[6]
- In 2008, the Company made changes to its retirement plan, as described by RMP witness Erich D. Wilson. Employees currently participating in the cash balance retirement plan were given an option to switch to an enhanced 401(k) plan. The Company forecasts that pension expense will decrease by $13.2 million in 2009, but this will be more than offset by a projected increase in 401(k) expense by $24 million (growing from $20.6 million actual for year ending June 2008 to $44.7 million projected for year ending December 2009).[7]

[6] RMP Dec 2008 MDR 1.3
[7] RMP Exhibit__(SRM-2SS), p. 4.11.2

- PacifiCorp has budgeted for a 58 percent increase in Worker's Compensation expense ($1.2 million) between the year ending June 2008 and the year ending December 2009.[8]
- Total utility labor expense, including benefits (after removing capitalized labor) is projected to be $519,316,465 for the test period. This is an increase of $26,370,572 over actual expenses for the year ending June 2008.[9]
- On September 2, 2008, after the Company's initial filing in this case, RMP issued a press release stating that the Company was taking several cost reduction actions in Utah. According to RMP's Response to CCS 22.13, these cost reductions applied to distribution maintenance programs in Utah, hiring of Utah-based employees, economic development in Utah, and funding for research associated with clean coal technology. According to RMP, these cost reductions will expire in May 2009 when a new rate order provides the Company with "adequate recovery of costs incurred on behalf of Utah customers." In the meantime, costs are reduced from January through April 2009. But then according to RMP, "[s]pending is then adjusted for the remainder of the year, so the total 2009 costs are unchanged."

Q. What is your recommendation to the Commission taking into account these observations as well as current economic conditions?

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[8] Ibid.
[9] Ibid.

A. I believe it is reasonable for the Commission to exclude from rate recovery wage and benefit expense increases in excess of $13,185,572 (total Company) relative to year ending June 2008 actual. This amounts to a reduction in expense of $13,185,000. This is one-half of the Company's proposed increase in this expense relative to the actual expense incurred for the year ending June 2008. It is also about half the amount by which benefit and overhead projections were over-estimated in 2008. I believe that taken in combination with the Company's aggressive worker's compensation assumptions, changes in pension programs, recent overestimates in benefit and pension budgets, and the current Utah cost-cutting actions that are not necessarily reflected in the 2009 wage and benefit budget, my recommendation is reasonable in the current economic situation.

This adjustment is presented in UAE-WM Exhibit RR 1.4 (KCH-4). The estimated impact on Utah revenue requirement is a reduction of $5,354,094.

Q. Are you recommending that this adjustment be applied to any specific wage and benefit accounts?

A. No. I am recommending that the adjustment be applied to wage and benefit expense generally. How the revenues available from rates are applied to the various categories of wage and benefit expense should be determined by the Company.

Q. Does this conclude your direct testimony?

A. Yes, it does.