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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. 09-035-23**

PREFILED DIRECT TESTIMONY OF KEVIN C. HIGGINS

[REVENUE REQUIREMENT, COST OF SERVICE, RATE SPREAD]

The UAE Intervention Group ("UAE") hereby submits the Prefiled Direct Testimony of Kevin C. Higgins on revenue requirement, cost of service and rate spread issues.

DATED this 8th day of October, 2009.

/s/ ______________________________
Gary A. Dodge,
Attorneys for UAE

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 8th day of October, 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

Docket No. 09-035-23

[Revenue Requirement, Cost of Service, Rate Spread]

October 8, 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 sponsored by the Utah Association of Energy Users ("UAE") Intervention Group.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before this Commission?

A. Yes. Since 1984, I have testified in twenty-three dockets before the Utah Public Service Commission on electricity and natural gas matters.

Q. Have you testified previously before any other state utility regulatory commissions?

A. Yes. I have testified in over one hundred other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Arizona, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings at the Federal Energy Regulatory Commission.

A more detailed description of my qualifications is contained in Attachment A, attached to my 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, cost of service, and rate spread issues in the general rate case filed by Rocky Mountain Power ("RMP," "Company" or "PacifiCorp").

In my revenue requirements 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 with respect to revenue requirements?

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 June 30, 2009; and

(b) Replacement of the Company's proposed wind integration charge of $6.91/MWh with a wind integration charge of $3.02/MWh.

The impact of these adjustments reduces net power costs by $21.2 million, which in turn reduces Utah revenue requirement by approximately $8,703,071.

(2) RMP's projected 401(k) matching contribution expense should be adjusted to better line up with the Company's 2009 projections for this

item. The estimated impact on Utah revenue requirement is a reduction of $1,102,258.

(3) The projected cost of the High Plains wind project has been reduced from $245.5 million to $236.4 million. Utah revenue requirement should be reduced to recognize this reduction. The estimated impact on Utah revenue requirement is a reduction $466,330.

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 $66,883,665 by $10,271,658. These results are summarized in Table KCH-1, below.

Table KCH-1

Summary of UAE Recommended Adjustments

Description	Est. Utah Revenue Impact	Cumulative Impact
Net Power Costs		
Updated forward price curve	$(2,157,046)	$(2,157,046)
Wind integration – inter-hour	$(3,512,501)	$(5,669,547)
Wind integration – intra-hour	$(3,033,523)	$(8,703,071)
401(k) contribution expense	$(1,102,258)	$(9,805,328)
High Plains capital cost reduction	$(466,330)	$(10,271,658)
Total	$(10,271,658)	

Q. What are your primary conclusions and recommendations with respect to cost of service?

A. I offer the following recommendations and conclusions with respect to cost of service issues:

(1) RMP's depiction of class cost of service at the rate mitigation cap revenue requirement is conceptually incorrect. Under the Company's approach, the class cost-of-service responsibility for the distribution function varies between the Rolled-in revenue requirement and the MSP cap revenue requirement, despite the fact that the only difference between the Rolled-in revenue requirement and the MSP Revised Protocol revenue requirement is the allocation of generation-related costs to Utah. As a result of this incorrect approach, the Company's depiction of Utah generation cost of service is overstated. Because the various Utah rate classes do not bear the same share of generation costs as they do distribution costs, RMP's calculation results in a distorted depiction of class cost responsibility under the MSP cap. In particular, RMP's calculation typically overstates the cost responsibility of Schedule 9.

I recommend that the Commission order RMP to correct its depiction of Utah class cost of service such that cost of service for the distribution function does not vary between the Rolled-in and MSP cap revenue requirements. This problem can be corrected by determining class cost-of-service by function using RMP's model at the (true) target rate of return for all functions at the unconstrained Revised Protocol revenue requirement, and then adjusting the generation cost-of-service downward to meet the constraint of the rate mitigation cap.

(2) RMP's practice of allocating income taxes rather than calculating them overstates the expenses for a class that is earning below the overall average return, and vice versa. Consequently, it distorts relative rates of return at current revenues: the relative return ratio is overstated for classes earning above the average return and it is understated for classes earning below the average return.

I recommend that the Commission require RMP in future rate cases to *calculate* class income tax expense at current revenues based on class operating revenue for return, rather than allocating income tax expense as RMP currently does. This change will produce a more accurate depiction of class relative returns at current revenues.

(3) Just 170 meters are used to estimate the hourly demands for approximately 710,000 Residential customers for the purpose of determining class loads during the hours of system coincident peak demand. I am concerned that these small samples may not be producing sufficiently accurate class cost allocations. This concern is magnified in light of the fact that the Company no longer calibrates its non-census estimates to match up with the Utah jurisdictional loads.

To gauge whether measurement error is potentially causing significant shifts in cost-of-service responsibility assigned to classes, I performed a sensitivity analysis in which I reran RMP's cost-of-service study using the jurisdictional loads assigned to Utah, rather than the sample estimates. The results show that the costs allocated to the census-measured Schedules 8 and 9 are materially reduced when costs are allocated using the Utah jurisdictional loads. For Schedule 9, the revenue deficiency is reduced by more than $8 million relative to RMP's cost-of-service study.

The decision not to calibrate non-census loads to the Utah jurisdictional load represents a methodology change that was introduced several years ago. Previously, the Company had routinely calibrated hourly load research estimates obtained from all non-census rate groups to the hourly Utah jurisdictional system loads. I believe it is necessary to revisit this change in light of the material and unexplained "gap" between the measured loads allocated to Utah for inter-jurisdictional purposes and the sum of Utah loads derived using a combination of census data and sample estimates. In my opinion, the decision to no longer reconcile the latter to the former is causing an unreasonable detrimental impact on census-measured classes.

Q. What are your primary conclusions and recommendations with respect to rate spread?

A. I offer the following recommendations and conclusions with respect to rate spread:

(1) I support the rate spread proposal put forward by RMP witness William R. Griffith. According to his proposal, at RMP's requested revenue requirement, Schedules 6 and 23, as well as Lighting, would receive an increase of 5.03 percent, approximately equal to the system average increase excluding special contracts. Schedules 8 and 9, as well as Irrigation customers, would receive an increase that is 1.0 percent greater, or 6.03 percent. Residential customers would receive the smallest increase of 4.03 percent. The proposal is reasonable in that it recognizes the direction of change indicated by RMP's cost-of-service study, as classes earning returns below the system average receive percentage rate increases that are above the average, and vice versa, while classes earning close to the average retail return receive an increase that approximately equal to the system average increase.

At the same time, Mr. Griffith's proposal properly does not adhere rigidly to the class revenue deficiencies indicated by RMP's cost-of-service study.

(2) The Commission should not adhere strictly to class revenue deficiencies indicated by RMP's cost-of-service study for a number of reasons, including the need to apply the principle of gradualism in the context of a major recession that is severely impacting Utah businesses.

(3) The Commission should also take into consideration that the cost of paying for growth is being disproportionately assigned to classes that are not growing. For the test period in this case, Utah industrial load is actually projected to <u>decline</u> relative to Calendar Year 2008 levels by more than 7 percent.

(4) The decision several years ago to stop calibrating estimated loads to the measured jurisdictional loads is causing an unreasonable detrimental impact on Schedules 8 and 9 in the cost-of service study. Re-running RMP's cost-of-service study using the jurisdictional loads assigned to Utah results in significantly smaller revenue deficiencies for these two rate schedules. Indeed, the revenue deficiency of 6.85 percent derived in this manner for Schedule 9 is very close to the rate increase recommended by Mr. Griffith for this class. This is an important additional reason to not go beyond the 6.03 percent rate increase proposed by Mr. Griffith for Schedule 9.

(5) If the revenue requirement approved by the Commission is less than that requested by RMP, then the rate spread proposed in UAE Exhibit 1.6 (KCH-6), should be the starting point for spreading the approved revenue change. Specifically, the revenue apportionment produced by that rate spread should be used as the basis for spreading the smaller revenue change.

REVENUE REQUIREMENTS

Net Power Costs

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 June 30, 2009. In addition, I make adjustments in RMP's GRID model for wind integration costs.

The combined impact of these adjustments is summarized in UAE Exhibit 1.1 (KCH-1), page 1. The output of the Net Power Cost study incorporating these adjustments is presented in UAE Exhibit 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-1).

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.

Updated Forward Price Curve

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

A. RMP's filing projects net power costs using forward price curves dated March 31, 2009. Since the filing of the Company's case, more recent forward prices applicable to the test period have become available. In response to UAE

Data Request 2.2, RMP provided the information needed to perform an updated GRID run using the Company's more recent forward price curve. The results of the updated GRID run are included in UAE Exhibit 1.2 (KCH-2).

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

A. The fuel cost for RMP's gas generating units was lower in the summer months than originally forecast, but greater in later months. The net effect of this change is that projected net power costs fall by $5.3 million in the updated run.

Q. What is your recommendation to the Commission?

A. I recommend using the June 30, 2009 forward price information in GRID to determine net power cost. As indicated above, this reduces net power cost by $5.3 million, which results in a corresponding estimated reduction in Utah revenue requirement of $2,157,046. This adjustment is included (along with my other net power costs adjustments) in UAE Exhibit 1.1 (KCH-1), page 1, and in the study results presented in UAE Exhibit 1.2 (KCH-2). The individual impact of each of my net power cost adjustments is tabulated in UAE Exhibit 1.1 (KCH-1), page 3.

Q. In making this recommendation, how do you respond to previous objections from RMP that other parties should not be permitted to use forward price information that is updated from the Company's filed case?

A. In the previous rate case, Docket No. 08-035-38, RMP objected to my recommendation to use an updated forward price curve as part of my direct testimony.[1] RMP objected on the grounds that in the 2007 rate case, the Commission rejected the Company's own proposal to update the forward price curve in its rebuttal testimony, an update which would have increased net power cost. According to RMP's rebuttal testimony in Docket No. 08-035-38, the Commission ruled that such an update required more review than was possible late in the case, and the evidence that the Company was fully hedged mitigated the need for an update. RMP maintained that this reasoning should apply to the forward price curve update that I (and DPU) had proposed, and that our recommended forward price curve adjustment(s) should be rejected.

RMP's argument ignores the fundamental difference between the utility updating its own pricing projection and the initial pricing projection suggested by an intervenor in its case-in-chief. It should be noted that RMP determines the date at which it will file a rate case. The Company has the advantage of developing and preparing its case without regard to a statutory clock. The Company can also elect to file, or not to file, a case depending on management's best judgment as to what course of action is to RMP's greatest strategic advantage. In contrast, other parties must respond to the Company's filing and are constrained by a schedule that is determined in significant part by statutory requirements. It would be unduly burdensome for these other parties to have to respond to a moving target. It is thus reasonable in such a situation for the

[1] Rebuttal testimony of Gregory N. Duvall, Docket No. 08-035-38, p.12, lines 258-266. The Utah Division of Public Utilities ("DPU") had also proposed to use an updated forward price curve. RMP objected both to my adjustment as well as DPU's.

Commission to preclude RMP from filing late adjustments in its case that further inure to the Company's advantage.

At the same time, it is also reasonable, and even essential, that other parties be permitted to prepare their own direct cases using the best information available to them at the time they make their initial filings. This situation is fundamentally distinct from RMP seeking to update in rebuttal the vintage of the forward price curves the Company elected to use in its direct case. RMP already controls the vintage of information used in its direct case; the Company should not be permitted to also control the cut-off date of information used by other parties in preparing their direct cases.

Wind Integration Charges

Q. What net power cost recovery has RMP proposed for wind integration charges?

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.

PacifiCorp purchases wind integration service for two of its wind facilities, Leaning Juniper and Goodnoe Hills, from Bonneville Power Administration ("BPA"). The remainder, and majority, of wind integration service is self-supplied. In this proceeding, RMP has dramatically increased its estimate of self-supplied wind integration charges from $1.16/MWh, proposed in the previous rate case, to $6.91/MWh – an increase of nearly 500 percent. RMP's proposed recovery of wind integration charges has increased from $6.1 million in the prior rate case to $28.3 million in this case. A portion of this increase is attributable to the greater amount of wind-generated megawatt-hours being integrated and a portion is attributable to an increase in the charges levied by BPA. However, the lion's share of the increase is due to proposed increase in the charge for self-supplied wind integration service that RMP is seeking to recover from Utah customers.

Q. In your opinion, is RMP's proposal for wind integration charges reasonable?

A. No. After having committed Utah customers to capital cost responsibility for over 1,100 MW of wind generation plant, the Company now claims that the energy cost of integrating the wind plants is actually nearly six times the Company's prior estimates. Indeed, it is striking that RMP is now seeking recovery for wind generation energy costs that are approaching the per-MWh fuel costs of some of the Company's coal-fired plants.[2] I suggest that RMP should have to bear a relatively high burden of proof to justify recovery of its claim of a nearly six-fold increase in costs. As I will explain below, I do not believe the Company has met this burden.

Q. What is the basis for RMP's claim of such a large increase in wind integration charges?

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[2] For example, the test year projected fuel cost for the Dave Johnston plant is $8.87/MWh. Exhibit RMP___(GND-1), p. 17.

A. As explained in the direct testimony of Gregory N. Duvall, the Company performed a new analysis of the cost of integrating wind generation as part of its 2008 IRP filed with the Commission on May 28, 2009. Whereas the Company's 2007 IRP wind integration cost analysis was limited to estimating the cost of wind forecast deviations, which is an intra-hour cost, the new analysis considers four additional costs: the reserve cost associated with "regulating up" and "regulating down," which are also intra-hour costs, plus the cost of day-ahead and hour-ahead system balancing, which are <u>inter</u>-hour costs.

As explained by Mr. Duvall (and also described in Appendix F of the PacifiCorp 2008 IRP), the Company's wind integration analysis proceeds sequentially, starting with the inter-hour costs and then moving to the intra-hour costs. The basic assumption of the inter-hour cost analysis is that deviations from expectations, i.e., either more wind generation than expected or less wind generation than expected, are resolved through market sales or purchases. In this case, RMP is seeking recovery of inter-hour wind integration costs in the amount of $2.09/MWh.

In the context of this rate case, the underlying expected output of each wind facility is already modeled into the test year GRID run. Conceptually, then, from a MWh standpoint, "planned" inter-hour wind integration sales must equal "planned" inter-hour wind integration purchases – otherwise the underlying MWh modeled in GRID would be incorrect for determining net power cost. At first blush, one might conclude that such offsetting sales and purchases, in the absence of knowledge about when they would occur, should produce a net incremental energy cost of zero. This would clearly be the case if inter-hour deviations from expectations were met using Company-owned resources (although the reserve cost of using Company-owned resources for this purpose would have to be considered, as I will discuss below).

However, as noted above, RMP does not assume that inter-hour wind integration is carried out using Company-owned resources; rather, RMP assumes that all inter-hour wind integration occurs through market sales and purchases. This is not a reasonable assumption, as I discuss below. Moreover, even if it were a reasonable assumption, the market-driven costs would still offset to zero incremental cost if the transactions are assumed to occur exactly at the market price. However, the RMP analysis assumes that the Company is a "loser" on each and every transaction, i.e., RMP assumes that it will pay $0.50/MWh above market for every inter-hour purchase and that it will sell at $0.50/MWh below market for every inter-hour sale. The Company thus projects inter-hour wind integration charges of $2.09/MWh, based on its combined assumptions that all inter-hour wind integration occurs in the market *and* that RMP is "always a loser" on the market transactions.

Q. Why is RMP's assumption that inter-hour wind integration occurs exclusively through market transactions unreasonable?

A. In the sequence of RMP's analysis, evaluation of inter-hour costs occurs before evaluation of intra-hour costs; thus, the Company's inter-hour analysis ignores the fact that its intra-hour analysis calls for massive amounts of Company-owned generation to be held in reserve to support intra-hour deviations in wind generation. RMP fails to consider these Company-owned reserves in its analysis of inter-hour wind integration costs. Given the magnitude of the assumed reserve requirement needed to support intra-hour wind integration, it is difficult to fathom that these Company-owned reserves would not also be used to support inter-hour wind integration. And, to the extent this support occurs, the Company-owned resources would displace the market transactions on which the Company is assumed always to "lose."

Q. What is the magnitude of the reserves estimated by the Company to be required to support intra-hour wind integration?

A. The Company's study estimates the incremental reserve requirement needed to support intra-hour integration to be 295 MW, which translates to about 26.7 percent of the nameplate capacity of the wind generation that is being integrated through self-provision. This amount of reserve is incremental to the 5 percent reserve requirement otherwise applicable to non-hydro resources (the cost of which for wind is already included in GRID). Thus, in total, RMP concludes that it must be compensated for carrying reserves equal to 31.7 percent of the nameplate capacity of its wind generation – which is many times greater than the reserve requirement estimated in the 2007 IRP. As the projected capacity factor of RMP wind generation is in the range of 30.4 to 40.3 percent, RMP's intra-hour reserve estimate is tantamount to assuming that the Company must carry an amount of reserves approaching the expected hourly output of its wind fleet over the course of the year.

If indeed RMP were to carry incremental reserves of 295 MW, such that the Company's total reserve in support of wind generation approached the expected hourly output of its wind fleet over the course of the year, then the notion that none of this reserve would be available to support inter-hour wind integration does not appear credible. Indeed, the opposite would appear to be the case: with such a substantial reserve assumed to be required for intra-hour wind integration, then we should also assume that all inter-hour wind integration can be performed using Company-owned resources already being held in reserve, rather than assuming it requires market transactions on which RMP always loses money.

Q. What is your recommendation to the Commission with respect to the treatment of inter-hour wind integration costs?

A. I recommend that RMP's wind integration charges be reduced by \$2.09/MWh to remove the cost of assumed transactional losses for performing inter-hour wind integration.

Q. Do you have any recommended adjustments to RMP's proposed intra-hour wind integration charge?

A. Yes. RMP's intra-hour wind integration charge incorporates the cost of reserves needed to support "regulating up" and "regulating down" within the hour. The former is performed when wind generation decreases, the latter is performed when wind generation increases. I agree that "regulating up" represents an incremental cost for a utility that is self-providing intra-hour wind integration. Therefore, I agree that the prudent cost of incremental reserves needed to perform intra-hour "regulating up" should be recovered from ratepayers. For a utility that self-supplies its ancillary services, such as RMP, the capacity cost associated with said incremental reserves is already recovered in the utility's return on 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. It is appropriate to include this incremental cost in net power cost.

However, the treatment of "regulating down" is a different matter. While I agree that it may be appropriate to charge third parties for regulating down, I do not agree that "regulating down" represents an incremental cost that should be charged to ratepayers. Therefore, I recommend that reserves included in RMP's intra-hour reserve requirement for "regulating down" be removed from the calculation of the wind integration charge recovered from ratepayers.

Q. Please explain how it may be reasonable to charge a third party for "regulating down," but not reasonable to levy such a charge to ratepayers.

A. "Regulating down" does not cause incremental costs to be incurred to serve ratepayers. When "regulating down," the utility backs down a generating unit in response to increased wind output. The cost of the facilities required for this action is already recovered from ratepayers. In contrast to "regulating up," this action does not require withholding resources from the market, and therefore does not result in an opportunity cost that must be recognized in GRID.

On the other hand, if a utility is providing wind integration service to a third party (e.g., a third-party seller of wind generation) then it may be reasonable to recognize that the third party realizes a benefit from the utility's ability to absorb variable increases in wind generation by backing down one of its own units. In certain circumstances, a charge for this service may be appropriate. In such a situation, there would be a rebuttable presumption that the revenues from such a third-party charge should be recognized as a revenue credit inuring to the benefit of the customers paying for the facilities used for providing the "regulating down" service. The charge to the third party would not represent recovery of incremental costs, but rather recognition of the value of the third party's reliance on facilities that other parties (i.e., ratepayers) have paid for.

The upshot is that RMP's analysis of charges for "regulating down" might be appropriate in some contexts. However, it is not appropriate to export the "regulating down" costs identified in RMP's IRP analysis for application to the Company's retail customers in GRID. Indeed, charging retail customers for the projected "regulating down" costs would represent over-recovery.

Q. What is your recommendation to the Commission with respect to the treatment of intra-hour wind integration costs?

A. I recommend that the Commission approve recovery of prudently-incurred incremental costs associated with "regulating up," but not allow additional recovery of costs claimed by RMP for "regulating down." Using the Company's workpapers, I have recalculated its intra-hour reserve requirement for wind integration with "regulating down" reset to zero. This produces an incremental reserve requirement of 221 MW instead of 295 MW. This change reduces the intra-hour wind integration charge from $4.83/MWh to $3.02/MWh.

Q. Does this adjustment change your conclusion, discussed above, that RMP should have sufficient Company-owned reserves from intra-hour wind integration to handle its <u>inter</u>-hour wind integration needs with no additional costs?

A. No, this adjustment does not change my conclusion. The 221 MW of incremental reserves that I recognize in the derivation of intra-hour wind integration costs chargeable to ratepayers represents 19.9 percent of the expected hourly output of PacifiCorp's wind fleet supported by self-provision over the course of the year. With this robust level of assumed Company-owned reserves, RMP's proposal to recover inter-hour wind integration costs from customers based solely on presumed market transactions (always transacted at a loss) should be rejected.

Q. Please summarize your recommendations with respect to the treatment of wind integration charges.

A. I agree that the prudent cost of holding incremental reserves needed to perform intra-hour "regulating up" should be included in net power costs to be recovered from ratepayers. However, I do not agree that "regulating down" represents an incremental cost to ratepayers. Therefore, I recommend that reserves included in RMP's intra-hour reserve requirement for regulating down be removed from the calculation of the wind integration charge recovered from ratepayers. This produces an incremental reserve requirement of 221 MW instead of 295 MW. This change reduces the intra-hour wind integration charge from $4.83/MWh to $3.02/MWh.

RMP's inter-hour wind integration analysis relies solely on assumed market transactions in which RMP "always loses." Given the magnitude of the assumed reserve requirement to support intra-hour wind integration, it is difficult to fathom that these Company-owned reserves would not also be available to support inter-hour wind integration. Therefore, I recommend that RMP's wind integration charges be reduced by $2.08/MWh to remove the cost of assumed transactional losses for performing inter-hour wind integration.

The combined impact of my intra-hour and inter-hour adjustments is to reduce wind integration charges from RMP's recommended $6.91/MWh to $3.02/MWh. The resulting charge is still 2.6 times greater than the $1.16/MWh proposed by RMP in its last rate case. The net impact of my wind integration adjustment in GRID is to reduce net power cost by $15.9 million. This adjustment is presented in UAE Exhibit 1.1 (KCH-1), page 3. It shows separately the impacts of my inter-hour adjustment and intra-hour adjustment. Taken together, it results in an estimated reduction in Utah revenue requirement of $6,546,024.

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 approximately $21.2 million. The estimated impact on Utah revenue requirement is a reduction of $8,703,071. This adjustment is presented in UAE Exhibit 1.1 (KCH-1), pages 1-3. As I noted above, the outputs for the Net Power Cost Study incorporating these adjustments are presented in UAE Exhibit 1.2 (KCH-2).

<u>401(k) Contribution Expense</u>

Q. What adjustment are you proposing to 401(k) contribution expense?

A. I recommend adjusting RMP's projected 401(k) matching contribution to better line up with the Company's 2009 projections.

In its filing, RMP seeks recovery of $34,487,345 in 401(k) matching contributions on a total company basis.[3] This amount is comprised of total projected costs of $35,400,000, with an adjustment downward of $912,655 to remove joint-venture-related contributions.

The Company's projected 401(k) contribution expense for 2009, including the joint venture contribution, is $31,100,000.[4] My recommendation is to use this projection as the baseline, with an escalation of 1.25 percent to represent 50 percent of 2010 projected wage and salary increases. After adjusting to remove

[3] RMP Exhibit___(SRM-2), p. 4.2.2
[4] RMP Response to DPU 36.7.

joint venture contributions, my recommended 401(k) matching contribution expense for the test period totals $30,676,939 on a total company basis. This adjustment is shown in UAE Exhibit 1.3 (KCH-3). The estimated impact on Utah revenue requirement is a reduction of $1,102,258.

<u>High Plains Wind Plant Capital Cost</u>

Q. What adjustments are you proposing to the High Plains wind plant capital cost?

A. RMP had originally projected that capital costs for the High Plains wind project would be $245.5 million.[5] This estimate included a contingency cost of $5.5 million, which ultimately was not needed. According to RMP's Response to DPU 42.6, the revised projected cost for the project is $236.4 million.

I recommend an adjustment that recognizes the reduced plant cost. This adjustment is shown in UAE Exhibit 1.4 (KCH-4). The estimated impact on Utah revenue requirement is a reduction of $466,330.

[5] RMP Exhibit___(SRM-2), p. 8.10.9.

CLASS COST OF SERVICE

Overview

Q. Do you have any comments on the class cost-of-service results presented by RMP?

A. Yes. The Company's class cost-of-service results are presented by RMP witness C. Craig Paice in his direct testimony. I have several specific disagreements with RMP's approach that I wish to address in this proceeding. Specifically, I disagree with how RMP translates the effect of the MSP Revised Protocol rate mitigation cap in presenting its Utah class cost-of-service results. I also disagree with RMP's presentation of income tax expense under current revenues. In addition, I have serious concerns over the measurement of customer class loads in RMP's Utah jurisdiction, an issue that has significant implications for the Company's class cost-of-service study results.

Treatment of MSP Cap

Q. Please explain your disagreement with how RMP translates the effect of the MSP Revised Protocol rate mitigation cap in presenting its Utah class cost-of-service results.

A. The Company presents its class cost-of-service results for the revenue requirement derived using the MSP Revised Protocol rate mitigation cap. I agree that this jurisdictional revenue requirement is the appropriate one to use for determining class cost of service. However, the calculation of class revenue responsibility is incorrect due to a conceptual error in the Company's approach. I discussed this conceptual error at length in Docket No. 04-035-42 and in the task force that was created pursuant to the stipulation and order in that case. I also discussed it in Docket No. 07-034-93. Nevertheless, RMP continues to adhere to its approach. As rate spread has been resolved through settlement since the approval of the MSP Revised Protocol, the Commission has not had the opportunity to rule on this issue.

Q. Please continue. How does the rate mitigation cap affect the allocation of costs to Utah customer classes?

A. The MSP Revised Protocol rate mitigation cap constrains the impact of the additional generation costs that are otherwise allocated to Utah under the MSP Revised Protocol. The cap provision of the Revised Protocol currently requires that the revenue requirement impact on Utah from adopting the MSP method be capped at 101 percent of the "Rolled-in" revenue requirement. <u>The only difference between the Rolled-in revenue requirement and the MSP Revised Protocol revenue requirement is the allocation of generation-related costs to Utah</u>. It follows, then, that class cost-of-service responsibility for the distribution function should be identical under "Rolled-in" as under Revised Protocol, and it should be identical, of course, under the MSP cap, as well. This concept is highly intuitive. Yet, under the Company's translation of the rate mitigation cap, the class cost-of-service responsibility for the distribution function <u>does</u> vary between the Rolled-in revenue requirement and the MSP cap revenue requirement – and therein lies the conceptual error with RMP's approach.

Q. Please explain how the class cost-of-service responsibility for the distribution function varies between the Rolled-in revenue requirement and the rate mitigation cap revenue requirement under RMP's calculation.

A. The allocation of distribution costs to Utah is lower under RMP's MSP cap allocation than it is under Rolled-in, even though the total cost allocation to Utah under the MSP cap is 1.0 percent greater than under Rolled-in. Specifically, Utah's allocation of distribution costs under Rolled-in is $352,839,148, whereas under the MSP cap (according to RMP) it is $352,036,836.[6] Of course, there is no reasonable basis for Utah distribution costs to be any different under the MSP cap than under Rolled-in – it particularly makes no sense for distribution cost-of-service to decline as the revenue requirement increases from the Rolled-in amount to MSP cap amount.

This reduction in cost responsibility for the distribution function is then improperly made up by assigning a greater increase to Utah generation cost.

Q. What are the implications for the class cost of service results of understating distribution cost of service while overstating generation cost of service?

A. Because the various Utah rate classes do not bear the same share of generation costs as they do distribution costs, RMP's calculation results in a distorted depiction of class cost responsibility under the MSP cap. In particular,

[6] Rolled in source: RMP Response to MDR 1.6. MSP cap source: RMP Exhibit__(CCP-3), TAB 4, p. 2.

RMP's calculation typically overstates the cost responsibility of Schedule 9, which, by its terms of service, does not use the distribution system.

The impact of the distortion has varied from case to case. In the 2007 case, the impact was quite material, as RMP allocated $13 million more to Utah generation costs than was warranted by the MSP cap. In the current case, however, the distortion is not as great, with the deviation in the allocation of distribution costs amounting to less than $1 million. In future cases, the impact may again be more significant.

Q. Have you determined how the understatement of distribution costs occurs in RMP's calculation?

A. Yes. RMP has chosen to reflect the effects of the rate mitigation cap as an overall reduction in its target rate of return for all functions. That is, even though RMP is requesting a rate of return of 8.54 percent in this proceeding, the Company presents its class cost of service results (at RMP's requested revenue increase of $66.9 million) using a lower target rate of return of 8.37 percent. This has the effect of assigning the impact of the rate mitigation cap to <u>all</u> functions – even though the Revised Protocol only affects the allocation to Utah of <u>generation</u> costs.

The upshot is that RMP's depiction of class cost of service at the rate mitigation cap revenue requirement is conceptually incorrect. Utah's distribution cost-of-service does not change as we move from Rolled-in to Revised Protocol. Because the MSP Revised Protocol allocates more generation costs to Utah than does Rolled-in, its adoption in Utah already has a relatively greater impact on classes for which generation is a relatively large component of rates, such as Schedule 9. RMP's depiction of class cost of service exacerbates this impact by assigning even more costs to generation than is called for by the Revised Protocol.

Q. How can this problem be corrected?

A. This problem can be corrected by determining class cost-of-service by function using RMP's model at the (true) target rate of return for all functions at the unconstrained Revised Protocol revenue requirement, and then adjusting the generation cost-of-service downward to meet the constraint of the rate mitigation cap. This adjustment to generation cost-of-service can be accomplished by reflecting a reduction in generation expense allocated to Utah, which is consistent with the way that the Revised Protocol adjusts Utah generation costs in the first instance (i.e., the Revised Protocol allocates greater generation costs to Utah via increasing generation expense). Alternatively, the adjustment could be made by reducing the target rate of return for generation (while holding the target rate of return for all other functions unchanged) until the constraint of the rate mitigation cap is met.

Q. What is your recommendation to the Commission on this issue?

A. I recommend that the Commission order RMP to correct its depiction of Utah class cost of service such that distribution cost of service does not vary between the Rolled-in and MSP cap revenue requirements. This can be accomplished by following the approach described above in my testimony.

<u>Calculation of Class Income Tax Expense</u>

Q. Please explain your disagreement with RMP concerning the calculation of class income tax expense.

A. In RMP's depiction of class cost of service at current revenues, RMP allocates income tax responsibility to customer classes based on each class's allocated share of rate base. This is a non-standard depiction, and in my opinion, it is incorrect. At current revenues, the income tax expense for a given class should be *calculated* based on the operating revenue for return produced by that class. RMP's practice of allocating income taxes rather than calculating them overstates the expenses for a class that is earning below the overall average return, and vice versa. Consequently, it distorts relative rates of return at current revenues: the relative return ratio is overstated for classes earning above the average return and it is understated for classes earning below the average return.

Q. What are the class returns at current revenues as presented by RMP?

A. This information is presented in Table KCH-2, below. It shows RMP's calculation of each class's rate of return at current revenues derived by allocating each class's rate of return.

Table KCH-2

EARNED RATE OF RETURN BY RATE CLASS – RMP DEPICTION

Schedule No.	Description	Earned Return on Rate Base	Earned Rate of Return Index
1	Residential	8.73%	1.16
6	Gen. Service – Large	7.74%	1.03
8	Gen. Service - + 1 MW	7.07%	0.94
7,11,12,13	Street & Area Lighting	17.23%	2.30
9	Gen. Service – High Voltage	5.16%	0.69
10	Irrigation	3.21%	0.43
15	Traffic Signals	6.16%	0.82
15	Outdoor Lighting	42.34%	5.65
23	Gen. Service – Small	7.57%	1.01
25	Mobile Home Parks	8.79%	1.17
SpC	Customer A	1.75%	0.23
SpC	Customer B	-3.71%	-0.50
SpC	Customer C	3.92%	0.52
Total	Utah Jurisdiction	7.49%	1.00

Data Source: Exhibit RMP _____ (CCP-3), Tab 4

Q. Have you recalculated class rates of return at current revenues?

A. Yes. This information is presented in Table KCH-3, below. Using the same class cost allocations otherwise presented by RMP, Table KCH-3 shows class rates of return when class income tax expense is calculated based on each class's operating revenue for return, rather than allocated per rate base. As shown in the table, calculating income tax expense at current revenues shows that the range of earned returns is actually narrower than depicted by RMP.

Table KCH-3

EARNED RATE OF RETURN BY RATE CLASS – CLASS INCOME TAXES CALCULATED

Schedule No.	Description	Earned Return on Rate Base	Earned Rate of Return Index
1	Residential	8.32%	1.11
6	Gen. Service – Large	7.59%	1.01
8	Gen. Service - + 1 MW	7.16%	0.96
7,11,12,13	Street & Area Lighting	12.86%	1.72
9	Gen. Service – High Voltage	6.17%	0.82
10	Irrigation	4.65%	0.62
15	Traffic Signals	6.53%	0.87
15	Outdoor Lighting	32.61%	4.35
23	Gen. Service – Small	7.62%	1.02
25	Mobile Home Parks	8.38%	1.12
SpC	Customer A	3.53%	0.47
SpC	Customer B	0.24%	0.03
SpC	Customer C	4.97%	0.66
Total	Utah Jurisdiction	7.49%	1.00

Q. Does allocating class income tax expense at current revenues result in an incorrect calculation of class revenue deficiency?

A. Sometimes it does, but not in this case. Depending on the steps used by the analyst to derive each class's revenue deficiency (or sufficiency), allocating income tax expense rather than calculating it can result in an incorrect determination of class revenue deficiency (or sufficiency). Indeed, this has occurred for other Utah utilities in the past.[7] However, the mechanics of the RMP class revenue deficiency calculation are such that RMP's (incorrect) depiction of class returns at *current* revenues does not produce an incorrect determination of class revenue responsibility at *proposed* revenues. Thus, the problem with the

[7] This was the case for Questar Gas Company until the treatment of class income tax expense was corrected in Docket No. 07-057-13.

RMP depiction is more a "problem of first impression." That is, it gives the impression that the class relative returns are further apart than they really are.

Q. What is your recommendation to the Commission on this issue?

A. I recommend that the Commission require RMP in future rate cases to *calculate* class income tax expense at current revenues based on class operating revenue for return, rather than allocating income tax expense as RMP currently does. This change will produce a more accurate depiction of class relative returns at current revenues.

<u>Measurement of Class Loads</u>

Q. What is your concern with respect to the measurement of class loads for the purpose of conducting class cost of service analysis?

A. As explained in the direct testimony of Scott D. Thornton, sample data is used to provide load estimates for the Residential class, Schedule 6, Schedule 23, and the Irrigation class. Loads reported for all other classes are derived through a full census in which the load of the class is directly measured using the load profile meters that are installed for every member of the class. As such, census data is used for Schedule 8 and Schedule 9.

Mr. Thornton explains that RMP uses a stratified random sampling technique to reduce the number of load research meters that would be necessary to produce statistically significant results using simple random sampling. The number of load research meters used by RMP for each sampled class and the respective population of customers in the class are shown in Table KCH-4, below.

Table KCH-4
Load Profile Meters and Population, by Class

Class	Load Profile Meters	Population
Residential	170	710,496
Schedule 6	107	15,463
Schedule 23	75	75,383
Irrigation	130	2,769

As shown in Table KCH-4, just 170 meters are used to estimate the hourly demands for approximately 710,000 Residential customers for the purpose of determining class loads during the hours of system coincident peak demand.

I am concerned that these small samples may not be producing sufficiently accurate class cost allocations. This concern is magnified in light of the fact that the Company no longer calibrates its non-census estimates to match up with the Utah jurisdictional loads.

Mr. Thornton defends the Company's sample design as meeting or exceeding the standard specified in 1978 by Section 133 of PURPA. While that may be the case, there is still cause for concern. One concern is that the sample kWh for classes varies significantly from the population kWh on a month-to-month basis. For example, as shown in RMP Exhibit___(STD-1), the Residential sample kWh estimate for July 2008 was 17.6 percent below the actual billing kWh for that class. With coincident peak loads measured at a single hour each month, similar shortfalls may well be occurring in the measurement of each class's share of coincident peak responsibility. My chief concern is that if such a shortfall is occurring, it is not being corrected in the cost-of-service analysis, as the Company no longer attempts to calibrate the sum of class loads (adjusted for losses) to the measured jurisdictional loads. Rather, the sample estimates are presumed to be equal to the actual loads at the time of the coincident peaks. In the absence of any calibration of sampled loads to jurisdictional data, it is fair to question whether the current approach is producing accurate results.

Q. Have you tested the reasonableness of the Company's cost-of-service results for census-measured classes?

A. Yes. To gauge whether measurement error is potentially causing significant shifts in cost-of-service responsibility assigned to classes, I performed a sensitivity analysis in which I reran RMP's cost-of-service study using the jurisdictional loads assigned to Utah, rather than the sample estimates. I used the jurisdictional allocation model load because it is the basis for the inter-jurisdictional allocation of costs to Utah in the first instance.

In the sensitivity analysis, cost-of-service results were derived for the census-measured Schedules 8 and 9, with all other classes aggregated as the difference between the Utah jurisdictional load and the loss-adjusted sum of the Schedule 8 and 9 loads.[8] The analysis was limited to changing two allocation

[8] The sensitivity analysis does not differentiate among the sampled-measured classes, and is not intended to draw inferences regarding the costs allocated to these classes on an individual basis. Rather, it is a proper test of the costs assigned to the two census-measured classes – Schedules 8 and 9 – in comparison to all of the other classes combined.

factors: F10 (75/25 Coincident Peak, System Factor) and F30 (MWH @ Input, System Factor).[9]

The census data for Schedules 8 and 9 are the same in both RMP's cost-of-service study and the sensitivity analysis that I performed. In the former case, the Schedule 8 and 9 census data is summed along with the sample estimates of the other classes to obtain the measurement of Utah retail load, of which Schedules 8 and 9 are apportioned shares. In the sensitivity case, we begin with the Utah jurisdictional load and apportion cost responsibility to Schedules 8 and 9 using their respective census data to determine their shares of the jurisdictional load. Conceptually, the Utah retail load should be approximately the same using either approach; that is, the jurisdictional load allocated to Utah in the jurisdictional allocation model should equal the sum of Utah class loads, but in practice, when the historical data is compared, there is a material gap between the two measures that is largely unexplained. That gap remains even when projected data is used for projected test periods, as shown in Table KCH-5, below. Indeed, it is the gap between the two measurements of Utah retail load that gives rise to the concerns over cost allocation that I am addressing here.

The key question is: do these two analyses produce materially different results for the census-measured classes? If no, then the question I have raised with regard to the efficacy of the cost allocation results using the sample estimates may not be material. If yes, then there are unanswered questions regarding the accuracy of RMP's cost-of-service results, including the extent to which any

[9] Secondary factors that use these factors as inputs are also affected.

difference in results between the two studies might be due to load measurement errors.

Table KCH-5 [10]

Comparison of Jurisdictional Allocation Model and RMP COS Model Loads for Utah

	JAM CP @ Input	COS CP @ Input	JAM vs COS (%)
Jul-09	4,169,459	3,672,684	13.53%
Aug-09	4,112,964	3,520,114	16.84%
Sep-09	3,799,020	3,003,803	26.47%
Oct-09	2,656,105	2,921,241	-9.08%
Nov-09	3,389,846	2,932,144	15.61%
Dec-09	3,442,319	3,320,859	3.66%
Jan-10	3,078,722	2,861,350	7.60%
Feb-10	3,123,245	3,052,238	2.33%
Mar-10	2,860,167	2,653,122	7.80%
Apr-10	2,793,625	2,938,896	-4.94%
May-10	3,590,775	2,953,345	21.58%
Jun-10	3,951,528	3,548,390	11.36%
Total	40,967,775	37,378,187	9.60%

Q. What are the results of your sensitivity analysis?

A. The results are presented in UAE Exhibit 1.5 (KCH-5). The results show that the costs allocated to the census-measured Schedules 8 and 9 are materially reduced when costs are allocated using the Utah jurisdictional loads. Specifically, the revenue deficiency for Schedule 8 (at RMP's requested system revenue requirement) is reduced from $7.2 million (a 6.11% rate increase per RMP's cost-of-service study) to $2.3 million (a 1.98% increase). For Schedule 9, the revenue deficiency is reduced from $19.0 million (11.87% increase) to $10.9 million (6.85% increase). These variances are material and troubling. They give rise to

[10] Sources: RMP Exhibit___(SRM-2), TAB 10, p. 10.13; RMP Exhibit___(CCP-3), TAB 5, p.7.

serious questions about the accuracy of RMP's cost-of-service results for the census-measured classes.

Q. What are your conclusions and recommendations to the Commission on this issue?

A. A cost-of-service analysis is more art than science and should be used only as a general guide in spreading rates. Extra caution is appropriate when, as here, there are serious questions about the data used to perform the study. I recommend that the Commission take the results of my sensitivity analysis into consideration in its review of RMP's cost-of-service results and the determination of rate spread in this proceeding. My analysis shows that significantly different cost-of-service results obtain for census-measured classes depending on whether the study uses measured jurisdictional loads or is based on a combination of census data and sample estimates with no calibration to the Utah jurisdictional load.

The decision not to calibrate non-census loads to the Utah jurisdictional load represents a methodology change that was introduced by RMP several years ago, following the issuance of a Load Research Working Group Report in July 2002. Previously, the Company had routinely calibrated hourly load research estimates obtained from all non-census rate groups to the hourly Utah jurisdictional system loads. I believe it is necessary to revisit this change in light of the material and unexplained "gap" between the measured loads allocated to Utah for inter-jurisdictional purposes and the sum of Utah loads derived using a combination of census data and sample estimates. In my opinion, the decision to no longer reconcile the latter to the former is causing an unreasonable detrimental impact on census-measured classes.

RATE SPREAD

Q. Have you reviewed the rate spread proposal presented by RMP witness William R. Griffith?

A. Yes, I have. The overall rate increase proposed by RMP is 4.54 percent. Excluding special contracts, the proposed increase is 4.83 percent. Mr. Griffith is proposing a rate spread in which Schedules 6 and 23, as well as Lighting, would receive an increase of 5.03 percent, approximately equal to the system average increase excluding special contracts. Schedules 8 and 9, as well as Irrigation customers, would receive an increase that is 1.0 percent greater, or 6.03 percent. Residential customers would receive the smallest increase of 4.03 percent.

Q. What is your assessment of Mr. Griffith's proposal?

A. In my opinion, Mr. Griffith's proposal is reasonable at RMP's requested revenue requirement. The proposal recognizes the direction of change indicated by RMP's cost-of-service study, in that classes earning returns below the system average receive percentage rate increases that are above the average, and vice versa, while classes earning close to the average retail return receive an increase that approximately equal to the system average increase. At the same time, Mr. Griffith's proposal does not rigidly adhere to the class revenue deficiencies indicated by RMP's cost-of-service study. I concur with this approach.

I present UAE's recommended rate spread at RMP's requested revenue requirement in UAE Exhibit 1.6 (KCH-6), which is a restatement of Mr. Griffith's proposal.

Q. Why is it reasonable to not adhere strictly to the class revenue deficiencies indicated by RMP's cost-of-service study?

A. As a general matter, strict adherence to cost-of-service results is often overridden by applying the principle of gradualism, which takes into consideration the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. In this case, the principle of gradualism is particularly important, given the grave economic circumstances in the economy, with Utah unemployment reaching 6 percent, and with major new layoffs announced even this month. A rigid adherence to RMP's cost-of-service results would produce a rate increase of nearly 12 percent for Schedule 9 customers at RMP's requested revenue requirement. This would come on the heels of a 2.49% increase this past September for DSM, which followed a 4.34% increase in May of this year, which itself followed a 2.72% increase in August 2008. With single-item rate cases anticipated in the near future, the cumulative burden on Utah businesses that have been struggling through a major recession cannot be ignored in determination of rate spread in this case.

Moreover, in this proceeding, there are additional reasons beyond gradualism to avoid giving significant weight to the specific class revenue deficiencies produced by RMP's cost-of-service analysis.

Q. Please explain.

A. As I discussed in the previous section of my testimony, RMP no longer attempts to calibrate class loads used in its cost-of-service study to the jurisdictional loads allocated to Utah. Instead, class cost allocations are based solely on a combination of census data and sample data, with only 170 meters used for estimating the hourly loads of 710,000 residential customers. Currently, there is a material and unexplained “gap” between the loads allocated to Utah for inter-jurisdictional purposes and the sum of Utah loads derived using a combination of census data and sample estimates. In light of this gap, the decision several years ago to stop calibrating estimated loads to the measured jurisdictional loads is causing an unreasonable detrimental impact on Schedules 8 and 9 in the cost-of service study. As I explained above, re-running RMP’s cost-of-service study using the jurisdictional loads assigned to Utah results in significantly smaller revenue deficiencies for these two rate schedules. Indeed, the revenue deficiency of 6.85 percent derived in this manner for Schedule 9 is very close to the rate increase recommended by Mr. Griffith for this class. This is an important additional reason to not go beyond the 6.03 percent rate increase proposed by Mr. Griffith for Schedule 9.

Q. Are there other reasons for being cautious in interpreting the revenue deficiencies in RMP’s cost-of-service study?

A. Yes. A consistent and recurring theme in the frequent RMP rate proceedings conducted in the past several years has been the need for the Company to recover the cost of the investments it has been making to accommodate Utah's growth in demand for electric power. Yet, Utah's industrial customers have not been the major contributor to that growth. This is apparent from a review of Table KCH-6, below, which identifies Utah retail MWH sales by major customer group since 1997. The table shows that Utah industrial load grew at about one-third of the annual rate of Residential and Commercial loads. For the test period in this case, Utah industrial load is actually projected to decline relative to Calendar Year 2008 levels by more than 7 percent. Nevertheless, despite declining sales and despite the lowest growth rate of the major Utah customer groups, the RMP cost of service study would assign Schedule 9 customers one of the largest class rate increases on the system.

Table KCH-6 [11]

Annual MWH Sales for Major Utah Customer Groups

	Residential MWh	Residential Growth %	Commercial MWh	Commercial Growth %	Industrial MWh	Industrial Growth %
1997 Total	4,279,332		4,840,806		6,809,086	
1998 Total	4,340,028	1.42%	5,033,571	3.98%	6,841,413	0.47%
1999 Total	4,747,184	9.38%	5,548,796	10.24%	6,889,968	0.71%
2000 Total	4,911,697	3.47%	6,051,214	9.05%	7,149,005	3.76%
2001 Total	5,080,081	3.43%	6,348,218	4.91%	6,597,374	-7.72%
2002 Total	5,250,613	3.36%	6,517,052	2.66%	6,205,029	-5.95%
2003 Total	5,407,852	2.99%	6,371,610	-2.23%	6,672,378	7.53%
2004 Total	5,530,304	2.26%	6,507,363	2.13%	6,871,223	2.98%
2005 Total	5,706,611	3.19%	6,775,714	4.12%	6,943,586	1.05%
2006 Total	6,139,297	7.58%	7,079,238	4.48%	7,311,992	5.31%
2007 Total	6,560,978	6.87%	7,464,604	5.44%	7,603,993	3.99%
2008 Total	6,560,579	-0.01%	7,440,933	-0.32%	7,913,408	4.07%
Compound Growth 1997-2008		3.96%		3.99%		1.38%
(TY)	6,616,982	0.86%	7,491,422	0.68%	7,314,906	-7.56%
Compound Growth 1997-TY		3.55%		3.56%		0.57%

Q. If growth is driving rate increases, how can such a relatively large revenue deficiency be assigned to a class that has exhibited comparatively little or even negative growth?

A. This occurs in part because cost-of-service studies do not attempt to assign costs to classes based on the cost impacts the classes may cause as measured from one historical period to another. There is no "cost of growth" component to a cost-of-service study – even though growth may be a major factor in causing rate increases. Instead, cost-of-service studies examine class usage in the test period on a *de novo* basis, i.e., each new test period is a "clean slate," with no attempt to measure cause and effect *over time*. Consequently, cost-of-service studies can produce counterintuitive results, such as the case here, in which the cost of paying for growth is disproportionately assigned to classes that are not growing.

Q. What are the implications of this statement for determining rate spread?

A. The fact that Schedule 9 is not a major contributor to Utah growth should be given weight by the Commission in determining rate spread. It supports the adoption of the 6.03 percent rate increase for Schedule 9 proposed by Mr. Griffith at the Company's requested revenue requirement.

Q. What is your recommendation to the Commission if RMP's proposed revenue requirement is not adopted?

A. If the revenue requirement approved by the Commission is less than that requested by RMP, then the rate spread proposed in UAE Exhibit 1.6 (KCH-6), should be the <u>starting point</u> for spreading the approved revenue change.

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[11] Source: RMP Response to DPU 32.11

Specifically, the revenue apportionment produced by that rate spread should be used as the basis for spreading the smaller revenue change.

Q. Please explain your recommendation further.

A. When I refer to the "revenue apportionment" produced by the initial proposed rate spread I am referring to each class's percentage share of total revenue requirement that results from that spread, exclusive of special contracts. For example, under Mr. Griffith's proposed spread, Residential customers would pay 41 percent of the total revenue requirement, excluding special contract revenues. If the Commission agrees that this proposed rate spread is reasonable, then by extension, the corresponding revenue apportionment is reasonable as well.

My recommendation is to retain the percentage revenue apportionment that results from the initial rate spread and to apply this revenue apportionment to whatever final revenue requirement is approved by the Commission. The advantage of this approach is that it balances the application of gradualism with moving toward cost-of-service. If there is agreement (or a determination) that a given revenue apportionment reasonably accomplishes this balance, then this balance should be retained for a range of different revenue requirements. My recommendation accomplishes this objective.

Q. Do you have an example of how this approach would work?

A. Yes. An example is presented in UAE Exhibit 1.7 (KCH-7) using a hypothetical revenue increase of $20 million.

Q. Does this conclude your direct testimony?

A. Yes, it does.