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

A. My name is Gregory N. Duvall, my business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232, and my present title is Director, Long Range Planning and Net Power Costs.

Q. Have you previously filed testimony in this case?

A. Yes. I filed direct testimony, supplemental direct testimony and rebuttal testimony in Phase I of this case. I also filed rebuttal testimony in Phase II-1 and supplemental direct testimony in Phase II-2 of this case.

Q. Will any other witnesses be presenting rebuttal testimony with this filing?

A. Yes. In addition to myself, three witnesses will present rebuttal testimony in support of Rocky Mountain Power's[1] Energy Cost Adjustment Mechanism ("ECAM"): Dr. Karl A. McDermott, Ameren Distinguished Professor of Business and Government at the University of Illinois at Springfield and a Special Consultant to National Economic Research Associates, Inc. ("NERA"); Dr. Samuel C. Hadaway, Principal in FINANCO, Inc.; and Mr. Stefan A. Bird, Senior Vice President, Commercial and Trading.

Q. What is the purpose of the Company's rebuttal filing?

A. The rebuttal filing responds to issues raised by the Division of Public Utilities ("DPU"), presented in the testimony of Mr. Charles E. Peterson; the Office of Consumer Services ("OCS"), presented in the testimony of Mr. Daniel E. Gimble; the Utah Association of Energy Users ("UAE"), presented in the testimony of Mr.

[1] Rocky Mountain Power is a division of PacifiCorp, however for simplicity references to Rocky Mountain Power or the Company at times denote PacifiCorp or another division, PacifiCorp Energy, unless in figures or charts a specific publication source cites to the company name.

Kevin C. Higgins; the Utah Industrial Energy Consumers ("UIEC"), presented in the testimony of Mr. Maurice Brubaker; and Western Resource Advocates and Utah Clean Energy ("WRA/UCE"), presented in the testimony of Ms. Nancy L. Kelly.[2]

I address a number of the design issues including the deadband and sharing mechanisms, the load growth adjustment, the level of the carrying charge, treatment of renewable energy credit ("REC") revenues, treatment of natural gas fuel costs, hedging costs and market purchases, treatment of hydro-electric generation and its effect on inter-jurisdictional allocation issues and the disposition of the deferral of incremental net power costs ("NPC"), and audit issues.

Dr. McDermott provides testimony on US regulatory practice with regard to prudence reviews in the context of ECAM mechanisms, particularly as it relates to the proposed deadband and sharing mechanisms, as well as the issue of management incentives.

Dr. Hadaway provides testimony responding to comments concerning the effect on allowed return on equity ("ROE") that should result from the adoption of an ECAM.

Mr. Bird provides testimony that corrects the analysis presented by the DPU to show the Company has not lost money on its hedging program, to explain the proper analysis to determine if a hedging program is effective and to explain why adoption of the DPU's proposed incentive to decrease the sharing band as the

[2] Unless otherwise noted, cites to testimony contained in this rebuttal testimony refer to the testimonies filed with the Commission on August 4, 2010.

Company reduces reliance on market purchases, the OCS's proposal to exclude natural gas fuel costs, natural gas hedging costs and market purchases and the DPU's, OCS', UAE's and WRA's proposals to exclude REC revenues from the ECAM would create perverse incentives that are not in customers' interests.

Summary of Testimony

Q. Will you please summarize the topics you will cover in your rebuttal testimony?

A. In my rebuttal testimony, I cover the following topics:

- Would the deadband and sharing mechanisms proposed by the parties result in just and reasonable rates and are they necessary?
- Should an ECAM include a load growth adjustment factor, and if so, how should it be designed?
- What is a reasonable carrying charge to be applied to the deferred ECAM balance?
- Is it preferable for incremental revenues from REC sales to be included in the ECAM?
- Should natural gas fuel costs, natural gas hedging costs and market purchases be excluded from the ECAM?
- Should hydro-electric generation be included in the ECAM?
- Should rolled-in allocations be implemented in this docket?
- What should be done with the balances that have accumulated in the deferred NPC and REC revenue balances?
- Does the complexity of auditing the utility's generation function in

comparison to the auditing of a Purchased Gas Adjustment ("PGA") justify a deadband and/or a sharing band be applied to an electric utility, while concurrently applying a dollar-for-dollar PGA to a gas utility?

At the end of my testimony, I address a few miscellaneous issues raised in the testimony of other parties.

Deadband and Sharing Mechanisms

Q. Please describe the deadband and sharing mechanisms proposed by the parties if an ECAM is adopted.

A. Mr. Peterson proposes a deadband of 2 percent on either side of forecast NPC. He and Mr. Gimble, Mr. Higgins and Ms. Kelly also propose sharing of differences between forecast NPC and actual NPC of 30 percent to the Company and 70 percent to customers. Mr. Peterson adds a proposal that there be no sharing if actual costs diverge by more than 30 percent from NPC allowed in rates.

Q. Would adoption of these proposals result in just and reasonable rates?

A. No. Professor Bonbright defines reasonable rates as follows:

> "reasonable" rates of charge for public utility services are held to be rates sufficient, but no more than clearly sufficient, to cover the total costs actually and prudently incurred by a company in supplying these services.[3]

The statute which authorizes the Commission to approve an ECAM states:

> Prudently incurred actual costs in excess of revenues collected shall: (i) be recovered as a bill surcharge over a period to be specified by the commission ….[4]

[3] Bonbright, James C., *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 240.

[4] Utah Code Ann. § 54-7-13.5(2)(h).

A deadband of two percent and recovery of only 70 percent of incremental prudently incurred costs appears to be inconsistent with Bonbright's definition of "reasonable" rates and with Utah's authorizing statute.

Q. What is the difference between the Company's actual prudently incurred costs and the costs that the Company would recover under the deadband and sharing mechanisms proposed?

A. The answer varies depending on the amount of forecast NPC and the amount of actual NPC. With regard to the deadband, the Company would not recover any actual NPC in excess of the amount included in rates unless it was in excess of two percent of NPC included in rates. With regard to the 70/30 sharing mechanisms proposed, the Company would only recover 70 percent of any incremental NPC not included in rates. This does not result in just and reasonable rates.

Q. Do you believe that deadband and sharing bands are effective incentive mechanisms to include in adjustment clauses?

A. No, for at least three reasons.

First, the most effective incentive is a prudence review and that is what the Company has proposed. Notably, no other party seems to have enough confidence in its proposed incentive to offer to eliminate the prudence reviews.

Second, the proposed deadband and sharing mechanisms do not incentivize the right behavior. For example, assume the average market cost increases by $200,000,000 in a 12-month period but, through extraordinary and prudent efforts, the Company is able to limit the increase to $50,000,000. The so-called incentives (a 70/30 sharing mechanism) would deny the Company recovery of $15,000,000 of out-of-pocket costs, even though the Company went through extraordinary efforts to mitigate cost increases. Now assume market prices decreased by $200,000,000 in the next 12-month period, and the Company does nothing more than ride the market down. The 70/30 sharing mechanism proposed by the other parties would allow shareholders to retain $60,000,000, for the Company doing nothing.

Third, cost disallowances based on artificial percentages are not effective in influencing the conduct of the decision makers. The decision makers in this instance are the power traders and fuel negotiators who must fulfill the obligation to serve customers. These decision makers are focused on making the most prudent transaction at the time they enter into a deal to meet customers' power needs. That is the incentive which drives their decisions, and it should also be the basis upon which their decisions are judged.

In summary, the so-called sharing bands are punitive because they would penalize the Company when it has done nothing wrong. Ultimately, the Commission will determine if the Company has acted prudently by conducting a prudence review, showing that a prudence review is the only true effective incentive.

Q. What do you recommend with regard to the proposed deadband and sharing mechanisms?

A. The Commission should reject them because they would not result in just and reasonable rates and because they are not necessary or effective in motivating the

Company to be prudent.

Load Growth Adjustment Factor

Q. Please describe the load growth adjustment factor proposed by UAE.

A. On page 5 of his testimony, Mr. Higgins recommends that a load growth adjustment factor should be included in an ECAM design. In UAE Exhibit 1.4.D, Mr. Higgins includes a specific calculation of his proposed factor, and recommends the factor should be set to $28.43 per MWh if the ECAM becomes effective before the conclusion of the next general rate case in 2011. He states that the value of the factor would be multiplied by each MWh of Utah load change that occurs relative to the test-period load used for setting rates in the most recent general rate case resulting in a symmetrical adjustment. Mr. Higgins claims, and the Company agrees, that the calculation in UAE Exhibit 1.4D is the same as the calculation of the load adjustment factor included in the Company's Idaho ECAM with the exception that UAE's proposed factor for Utah adds the revenues associated with transmission plant.

Q. What is the Company's response to this proposal?

A. The Company is opposed to a load growth adjustment factor as part of the ECAM for several reasons.

First, the investment and expenses functionalized to generation and transmission used to calculate the proposed load growth adjustment have no direct connection to NPC, are dissimilar to and not part of NPC and are beyond the scope of the ECAM. The ECAM, as proposed, trues up highly volatile and unpredictable forecasts of NPC-related revenues with actual NPC. The proposed load growth adjustment is a step, although an incomplete and one-sided step, toward a generation and transmission cost adjustment mechanism, which no party has proposed.

Second, the proposed load growth adjustment is one-sided in that it reflects increases in revenues associated with load growth, but does not reflect any increases in non-NPC costs associated with that load growth. This is particularly an issue when rates remain in effect beyond the test period. If the test period used to set base rates is perfectly aligned with the rate-effective period, this issue is mitigated to a large extent during the first year rates are in effect. For any period beyond the test period, however, the mismatch of reflecting increased revenues from load growth without also reflecting the increased cost associated with that load growth remains.

Third, a load growth adjustment penalizes utilities, like Rocky Mountain Power, that are engaged in a significant capital investment program and exacerbates the impacts of regulatory lag. Regulatory lag occurs even when incremental revenues from additional retail sales are retained by the utility if the incremental investments are more expensive than embedded costs. When a portion of those revenues are returned to customers, the impacts of regulatory lag become even greater and would incent the Company to file annual rate cases to keep costs and revenues aligned. While the Company has the opportunity to request recovery of major plant additions, they account for far less than the total capital investment and cost increases experienced by the Company.

Finally, a load growth adjustment that reflects revenue increases without reflecting increases in costs would violate the regulatory principle of matching which would be exacerbated the further the test period lags the rate-effective period.

If the Commission decides that a load growth adjustment is appropriate, it should only be included as part of a comprehensive ECAM that incorporates all NPC components and includes very tight, if any, sharing bands and no dead band. If the Commission decides a load growth adjustment and sharing bands are appropriate, the sharing bands should apply to the load growth adjustment. In addition, a load growth adjustment should only be included if the revenue requirement and base NPC are established in a general rate case using a fully forecasted test period that aligns with the rate-effective period, as allowed by statute, to address the mismatch between costs and revenues described above. The load growth adjustment would be positive or negative depending on whether the actual Utah loads are higher or lower than the test-period loads.

Q. In support of his proposal Mr. Higgins references the load growth adjustment in the Idaho ECAM. How does the Company respond to this reference?

A. Rocky Mountain Power did not propose and, in fact, opposed the load growth adjustment in Idaho for the reasons addressed above. The load growth adjustment, which does not include a transmission component, was included in the Idaho ECAM as part of a quickly achieved, comprehensive ECAM settlement that included no deadband and 90/10 sharing, which also applies to the load growth adjustment. As opposed to the ECAM recommended by UAE and other parties in

Utah, the Idaho ECAM, which was filed approximately five months before the Company filed its ECAM application in Utah and is now in its second year of operation, incorporates all NPC components, including hedging costs and front office transactions. It also includes a renewable energy investment adjustment.

If the load growth adjustment factor presented by Mr. Higgins in UAE Exhibit 1.4D is adopted, two minor corrections need to be made to his calculations.

Q. What corrections need to be made to Mr. Higgins' calculation?

A. Mr. Higgins uses data from the Company's original major plant addition filing in Docket No. 10-035-13 and does not include the impacts of the updates or settlement in that Docket. Based on the final order in the Company's general rate case, Docket No. 09-035-23, the Company updated the capital structure and ROE in the major plant addition case, resulting in a pre-tax return on rate base of 11.65 percent consistent with the Commission's order. This update was not reflected in Mr. Higgins' exhibit. He also did not reflect the Company's updates to reflect the actual amount spent on the additions as agreed to in the major plant addition settlement. These two corrections reduce the $28.43 per MWH load growth factor by $0.57, resulting in a corrected load growth factor of $27.86 per MWh.

Q. Did DPU witness Mr. Peterson propose a load adjustment factor?

A. Yes. In the formula on page 19 of Mr. Peterson's testimony, line 417, there is a term that is the actual annual revenues less the forecast revenues over the annual ECAM period approved by the Commission in a general rate case. He does not provide any additional detail in testimony on the mechanics of this proposal or why it is reasonable. For example, he does not identify which revenues should be included.

Q. Is Mr. Peterson's load adjustment factor calculation similar to the one proposed by Mr. Higgins?

A. No. DPU Exhibit 3.3 appears to detail the calculation of the load adjustment factor proposed by Mr. Peterson. His proposal is based on measuring the difference in total Company system load, and multiplying that difference by the total Company average revenue from Form EIA-826. Based on this example, if loads in Oregon were to increase, then Utah customers would receive a revenue credit in the ECAM calculation even if Utah actual loads matched Utah forecast loads included in rates. Mr. Peterson's load adjustment factor proposal could lead to unintended consequences and should be rejected by the Commission.

Carrying Charge on ECAM Balancing Account

Q. On page 31 of Mr. Higgins' testimony, he disagrees with the Company's proposal that the ECAM balancing account earn the Company's most recently approved rate of return and use instead the Company's cost of long-term debt consistent with the carrying charge of 5.98 percent approved in this docket for any deferred NPC or REC revenues. How do you respond to his recommendation?

A. The Company does not object to using the cost of long-term debt from the Company's most recently approved cost of capital as a carrying charge for the ECAM balance. However, if the Commission adopts this proposal, the cost of long-term debt should be updated each time a new cost of capital is approved by the Commission.

Renewable Energy Credits

Q. Has any party to this proceeding proposed the inclusion of REC revenues in the Utah ECAM?

A. Yes. The Company proposed to include REC revenues in the Utah ECAM in its supplemental direct filing in Phase II-2 of this proceeding.

Q. Does any other party support this proposal?

A. No. However Mr. Higgins expresses a preference for incremental REC revenues to be included in an ECAM rather than to not be recognized as a credit to customers at all. (Higgins page 38, lines 797-799)

Q. What is Mr. Higgins' view?

A. Mr. Higgins states that his view is that incremental REC revenues should be credited to customers as an offset to rates irrespective of whether an ECAM is approved. (Higgins page 35, lines 758-760)

Q. What is the basis of Mr. Higgins' view?

A. He claims that there is no direct or necessary relationship between NPC and REC revenues. (Higgins page 35, line 756)

Q. Do you agree that there is no direct or necessary relationship?

A. No. There is a direct and necessary relationship between NPC and REC revenues because both RECs and energy are generated from the same source. Since the energy generated from the resources that generate RECs is included in the Utah ECAM, the REC revenues should be included in the ECAM.

Q. Is there any other reason that it is necessary to treat incremental NPC and incremental REC revenues the same?

A. Yes. Both are large, volatile, unpredictable and largely outside the control of the Company. Allowing incremental REC revenues to be tracked and passed through to customers in the absence of similar treatment of NPC would be inequitable.

Natural Gas Fuel and Hedging Costs and Market Purchases

Q. Mr. Gimble recommends that natural gas fuel costs, natural gas hedging costs and market purchases be excluded from the Utah ECAM. Are these recommendations sensible?

A. No. If these recommendations, along with Mr. Gimble's recommendation to include wheeling revenues in the ECAM, were adopted, the Utah ECAM would include non-gas related fuel expense (primarily coal expense), purchased power expense that is not considered a "market purchase"[5], and wheeling expense; offset by wholesale sale and wheeling revenues and adjusted by a load growth factor.

Q. How does Mr. Gimble characterize his proposal?

A. He characterizes it as a partial ECAM which could create unintended perverse incentives. (Gimble page 19, lines 545-546). I agree. DPU witness Mr. Peterson indicates that the DPU abandoned the approach of excluding specific elements from the ECAM due to the potential of perverse and unintended incentives as well. (Peterson page 11, lines 224 and 234, and page 23, line 510)

[5] It is unclear from Mr. Gimble's testimony what is included in "market purchases".

Q. Please give an example of a potential perverse and unintended incentive that could result if the Commission were to adopt the ECAM proposed by Mr. Gimble.

A. Mr. Gimble proposes to include all wholesale sales revenues in the ECAM, even though they are made possible by total system generation including natural gas generation. Under this approach, if the Company could reduce NPC by making additional wholesale sales by turning on a natural gas plant, it would be incented not to do so since customers would see cost reductions due to the increase in wholesale sales revenues, but shareholders would pay for the natural gas.

Q. How does the Company's hedging strategy benefit Utah customers?

A. The Company's hedging strategy mitigates the volatility of NPC and protects against increases in NPC as a result of unforeseeable changes in wholesale market prices for electricity and natural gas. For example, if the Company had not had a hedging program prior to the last general rate case, forecast NPC determined by GRID in that case could have been $120 million higher due to changes in market prices alone. The Company's hedging program reduced this range to about $10 million and protected retail customers from adverse market prices that could increase NPC significantly due to circumstances outside the control of the Company.

Q. How did you determine the range of NPC outcomes with and without hedging?

A. The Company started with the Commission ordered NPC in the most recent general rate case, Docket No. 09-035-23. For the hedged cases, GRID runs were made using the Company's official forward price curves for June 2008, March 2009 (the official price curve in the docket) and June 2010 to test a range of prices. For the unhedged cases, all short-term firm physical and financial contracts were converted to index contracts. The unhedged results were developed using the same set of three forward price curves.

Q. Do retail customers receive this benefit today?

A. Yes. Retail customers receive benefits from the Company's hedging strategy whether or not there is an ECAM as illustrated by the example cited above.

Q. What do you recommend with regard to Mr. Gimble's proposal that natural gas fuel costs, natural gas hedging costs and market purchases be excluded from the Utah ECAM?

A. The Commission should reject Mr. Gimble's proposal because it could create unintended perverse incentives and excludes hedging costs that provide benefits to Utah customers. Mr. Bird further responds to Mr. Gimble's proposal in his rebuttal testimony.

Hydro, Rolled-In Cost Allocation and Treatment of NPC and REC Revenue Deferrals

Q. Why have you grouped hydro, rolled-in cost allocation and the disposition of the deferred accounts together?

A. Parties have made recommendations that create dependencies among these three items.

Q. Please explain.

A. Parties express a concern with the treatment of hydro which leads to recommendations about implementation of rolled-in and what to do with the deferred incremental NPC. Specifically, they express concern that Utah customers should not be exposed to actual hydro risk through the ECAM when all of the benefits of hydro are not included in base rates.

Q. How does the DPU propose to address this concern?

A. The DPU proposes that the disposition of the incremental NPC deferral not be included in the ECAM and be decided separately by the Commission in the next general rate case. They also recommend that the ECAM not start until base NPC are set by the Commission in the next general rate case.

Q. What does the Office propose?

A. The Office recommends if the Commission orders an ECAM, it should also calculate revenue requirement based on rolled-in. Mr. Gimble recommends a reduction in revenue requirement of approximately $14.9 million should be implemented the first time any accumulated balance in the ECAM is amortized in rates.

Q. What does UAE propose?

A. Mr. Higgins identifies three alternatives, but it is unclear which alternative he is recommending. The first alternative would be to include the deferral along with a credit to adjust for the 1 percent premium over rolled-in included in Utah rates. It appears he is suggesting this credit begin in February 2010, potentially resulting in retroactive ratemaking. The second alternative is to implement the ECAM at the conclusion of the next general rate case as long as the Commission adopts rolled-in. Under this alternative, the accruals would cease and it is unclear what would happen with the balance that has already been accrued. The third alternative is to recognize the deferral in the ECAM as requested by the Company and apply rolled-in after it is litigated and approved by the Commission in the next general rate case.

Q. How does the Company respond to these proposals?

A. The Company filed its proposed ECAM at least three months prior to the filing of the last general rate case in accordance with its acquisition commitments and Utah law. I understand that this was required so that the ECAM could be implemented concurrently with the change in rates at the conclusion of the general rate case. However, this proceeding has extended months beyond the conclusion of the prior rate case when the ECAM should have been implemented. To keep the Company whole under these conditions, it is necessary to include the NPC deferrals in the ECAM.

Moreover, to mitigate carrying charges and the size of the ECAM balance, the approval of the ECAM should not be deferred until after the conclusion of the next general rate case as proposed by the DPU and UAE.

Moving to rolled-in prior to addressing this issue in the Company's next general rate case does not give parties the ability to create an evidentiary record upon which the Commission can base a decision, so the proposal by the Office and the first alternative from UAE would not be procedurally proper. It also seems that the positions of the parties are inconsistent with their Stipulation in Docket No. 02-035-04, which states:

> Unless and until any amendments to the Revised Protocol are ratified by the PSCU, for the Company's fiscal years beginning

> April 1, 2009 through March 31, 2014, for all general rate proceedings, the Company's Utah revenue requirement to be used for purposes of setting rates for Utah customers will be the lesser of: (i) the Company's Utah revenue requirement calculated under the Rolled-In Allocation Method multiplied by 101.00 percent; or (ii) the Company's Utah revenue requirement resulting from the Revised Protocol, plus the Rate Mitigation Premium referenced in Paragraph 3, if applicable. (Stipulation in Docket No. 02-035-04, page 4, Section 4.b.)

The only practical alternative left is the third alternative identified by UAE, where the deferral is included in the ECAM, and the change in inter-jurisdictional allocation methods is litigated in a general rate case.

Q. Are any of the benefits of the Company's west-side hydro facilities currently included in Utah rates?

A. Yes. The reserve carrying capability of the west-side hydro facilities are not part of the hydro endowment; rather they are shared system-wide. In the NPC study, west-side hydro units carry reserves in both the west and east balancing areas. By carrying reserves on hydro units, the Company's thermal units can produce more energy to be used to meet load, avoid market purchases, and make wholesale sales, thereby reducing NPC.

Q. How do you respond to the concerns that Utah customers should not be exposed to hydro risk when base rates do not include all the hydro benefits?

A. To date, no party has identified any damage of allowing hydro in the ECAM, other than conceptually. It is possible that exposure to the hydro risk in the ECAM results in lower costs to Utah customers if actual hydro generation exceeds the level of normalized hydro generation included in the GRID model. I would also note that the mismatch is anticipated to be temporary and can be remedied by the Commission at the end of the next general rate case. At this time, it appears that parties in Utah and other states are supportive of a change to the Revised Protocol to deliver Utah an outcome that is very close to rolled-in thereby making this concern moot.

Q. Does the Company have any recommendations that would help offset any potential cost increases that would result from exposure to hydro risk?

A. Yes. The Company's recommendation to include incremental REC revenues in the ECAM could help mitigate any cost increases that materialize as a result of including hydro risk in the ECAM. This is consistent with Mr. Higgins' preference that it would be better for incremental REC revenues to be included in an ECAM than to not be recognized as a credit to customers at all.

Complexity of Auditing

Q. Mr. Brubaker proposes minimum performance standards be applied to the Company's lowest cost resources because, unlike gas utilities, a prudence standard is not sufficient for an electric utility because the complexity of auditing an electric utility is overwhelming compared to the more limited analysis required under the PGA. How do you respond to this claim?

A. Mr. Brubaker has not supported his allegation that auditing electric NPC costs is more complex than auditing natural gas procurement. But, even assuming there was more complexity, the ECAM proposed by the Company does not add to that complexity.

NPC are currently subject to audit and prudence review in a general rate case. The same NPC would be subject to exactly the same review under the

Company's proposed ECAM. In fact, an argument could be made that the Company's ECAM will actually enhance the auditing and prudence review as compared to the status quo because NPC will be the sole focus of the ECAM prudence review, unlike a rate case where it is one of thousands of items of revenue requirement. In addition the audit will be of actual rather than forecasted costs.

Q. Do any other witnesses make a similar claim?

A. Yes. Mr. Higgins cites the number of transactions involved in managing NPC on page 12 of his testimony which in part leads to his recommendation that a 70/30 sharing band be incorporated in the design of the Utah ECAM. Many of these are standard products transacted at market price and would be straightforward to audit. The Company manages the prudence of these transactions through written policies and procedures that are monitored and enforced under strict governance.

Q. Are there alternatives to performance standards, sharing bands and deadband for addressing the claim that the Company energy costs are more complex than Questar Gas's?

A. Yes. A straightforward way to address this is to allow parties sufficient time to conduct a prudence review and audit. This could be accomplished by allowing the ECAM rates to go into effect subject to refund as proposed by the Company and supported by the DPU (Peterson page 9, lines 185-187). By allowing parties the time necessary to review and audit the actual NPC data to assess the prudence of the Company actions in operating the system, the need for performance standards, sharing bands and deadband would be eliminated. Implementing an ECAM absent sharing bands and deadband would substantially reduce the time and effort parties currently spend on modeling issues and forecasting NPC and would allow parties to redirect their efforts towards conducting a prudence review and audit of actual costs.

In addition, the parties ignore the fact that it is not necessary to review each and every transaction to audit a company's performance. One can look at totals, averages, general trends and samples to determine if it is necessary to look deeper.

Other Issues

Q. On page 8, line 152 of Ms. Kelly's testimony, she indicates that the ECAM would only take effect if the Company meets the acquisition targets based on its Step-Three (least cost, least risk) Portfolio. Does the Company have a Step-Three Portfolio?

A. No.

Q. How does Ms. Kelly define the Step-Three Portfolio?

A. Ms. Kelly defines the Step-Three Portfolio by saying "Use of the three-step approach identifies a 20-year portfolio that best balances cost, risk, and uncertainty across multiple possible futures." (Kelly, page 7, lines 138-139, and footnote 11.) She goes on to say that there would be a three-year Action Plan based on that portfolio called the Step-Three Portfolio Action Plan and suggests if the Company takes the actions identified in the Step-Three Portfolio Action Plan in the two years prior to the year in which it is seeking recovery through an ECAM, it would be considered compliant.

Q. Who decides what is in the Step-Three Portfolio?

A. Ms. Kelly does not specify who makes that decision other than the three-step approach. However she does say that the Company would be required to develop the action plan for this undefined portfolio as part of the Integrated Resource Planning process (Kelly page 10, lines 190-191) and could file for approval of a revised action plan under certain conditions. (Kelly page 9, line 178) She gives no indication how the Commission would approve a revised action plan when it does not approve an initial action plan under its current practices.

Q. Does an action plan contain targets for resource acquisition?

A. No.

Q. What does the Company recommend regarding this proposal?

A. The Company recommends the Commission reject Ms. Kelly's proposal. It is undefined, and even if it were defined, appears to be inconsistent with the use of the Integrated Resource Planning process in Utah. It also would require acceptance of the plan by all states receiving generation service from the Company.

Q. On page 7, line 140, Mr. Peterson indicates that the DPU proposes the Company be required to file a general rate case at least every three years in order to keep the baselines and other elements of the Company's revenue requirement in balance. Do you agree with this proposal?

A. No. However, the Company supports the concept of updating the base NPC for the ECAM on a periodic basis as necessary. This issue may best be deferred until a future time when the Company is not filing rate cases at the current frequency.

Furthermore, as noted above, if a load growth adjustment is adopted, it will certainly be necessary to update load levels more often than once every three years.

Q. On page 9, lines 181-182, Mr. Peterson says that the DPU would expect the Company to file for recovery of the accumulated ECAM balance 30 days after the close of the twelve-month ECAM period. Is this practical?

A. No. The data is not available in 30 days. The Company's proposal is to file on December 15 of each year which is two and a half months after the close of the twelve-month ECAM period. This amount of time is necessary for the Company to finalize the actual NPC and prepare its filing. In response to RMP Data Request 2.7, the DPU stated that it would be willing to consider a proposal for a filing time longer than 30 days if needed by the Company.

Q. Does this conclude your testimony?

A. Yes.