- 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, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge	DOCKET NO. 07-035-93 REPORT AND ORDER ON REVENUE REQUIREMENT

ISSUED: August 11, 2008

SHORT TITLE

Rocky Mountain Power 2007 General Rate Case
Phase I Order on Revenue Requirement using 2008 Forecast Test Period

SYNOPSIS

The Commission increases Rocky Mountain Power's annual revenue requirement by $33.378 million, based on a forecasted 2008 test period and an allowed rate of return on equity of 10.25 percent. This is a 2.4 percent increase in Rocky Mountain Power's general business revenues in Utah. The Commission approves a uniform percentage increase to be applied to all tariff customers' bills as a line item for service prior to the Commission's determination of costs of service rate spread and rate design in Phase II of this docket.

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I. PROCEDURAL HISTORY

On December 12, 2007, PacifiCorp, doing business in Utah as Rocky Mountain Power ("Company" or "PacifiCorp"), filed an Application to Open Docket and for Issuance of a Protective Order to address the Company's anticipated request for a revenue increase of approximately $161.2 million and approval of a new large load surcharge. In response to this filing, the Utah Public Service Commission ("Commission") issued a Protective Order on December 17, 2007. On December 13, 2007, the Commission issued a Notice of Scheduling Conference to be held on December 20, 2007.

On December 17, 2007, the Company filed an application for a revenue increase of approximately $161.2 million, or 11.3 percent, based on a future test period beginning July 1, 2008, and ending June 30, 2009, and a return on equity of 10.75 percent. The Company also requested approval of a large load surcharge. The application includes direct testimony on test period, capital structure and capital costs, load and retail sales forecast, revenue requirement, cost of service, revenue spread to rate schedules, rate design, modifications to the Utah Electric Service Schedules and Regulations, and the large load surcharge. The application assumes Commission approval of the Company's requests in the following dockets: Docket 07-035-13, In the Matter of Rocky Mountain Power, a Division of PacifiCorp, for Authority to Change its Depreciation Rates Effective January 1, 2008; Docket 06-035-163, In the Matter of Rocky Mountain Power, a Division of PacifiCorp, for a Deferred Accounting Order to Defer the Costs of Loans Made to Grid West, the Regional Transmission Organization; Docket 07-035-04, In the Matter of the Application of Rocky Mountain Power for an Accounting Order to Defer the Costs related to the MidAmerican Energy Holdings Company ("MEHC") Transfer; and Docket 07-035-14, In the Matter of the Application of Rocky Mountain Power for an Accounting Order for the Costs related to the Flooding of the Powerdale Hydro Facility. Pursuant to notice, the Commission held a scheduling conference on December 20, 2007.

Between December 21, 2007, and March 18, 2008 the following parties petitioned for leave to intervene in this case which the Commission granted: The Utah Association of Energy Users Intervention Group ("UAE"), including the Utah Association of Energy Users, ATK Launch Systems, American Pacific Corporation, Chevron U.S.A., Inc., ConocoPhillips Gas and Power, Hexcel Corporation, IHC Health Services, Inc., IM Flash Technologies, LLC, May Foundry & Machine Company, Simplot Phosphates and Tesoro; Roger Ball; US Magnesium LLC ("US Mag"); Fairchild Semiconductor, Holcim, Inc., Kennecott Utah Copper Corp., Kimberly-Clark Corp., Malt-O-Meal, Praxair, Inc., Proctor & Gamble, Inc., Tesoro Refining and Marketing Co., and Western Zirconium, collectively referred to as Utah Industrial Energy Consumers ("UIEC"); International Brotherhood of Electrical Workers, Local 57 ("IBEW Local 57"); Central Valley Water Reclamation Facility ("Central Valley"); the Kroger Co. ("Kroger"); Nucor Steel, a Division of Nucor Corporation ("Nucor"); Western Resource Advocates ("WRA") and Utah Clean Energy ("UCE"); Utah Farm Bureau Federation ("Farm Bureau"); Salt Lake Community Action Program and Crossroads Urban Center, collectively referred to as the Utah Ratepayers Alliance ("URA"); AARP; Interwest Energy Alliance ("Interwest"); and Wal-Mart Stores, Inc. ("Wal-Mart").

On December 24, 2007, Roger Ball filed a Request for Publication of Notice of Application to Increase Rates and of Hearings; to Subdivide Intervention; to Expedite Test Period Intervention and the Exchange of Data; and to Intervene. On December 27, 2007 the Commission issued a scheduling order in this proceeding. Between December 24, 2007, and January 7, 2008, the Commission received several written public comments.

On January 7, 2008, the Company filed replacement paper copies of Exhibits RMP_(CCP-1) and RMP_(CCP-2) for the hard copy version of the Company's application and the Company filed a Response to Roger J. Ball's Request for Publication of Notice of Application to Increase Rates and of Hearings; to Subdivide Intervention; to Expedite Test Period Intervention and the Exchange of Data and to Intervene. On January 9, 2008, the Commission issued an Amendment to and Modification of December 27, 2007, Scheduling Order. On January 11, 2008, the Utah Division of Public Utilities ("Division") filed a Notice and Statement of the Utah Division of Public Utilities Regarding Test Year, and UAE filed a Request for Hearing on Test Period.

On January 14, 2008, Roger Ball filed a Reply to Rocky Mountain Power's Response to Roger J. Ball's Request for Publication of Notice of Application to Increase Rates and of Hearings; to Subdivide Intervention; to Expedite Test Period Intervention and the Exchange of Data; and to Intervene. On January 15, 2008, the Company filed a Petition for Clarification and Reconsideration of the Public Service Commission of Utah's Scheduling Order, as Amended January 9, 2008. On January 17, 2008, the Utah Committee of Consumer

Services ("Committee") filed a Utah Committee of Consumer Services Response to Rocky Mountain Power Request for Clarification of Scheduling Order.

On January 22, 2008, the Company filed an Opposition to Request for Hearing on Test Year and the Division filed a Response by the Division of Public Utilities to the Petition for Clarification and Reconsideration of the Commission's Scheduling Order filed by Rocky Mountain Power. On January 24, 2008, the Division filed a Response by the Division of Public Utilities to the Opposition to a Test Year Hearing Filed by Rocky Mountain Power Dated January 22, 2008. In addition, the Division, the Committee and its Consultant, Larkin & Associates, PLLC, UAE, and Roger Ball each filed direct testimony on test year.

On January 28, 2008, UIEC filed a Response to Rocky Mountain Power's Petition for Clarification and Reconsideration of Scheduling Order and Roger Ball filed a Request for Review and Clarification of Scheduling Order. On January 30, 2008, the Commission issued a Notice of Hearing on Test Year Selection.

On February 1, 2008, the Company filed a Notice of Adoption of Testimony. On February 4, 2008, the Company, the Division, Roger Ball, and UIEC each filed rebuttal testimony on test year. After due notice, a hearing was held on February 7, 2008, to take evidence and hear argument by parties regarding the appropriate test period to be used in this matter. On February 13, 2008, the Commission issued a Modification and Clarification of Part 6 of December 27, 2007, Scheduling Order; the Company filed a Closing Argument of Rocky Mountain Power and a Late Filed Exhibit - PacifiCorp Test Periods; the Division filed a Closing Argument of the Utah Division of Public Utilities Regarding Test Year; UAE filed a Post-

Hearing Memorandum of UAE Intervention Group Re: Test Period; UIEC filed a Post-Hearing Statement; and Roger Ball filed a Test Year Closing Argument and Motion to Dismiss. On February 14, 2008, the Commission issued an Order on Test Period, approving use of a projected 2008 calendar year test period.

Pursuant to the Commission's Order on Test Period, on March 6, 2008, the Company filed supplemental direct testimony updating its rate case filing using a calendar year 2008 test period, reducing its request for a revenue increase to $99.834 million. On March 31, 2008, the Division, the Committee, and Roger Ball filed testimony on rate of return in this proceeding.

On April 7, 2008, direct testimony on revenue requirement was filed by the Division, the Committee, IBEW Local 57, UIEC, Roger Ball and jointly by UAE and Wal-Mart ("UAE/Wal-Mart"). On April 15, 2008, the Committee filed a corrected version of Exhibit CCS 4.12 for Randall Falkenberg's April 7, 2008, testimony. On April 21, 2008, the Division filed Erratum Testimony of Matthew Croft. On April 22, 2008, the Company filed a Notice of Appearance of Attorneys Licensed in a Foreign State. On April 28, 2008, the Company and Roger Ball each filed Rate of Return Rebuttal Testimony. On April 30, 2008, the Division filed Supplemental Direct Testimony of James Dalton and the Committee filed a missing Appendix A to the April 7, 2008, revenue requirement testimony of Helmuth Schultz.

On May 2, 2008, the Commission issued an Amended Notice of Settlement Conference. On May 8, 2008, the Company filed a Motion of Rocky Mountain Power to Strike Rate of Return Direct and Rebuttal Testimony of Roger J. Ball. On May 9, 2008, the Company, the Division, and the Committee filed revenue requirement rebuttal testimony. In its rebuttal testimony, the Company reduced its requested revenue increase to $84.529 million.

On May 12, 2008, the Division, the Committee, and Roger Ball filed surrebuttal testimony addressing rate of return. On May 15, 2008, the Company filed a Notice of Intent to Present Sur-Surrebuttal Testimony in the Rate of Return Hearing on May 20. On May 16, 2008, the Commission issued a Rate of Return Witness Order Letter. On May 19, 2008, Roger Ball filed a Response Motion to Rocky Mountain Power's Motion to Strike His Rate of Return Direct and Rebuttal Testimony and filed an e-mail memorandum regarding the order of witnesses for rate of return hearings.

On May 23, 2008, the Division, the Committee, UAE/Wal-Mart, UIEC, and IBEW Local 57 each filed separate revenue requirement surrebuttal testimony and the Company filed a Joint Issues List. On May 27, 2008, the Company filed a Notice of Intent to Present Sur-surrebuttal in Revenue Requirement Hearing Commencing June 2, 2008 and a Notice of Peter Eelkema's Adoption of Pre-Filed Direct Testimony of G. Michael Rife on Rocky Mountain Power's Load Forecast. On May 28, 2008, the Division filed Supplemental Surrebuttal Testimony and Exhibit of Thomas C. Brill. On May 29, 2008, IBEW Local 57 filed Supplemental Surrebuttal Testimony and Exhibits of Gary Cox. On May 30, 2008, the Committee filed an Objection to the Presentation of Sur-Surrebuttal Testimony and Exhibits and the Company filed Supplemental Rebuttal Testimony of Jonathan D. Hale. After due notice, a hearing was held on rate of return issues on May 30, 2008.

On June 2, 2008, the Company filed its Response to the Objection to the Presentation of Sur-Surrebuttal Testimony and Exhibits. On June 2 through June 5, 2008, hearings were held to receive testimony and cross examination from parties on contested issues associated with revenue requirement and public witness testimony was received on June 5, 2008. At hearing, the Commission sustained the Committee's May 30, 2008, objection to the Company's presentation of sur-surrebuttal testimony. In response to the Commission's decisions at hearing, on June 13, 2008, the Company filed a Revenue Requirement Joint Issues List and on June 19, 2008, post-hearing briefs were filed by the Company, the Division, the Committee, UAE, UIEC, and IBEW Local 57. At hearing, the Company reduced its request for a revenue increase to $74.456 million.

II. BACKGROUND

In our December 27, 2007, Scheduling Order, we bifurcated this proceeding into two phases to better manage resources and accommodate the statutory 240-day requirements for the setting of rates in this case and the concurrent case for Questar Gas Company in Docket No. 07-057-13. This Scheduling Order established four separate hearings on: (1) the choice of test period (alternatively referred to as "test year" thoughout this proceeding); (2) the allowed rate of return, (3) all other revenue requirement issues, and finally (4) cost of service and rate design issues. This schedule represents a departure from our recent practice in which the issues considered in the last three of these hearings are combined and heard in a single hearing, with a single order issued within 240 days of the filing by the Company of its application for a revenue increase.

The first hearing on selection of the appropriate test period was held on February 7, 2008. This was followed by our Order on Test Period issued February 14, 2008, wherein we approved use of a forecasted 2008 calendar year for the test period in this matter. The Company originally requested a $161.229 million revenue increase based on forecasted results of operations for the 12 months ending June 30, 2009. As a result of the test period decision, the Company filed updated direct testimony, reducing its requested revenue increase to $99.834 million based on the forecasted results of operations for the 12 months ending December 31, 2008.

The second hearing addressed allowed rate of return and was held on May 20, 2008. The third hearing, held June 2 through June 5, 2008, addressed all other revenue requirement issues. This order responds to the issues raised in the second and third hearings, and decides the overall revenue change granted to the Company and the spread of this change to customers prior to conclusion of the fourth and final hearing. This order thereby completes what is termed in the December 27, 2007, Scheduling Order as Phase I of this proceeding. Table 1 attached to this order summarizes the revenue requirement impact on the Utah jurisdiction for the Commission's decisions on cost of capital and each disputed revenue requirement issue.

The fourth and final hearing, on cost of service and rate design issues, is scheduled to begin October 6, 2008. The order to be issued as a consequence of this final hearing will address what is termed in our scheduling order as Phase II of this proceeding. The Phase II order will decide the spread of the overall revenue increase to rate schedules and set rates based on an analysis of cost of service issues and consideration of rate design proposals.

III. PROJECTED 2008 TEST-PERIOD REVENUE REQUIREMENT

A. COST OF CAPITAL

Using a projected capital structure, with a long-term debt ratio of 49.2 percent, a common equity ratio of 50.4 percent, a preferred stock ratio of 0.4 percent, a cost of long-term debt of 6.3 percent, a cost of preferred stock of 5.41 percent and an allowed rate of return on common equity of 10.25 percent, we conclude that an overall rate of return of 8.29 percent is fair and reasonable.

The Company, the Division, the Committee and Mr. Ball present testimony concerning the Company's capital structure and cost of capital. The Company relies upon the expert financial testimony of Mr. Williams and Dr. Hadaway and the testimony of Mr. Walje. The Division presents the expert financial testimony of Mr. Peterson. The Committee uses the expert financial testimony of Mr. Lawton. Mr. Ball provides his own testimony.

1. Capital Structure and Cost of Preferred Stock

There is no disagreement among the parties relating to the capital structure for the Company. For those parties who addressed the issue, all agree the Company's proposal of 49.2 percent long-term debt, 0.4 percent preferred stock and 50.4 percent common equity is reasonable. Messrs. Williams, Lawton, Peterson and Dr. Hadaway all agree these proportions are reasonable. These parties, through their witnesses, conclude the Company's proposed capital structure is reasonably similar to the capital structure of comparable companies used in making their financial analyses and is consistent with a reasonable balance of the interests of creditors, equity owners and customers. No other party disputes these conclusions.

Similarly, there is no dispute on the Company's calculation and proposal for the cost of preferred stock. The witnesses analyzing this issue all concur that a return on or cost for preferred stock of 5.41 percent is reasonable in calculating the Company's cost of capital. No other party disputes this position.

2. Cost of Long-term Debt

The parties addressing long-term debt differ on its cost. Throughout these proceedings, the Company's witnesses have maintained the cost for long-term debt should be 6.3 percent. In the test-year projections made by the Company, the cost-of-capital calculations are to reflect the issuance of $700 million in additional debt, to be issued prior to the end of 2008. Mr. Williams and Dr. Hadaway argue the cost of this additional debt will be 6.52 percent. The position is based on the Company witnesses' views of the appropriate base rate for debt, appropriate risk premium adder (added to the base rate) and issuance costs (also added to the base rate) for the new debt when issued. Combining the Company's projected cost of new debt with the Company's exiting debt cost results in the Company's over-all cost of long-term debt estimate of 6.3 percent.

The Division, through its witness Mr. Peterson, proposes a reduction in the Company's long-term debt calculation. Mr. Peterson believes the Company has incorrectly projected the cost of new debt. He observes that the beginning reference cost of debt, the interest rates on or costs of U.S. Treasury ("Treasury") securities, has decreased from the time the Company prepared its initial testimony and calculation. While the Company has acknowledged interest rates have decreased during the course of these proceedings, Mr. Peterson disagrees with the Company's subsequent argument that the appropriate risk premium adder has increased. The Company argues this widened Treasury-to-Company bond spread as well as the Company's views of the future Treasury bond rates continue to support its initial 6.3 percent proposal. Mr. Peterson argues the Company consistently uses incorrect Treasury security interest rate references in its attempts to justify the 6.3 percent estimate. Based on Mr. Peterson's views of appropriate Treasury bond rates and the appropriate risk premium and issuance adders, he concludes a two basis point reduction to the Company's 6.3 percent calculation is warranted, resulting in his over-all cost of long term debt estimate of 6.28 percent.

The Committee also argues for a reduction in the Company's long-term debt cost estimate. Mr. Lawton, the Committee's witness, argues the Company's witnesses have used Treasury security rate projections which should not be used. The projections have been wrong in the past and the Company has failed to explain why their accuracy now is any better. Mr. Lawton also notes that the Company's analysis has been inconsistent in the use of the projected interest rates. The Company's most recent calculation for a 6.3 percent estimate relies on projections for 2009, rather than 2008 projections as originally used. The 2009 projections are beyond the test period to be used in this rate case. Mr. Lawton recommends the Commission not use projections but use a base interest rate computed from an average of the latest three months of actual Treasury rates.

Mr. Lawton also disagrees with the Company's contention that the risk premium between Treasury bonds and corporate bonds is increasing. He presents an analysis of past spreads and opines that current market conditions lead him to conclude the risk spread should not be increasing, as the Company argues, but could be decreasing. Using what he believes is the appropriate base Treasury interest rate, risk premium adder and issuance cost adder, Mr. Lawton recommends a three basis point reduction to the Company's estimate of the cost of long-term debt, or an overall rate of 6.27 percent.

3. Cost of Common Equity

One of the Company's financial witnesses, Dr. Hadaway, gives testimony providing his opinion of an appropriate rate of return for common equity. Dr. Hadaway employs the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM") and another risk premium model in forming his recommendation. The Company applies these financial models and derives a rate of return on common equity estimate of 10.75 percent. Dr. Hadaway critiques the positions of Messrs. Peterson and Lawton and suggests that 'correction' of their analyses, using his views of the appropriate selection of model inputs and weighting of the iterations of the various financial models, should lead the Commission to discount their testimony and accept his. Likewise, Messrs. Peterson and Lawton suggest how Dr. Hadaway's analyses may be 'corrected' and 'updated' to lead to the adoption of their individual recommendations for common equity, 10.1 and 9.85 percent respectively.

Mr. Peterson argues Dr. Hadaway's selection of comparable companies is in error, having included companies which Mr. Peterson views are too small, or derive too much revenue or income from non-electric utility and/or foreign operations. Mr. Peterson would not include eight of the companies Dr. Hadaway selected and has alternative companies included in his group. Messrs. Peterson and Lawton have substantial disagreement with Dr. Hadaway's

DCF model inputs and results weighting. Mr. Peterson questions the relevance of gross domestic product ("GDP") growth rates, particularly as calculated and used by Dr. Hadaway, relative to the expected growth rate for regulated electric utilities. Mr. Peterson remains unconvinced Dr. Hadaway's weighted averaging of historical GDP growth rates is a proper growth rate input to be used in any DCF based analysis. Mr. Lawton also challenges the GDP growth rate inputs used in Dr. Hadaway's DCF models, particularly the manner by which Dr. Hadaway arrived at a weighted historical average used in the Company's analyses. If GDP rates are to be used, Mr. Lawton suggests using a simple average of GDP rates from more recent periods, rather than the method or approach used by Dr. Hadaway. Messrs. Peterson and Lawton suggest and advocate other growth rate inputs, from other sources, are also appropriate in conducting DCF based analyses to estimate the cost of common equity. They use competing CAPM and other risk premium analyses, with alternative inputs and assumptions, from those advanced by Dr. Hadaway.

Messrs. Peterson and Lawton critique Dr. Hadaway's weighting of model selection, model runs and accompanying results because they may produce what Dr. Hadaway viewed as a 'wrong' result. They note Dr. Hadaway initially used but subsequently abandoned the CAPM model, simply because it later provided a result which Dr. Hadaway felt is too low. They view Dr. Hadaway's actions reflect having a pre-determined equity return guiding how and if a financial model is used in the analysis, rather than using multiple model analyses to arrive at an estimate of the cost of equity. The Company counters Messrs. Peterson and Layton similarly weighted various models and results; the issue is the extent or degree and reasons given for why a witness may discount or rely upon any particular model and the model's applications and results.

Mr. Walje, on behalf of the Company, provides non-technical testimony based on his professional experience. He argues the Company faces numerous business risks which he believes affect the Company's ability to attract or obtain capital. He criticizes the Division and Committee for recommending returns which do not reflect these risks or exacerbate them. Messrs. Peterson and Lawton counter their analyses have appropriately factored in risk, as any financial analysis must, and their recommended rates of return are appropriate for the capital markets and capital needs facing the Company. They argue Mr. Walje's testimony is not driven by any analysis of risk, business or other, but simply the disparity between the Company's erroneously high rate of return estimate and their correct estimates using appropriate and market derived inputs for the financial models used.

Mr. Ball provides testimony which was subject to a Motion to Strike, filed by the Company, arguing Mr. Ball lacked expertise and his testimony should be stricken due to procedural and substantive failings. Mr. Ball argued he had adequate qualification, relevant to the nature of his testimony and purpose for which it was offered and the procedural error claims were without merit. Mr. Ball essentially argues that the ownership of the Company's stock, indirectly through the ultimate control of Berkshire-Hathaway, is such that the Commission need not be overly concerned with the financial analysis performed by the other witnesses. He notes ownership of the Company has changed twice over the past ten years. If the rate of return set by the Commission is too low, its current owners can simply sell the Company again, presumably to owners who will not be concerned about Commission-set returns. Mr. Ball further suggests the Commission adjust the rate of return determination to reflect costs of a test period which Mr. Ball believes should be the rate case basis for revenue requirement considerations, rather than the test period used in this rate case.

4. Discussion, Findings and Conclusions

As we recently experienced with the concurrent general rate case proceeding involving Questar Gas Company, Docket No. 07-057-13, we resolve the cost of capital disputes of the parties recognizing that reasonable people may reach different conclusions on these issues. The parties only agree upon capital structure and the cost of preferred stock. On the other issues, parties present multiple model analyses providing a range of estimates for the costs of various components of capital and discussion of why certain input values and assumptions may or may not be appropriate. Witnesses provide testimony for and against the use and weighting of various iterations of a model, the aggregate consideration of all models' results to obtain an estimate for the cost of a capital component, and other factors which are believed to influence the selection.

a. Capital Structure and Cost of Preferred Equity or Preferred Stock

We accept and adopt the parties' unanimous position regarding a capital structure consisting of 49.2 percent long-term debt, 0.4 percent preferred stock and 50.4 percent common equity. This capital structure is similar to those of the witnesses' comparable companies. We find it reasonably balances the needs and interests of creditors, owners and customers. We also accept and adopt the parties' calculation of the cost of preferred stock. We find no basis to reject the calculated cost of 5.41 percent.

b. Cost of Long-term Debt

In resolving the parties' dispute on the cost of long-term debt, we recognize the differences in witnesses' views of what the cost or rate will be when the Company issues new debt. While we agree that the selection should be based on what is expected in 2008, rather than views or inputs extending beyond the test period, we are not convinced that any party has conclusively established its analyses have identified the cost of new debt. The cost of new debt when combined with existing cost of debt sets the overall cost of long-term debt to be used to calculate the Company's revenue requirement. Using the information provided by the witnesses relating to a base Treasury debt rate, a risk premium spread between Treasury and corporate bonds and issuance costs, but using our own consideration and weighting, we conclude an overall cost of long-term debt of 6.3 percent is reasonable.

c. Cost of Common Equity or Common Stock

We find use or application of the financial models used by the parties' witnesses provides relevant information to our determination of the cost of common equity. We may place greater reliance upon the DCF model results, but the other models also provide information which informs our determination of the rate of return. We are faced with evidence showing a DCF-based range of estimates from 6.82 to 11.3 percent, depending upon the various versions of the DCF model and which inputs are used. With risk premium models, whether CAPM or another variation, the parties present a range of estimates from 6.48 to 11.43 percent. The parties make their own syntheses of the results of the financial models, each with their own views of appropriate weighting and model use, and reach differing conclusions for what constitutes the correct rate of return. The parties present a range of point estimates of 9.85 to 10.75 percent. Again, we are not convinced any one party has established its approach and resulting point estimate is correct to the exclusion of any other.

As we sift through the evidence presented by the financial expert witnesses, we give less weight to the testimony presented by Mr. Walje. We conclude the points Mr. Walje raises are incorporated in the application and consideration of the financial evidence. The circumstances Mr. Walje references are not unique to the Company and are factored into the data and inputs used in the financial modeling. As we stated in our June 27, 2008, Docket No. 07-057-13 rate case order for Questar Gas Company, we "recognize our determination of a specific rate of return will be analyzed and factored in the recommendations and ratings of credit rating agencies, stock analysts, and current and future shareholders. What we do will have an effect on the Company's ability to obtain capital in the future. It will also affect Company customers through the rates they will pay. Although equity and debt capital markets are always in flux, the current capital market has distinguishing characteristics. Many of the witnesses have given us their views and opinions on the current capital market and we as well make our determination weighing the long term interests of the Company, investors and ratepayers."

We do not accept Mr. Ball's suggestion that the rate of return we set is to be influenced by an alternative test period. We have made the test period selection for this case and will not follow alternative routes to another.

As we have necessarily done in previous cases, we take the evidence presented in the record and consider what may be appropriate inputs to the financial models, what weighting may be made among the results of any particular model's iterations and across the various models, and consider a reasonable balance of the interests of the Company, debt and equity investors, and customers to set a return on common equity. Through our consideration of the financial models as we deem appropriate, with the inputs or components and weighting we believe reasonable, and weighing all of the expert financial testimony and other witness testimony received, we find and conclude that a rate of return on common equity of 10.25 percent is reasonable.

B. REVENUE REQUIREMENT ADJUSTMENTS

1. Introduction

On March 6, 2007, the Company filed supplemental direct testimony and exhibits in support of an updated requested revenue increase of $99.834 million for the 2008 test period. Subsequently, through rebuttal and surrebuttal testimony and at hearing, the Company revised this requested revenue increase to $74.456 million based on the Company's rate of return proposal. Parties recommend adjustments which the Company disputes. The disputed issues address net power costs, labor costs, other expenses, other revenues, capital additions and inter-jurisdictional cost-allocation factors. We conclude this section with a numerical summary of the approved adjustments to the Company's forecast of the Utah jurisdictional revenue requirement for the 2008 test period.

2. Net Power Costs

Net power costs are a subset of total Company power costs and are equal to the sum of system-allocated costs in several specific Federal Energy Regulatory Commission ("FERC") accounts less the system-allocated revenues in another specific FERC account. These numbered accounts are: fuel costs 501, 503, 547; wheeling expenses 565; system allocated wholesale purchases 555; and system-allocated wholesale sales 447. The dollars in these accounts are adjusted from actual results in order to normalize and/or forecast net power costs for the test period. To this end, the Company uses an hourly production dispatch computer model called Generation and Regulation Initiatives DecisionTool ("GRID") to simulate normal system operating conditions and estimate net power costs. All other power related accounts are determined for the test period outside of GRID.

In the Company's supplemental direct testimony, it requests about $1.051 billion in total Company net power costs for the test period. In rebuttal testimony and at hearing, the Company proposes additional adjustments supporting $1.044 billion in net power costs, depending on the adoption of alternative adjustments referred to as Alternative 1 and Alternative 2. Parties propose additional adjustments which the Company disputes and some parties dispute adjustments proposed by the Company in its rebuttal testimony or at hearing. Because of the disputes regarding the Company's rebuttal and hearing adjustments, the amounts of all proposed adjustments are with respect to the Company's supplemental direct testimony forecast of $1.051 billion in total Company net power costs.

a. Call Options

The Company, the Committee and UAE/Wal-Mart provide testimony on the simulation of call options in GRID. Generally, a call option is a contract that commits the Company to paying a fixed premium, in the form of a demand or capacity charge. This premium is paid whether or not the option is exercised. If the option is exercised, then the Company additionally pays for the energy per the terms of the contract.

UAE/Wal-Mart and the Committee argue some call options are dispatched by GRID when it is uneconomic to do so. Additionally, the Committee questions the value to the ratepayer of the demand charges of some call options.

UAE/Wal-Mart proposes to remove the variable costs of three uneconomic contracts in the months in which calling on these resources causes net power costs to increase. This adjustment reduces the Company's forecast of net power costs by $0.870 million.

The Committee expresses concern with five call option purchases. The Committee proposes to remove the contracts from GRID if the dispatch benefits of the contracts are negative and to remove demand charges for contracts during months when the contracts are not dispatched in the model. This, the Committee testifies, is the proposal the Company made and the Oregon Commission accepted in a recent case in which the test period was also calendar year 2008. The Committee here proposes a minor modification to this method. First, eliminate any uneconomic generation associated with these contracts from GRID. Second, if a specific contract fails to provide meaningful dispatch benefits during a month, then remove it from the model. The primary effect of the second step, removing the contracts after uneconomic generation is removed, is to eliminate the contract demand charges in months when the contract is not dispatched in the model. Addressing only the net power costs associated with the first step, the uneconomic generation of the call options, the Committee calculates a reduction in total Company net power costs of $0.923 million. Addressing both steps, the Committee's adjustment reduces total Company net power costs by $3.587 million.

The Committee argues call options present modeling challenges and policy issues that need to be considered. The Committee argues the Company enters into such contacts to provide price protection for the Company, but in most cases, they fail to produce ratepayer benefits in GRID. Since the call options are not allowed to carry reserves in GRID, the Committee disputes the Company's contention call options provide reliability benefits.

In rebuttal, the Company believes net power costs should include the capacity charges of call options in all cases, arguing the contracts provide reliability benefits by providing physical delivery of energy into the Utah load area during periods of increased demand and/or transmission constraints when prices are higher. The Company agrees with UAE and the Committee the contracts should not be dispatched in a manner that increases net power costs. However, the Company argues when it screens the contracts identified by UAE, it calculates an increase in net power costs rather than a decrease and further, it could not determine how the Committee adjustment addressing only uneconomic costs was determined. In its post-hearing brief, the Company states it concedes the adjustment for the uneconomic dispatch of call options, agrees with UAE/Wal-Mart's quantification of the adjustment in surrebuttal and includes the result in its rebuttal Alternative 2 position.

We are persuaded by UAE/Wal-Mart, the Committee and the Company that at a minimum, the uneconomic dispatch costs of the call options should be removed. Both UAE and the Committee provide evidence showing the removal of the uneconomic generation costs of certain call options causes net power costs to decrease. The Company does not provide countervailing evidence to demonstrate its assertion that when it screens the contracts, net power costs increase. Nonetheless, the Company concedes to a call option adjustment in the Company's Alternative 2. We concur with the Committee that four of the five call options exhibit uneconomic dispatch and should be adjusted. This adjustment reduces total Company net power costs by $0.923 million and Utah revenue requirement by $0.083 million.

b. Sacramento Municipal Utility District ("SMUD") Contract

The SMUD contract is a long-term firm sales contract scheduled to expire in 2014, whereby the Company supplies SMUD with 350,400 megawatt hours of on-peak power annually at a rate of 100 megawatts per hour. The 2008 contract price is $21.46 per megawatt hour, based on a formula tied to the average cost of fuel, operations and maintenance ("O&M") costs for the Jim Bridger coal-fired generating plant.

Three issues are raised regarding the modeling of the SMUD sales contract. First, the Committee identifies an error in GRID in which the model assumes the contract volumes are increased to accommodate an extra day in the leap-year. This adjustment reduces total Company net power costs by $0.034 million. The Company agrees this is an error and makes an adjustment in its rebuttal position, both to Alternative 1 and Alternative 2. We accept this adjustment to total Company net power costs which reduces Utah revenue requirement by $0.015 million.

Second, the Committee argues GRID models the SMUD contract such that it is more expensive to serve the obligation than has been the actual experience. The Committee compares the monthly sales volumes modeled in GRID to the actual monthly sales of SMUD volumes for the four-year period (2003 through 2007) showing the SMUD contract has been served at substantially different times than predicted by GRID. To address this concern, the Committee develops the monthly energy for SMUD based on the four-year average of actual sales from 2003 through 2007. The Committee then assumes that on a monthly basis SMUD would optimize the contract based on maximizing California-Oregon Border market revenues. This adjustment reduces total Company net power costs by $2.594 million.

The Company opposes this adjustment and argues GRID appropriately normalizes the contract by assuming SMUD will maximize the value of the contract and take the power at the highest cost hours. The Company argues basing the contract on historical patterns is akin to using "actual" rather than normalized power costs. The Company also argues this adjustment is a one-sided and selective adjustment to the model and if this adjustment is made, other similarly modeled contracts should be similarly adjusted.

We are persuaded by the Committee. The modeling assumptions for the SMUD contract do not do a good job of "normalizing" the contract for ratemaking purposes. The historical data is persuasive in showing that SMUD does not take the power at the highest cost hours as modeled by GRID. Further, as the Committee notes, four-year averages are used for the purpose of normalizing other GRID inputs. Basing the monthly sales for modeling purposes upon a four-year average of historical monthly sales is reasonable and we accept the Committee adjustment. This adjustment reduces total Company net power costs by $2.594 million and reduces Utah revenue requirement by $1.137 million.

The third issue raised by the Committee is the pricing of the SMUD contract. This contract has been subject to revenue imputation in past proceedings before us, and the Committee argues the Company's imputed price of $37 per megawatt hour, based on the last litigated case addressing this issue, is no longer compensatory. The Committee reviews the unique history of this contract and past Commission orders approving an imputation, and proposes indexing the $37 imputed price to the contractual SMUD price, resulting in an imputed price in this case of $43.80 per megawatt hour. This, the Committee argues, will exactly equal the disallowance the Company first encountered in 1999 of $7.8 million. This adjustment reduces total Company net power costs by $2.383 million.

The Company opposes this adjustment and argues revenue imputation should continue at $37 per megawatt hour to be consistent with treatment for the last several years and the regulatory principle that prudence should be based on information available at the time the transaction was consummated. The Company argues the $37 per megawatt hour imputation is based on a Southern California Edison ("SCE") wholesale sales contract entered into at approximately the same time, also for a long-term period and was negotiated at market prices at the time. Therefore, it sets a fair market price of the SMUD contract.

In rebuttal, the Division concurs with the Committee's argument that since the Company received a lump sum payment of $98 million from SMUD at contract execution and retained the funds for itself, i.e., shareholders, the Company should share a commensurate amount of burden to ensure that the contract terms are compensatory, per Commission order.

Further, it agrees with the Committee's argument that since the imputed price has not been adjusted for several years it is no longer compensatory, as wholesale prices have increased over the intervening period and unless an adjustment is made, ratepayers will continue to pay ever increasing costs of serving a below-market contract. The Division concludes the $37 per megawatt hour price is not compensatory and therefore warrants adjustment. However, the Division disagrees with the method the Committee uses to calculate the adjustment and proposes an alternative method. The Division argues it is more appropriate to apply the percent change from the earlier SMUD contract price to the 2008 forecasted contract price than the dollar change in these two prices. This results in an imputed price of $54.16 per megawatt hour, or a $17.16 increase in the Company's filed price of $37 per megawatt hour, resulting in a decrease in total Company net power costs of $6.013 million.

In surrebuttal, the Division withdraws its proposed adjustment and its support for further revenue imputation in this case beyond that achieved through the $37 imputed price in the Company's filing. The Division bases its withdrawal upon a reasonableness check it performed subsequent to filing rebuttal testimony. This reasonableness check involved levelizing the net present value of the $94 million lump-sum payment[1] over the contract period (1987 to 2014), and dividing this annual levelized amount by the contract's annual sale of

[1] In rebuttal and surrebuttal testimony, the Company and Division, respectively, reference without explanation, a $94 million lump-sum payment rather than the $98 million lump-sum payment noted by the Committee in its direct testimony. The Committee provides an exhibit which is a 1991 letter from the Company to regulators in Montana which states the lump-sum amount is $98 million. In previous cases before the Commission, the amount was noted in testimony as $94 million and we presume the Division and Company are referencing that previously noted amount rather than the current record evidence.

350,400 megawatt hours to arrive at the imputed price per megawatt hour. The Division calculates this imputed price ranges from about $34 per megawatt hour to $38 per megawatt hour in 2008, depending on discount rate assumptions, which appears to be in line with the Company's filed imputed price of $37 per megawatt hour. The Division believes it is erroneous to add the 2008 SMUD contract price, as the actual levelized values ($34 to $38 per megawatt hour) are the only amounts that should be imputed to reflect the current value of the $94 million payment.

A brief summary of the history of this contract, as provided by the Committee, Company and Division, will provide context for the remaining discussion of the SMUD pricing issue. In 1985, Company shareholders received a power entitlement, i.e., firm rights to power in the future, from the Bonneville Power Administration ("BPA") to settle a law suit concerning Company shareholder investment in a failed nuclear power plant. In 1987, the Company assigned this BPA power entitlement to SMUD in exchange for an up front payment of $98 million recorded by the Company as non-utility property. At the same time, the Company executed a power exchange agreement with SMUD wherein SMUD traded the seasonal power entitlement back to the Company in exchange for 100 megawatts of power at a 40 percent load factor. In addition, SMUD would pay the production cost of the energy delivered, a rate below the prevailing market price. Finally, it was expected the Company's customers would receive the BPA power entitlement by paying surrogate nuclear costs upon execution of the agreement, by 1996, with BPA. The Company did not execute this agreement by 1996 and therefore forfeited its right to the entitlement.

We addressed this issue in our order in Docket No. 99-035-10 and last addressed the issue in Docket No. 01-035-01 ("2001 Order"). In our 2001 Order, the record was clear the $37 imputed price based on the SCE contract was in dispute as the appropriate value, however, we maintained the $37 imputed price, finding it compensatory at that time, and invited further discussion on the appropriateness of this value in a future rate case. The Committee has provided unrebutted testimony the SCE contract price was renegotiated many times. Indeed, the record shows the $37 per megawatt hour SCE price was not even its initial price and therefore it was not a market price negotiated at the same time the SMUD agreement was executed. Therefore, we find the SCE contract price does not necessarily serve as an appropriate market proxy for the below market price set in the SMUD agreement, as asserted by the Company in this case.

Nonetheless, we generally agree with the Company that the SMUD contract revenue imputation should be based on information that was known at the time of contract execution. Further, our goal is to provide a reasonable 'revenue' imputation, rather than 'price' imputation as a price imputation is the means to achieve the appropriate revenue imputation for the SMUD contract. To this end, we conclude the Company agreed to serve this power sale in 1987 in exchange for a $98 million lump-sum payment plus the contract prices which are based on the production costs of energy delivered and are now tied to Jim Bridger fuel and O&M costs, which change from year to year. We also conclude the Company determined at some point that executing the BPA power entitlement in 1996 carried no additional value. It is the sum of the two components of revenue, the lump-sum payment and the ongoing contract revenue, that the Company agreed to accept at the time it executed the contract as compensation for the power provided to SMUD and therefore both sources of revenue must be accounted for in the imputed price for this contract.

We accept the Division's 2008 value of $37 per megawatt hour to serve as the component of annualized per unit revenue associated with the $98 million lump-sum payment and add this to the forecasted per unit contractual revenue, $21.46 per megawatt hour, SMUD is obligated to pay. This raises the imputed price to $58.46 per megawatt hour in the 2008 test period in order to account for an appropriate revenue imputation. We order the Company to apply this decision, calculation of an imputed price which accounts for both the $98 million lump-sum revenue and the ongoing contract revenue, to this contract until it expires. Our decision reduces total Company net power costs by $7.520 million and Utah revenue requirement by $3.287 million.

c. Uneconomic Model Operation

The Committee argues some generating resources operate in GRID when it is uneconomic to do so. The Committee believes this occurs because the logic in GRID separates the decision to commit (to start up or shut down) a resource from the operating constraints (transmission limits and market capacity limits) imposed in the model. These operating constraints are later used to determine the optimal dispatch of resources. Thus, GRID assumes energy produced by a generator can always be sold in markets when making the commitment decision. As a result, units run when there is no market for the energy they produce.

The Committee suggests the long-term solution for this problem is for the Company to change the GRID logic to harmonize the commitment decision process with the operating constraints. The Committee recommends the Commission require the Company to do this prior to the next Utah general rate case. Alternatively, adding non-firm transmission capabilities to GRID may minimize the impact of the uneconomic generation problem.

For this case, the Committee proposes an interim solution which it applies to three resources: the West Valley contract and the Currant Creek and Lake Side combined cycle generating plants. For the West Valley contract, the Committee removes the resource from operating on days when an analysis shows the model should not have committed the resource. For the combined cycle generating plants, the Committee developed night-time shut-down screens. Additionally, the Committee prepares an adjustment to account for the incremental start-up fuel and O&M expenses resulting from daily cycling of the combined cycle units. It is the Committee's understanding these costs are not addressed in GRID outputs but rather elsewhere in the Company's filing. The Committee's interim solution reduces total Company net power costs by $20.199 million. The incremental start-up fuel and O&M expenses increase total Company expenses by $9.389 million.

The Company agrees the current version of GRID systematically dispatches the West Valley, Currant Creek and Lake Side resources in an uneconomic manner. The Company is working on additional refinements to GRID's commitment logic but this work is not yet complete. Therefore, the Company also proposes a manual adjustment to remove the uneconomic generation. For the West Valley contract, the Company applies a light load hour screen. The Company applies a 6-hour night-time screen to the Currant Creek and Lake Side generating plants, which is similar to the Committee's approach. The Company concurs with the Committee's calculation of increased fuel and O&M expenses for the additional unit start-ups.

The Company's adjustment reduces total Company net power costs by $18.6 million and increases net power costs by $9.389 million for additional unit start-ups. These adjustments are included in the Company's Alternative 2 net power cost analysis but not in the Alternative 1 analysis.

We concur with the Company and Committee an adjustment to remove the uneconomic generation produced by faulty GRID logic is necessary. We adopt the Committee's adjustment because it is calculated based on the Company's direct supplemental testimony which is our base point of reference. The calculation of the Company's adjustment is dependent on the adoption of other adjustments in its Alternative 2 net power cost analysis. As discussed later, we do not adopt all of the Alternative 2 proposed adjustments. These adjustments reduce total Company net power costs by $10.810 million and Utah revenue requirement by $4.581 million.

d. Planned Outage Schedule

Planned outages occur when generators are taken out of service for routine scheduled repairs and maintenance. Rather than use the actual generator maintenance schedule for a given year, the Company uses a "normalized" schedule, with outage durations based on a four-year average.

Both the Division and Committee propose adjustments to the Company's planned outage schedule in GRID in order to better reflect historic practices. In rebuttal testimony, the Company agrees some adjustment is necessary and provides an alternative planned outage schedule in its Alternative 2 rebuttal net power cost analysis. It adopts the Division's planned outage schedule in its Alternative 1 rebuttal net power cost analysis.

The Committee evaluates actual generating plant scheduled outages, planned scheduled outages for 2008 and 2009 and the work papers the Company used to develop the schedule for planned outage in GRID. During its on-site interviews, the Committee learned planned outages are normally scheduled in spring when demand and market prices are at their lowest levels. The Committee shows GRID assumes more planned outages in winter months and fewer in April and May than actually occur. The Committee's proposal modifies the schedule assumed in GRID to better reflect average historic practice. The Committee shifts the winter-spring coal plant outages forward to better match historical and planned outages. Additionally, the Colstrip generating plant outages are moved from fall to spring. The Committee presents testimony its proposed schedule has a better correlation with the four-year average of actual outages, a more reasonable negative correlation to market prices, no single month has an excessive amount of maintenance planned, and addresses considerations noted by the Company in its work papers. The Committee's planned outage schedule reduces total Company net power costs by $10.993 million.

Alternatively, the Committee suggests the Company reflect the actual history of planned outages in the computation of forced outage rates. While these outages are fundamentally different, in GRID modeling they both result in removal of a specific amount of capacity at a specific time. This approach would result in each unit having the correct amount of scheduled outage energy on a monthly basis. Use of this approach would reduce total Company net power costs by $10.6 million.

The Division identifies planned outage dates in GRID for specific generating units which are inconsistent with both historic outages and the Company's preferred planned outage periods. The Division changes the GRID inputs to dates for these units that closely match historical outages. The Division states in hearing that this adjustment reduces total Company net power costs by $4.3 million.

The Company generally agrees the planned outage schedule in GRID deviates in some ways from the Company's historic practices, particularly by scheduling outages in January and February. While the Company generally agrees with the Division's approach, it develops an alternative planned outage schedule in its rebuttal testimony. The Company removes all planned outages from the months of January and February and smooths them into the spring and fall months of the schedule. Application of this new planned outage schedule reduces total Company net power costs by $1.7 million, assuming the Company's rebuttal Alternative 2 net power cost analysis. The Company also appears to agree with the Division's adjustment and includes this amount in its rebuttal Alternative 1 net power cost analysis.

In rebuttal, the Committee performs a test of its proposed schedule in comparison to the Division's and Company's. The test compares the costs of each proposed schedule to the costs of actual outage schedules used during the four year period. The results show the Committee's proposed schedule is much more in line with the four-year average than either the Company or Division schedules, demonstrating it is reasonable.

We are persuaded by the Committee, its planned outage schedule best normalizes planned outages to reflect both actual historic practice and planned outages, while taking into consideration other factors important to scheduling outages. The Committee's data shows both the Company and Division proposals schedule fewer outages in May and June than is historically the practice. We are additionally persuaded by the Committee's analysis that its planned outage schedule better reflects the costs incurred, on average, in the four years, 2003 through 2007, than the Division or Company proposed schedules. This adjustment reduces total Company net power costs by $10.933 million and Utah revenue requirement by $4.796 million.

e. Unplanned Outage Modeling

The Committee testifies the generating unit "unplanned" or "forced" outage rate defines the percentage of time that a generating unit will likely be out of service in the future due to unexpected forced outages. Further, utility industry practice is to develop expected forced outage rate assumptions by averaging historical forced outages over some period of time. The Company uses an average of four years of monthly data to derive monthly forced outage rates for GRID.

The Committee objects to the use of averaging monthly data to derive monthly forced outage rates arguing it is not standard industry practice. The Committee testifies it is standard utility practice to use the historical data to compute average annual forced outage rates because there is no basis for monthly variation in unplanned outages.

The Committee argues there are three reasons annual average forced outage rates should be used in the Company's modeling of net power costs. First, forced outages are random events and therefore it is unreasonable to assume forced outages can be predicted to occur more frequently in specific months. Conversely, assuming forced outages will occur randomly over a twelve month period is entirely reasonable. Second, evaluating monthly outage rates is much more time consuming than annual outage rates, provides no additional value and may call the results into question. The Committee argues the Company provides no compelling evidence proving why the use of monthly forced outage rates is reasonable. The Committee argues utilities do not typically use monthly forced outage rates because no physical or engineering considerations can be readily identified to explain why generating units would be more likely to fail during certain seasons or months. This adjustment increases total Company net power costs by $0.889 million.

The Company agrees with the Committee's adjustment but only if the weekday and weekend split for modeling outages is eliminated. The Company argues the use of annual modeling of forced outages means there is no justification for retention of a weekend/weekday split in the forced outage rate, i.e., there can be no discernable weekday/weekend pattern if events are random. The use of an annual forced outage rate and eliminating the weekday and weekend split in the forced outage rate increases total Company net power costs by $4.4 million and the Company includes this adjustment in its rebuttal Alternative 2 net power cost analysis. The Company provides no adjustment in its Alternative 1 position.

The Committee disagrees the two issues are the same. In contrast to monthly modeling, the Committee argues there are valid operational reasons why unplanned outages rates are higher on weekends than on weekdays. Certain types of outages, maintenance outages, can be deferred to avoid taking units offline during high cost periods. The North American Electric Reliability Council ("NERC") defines a maintenance outage as an event that can be deferred until beyond the next weekend, but not beyond the next planned outage. These types of outages have flexible start dates and the lost energy associated with them occurs more frequently in the weekend and other off-peak periods. The Committee testifies these types of unplanned outages make up 15 percent of all energy lost by Company generators. As a result, more than 90 percent of the Company's thermal resources have higher weekend than weekday outage rates. The Committee provides an exhibit of the average of the four years ending June 2007 of weekday and weekend outage rates for Company resources showing most units have higher weekend outage rates. Thus, the Committee argues, there are two justifications for maintaining the weekend-weekday outage rate split: it reflects the actual cost minimizing practices of the Company, and there is a sound analytical basis for its use. Additionally, it is industry practice.

Based on the Committee's testimony and hearing no dispute regarding the reasonableness of using historical data to compute average annual forced outage rates rather than using an average of four years of monthly data to derive monthly forced outage rates for GRID, we adopt the Committee's adjustment and direct the Company to apply this method in its net power cost studies going forward. This adjustment reduces total Company net power costs by $0.889 million and Utah revenue requirement by $0.390 million.

We are not persuaded by the evidence before us the same concern exists regarding the weekend and weekday split and therefore decline to remove this aspect from modeling unplanned outages. It seems reasonable to us an outage event can be random as to its date of occurrence or identification but that the duration of the outage, per NERC definition and criteria, can be deferred to the weekend. Further, the four year historical data provided by the Committee shows this to be the case.

f. Minimum Loading Deration and Heat Rate Modeling

In order to account for forced outages, the Company uses the deration method in GRID, which essentially reduces the amount of capacity of each generating unit by the expected forced outage rate.

The Committee argues the deration method is a common technique to account for forced outages in production cost modeling but that GRID has a flaw in the way it models capacity derations. In GRID, thermal deration factors which are based on expected forced outage rates, control the amount of generation available from thermal units. GRID only derates the maximum capacity of the unit by its availability rate, but does not derate the other capacity segments, such as the minimum capacity segment. Unless this adjustment is made, the Committee argues, the unit's minimum capacity could exceed its maximum capacity. The Committee found this event occurred in some GRID simulations for the test period with respect to Currant Creek. Thus, the Company's method results in the model violating minimum loading constraints, but only by a small amount. However, the Committee notes a number of resources now operate at minimum loading and therefore this modeling flaw is a serious oversight.

Similarly, the Committee testifies, an issue arises with respect to the heat rate curve used to account for the efficiency of the generating unit. Normally, each unit capacity point is associated with a unique point on the heat rate curve. When capacity segments are derated, an adjustment must be made to the heat rate curve so that the proper heat rate is still associated with the derated capacity. If an adjustment is made to derate the capacity of a generating unit, but no corresponding adjustment is made to the heat rate curve, then the wrong heat rate will be used for modeling purposes.

The Committee provides an exhibit showing the affect on net power costs of derating units at the minimum capacity segment and of adjusting the heat rate curve, in comparison to an example wherein these changes are not made. The results show a decrease in net power costs in each case. Making these corrections to the Company's direct supplemental net power cost study, the Committee's adjustments for minimum loading deration and heat rate modeling reduce total Company net power costs by $1.083 million and $3.606 million, respectively.

The Company opposes these adjustments for several reasons. First, the Company has been modeling forced outages for over 25 years without such adjustments. Second, the Company testifies the Committee's example is not realistic. The heat rate adjustment is based on the flawed assumption that forced outages result in plants being either on or off which is inconsistent with normal system operations. Further, it assumes each plant runs at its most efficient heat rate during partial forced outage which is impossible. Third, the plant minimum cannot be reduced below its minimum. Finally, the Company argues the Committee cites only one utility that makes these adjustments, and therefore refutes that it is standard industry practice.

In response, the Committee argues it is appropriate to address these issues now because this may be the first time the issue is relevant. Further, the Committee argues GRID already models partial plant ownership similarly. Finally, the Committee lists additional utilities that may have used the deration methods the Committee proposes here.

We find this issue warrants further investigation prior to making any adjustments to the Company's modeling. For example, we would like to review alternatives for addressing this issue, review actual operations in comparison to modeling predictions, and to understand the extent of the issue.

g. Thermal Ramping

The Company includes a manual ramping adjustment to its net power costs to account for decreased availability when generating units are started-up and shut-down. GRID does not include the ability to ramp units as part of its dispatch logic. The Company's manual adjustment reduces thermal availability to reflect generation not available due to ramping.

The Committee opposes the Company's adjustment. First, the Committee argues this adjustment is very unusual and contrary to standard industry practice. Second, the Committee identifies problems with the adjustment. For example, the Company's method assumes that any difference between the actual loading of a unit after it has been started up and 90 percent of its available capacity is due to ramping. In one examination of the issue, Gadsby unit 3 generated 916 megawatt hours in a given month and lost 994 megawatt hours due to ramping.

Another problem, the Committee argues, is the Company assumes that unless a unit is running at 90 percent of its full loading, it must be losing generation due to ramping, no matter how long it has been running when, to the contrary, units may be economically dispatched at less than full loading or may be assigned to carry reserves. The Committee identifies a gas unit assigned to carry reserves every single hour that under the Company's method assumed it would otherwise be losing generation to ramping.

The Company argues the only unusual aspect of its ramping adjustment is that it is a manual adjustment, since GRID does not include the ability to ramp units as a part of its dispatch logic. There is nothing novel in factoring ramping into a generating unit's availability. However, the Company agrees its current ramping calculation could inadvertently cover a gas plant being held in reserve. To address that possibility, the Company agrees to remove the Gadsby units (the only gas plants included in the Company's ramping adjustment are Gadsby units 1, 2, and 3) from the ramping adjustment. This reduces total Company net power costs by \$1.738 million and is included in the Company's Alternative 2 net power cost position but not Alternative 1.

In surrebuttal, the Committee disagrees the problem only applies to gas units. The Committee argues a more accurate approach to determining the ramping loss adjustment would be to use the actual ramp rate for the unit. The Committee examines the total amount of energy lost due to ramping based on the number of starts in the four year period and actual unit ramp rates and concludes the Company's approach overstates the total amount of energy lost due to ramping. The Committee calculates the amount of lost energy due to ramping amounts to 23 percent of the amount the Company includes in GRID. Although opposed to the Company's ramping adjustment, the Committee revises its ramping adjustment as a compromise in this case allowing the maximum possible ramping energy based on the actual thermal unit ramp rates. The Committee's adjustment reduces total Company net power costs by $2.472 million.

At hearing, the Company argues the Committee's adjustment relies on inapplicable operating ramping rates which are used when a plant is actually running and therefore hot, rather than ramping from a cold start. The Company's adjustment is designed to cover cold starts which can take six to ten hours. The Company argues the Committee's analysis reduces start-up time to an hour and suggests a coal plant can ramp up faster than a gas plant.

While we are concerned by the Committee's testimony the Company's adjustment may overstate energy lost due to ramping, at this point in time we accept the Company's proposal to remove the Gadsby units from the ramping adjustment. This adjustment reduces total Company net power costs by $1.737 million and Utah revenue requirement by $0.771 million.

We invite further discussion on this issue in the next general rate case. For example, the Company testifies this adjustment addresses ramping a unit from a cold start, yet the Committee testifies the Company's method assumes a unit must be losing generation due to ramping unless a unit is running at 90 percent of its full loading, no matter how long it has been running. These two statements do not appear to be compatible and therefore we would like further explanation. Also, if it is standard practice to address ramping through modeling logic, we would like to know what can be done to improve GRID's capabilities. Finally, we are concerned by the

Company's statement the Committee's approach results in outcomes that do not make sense, like a coal plant ramping faster than a gas plant. We wish to confirm that any method adopted to address this issue will provide sound results.

h. Hermiston Losses

The Committee testifies the Company transmits power from the Hermiston generating plant over the BPA transmission system. As a result, the Company imposes losses on the BPA system that it must later return to BPA. The Company models these losses as a zero revenue sale in GRID. The Committee argues the amount of losses assumed in GRID is premised on an assumed loss level of 75,000 megawatt hours per year allegedly occurring during the period October 1999 to January 2005. However, the Committee provides evidence the actual losses during this period were much lower. The Committee calculates the correct amount of losses for this period to be only 55,000 megawatt hours. Reducing losses to the appropriate level reduces total Company net power costs by $1.046 million.

The Company considers this adjustment to be an update to its filed net power costs and argues this adjustment should only be adopted if the Commission also allows other updates to net power costs proposed by the Company in rebuttal testimony. The Company provides no other rebuttal to this issue. The Company includes this adjustment to net power costs in its Alternative 2 net power cost analysis.

We view the two issues, the Hermiston losses adjustment and the Company's proposed updates, as separate issues. Each proposed adjustment to the Company's filed net power costs must stand on its own merits. Further, it appears this adjustment is a correction rather than an update. Since the Company does not rebut the amount of losses proposed by the Committee, nor provide countervailing evidence supporting the reasonableness of the amount of losses included in its net power cost analysis, we accept the Committee's adjustment to correct the amount of losses assumed for transmitting Hermiston power over the BPA transmission system. This adjustment reduces total Company net power costs by $1.406 million and Utah revenue requirement by $0.454 million.

i. Biomass Non-Generator Agreement

The Biomass contract is a high-cost qualifying facility contract. The current contract price per GRID output report, is $151 per megawatt hour. The Committee testifies the Company has negotiated non-generation agreements with Biomass over the past three years. For example, in 2007, Biomass produced no energy for a set period of time (April to June in 2007). In exchange, Biomass was paid an amount that represented a discount from its standard contract rate. For the Company, costs were lower than otherwise because the discount from Biomass was larger than the cost to replace the power. Apparently, Biomass benefitted because it did not have to purchase expensive fuel when replacement power was available at a lower cost in the market. The Committee argues the underlying circumstances of the non-generation agreement are likely to continue and therefore recommends the Company reflect this arrangement in its normalized net power costs. This adjustment reduces total Company net power costs by $0.458 million.

The Company provides no rebuttal specific to the Committee's adjustment. It argues in rebuttal this adjustment is an update and concurs with the adjustment on the condition other updates it proposes are also adopted. The Company includes this adjustment in its Alternative 2 net power cost analysis.

We conclude the Committee's adjustment is a reasonable normalizing adjustment. This adjustment reduces total Company net power costs by $0.458 million and Utah revenue requirement by $0.190 million.

j. Sunnyside Contract

The Company models the Sunnyside purchase power agreement according to the terms and conditions of the Third Amendment to the contract. The Commission held a hearing on March 18, 2008, and issued an order on April 3, 2008, approving the Fourth Amendment to the contract. The Fourth Amendment changes the basis for pricing the purchase of power from Sunnyside and the Company represented in hearing the Fourth Amendment pricing provides benefits to Utah customers in comparison to the Third Amendment. The Division, Committee and UAE/Wal-Mart recommend the terms and conditions of the Fourth Amendment be reflected in the test period net power costs. All three parties represent this adjustment reduces Utah's revenue requirement by $1.578 million. The Committee testifies the Fourth Amendment revisions reduce total Company net power costs by $3.642 million.

The Company includes an adjustment in its Alternative 1 to account for terms and conditions of the Fourth Amendment. The Company also characterizes this change as an update and qualifies its support of this adjustment to be made along with its own updates in its Alternative 2 position.

We take note of the administrative record in Docket No. 07-035-99, wherein we approved the Fourth Amendment to the Sunnyside contract. First, the Company represented it didn't know if it would file supplemental information to reflect the approval of the Fourth Amendment in its pending rate case, but noted if parties were to request the Company to adjust the rate case to address this issue once the contract has become effective, it would certainly have no reason not to do so. Further, we note the effective date of the Fourth Amendment was July 1, 2007. Therefore, we view this adjustment as a result of a prior Commission proceeding approving the terms and conditions which are reflected in this adjustment. We accept the Committee's calculation of the affect of this adjustment which reduces total Company net power costs by $3.642 million and Utah revenue requirement by $1.578 million.

k. Schwendiman Contract Deferral

The Committee recommends the start date for the Schwendiman contract be changed from May 1, 2008 to November 1, 2008. The Committee testifies the May start date coincides with the second amendment to the contract, dated September 7, 2007. The Committee reviewed the contract and testifies the third amendment to the contract, dated October 17, 2007, has a start date of November 1, 2008. This adjustment reduces total Company net power costs by $0.164 million. The Company refers to this contract adjustment as an update and includes it in its Alternative 2 position.

We accept the Committee's adjustment as a correction, based on a known and measurable change. This adjustment reduces total Company net power costs by $0.120 million and Utah revenue requirement by $0.053 million.

I. Transmission Wheeling Expenses

The Committee proposes four adjustments to transmission cost inputs to GRID. First, the Company includes a pro-forma adjustment for the Goodnoe Hills wind facility for the entire test year. However, Goodnoe Hills has been delayed and is now not expected to come online until June 2008. The Committee testifies the Company agreed the Goodnoe Hills pro-forma adjustment was incorrect in its response to CCS 21.1. This adjustment reduces total Company net power costs by $1.072 million.

Second, the Company included escalations for several transmission contracts in the test period. Many of these reflect a BPA rate increase that took place in October 2007. The Company developed these escalations from a comparison of changes in individual rate components rather than billing out the actual charges as applied to its requirements. Based on the Committee's review of October and November 2007 actual data these escalations are overstated. This adjustment reduces total Company net power costs by $1.544 million.

Third, the Committee contends the Company could not support the wheeling rate assumed in the Borah Brady transmission cost pro-forma adjustment. The Committee recomputes this charge using a rate schedule obtained from the Idaho Power Open Access Same-time Information System. This adjustment increases total Company net power costs by $0.379 million.

Fourth, the Committee includes the benefits of transmission imbalance charges the Company collects from third party customers which the Company has not reflected in GRID. This adjustment reduces total Company net power costs by $0.882 million.

The Company supports the first three of these adjustments provided that its forward price update is also included, and includes these adjustments in its Alternative 2 net power cost study. The Company does not rebut the inclusion of transmission imbalance charges.

We accept all four of the Committee's adjustments to the Company's net power cost analysis. These are reasonable corrections, based on the evidence, for the test period. This adjustment reduces total Company net power costs by $3.119 million and Utah revenue requirement by $1.349 million.

m. Tesoro and Kennecott Qualifying Facility Contracts

The Division testifies the Company uses an incorrect termination date in GRID for the Tesoro power purchase agreement. The Commission approved this contract in Docket No. 07-035-78 on December 20, 2007, and this contract runs for a term of twelve months from January 1, 2008, to December 31, 2008. GRID assumes the contract terminates January 1, 2008.

The Division testifies the Company employs an incorrect line loss factor for the Kennecott power purchase agreement. In its December 21, 2007 order in docket No. 07-035-71, the Commission ordered the avoided line loss adjustment factor be reduced from 1.034 to 1.02. The GRID model does not include this adjustment.

Correction of these two GRID inputs reduces total Company net power costs by $0.217 million. The Company concurs with these two adjustments and includes them in both its Alternative 1 and Alternative 2 net power cost analyses.

As the corrections are undisputed, we accept the adjustment to total Company net power costs which reduces Utah revenue requirement by $0.092 million.

n. Electric Swaps, Indexed Gas Transactions

The Company includes gas swaps and indexed electric transactions in its initial net power cost study. In rebuttal testimony, the Company contends it inadvertently omitted electric swaps and indexed gas transactions in its initial and supplemental direct filings and proposes to include them as an adjustment. The Company testifies it undertakes these transactions as a hedge against market risk. Including these omitted transactions increases total Company net power costs by about $3.2 million.

The Committee opposes this adjustment because it allows a selective update of data favorable to the Company. The Committee argues this adjustment includes new costs, making it more of an update than a correction. The Committee is concerned the Company did not inform parties of this substantial error until filing rebuttal testimony. By introducing new kinds of costs at this time, the Company effectively limits the parties' opportunity to inquire as to the prudence of the costs and the most appropriate rate making treatment. The Committee is concerned this could be considered as establishing precedent. Further, the Committee believes the Company could have included new information in its supplemental direct filing.

We concur with the Committee primarily on procedural grounds but also for lack of evidence. The Company presented this information for the first time in its rebuttal testimony. We are not convinced this is adequate time for parties to evaluate the credibility and efficacy of the information. We agree mistakes should be brought forward. While we do not opine on the amount of time necessary for review, we conclude rebuttal testimony is late for this type and amount of a change for reasonable evaluation by regulators and other parties. Further, the Company provides no testimony describing these transactions and demonstrating they should be included in the test period. Indeed, no party testifies it has reviewed these additional transactions, including their terms, conditions and costs, nor finds them to be reasonable. Although the Division testifies it spent time reviewing the Company's hedging process and found the hedging process was correct in that most of the energy prices were as given, or close to the hedge price of the Company, in the GRID model, the Division is silent with respect to the addition of the omitted transactions. We decline to adopt this adjustment to the Company's net power costs.

o. Currant Creek Outage Rate

The Committee argues the Company uses an unsupported and incorrect formula to compute the Currant Creek outage rate in GRID. Further, the formula uses incorrect inputs for the combustion turbine capacities, using 180 megawatts rather than 140 megawatts. Also, the Committee testifies the Company overstates the number of days of required maintenance for Currant Creek because it considers a planned outage of one combustion turbine as resulting in an outage of the entire plant. In reality, the Committee argues, when one combustion turbine is down, the plant can still run at half of its capacity. The Committee corrects the calculation of Currant Creek's planned and unplanned outage rate in GRID. This adjustment reduces total Company net power costs by $0.220 million.

The Company concurs this is a modeling error and includes an adjustment in both its Alternative 1 and Alternative 2 net power cost analyses. However, the Committee argues in its surrebuttal testimony the Company has only conceded to make an adjustment for the incorrect expected forced outage rate and has neglected to reduce the Currant Creek planned outage duration for the test year from 9 to 8 days. The Committee maintains its recommendation on this correction.

We accept both components of the Committee's corrections to the Company's net power costs. We have no rebuttal from the Company contesting the full adjustment. Rather, the Company states it agrees to the Committee's adjustment without further discussion qualifying its agreement. This adjustment reduces total Company net power costs by $0.220 million and Utah revenue requirement by $0.097 million.

p. Remove Self-Supply Non-Owned Reserve

The Committee testifies there are many independent generators inside the Company's control area and the Company is required to provide reserves for some of these generators. In some cases, the generators do not pay the Company for such reserves because they are reflected in the contract prices for generation provided. However, the Committee argues, the Company includes the requirements for certain generators that self-supply reserves, and/or who do not pay the Company for any reserves when the above stated exceptions don't apply. In these cases, the Committee recommends the associated requirements should be removed from GRID because the generator doesn't require reserves from the Company and/or are not providing the Company compensation for the service. Correcting these inputs reduces total Company net power costs by $1.945 million.

The Company concurs with this correction and includes it in both its Alternative 1 and Alternative 2 net power cost analyses. However, in surrebuttal, the Committee contends the Company does not fully implement this adjustment. The adjustment includes both an eastern and a western control area component and the Company includes only the eastern control area component of the adjustment in its Alternatives 1 and 2. At hearing and in its post-hearing brief, the Company agrees to the Committee's full adjustment, including the adjustment to exclude self-supply generation n the West control area. We accept these undisputed corrections which reduce the Company's net power costs by $1.945 million and the Utah revenue requirement by $0.848 million.

q. Updated Forward Price Curve

In its rebuttal testimony, the Company proposes to update its "forward price curve" or "official price curves." The Company argues this is necessary in order to ensure symmetry in adjustments to net power costs. Further, update of the price projections will mitigate the problem of regulatory lag caused by the future test period adopted by the Commission in this case. The Company argues its forward price curve is used for various regulatory purposes and therefore has been subject to audit for many years. Finally, other jurisdictions allow updates to power costs for the forward price curve during pending cases without adverse results. This adjustment increases net power costs by $7.5 million.

The Committee opposes this adjustment for several reasons. First, the Company ignored other inputs that would reduce its cost, like shaping hydro to accompany the new price curve; second, in other jurisdictions where updating information is allowed, it is not optional at the Company's discretion but requires a separate GRID run for each new contract or major input so parties can evaluate the changes. In the present proceeding the Company has not even provided the actual value of this forward curve adjustment but instead couples it with other adjustments. The Committee rebuts the Company's contention new forward price curves can be used in other states because, for example, in Oregon, the process allows for parties to challenge adjustments by requesting a new procedural schedule. Further, procedurally this is another bite at the apple because the Company could have updated its case when it produced the 2008 test year and it should not be allowed to alter its case because its initial net power cost study was so flawed. Finally, the Committee asserts this adjustment is not minor.

In response to the Committee, the Company agrees in hearing and in its post-hearing brief, to shape hydro to the new price curve. The Company includes this additional adjustment in its Alternative 2 position.

We find the Company's proposed change to its forward price curve is untimely and not well supported. Changes by the Company to its own uncontested forecasts fairly late in the process are subject to a high standard of review. The regulatory "known and measurable" standard of review can not be readily applied to projections and forecasts. All projections must be evaluated for general reasonableness and also to ensure consistency with other inputs and assumptions and the appropriate matching of costs and revenues throughout the test period. We do not see such support in this record. In this case we do not even have a definition of what is meant by the "forward price curve." Nowhere is there a discussion of whether this includes natural gas and wholesale power prices or only wholesale power prices. Nor are the initial or proposed values provided in the record for any cursory reasonableness check. Further, the record indicates the Company is nearly 100 percent hedged with respect to natural gas prices and well hedged with respect to wholesale power prices but the connection between these hedges and the impact on net power costs from the Company's proposed change in its forward price curve remains unclear. For the foregoing reasons, we decline to accept this adjustment.

r. Wind Integration Expense

The Committee testifies the Company models wind integration expense two ways in GRID. First, it includes reserve requirements equal to 5 percent of on-line wind capacity for contingency (spinning) reserves. Second, it models an additional cost of $1.14 per megawatt hour, based on an analysis contained on page 193, of Appendix J, of the Company's 2007 Integrated Resource Plan ("IRP"). The first charge is to compute the inter-hour reserve requirement and the second charge is for intra-hour wind integration.

The Committee argues the Company has incorrectly applied the findings in the IRP to the calculation of wind integration cost in GRID. The Committee states the IRP additional reserve requirements are calculated for the Company's planned 2,000 megawatts of wind resource rather than the test period amount of wind resource which the Company states in rebuttal testimony is 1,200 megawatts. The Committee argues the average cost of wind integration depends upon the amount of installed wind capacity. As more wind resource is added into the Company's system, a new charge should be computed and applied to all wind resources. Applying the IRP method to the amount of wind resource included in the test period results in lower wind integration charges. In its surrebuttal testimony, the Committee calculates a wind integration charge of $0.22 per megawatt hour based upon applying the IRP method to the 1,200 megawatts of wind in the test period rather than the 2,000 megawatts planned for in the 2007 IRP. The Committee's adjustment reduces the Company's forecast of total Company wind integration cost by $1,242,997.

The Company argues the $1.14 per megawatt hour wind integration cost from Appendix J of the 2007 IRP was developed to support a 2,000 megawatt portfolio of resources and was not designed to be parsed out to individual projects. At hearing the Company maintains $1.14 per megawatt hour is a reasonable assumption because it is consistent with the IRP assumptions. In the absence of the 2007 IRP, the Company argues parties would likely look to a proxy such as the pending BPA tariff which is equivalent to approximately $2.82 per megawatt hour.

We recognize the Company has limited experience to date in forecasting integration costs as the Company adds greater amounts of wind resource to its system and therefore accept its wind integration charges in this case which are based on planning assumptions consistent with a portfolio view. We invite continued discussion and further proposals from interested parties on the best way to calculate, forecast and reflect in rates, the costs of wind integration.

s. Currant Creek Minimum Operating Level

UAE/Wal-mart testifies the GRID model constrains the Currant Creek facility's operation such that it does not operate below 340 megawatts with both units operating at 170 megawatts. This minimum run level is significantly higher than the minimum run level the Company represented to the Commission in the 2003 Currant Creek certification proceeding.[2] UAE/Wal-Mart contends when lower-cost generation is available, and the Currant Creek facility is otherwise running in the model, the operation of the plant is not reduced below 340 megawatts. Instead, the plant stays in operation at 340 megawatts, displacing lower-cost

[2]Docket No. 03-035-39 In the Matter of the Application of PacifiCorp for a Certificate of Convenience and Necessity Authorizing Construction of the Currant Creek Power Project

resources (often coal-fired generation) thereby increasing net power costs. UAE/Wal-Mart calculates the impact on net power costs of this modeling constraint reduces total Company net power costs by $4.58 million.

The Company disagrees with this adjustment and asserts that UAE/Wal-Mart has combined the minimum generation level of a one-by-one plant with the heat rate, size, capability for duct firing and other parameters that are only available with a two-by-one configuration. The reduction in net power costs shown by UAE/Wal-Mart arises from the mismatched configuration of the Currant Creek plant. While the Company agrees with UAE/Wal-Mart that the Currant Creek unit has the operational capability to operate in the one-by-one mode, the most cost effective mode of operating the unit is the two-by-one mode. Further, the Company maintains the one-by-one units have a higher heat rate than the unit running in the combined cycle mode.

The Company testifies GRID does not have the capability of simultaneously running the units in a one-by-one mode and then switching back to a two-by-one mode. When setting up both GRID and the Planning and Risk model used for integrated resource planning, the Company must choose between a two-by-one and one-by-one configuration and has chosen to model Currant Creek as a two-by-one facility in both models.

In evaluating this issue the Company found that the implementation of the commitment logic workaround in net power cost Alternative 2 position reduced UAE/Wal-Mart's proposed adjustment by 80 percent, to approximately $0.9 million**.** The Company, however, recommends the Commission reject this adjustment and continue to allow the units to be modeled in their lowest cost mode, which is two-by-one combined cycle mode.

For the purposes of this proceeding UAE/Wal-Mart accepts the Company's proposed workaround logic under Alternative 2 would address the Currant Creek minimum operating level. However, to the extent net power costs are calculated under Alternative 1, UAE/Wal-Mart continues to support its proposed adjustment.

In addressing the Currant Creek minimum generation issue we observe UAE/Wal-Mart does not refute the Company's assertion that UAE/Wal-Mart has combined the minimum generation level of a one-by-one plant with the heat rate, size, capability for duct firing and other parameters that are only available with a two-by-one configuration. Absent additional testimony or argument addressing the issue of the mismatched configuration relating to GRID modeling, we are persuaded by the Company's argument. We accept the Company's position on this issue in this case and await further discussion of this issue in the event the Company's commitment logic workaround fails to adequately address the problem in the future.

3. Labor Costs

The Company's forecast of total labor-related costs for the test period, the 12 months ending December 2008, is based on the actual labor-related costs for the 12 months ending June 2007, termed "the base year." Labor-related costs for the base year were $729.114 million. Of the labor-related costs, $194.069 million, or 26.6171 percent, were capitalized, and $535.045 million, or 73.3829 percent, were booked as expenses.

The Company's forecast of total labor-related costs in the test period is $738.872 million, representing an increase of $9.759 million over the base year. The total labor-related costs for the test period are capitalized and expensed based on the percentages which were incurred in the base year, i.e., 26.6171 percent are capitalized and 73.3829 percent are expensed.

Thus the labor-related costs in the test period consist of $196.666 million which are capitalized and $542.207 million which are expensed. This represents an increase in labor expenses only for the test period of $7.162 million relative to the base year.

This forecast of labor expense does not include an adjustment for the MEHC transition in which positions in the Company were eliminated and the affected-employees received a Change in Control ("CIC") severance payment. In its overall request for a revenue increase, however, the Company makes a separate adjustment which removes the severance payments and captures future labor savings resulting from the elimination of these positions.

The total of labor expenses for the test period is spread to the FERC accounts, and categories within these accounts, based on the relative amounts of actual labor expenses reported in these accounts and categories for the base year ending June 2007. The labor expenses are subsequently apportioned from the Company to its jurisdictions based on the test period interjurisdictional allocation factors associated with the categories within the FERC accounts. Overall, Utah is apportioned 42.7305 percent of the Company's labor expenses. Consequently, for the test period, the Company is seeking recovery from the Utah jurisdiction of $231.687 million in labor expenses.

The Division and Committee take issue with several aspects of the Company's forecast of labor-related costs for the test period. We next address their proposed labor-related adjustments.

a. Capitalization Rate

In this case the Company uses a 26.62 percent capitalization rate based on the results of operations for the twelve months ending June 2007. The Division proposes a capitalization rate of 28.08 percent based on the results of operation reported in the December 2007 Semi-Annual Report. The Division maintains this capitalization rate is closer in time to and more representative of the 2008 test period and therefore should be used in calculating test period labor expenses. This adjustment decreases the Company's test period forecast of Utah jurisdictional revenue requirement by $3.079 million.

At hearing, the Company argues the Division did not take into account the changes in labor expenses due to the MEHC transition as addressed in DPU Data Request 49.1.[3] Furthermore, the Company testifies if the MEHC transition savings are recognized, the December 2007 Semi-Annual Report supports a $4.5 million *increase* in labor expense rather than a decrease as proposed by the Division. The Division did not respond to the Company's rebuttal testimony presented at hearing. We are persuaded by the Company's testimony on this point and therefore accept its requested test period capitalization rate.

b. Overtime Pay

The Company proposes a 4.77 percent increase in overtime pay costs between the base year and test year. The Committee proposes a decrease in the Company's forecast of overtime pay based upon increasing the 2005 actual overtime pay by three percent annually

[3] Responding to the DPU data request 49.1 the Company identified an error in the data used in the Semi-Annual Report.

through 2008. The Committee's adjustment reduces overtime pay expense by $4.536 million and $1.939 million, for total Company and the Utah jurisdiction, respectively.

The Committee testifies the Company's forecast of overtime pay is greater in the test period than in calendar years 2006 and 2007, and the amounts of overtime pay in these years are approximately 20 percent higher than any of the previous three years, 2003 through 2005. The Committee cites the Company's response to CCS Data Request 9.12, in which the Company provides a comparison of 2005 to 2006 overtime and an explanation attributing the increase in overtime to unfilled budgeted positions, capital work and storms. In addition, the Committee notes the Company's response to CCS Data Request 9.12 makes reference to the "storm of the century" which occurred in December 2007. The Committee contends it would be inappropriate to assume the "storm of the century" will reoccur in the test period. Finally, the Committee argues the Company has furnished no evidence to rebut the assertion overtime was influenced by the storms, not a decrease in employees.

The Company indicates it has taken a number of steps to become more efficient and cost effective, including a restructuring plan that includes "significant staff reductions" which will result in "significant overall savings." The Company provides information showing 270 employees were displaced between March 21, 2006, and May 23, 2007, as a result of the MEHC transaction. In addition, the Company provides an exhibit showing the number of employees on a month by month basis from July 2006 through June 2007. With leaner staffing levels, the Company projects the need for more overtime than experienced in the past. IBEW Local 57 supports the Company's position on overtime pay and provides additional information on employee reductions and un-filled positions. IBEW Local 57 contends the Committee's adjustment entirely disregards storm activity and manpower reductions since 2005.

The Committee observes the proposed overtime pay has increased but fails to provide us with convincing evidence sufficient to support its adjustment. The Company provides information on employee reductions related to the MEHC transaction. IBEW Local 57, provides a convincing argument for supporting the Company's forecast of overtime pay. In addition to manpower reductions which necessitate increased overtime for an expanding utility system, we note annual outages resulting in employee overtime are the result of not only storms but also fires, flooding, animal interference, willful damage and other events beyond the Company's control – and a certain level of these events occur every year. Therefore, we accept the Company's test period forecast for overtime pay.

c. Merit Pay Increases

In forecasting the merit increases to salaries for exempt and non-exempt employees, the Company applies an increase from the prior period of 2.25 percent to the base period and 3.5 percent from the base period to the forecast test period. The Division proposes an adjustment to the annual increase for officers and exempt employees in the base period from the Company's proposed 2.25 percent to 1.67 percent. This is based on the Company's Rebuttal Exhibit 11.5.9, which indicates the average monthly pay of officers and exempt employees increased by only 1.67 percent for the base period. This reduces the Company's forecast of test period merit pay expenses by $0.238 million in the Utah jurisdiction.

The Committee proposes an overall 3.0 percent merit increase for the test period over the prior period based upon the Company-proposed union employee increase and the

Company's lack of testimony, studies, or documentation which would justify increasing the exempt and non-exempt employee compensation in the test period by 3.5 percent over the prior period. The Committee's adjustment reflects its concern that compensation practices relating to evaluation of jobs, and consequently of pay levels, are not being implemented as indicated by the Company. Absent any documentation or analysis specific to the Company's compensation program, the Committee contends there is no justification for the merit increases proposed by the Company. The Committee's adjustment reduces the Company's forecast of merit pay expenses by $0.659 million and $0.282 million, for total Company and the Utah jurisdiction, respectively.

The Company maintains the Division's adjustment was calculated by comparing the six months ending December 2006 to the six months ending June 2007. In the Company's view, it is more appropriate to compare the six months ending December 2006 to the corresponding six months ending December 2007. For the latter, the increase in merit pay is 2.16 percent, which is similar to the 2.25 percent the Company included in its forecast.

In an attempt to ensure its salaries are competitive, the Company emphasizes it relies on third-party surveys, especially compensation surveys by Mercer, Hewitt and Towers Perrin, keeps a significant number of surveys in hard copy form, and that it also uses a new on-line tool, Market_Pay.com. In response to the Committee's proposal to apply an overall 3 percent union increase during the test period, the Company maintains union and non-union compensation is arrived at in completely different ways. For example, market compensation for union employees is arrived at through collective bargaining whereas for non-union employees it is determined through market research.

Parties here do not argue the concept of a merit pay increase, rather whether the Company has sufficiently justified the amount of its proposed merit pay increase. We are concerned the Company is unable to provide to the parties easily accessible documentation of its specific job-title salary evaluations, including the date of the review, the sources of data used, and the results of the review. We consider these salary evaluations as the heart of the Company's compensation program. In this case, however, this lack of information is overcome by Company testimony showing its merit pay increase appears in line with the group of comparative companies provided by the Company. Therefore, we accept the Company's test period forecast for merit increase pay.

d. Incentive Pay

The Company's incentive compensation forecast is based upon 14.7 percent of exempt and non-exempt payroll. The Committee recommends a test year incentive compensation amount based upon 10 percent of exempt and non-exempt payroll. The Committee's adjustment reduces the Company's test period forecast of incentive pay expenses by $7.632 million and $3.366 million, for total Company and the Utah jurisdiction, respectively. The Committee contends the target goals of the Company's incentive program are questionable and the target percentage for each employee is excessive. Furthermore, the Company has not justified the requested level of spending. According to the Committee, incentive compensation is supposedly compensation at risk. However, the Company has indicated the target incentive level, as set by the competitive market, will be achieved on an annual basis and therefore paid at that level. The Committee provides testimony showing the incentive percentages for individual job positions have ranged from a low of 4 percent to a high of 75 percent, with a majority of incentive rates in the 10 to 15 percent range. In the Committee's view, compensation which is referred to as incentive compensation is not truly incentive compensation if it does not require employees to perform at levels over and above those which have been previously achieved.

The Company explains the base salary and incentive compensation are integral parts of the Company's total compensation package, and it is the total which is geared toward the market average for the employees' duties and experience. In addition, in order to encourage superior performance, the Company believes a certain percentage of the market-based compensation must be at risk. In the incentive program each employee is judged against specific goals designed to motivate employees to improve safety, reliability and customer service. Specifically, 70 percent of the incentive compensation is based upon goals unique to the employee, with the remaining 30 percent based upon an employee's performance with respect to six behavioral factors. When an employee performs at the expected levels, the employee receives the base pay plus the target incentive. The Company indicates there is a separate plan for Company executives based upon financial results and the expenses associated with that plan are not included in the Company's filing.

We make no judgment regarding the effectiveness of the Company's incentive program, but instead we are persuaded the total compensation, including both base pay and incentive compensation, is reasonably targeted to the market average of total compensation. We conclude the elements of the incentive compensation program, for which the Company seeks recovery from ratepayers, are not related to financial goals. Therefore, we accept the Company's test period forecast for incentive pay.

e. Pensions and PBOPs

In estimating the costs of the 2008 pensions and post-retirement benefits other than pensions ("PBOP") plans for the test period, the Committee raises two issues with respect to the Company's forecasts of these expenses. First, the Committee observes the Company modified some of the actuarial assumptions from those used in prior years. The Committee recommends the test period pension and PBOP costs be revised to reflect the effect of the actual experience of the plans in 2007. The Committee cites the Company responses to Committee Data Requests 22.2 and 22.3, in which the Company indicates the pension and PBOP plan asset experiences during 2007 were more favorable than what was incorporated in the actuarial assumptions used in the Company's test period forecast. The Committee proposes using these revised assumptions which result in $1.1 million and $0.7 million reductions in the projected 2008 pension and PBOP costs on a total Company basis, respectively. The Committee contends these are known and measurable changes based on actual 2007 experience. This adjustment reduces the Company's test period forecast of these costs by $1.8 million on a total Company basis.

Second, the Committee recommends revising the Company's actuarial assumptions used in deriving the 2008 estimated costs for pension and PBOP plans by increasing the projected long term rate of return on plan assets for the pension and PBOP plans by 25 basis points. This would align actuarial assumptions used in this case with the information reported in the Company's 2007 U.S. Securities and Exchange Commission Form 10-K (SEC Annual Report). The Committee states the expected long term rate of return used by the Company in this case is much lower than the average assumptions for other U.S. entities identified in an annual survey conducted by Deloitte Consulting.[4] This adjustment reduces the Company's forecast of test period costs by approximately $3 million on a total Company basis. The net impact of both adjustments reduces the Company's forecast of Utah jurisdictional pension and PBOP expenses by $1.5 million.

It has been many years since we have addressed matters associated with pensions and PBOP plans. In our evaluation of these issue we recognize the complicated interrelationships associated with the accounting treatment of pension and PBOP funding. The Committee provides testimony regarding the actual pension and PBOP plans' experiences in 2007 only. In light of the uncertainty of economic conditions which influenced our selection of the test year in this case, we find the Company's proposed pension and PBOP forecasts reasonable in recognition of the current low interest rates and market downturn, both of which may have an effect on this expense. While pension contributions for the Company are variable by law it is our expectation that the Company will attempt to reduce the current pension and PBOP underfunding to the maximum extent practical in accordance with the Pension Protection Act of 2006.

As stated above, the Company uses different actuarial assumptions in this case and in its SEC Annual Report for the expected long term rate of return on plan assets for both the pension and PBOP plans. The Committee testifies the expected long term return on plan assets is based on projected long term returns on the assets as opposed to assumptions regarding potential returns at one point in time.

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[4] "2007 Survey of Economic Assumptions Used for FAS No., 87, 106, 132, 158 and Related Measurements"

We note the costs of pension and PBOP plans have dramatically decreased in this case and we recognize the pension and PBOP benefit obligation and net benefit cost determinations rely on, among other actuarial assumptions, estimates of the discount rate, rate of compensation increase, and expected return on plan assets. In this case we view the long term return on plan assets as solely an estimate and we are not convinced that in our determination of the revenue requirement associated with just and reasonable rates in this case, the Committee's proposed 8 percent long term rate of return on plan assets for the pension and PBOP plans is correct to the exclusion of the Company's position. We accept the Company's test period forecast of pension and PBOP expenses in this case.

f. Pension Administration

The Committee proposes an adjustment to the expenses of administering the Company's pension plan, asserting the Company failed to justify the expense increase. In response to a data request, the Company simply stated these administrative expenses are paid to Hewitt and Associates ("Hewitt") and no other explanation was given. The Committee's adjustment is based upon a three year average of these expenses. This adjustment reduces the Company's test period forecast of pension administration expense by $0.299 million and $0.128 million, for total Company and the Utah jurisdiction, respectively.

In surrebuttal, the Company testifies that the increase in pension administration expense is related to three factors, and disagrees with the Committee's attempts to tie the 2008 expense increase to plan design changes made in 2007. First, the recently enacted Pension Protection Act mandated certain administrative changes to the Company's plan, the implementation of which will result in administrative expenses. Second, the Company will be offering a choice to those employees currently covered by a cash balance plan. Employees will either be allowed to stay in the cash balance plan or move entirely into a defined contribution (401k) plan. While this change will reduce pension expenses in the long run, the change does involve certain initial administrative expenses. Third, the Company is anticipating significant union negotiations in 2008 in which changes to the Company's medical and retirement plan offerings will be addressed. These changes should reduce both the level and volatility of such expenses, but cannot be achieved without some up-front administrative costs.

In response to the Company's rebuttal testimony, the Committee contends pension revisions have occurred in the past and may occur in the future and the costs associated with such changes could fluctuate from year to year, further supporting the Committee's recommendation to base these expenses upon an average over a period of time.

As the Company's pension plan continues to undergo substantial change both by choice, in order to reduce pension expenses in the long run, and by law, we are persuaded by the Company's testimony and accept its test period forecast of pension administration expenses in this case.

g. Medical Costs

In its supplemental filing, the Company proposes a 2008 test period medical cost of $51.062 million. The Division observes the Company's forecasted test period medical cost represents an increase of $6.519 million over the annualized June 2007 level of $44.543 million. This, the Division claims, represents an increase of 14.6% for the 18 month forecast period or

9.8% annually.[5] The Division's proposed medical plan cost is $47.925 million, which it maintains represents a 7.6 percent increase for the eighteen month forecast or 5.06 percent annually. This adjustment reduces the Company's forecast of test period medical costs by $0.984 million for the Utah jurisdiction. The Committee proposes the Company's medical cost request should be reduced by $7.661 million to $43.301 million, representing a 2.6 percent decrease for the eighteen month forecast. This adjustment reduces the Company's forecast of test period medical costs by $5.622 million and $2.403 million, on a total Company and Utah basis, respectively.

The Company indicates for fiscal year 2005 and calendar years 2006 and 2007, budgeted health care costs totaled $41.5 million, $49.9 million and $60.8 million, respectively. Hewitt, the Company's health care advisor, has informed the Company current trends indicate the costs for the Company's medical plans are anticipated to increase by between 8 and 12 percent in 2008.

The Division relies on the Towers Perrin 2008 Health Care Cost Survey ("Towers Perrin Survey") which states health care costs for U.S. employers are expected to increase by 6 percent in 2008 and high performing companies should expect increases of 5 percent or less. The Company contends the Towers Perrin Survey is not helpful for the Company in forecasting medical costs. In reviewing the Towers Perrin Survey, the Company identifies only two

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[5] Letting V_1 be the value of medical costs for the 12 months ending June 2007, and V_2 the value of medical costs for the 12 months ending December 2008, the inflation rate "i" is obtained as the solution to $V_1 * (1 + 1/2*i)*(1 + i) = V_2$

comparably-sized electric utilities among the participating companies, notes the Towers Perrin Survey is geographically-based, and contends the Towers Perrin Survey does not address the demographic challenges facing the Company's industry. The Company states the range and rate of increases proposed by Hewitt is based on information specific to the Company, including demographics regarding the Company's employees, claims experience, and market conditions. The Company contends Hewitt uses this information in combination with its own data to forecast medical costs specific to the Company resulting in a significantly more accurate forecast.

The Division disagrees with the Company's assessment of the Towers Perrin Survey. A total of 500 employers, with operations in numerous locations nationwide, responded to the survey. Only one-half of the employers participating in the survey are identified, so more than two comparably-sized electric utilities may be included. With respect to the aging utility workforce, the Towers Perrin Survey provides expected increases in medical costs for active employees, retirees under the age of 65, and retirees over the age of 65. The expected increase for all three groups is 6 percent. The Division contends the Towers Perrin Survey is a reasonable standard for calculating medical cost increases, and if the average increase for companies is 5 percent, a regulated utility should be held to that standard for purposes of projecting a forecasted test period. The Division also presents as evidence a report from Hewitt's website which indicates Hewitt is projecting an 8.7 percent average increase in medical costs for employers in 2008. Hewitt indicates the softening of rate increases is due to employers passing on a significant percentage of costs to employees.

The Committee contends the Company's forecast for 2008 was developed along with the forecast for 2007. By way of comparison, the Committee highlights the inadequacy of the 2007 forecast. The actual medical costs for 2007 were $45.626 million, significantly less than the Company's forecasted costs in 2007 of $53.287 million.

The Company disagrees with the Committee's proposed adjustment, indicating the Company's proposed medical costs are based upon a forecast for the calendar year 2008, whereas the Committee bases its adjustment on the difference in the original forecast and actual results for the calendar year 2007. The Company states the 2007 numbers were never used in this case, since the Company prepared its case after it had more information. If the 2008 forecast is to be evaluated, the Company proposes the forecast should be compared to 2008 actual information. Based on the first four months of 2008, annualized medical cost would be $53.135 million, an increase of $2 million more than the Company's requested amount.

We recognize predicting health care costs is a difficult undertaking. We are not convinced, however, that Hewitt's estimate for PacifiCorp's medical costs on which the Company has historically relied is superior to those estimates provided in the Towers Perrin Survey or Hewitt's website report. The Company has testified it budgeted $60 million for health care costs in 2007. Yet the Committee provided testimony, based upon the Company's response to a data request, that the actual amount spent on medical costs in 2007 was only $45.626 million. While the Company identifies only two electric utilities as having participated in the Towers Perrin survey, we can identify other participating major oil, gas, and construction companies which most likely face similar demographic issues and work environment issues as does the Company.

We find reasonable an increase in medical costs based on an average of the Hewitt general report, 8.7 percent, and the Tower's Perrin Survey, 6 percent. This provides an annual increase of 7.35 percent, or 11.025 percent for 18 months. Increasing the actual medical costs for the 12 months ending June 2007 by 11.025 results in a value for test period medical costs of $49.454 million. Our decision reduces the Company's test period forecast of medical costs by $1.608 million, total Company expenses by $1.180 million, and Utah revenue requirement by $0.514 million.

h. Other Salary Overhead

The Committee proposes an adjustment to the Company's test period forecast of Other Salary Overhead costs based on the Company's failure to explain the forecasted increase. The Committee observes the Other Salary Overhead costs in year ending March 31, 2005, year ending March 31, 2006, the base year, and the test period were $0.18 million, $1.3 million, $1.0 million, and $1.7 million, respectively. In response to why these costs increased by $0.7 million between the base period and the test period, the Company stated the mid-period [6] adjustment was necessary to adjust the base period actual to the mid-period forecast amount. The Committee proposes a two year average of costs for the years ending March 31, 2006, and June 30, 2007. This adjustment reduces the Company's test period forecast of Other Salary Overhead costs allocated to Utah by $0.487 million.

The Company opposes the Committee's adjustment. First, the Company testifies it recently implemented a random drug and alcohol policy whereby a defined percentage of the

[6] In the December 27, 2007, Application and Direct Testimony, the Company identified the "Mid Period" as the twelve months ending June 30, 2008.

its employees will be tested at random on an annual basis. This policy was initiated to improve the overall safety of employees, the business, and the Company's customers. Second, with the aging work-force in mind, the Company is working more closely to evaluate and determine the "fitness-for-duty" of its workforce. As a result, fitness-for-duty examinations have become more detailed and thus more costly. Third, the Company has made changes to the annual benefits open enrollment program and as a result the open enrollment process continues to increase in complexity and importance. Better processing through this effort improves overall selection and utilization of the plan per employee.

While the Company's reasons for the costs increase may ultimately benefit customers, the Company's rebuttal testimony lacks specificity to substantiate its proposed increase in Other Salary Overhead costs. For instance, we note the Company already administers a random drug and alcohol testing program for those employees subject to certain U.S. Department of Transportation regulations. The Company has not provided a description of the employee group subject to this new program, the testing rate, and the projected cost of this program. Regarding fitness-for-duty, the Company provides no information whether such examinations are required by law or are part of an employee health program, how many examinations will be conducted, and the estimated costs of these examinations. Finally, the Company has provided no information regarding what costs are associated with the annual benefits enrollment and how these are different from preceding cases. Therefore, we accept the Committee's adjustment on this issue. This adjustment reduces the Company's test period forecast of Other Salary Overhead costs by \$0.487 million, total Company expenses by \$0.357 million, and Utah revenue requirement by \$0.156 million.

i. Productivity

The Division proposes a one percent per year, or 1.5 percent over the 18 months between the base period and the test period, productivity adjustment to payroll costs based upon information from the U.S. Bureau of Labor Statistics ("BLS"). The Division estimates this adjustment reduces payroll expenses by $5.624 million and $2.404 million, on a total Company and Utah basis, respectively. While the Company proposes incremental increases to specific components of payroll costs, the Company did not include offsetting effects of increased productivity. The Division contends labor productivity must be recognized in order to provide an accurate projection of labor costs in a future test period. The Division states one percent is a modest productivity adjustment and provides testimony that in recent years, productivity for the electric utility sector has been increasing and has outperformed the general business sector productivity growth. This adjustment reduces the Company's test period forecast of labor costs allocated to Utah by approximately $2.404 million.

The Company argues the Division's proposal to reduce labor costs by the BLS productivity estimate is an arbitrary adjustment that has no relevance in this case. In addition, the Company states it has already included increased productivity in its cost structure. The Company's proposed labor costs reflect a significant decrease in personnel through the MEHC CIC adjustment and the automated meter reading adjustment. Moreover the Company's proposed labor costs assume no increased manpower except for new generation plants brought online, even as the Company is experiencing load growth. The Company concludes the Division's adjustment would far overstate any increases in productivity beyond what reasonably could be expected.

The Company testifies it is able to hold labor costs down through the CIC adjustment and the automated meter reading adjustment. The Division argues that the CIC adjustment reflects past actions whereas productivity is forward-looking. The Company also testifies it strives on a regular basis to make improvements and it anticipates there would be labor improvements into the future.

We concur with the Division a forecast test period, unlike an historic test period, must take labor productivity increases and other efficiency gains into account in the determination of the revenue requirement. In this case we acknowledge the Company's automated meter reading program will increase productivity in the test period. In this docket, we make no further adjustment for productivity beyond what is incorporated by the Company's projections. Further, it is our expectation the Company will continue to look for ways to increase productivity and efficiency in the future..

4. Other Expense Adjustments

a. Relocation Expense

The Committee proposes a reduction to the Company's test period relocation expense based upon a five year average of actual relocation expenses resulting in a decrease in test period relocation expense of $0.473 million and $0.219 million, on a total Company and Utah basis, respectively. The Committee observes the Company's forecast for the base year ending June 2007 exceeds the 2007 calendar year costs as well as those of the previous four years. The Committee contends the Company's forecast ignores changes occurring in the base year due to the MEHC transition. In addition, the Company provides no supporting documentation showing the extent to which the base year was affected by relocations associated with the transition.

In order to attract and maintain a skilled workforce, the Company asserts its relocation program must be competitive with the relocation programs of the companies with whom the Company is competing for employees. To ensure the relocation program is competitive, it is reviewed annually and administered by a third-party organization which specializes in administration and plan design. The Company attributes the increased costs of this program to many things including changes in the economy, housing and other local market issue as well as a shortage of employees with required skill sets. In addition, the downturn in the housing market has had a very significant role in increasing the costs of relocating employees. The Company testifies it has made substantial changes to its relocation program in an effort to control costs such as reducing food allowances, rental storage, and transportation benefits but does not believe it is prudent to further reduce the program benefits.

The Company fails to provide persuasive testimony to refute the Committee's adjustment. The Company does not provide estimates of the cost per move, the number of moves, or other specific evidence of cost increases. Nor does the Company address the issue of the affect of the MEHC transition on relocation expenses. The generalities provided by the Company do not adequately support its case. We find the Committee's adjustment reasonable. This adjustment reduces total Company expenses by $0.473 million and Utah revenue requirement by $0.204 million.

b. Injuries and Damages

In direct testimony the Committee proposes a reduction to the Company's test period injuries and damage expense based upon a three year average of actual claims made against the Company. This adjustment reduces the Company's test period forecast of total Company injuries and damage expense by $3.819 million. The Committee testifies the injuries and damage expense in the base year was high when compared to the previous two historical periods and that the driving force for the increase in the base year expense was essentially the re-establishment of the reserve account balance, not the actual claims for injuries and damages made against the Company.

In rebuttal testimony, the Company indicates it sees merit in using an average to set the projected level of injuries and damages expenses. However, rather than basing it on cash expenses, the Company proposes an adjustment based upon a three year average of booked accruals. The Company's adjustment reduces the total Company forecast of injuries and damages expense by $3.866 million. The Company's decrease is slightly larger than the Committee's decrease. The Company explains when an incident occurs, monetary payment of damages may not occur for years. In addition, the statute of limitations governing how long a claimant has to present a claim varies from one to six years depending upon the state and the type of damage or injury. Once a claim is presented, an analysis is made by a reserve committee to determine what the accrual should be. The Company testifies that establishing an accrual and maintaining a reserve is governed by FAS 5 accounting rules and Sarbanes-Oxley legislation.

We recognize that establishing an accrual and maintaining a reserve are governed by accounting standards and Sarbanes-Oxley legislation. However, due to the uncertain nature of, and difficulty in, predicting this type of expense we conclude the Committee's proposal to use an average of historical expenses is more appropriate for utility rate making. This is supported by testimony that an actual expense may lag a claim by six or more years. The Committee's proposal will ensure timely recovery of this type of expense for the Company, provide simplicity in determining the forecast and is consistent with averaging already undertaken for other accounts. While we view a five-year average acceptable for this type of account, neither party provides testimony specific to the appropriate time frame. Without such testimony we defer to the Committee's position to use a three year average and accept the Committee's adjustment. This adjustment, relative to the Company's rebuttal position, increases total Company expenses by $0.048 million and Utah revenue requirement by $0.020 million.

c. Property Taxes

The Division proposes a test period property tax expense of $79.67 million, an amount the Company accepts in its rebuttal testimony. The Committee proposes a property tax expense of $70.7 million based upon the Company's 2007 actual property tax expense escalated by 2.36 percent, the actual percentage increase experience by PacifiCorp in 2007. Over the past five years, the Committee testifies, the total amount of property tax expense incurred by the Company has fluctuated annually, ranging from a decline of 3.07 percent to an increase of 3.95 percent, this during a period of rapid investment and significant increases in net plant in service. The Committee contends there is no reason to now assume the annual increase in property tax expense will suddenly jump 15 percent as projected by the Company. The Committee provides evidence showing Company projections have proven to be inaccurate in the past several rate case proceedings. The Committee emphasizes it is important not only to consider the percentage increase in property subject to assessment and net operating earnings, but also to consider what property tax expense has actually been incurred.

While the Company's projected increase in property tax expense is significant, the Company argues the increase is driven by a correspondingly significant increase in the level of property subject to assessment and in the level of Company earnings that taxing jurisdictions rely upon when estimating the value of the Company's property. The Company further contends previous tax amounts were influenced by multiple factors such as unanticipated changes in property tax rates and legislative activity; the Committee's proposed adjustment necessarily assumes those same factors will impact 2008 tax expense to an equivalent degree. In addition, the level of net operating income significantly affects the value assigned to the Company's assets and the Committee fails to recognize this. Finally, the Company testifies six million dollars in property tax paid to taxing authorities during the 2005 to 2007 period were recorded as an increase in the capitalized cost of the Company's Lake Side and Currant Creek generating plants. Now taxes associated with those projects will be charged to property tax expense.

We find the Company's proposal for a 15 percent increase in property tax unsubstantiated. We recognize the Company has recently increased its plant in service by over $900 million, but we note some of these investments, such as those related to the installation of pollution control equipment, could be subject to either property tax exemptions or special taxing situations.

We find persuasive the Committee's argument regarding property tax increases but we also take into consideration the Company's testimony regarding $6 million in property tax paid to taxing authorities during the 2005 to 2007 period for Lake Side and Currant Creek facilities which were capitalized [7] and not included in the Committee's assessment. Some of the assessments for Lake Side and Currant Creek during those years may not have reflected the full value of the plants. Therefore, we find it reasonable to include an amount of taxes capitalized in 2007 in the estimation of property tax expense and increase the Committee's total recommended property tax expense of $70.736 million. Our decision reduces total Company property tax expense by $6.929 million and Utah revenue requirement by $2.988 million.

d. Non-labor O&M Escalation Rate

In developing its test year non-labor O&M expenses excluding net power costs, the Company starts with the actual expenses for the 12 months ending June 30, 2007, the base period, which are then split into labor and non-labor components. Known and measurable adjustments are made to the base period non-labor O&M expenses, then utility inflation indices prepared by Global Insight are used to escalate non-labor O&M expenses other than net power costs to December 2008. Finally, additional adjustments are made to construct the normalized test year levels of non-labor O&M expenses other than net power costs.

The Committee recommends the utility inflation indices used by the Company, ranging from 1.3 percent to 5.7 percent depending on the specific FERC account, be replaced with an escalation rate of 1.25 percent for all of the accounts. The 1.25 percent escalation rate is one-half the 2.5 percent non-labor inflation rate used by the Company in constructing its 2007 budget. The Committee states in confidential testimony the Company's budget and projections

[7] In response to CCS Data Request 32.3 the Company indicated that $1.6 million, $2.4 million, and $2.0 million of property taxes were capitalized in 2005, 2006, and 2007, respectively.

beyond 2007 support lower non-labor O&M escalation rates. The Committee also notes the non-labor O&M expenses in the Company's finalized and approved 2008 budget declined from the expenses in the 2007 budget used by the Company in preparing its rate case. The Committee claims its 1.25 percent escalation rate, rather than Global Insight's inflation indices, is likely to be more reflective of the inflation pressures facing the Company in going from the base year to the test year.

The Company states its test year total O&M expenses, including labor and based on its escalation of non-labor, are $2 million less than the actual amounts in the base year. This reduction is due to Company initiatives to reduce cost in the face of inflationary pressures. In part, such efficiencies are reflected separately in the Company's MEHC transition and automated meter reading adjustments.

We are persuaded by the Company's arguments. In this case, we find use of the Global Insight inflation forecasts is appropriate and provide the Company adequate incentive to manage their non-labor O&M costs (other than net power costs). We therefore accept the Company's test year forecast of non-labor O&M expense.

e. Generation Overhaul

In its direct testimony, the Company calculates generation overhaul expense beginning with the actual costs incurred for the 12 months ending June 2007, the base year, equal to $40.08 million. It then applies its proposed non-labor O&M escalation rates to this base year expense, obtaining a value of $41.44 million for the 12 months ending December 2008.

In its direct testimony, the Committee compares the base year expense to actual historical experience and concludes the expense in the base year is not reflective of a normal, ongoing expense level. To obtain a normal level of expense, the Committee uses an average of the actual costs incurred in fiscal years 2004 and 2005 and calendar years 2006 and 2007, which equals $28.23 million. The Committee states additional overhaul expenses associated with the Currant Creek and Lake Side generating plants are included in its net power cost adjustments. The Committee notes the Company's budgeted 2008 expense is $27.687 million, an amount less than the Committee's proposed expense, and states this alleviates any concerns regarding potential under recovery of this expense.

In its rebuttal testimony, the Company agrees with the Committee to use a four-year average since averaging smooths out annual variations and the GRID model uses a four-year average of planned outages to determine net power costs. The Company identifies overhaul expense for the calendar years 2004 through 2007, escalates the expense of each year to the test period to account for inflation, then calculates a four-year average of the escalated amounts, resulting in $31.04 million. To this average expense is added an average over the calendar years 2008 through 2011 of the budgeted overhaul expenses for the Currant Creek and Lake Side generating plants, or $4.53 million (less $0.65 million for the Lake Side plant contained in its Incremental Generation O&M adjustment). Thus the Company proposes $34.92 million for overhaul expense, which is a reduction of $6.52 million from the amount contained in its supplemental direct filing.

In its surrebuttal testimony, the Committee agrees to use an average of expenses over the calendar years 2004 through 2007. However, the Committee opposes the escalation of historical expenses to account for inflation and opposes the inclusion of the future expected expenses associated with the Currant Creek and Lake Side generating plants. Thus the

Committee proposes $28.96 million for overhaul expense, which is a reduction of $12.48 million from the amount contained in the Company's supplemental direct filing.

Since the Committee accepts $0.65 million of additional expenses for the Lake Side plant in a separate Company adjustment, the Committee proposes a total of $29.6 million of overhaul expense be included in the test year. This is nearly $2 million higher than the Company's 2008 budgeted expense of $27.687 million, and in its view is more than adequate. The Committee argues the Company proposal is $7.2 million greater than the amount budgeted for the test year, and is not representative of an on-going level. In addition, the Committee argues more weight should be given to the 2008 budgeted expense since the Company has notified the Commission it intends to immediately file another rate case. In response, the Company states its escalated and forecast average should be used, regardless of the level included in the budget for the test year.

We accept the Committee's adjustment, in part. First, in our recollection, this is the first time escalation within averaging has been proposed. We are not persuaded this is an appropriate approach and are concerned, if accepted here, such a practice would be extended to other cost items, by both PacifiCorp and Questar Gas Company. The basis for using averages of actual costs is because booked amounts vary from year to year, and the costs in any one year are not considered normal. In the next case, following the precedent established here, the Company will assert this year's actual expense, considered in this case to be abnormal, can be escalated to obtain a reasonable level of expense for the next year. This seems to defeat the purpose of constructing an average, which is to smooth out the year-to-year abnormalities. Escalation in the

Company's approach serves merely to inflate the average, and the average is already higher than the budget.

However, we also accept there is little to no history of overhaul activity available for the Currant Creek and the Lake Side generating plants. Further, overhaul costs are not included in the four-year history used by the Committee nor included in the Company's rebuttal adjustment. Therefore, we accept the Company's rebuttal proposal with respect to overhaul costs for the Currant Creek and Lake Side generating plants. By accepting the Committee's proposal to use a four-year average of actual rather than escalated costs, and the Company's proposal to include a test period amount for Currant Creek and Lake Side generating plants which is based on the four year average of its budgeted amounts for 2008 to 2011, we approve an amount for generation overhaul in the test period of $32.8 million. Our decision reduces total Company expenses by $8.610 million and Utah revenue requirement by $3.733 million.

f. Powerdale Decommissioning

On November 6, 2006, a flood and debris flow on the Hood River severely damaged the Company's Powerdale Plant. The Company decided it was more economic to retire rather than repair and operate the plant prior to its scheduled decommissioning date of April 1, 2010. On March 22, 2007, the Company filed an application in Docket No. 07-035-14 requesting an order permitting transfer of the undepreciated plant investment to other accounts, authorizing the creation of a regulatory asset for estimated decommissioning expenses and designating an amortization period. On January 3, 2008, the Commission issued an order in Docket No. 07-035-14 approving deferred accounting treatment for Powerdale decommissioning and deferred the specific issues regarding cost recovery to a future general rate case. However, the Commission did set a tentative amortization period of three years beginning January 1, 2007.

The Commission's order approving the accounting treatment for Powerdale decommissioning was issued after the Company had filed its direct testimony but before the Company filed its supplemental direct testimony in this case. Partly in response to the direct testimony of the Committee, and in response to the Commission order, the Company proposes in its rebuttal testimony to amortize the decommissioning costs over a three-year period, beginning on January 1, 2008, and agrees to exclude the regulatory asset from rate base. The Committee contends the Company's supplemental direct testimony reflects a five-year amortization period and that its change in position to the proposed three-year period is not in rebuttal to any party's recommendations but is rather a change in position. Further the Committee contends the Company provides no testimony on why a three-year period would be superior to a five-year period.

The Committee recommends the amortization not be included in this case, but instead be deferred until and commence with the decommissioning of the plant, since at that time the costs will be incurred and known. Alternatively, if the Commission accepts the Company's proposal to begin amortization in this case, the Committee recommends rate base be offset by the average balance collected from customers, or one-half the annual amortization expense for this test year, to recognize the funds being pre-collected from ratepayers.

We find the Company's rebuttal proposal better matches benefits and costs than does the Committee's basic proposal. It is more appropriate for customers who benefitted from the use of the plant, rather than future customers, to pay for the costs of decommissioning the plant. Also, since our order approving deferred accounting treatment was issued in January 2008, we accept the Company's rebuttal proposal to amortize decommissioning costs over three years beginning January 1, 2008. The Company's rebuttal proposal is reflected in its $74.5 million revenue request.

g. Office Reconfiguration

The Division proposes an adjustment to the Company's office reconfiguration expense based upon averaging 27 months of data. This adjustment decreases the Utah revenue requirement by $0.120 million. Generally speaking, the Division agrees reconfiguration and consolidation costs are ongoing expenses, but contends the Company's proposed moving/relocation expenses are at an abnormal level. In support of its position, the Division provides DPU Exhibit 7.1SR showing data from February 2006 through May 2008 for the total moving/relocation expenses with and without transactions labeled "MEHC transaction."

At hearing the Company proposed to take those costs labeled "MEHC Transaction" and amortize them over a three year period. The Company contends these costs were erroneously recorded as MEHC transaction costs, however they are actually the result of Company initiatives to reduce lease expenses, and are part of the ongoing expenses of the Company. The Company believes these expenses are significant enough to deserve recovery but not significant enough to file for a deferred accounting order. In response to cross examination, the Company agrees its options in the beginning of the case to recover these expenses were to either identify them and ask for a deferred accounting order for future treatment or identify them as abnormal and request amortization.

We agree moving and relocation costs are an ongoing expense faced by the Company and note the Company had ample opportunity to challenge the Division's proposal prior to hearing or to seek alternative rate treatment for this expense prior to or during this case. It did not do so. We find persuasive the Division's testimony, as provided in DPU Exhibit 7.1., and accept the Division's adjustment reducing Utah revenue requirement by $0.120 million.

h. Cash Working Capital

The Division and Committee testify the Company's current lead/lag study was conducted utilizing information for the 12 months ending March 31, 2003, with a few exceptions, and is no longer reflective of current circumstances.

The Division argues cash working capital is not a hard asset like a plant and therefore the Division recommends a high standard of proof exists before this asset should be allowed in rate base. This high standard of proof will avoid the incentive for the Company to turn its cash management center into a profit center. The Division argues this high standard of proof was not met in this case and can only be met with the use of a current lead/lag study. Because of the age of the study, it can not be relied upon to determine the proper leads and lags necessary to set a cash working capital allowance. The Company only provides a summary of the study and the underlying data can not be reviewed by any party. Therefore, an auditor can not test the validity or reliability of the calculations or conclusions reached in the study. The Division testifies the Company has failed to meet its burden to show the amount of cash working capital needed and recommends the Commission set that level at zero until a new study is submitted in the next rate case and a review by all parties can take place of the underlying data to determine the appropriate amount of cash working capital to include in rate base. The Division's proposed adjustment reduces the Company's test period forecast allocated to Utah by $3.5 million.

The Committee recommends the Commission order the Company to file a new lead/lag study in its next rate case. Absent an updated study, the Company should not be allowed a cash working capital component in rate base in its next rate case. The Committee supports its recommendation by citing recent changes in the structure, organization and operations of the Company.

The Committee also recommends interest expense on long term debt be included in the calculation of cash working capital. The Company receives revenues from its customers prior to the time it is required to pay the interest on its long term debt. This cash is available to fund the Company's day-to-day operations, and therefore this cash should be recognized in the calculation of cash working capital. The Committee states interest expense is typically a component in utility lead/lag studies and cash working capital calculations in other jurisdictions. The Committee's adjustment reduces the Company's test period forecast by $1.8 million.

The Company cites the decision regarding cash working capital in a general rate case for Mountain Fuel Supply Company (now Questar Gas Company) in support of the Company's position to exclude interest expense. This decision appears in the Report and Order issued January 10, 1994, in Docket No. 93-057-01. In that case, the Committee argued interest expenses and preferred dividends be included in the calculation of cash working capital, using the same rationale as that presented in this case. In its 1994 order, the Commission reaffirmed its long standing policy of excluding from cash working capital: (1) depreciation, (2) interest expense, (3) preferred dividends, and (4) common dividends. We affirm here the conclusion reached then. "If this method is to be changed, a strong burden of persuasion will first have to be met which must include a comprehensive analysis of all four of the above-mentioned items." Hence we do not accept the Committee's proposal to include interest expense.

We are concerned by the use of such an outdated, unsupported study and will consider appropriate adjustments in the next general rate case in which such a study is used by the Company. We agree with the Division and the Committee regarding the need to update the Company's cash working capital study for use in the Company's next general rate case. At that time, and in the context of a comprehensive analysis, issues such as interest expense may be addressed. For this case, we accept the Company's test period forecast for cash working capital.

i. Regulatory Fees

Roger Ball recommends the Commission exclude the Utah public utility regulatory expense of $3.483 million from the Company's revenue requirement. This adjustment reduces the Utah jurisdiction revenue requirement by approximately $3.57 million. Mr. Ball argues this is not an appropriate expense to be passed on to ratepayers as a large portion of the expense is spent to ratepayer detriment when the Company argues for increased rates. Mr. Ball, referencing Utah Code 54-5-1.5(4)(a),[8] states the Utah Legislature has imposed all costs of regulating the Company upon the Company. Mr. Ball argues that even though Utah utilities' rates have been set based upon revenue requirements including regulatory costs for several

[8] UCA 54-5-1.5(4)(a) It is the intent of the Legislature that the public utilities provide all of the funds for the administration, support, and maintenance of: (i) The Public Service Commission; (ii) state agencies within the Department of Commerce involved in the regulation of public utilities; and (iii) expenditure by the attorney general for utility regulation.

years, it is illegal, and the Commission will act 'ultra vires' if it chooses to do so in this proceeding.

We disagree with Mr. Ball's interpretation of Utah Code 54-5-1.5(4)(a) and accept the Company's forecast of regulatory fees. We find regulatory fees are appropriate expenses to be included in determining the revenue requirement in this and other general rate cases.

j. Leaning Juniper Operating and Maintenance Expense

The Committee proposes a reduction to the Company's proposed O&M expenses to remove 25 percent of costs associated with the two-year warranty agreement on the Leaning Juniper 1 Wind Plant which will expire during the test period. This adjustment reduces the Company's forecast of total Company expenses by $0.218 million.

The Company disagrees with this adjustment indicating that while the warranty will expire the costs covered by the warranty will continue. The Company maintains it expects to incur a similar level of costs once the warranty expires due to costs associated with unscheduled maintenance. Instead of the expense associated with the warranty, the Company will directly incur the cost associated with replacing or repairing defective equipment and performing unscheduled maintenance on wind turbines.

The Committee points out the Company's rebuttal testimony includes a test year total incremental generation O&M expense of $3.66 million for the Leaning Juniper wind plant. Therefore, if the adjustment is accepted, approximately $3.4 million for ongoing operating costs remains. At hearing the Company argues they considered the expiration of the warranty agreement in their calculation of the revised O&M expense for this plant.

We accept the Committee's adjustment. We see no evidence the cost of the O&M activities currently covered under the Leaning Juniper warranty agreement is equal to the remaining cost of the warranty. It is reasonable to remove a portion of the costs of a warranty that expires during the test period. This adjustment reduces total Company expenses by $0.218 million and Utah revenue requirement by $0.094 million.

5. Other Revenue Adjustments

a. SO2 Allowance Amortization

UAE/Wal-Mart recommends the amortization period for sales of SO_2 allowances made after January 1, 2008, should be reduced to three years. In addition, the amortization schedules for the remaining unamortized balances as of December 31, 2007, for SO_2 sales made before January 1, 2008, should be accelerated from a four-year to a three-year schedule. UAE/Wal-Mart's adjustment, corrected for calculation input errors in surrebuttal testimony, reduces the Company's forecast of Utah revenue requirement by $1.86 million.

UAE/Wal-Mart indicates that in Docket No. 97-035-01[9] Utah parties stipulated and the Commission approved that the revenues from the sale of SO_2 allowances would be amortized over four years. UAE/Wal-Mart references RMP Exhibit (SRM-1S), p. 3.2.1, which demonstrates the sale of SO_2 allowances occurs with regularity. In 2007, revenue from sales of SO_2 allowances was $14.6 million and in 2008, revenue from the sales of SO_2 allowances is projected to be $15.9 million. UAE/Wal-Mart contends that while the four-year amortization

[9]In the Matter of the Investigation of the Reasonableness of the Rates and Charges by PacifiCorp, dba Utah Power & Light Company

period was reasonable at the time of its adoption, it is now preferable to shorten the amortization period to allow customers to realize the benefits from the sales more quickly.

The Company disagrees with UAE/Wal-Mart's proposal pointing out that since the 97-035-01 proceeding the Company has filed four additional general cases in which SO_2 allowance sales were amortized over four years. In addition, the Company uses between four and fifteen years for amortization of the sales of SO_2 allowances in its various jurisdictions and the four year amortization period in Utah is already the shortest. The Company contends UAE/Wal-Mart does not provide sufficient justification for accelerating the amortization period and departing from the precedent set by the Commission in the prior cases. The Company maintains that the amortization of SO_2 allowance sales should be viewed as a smoothing mechanism for including related revenue in results of operations; not to, as UAE/Wal-Mart suggests, determine the rate at which SO_2 allowance sales are credited to customers. Shortening the amortization period would result in increasing customers' exposure to the market conditions that drive varying levels of SO_2 allowance sales from period to period.

In surrebuttal, UAE/Wal-Mart also agrees with the Company that the amortization of the SO_2 allowance sales acts as a smoothing mechanism for including related revenue in results of operations. UAE/Wal-Mart, however, contends this function would also be accomplished using a three-year amortization period and this change would provide the additional benefit of allowing customers to realize the benefit of these sales sooner.

We view both parties as having legitimate positions on this issue and we are faced with the choice of increased speed of return of revenue associated with the sale of SO_2 allowances versus a longer period of smoothing of revenue associated with the sale of SO_2

allowances. We note the Company's testimony that the SO_2 allowance amortization rate in Utah is currently the shortest in all of the Company's jurisdictions. Absent additional justification for change, and in light of the use of a future test period, we are persuaded by the Company's arguments and agree with the four-year amortization of SO_2 allowances in this case.

b. Goodnoe Hills Green Tags

Goodnoe Hills is a 94 megawatt wind project owned by the Company which is located in Washington State and scheduled to be operational by June 2008. UIEC argues the amount of revenue included in the test period from the expected sales of renewable energy credits ("RECs" or "Green Tags") associated with the expected output of this project is too low. UIEC argues the Company used a much higher value for sales of RECs in the analysis the Company presented to justify the project. In order to be consistent with the assumptions used to justify the project, UIEC proposes an adjustment to increase by $0.685 million total Company revenue from renewable energy credits. This reduces the Company's test period forecast for the Utah jurisdiction revenue requirement by about $0.290 million.

In rebuttal, the Company opposes this adjustment. First, the Company argues it does not assign a REC value per project. Rather, the value of a REC in this case is $3.50 per megawatt hour for 75 percent of the RECs allocated to Utah. Second the Company argues it did not assume RECs from the Goodnoe Hills project were worth $6.50 per megawatt hour. Rather, it determined the differential present value revenue requirement for the project was $0 on a total project basis (inclusive of avoided market purchases) if the value of a REC or the cost of compliance with renewable portfolio standards rises to approximately $6.37 per megawatt hour during each year of the projects's life. The $6.37 per megawatt hour is a nominal levelized amount during the life of the project and is not the exact value of a REC from the Goodnoe Hills project to customers over the life of the project or in a given year. The Company expects REC values will fluctuate due to changes in the market value of RECs, formalized agreement under the multi-state process for inter-jurisdictional allocation of RECs, or enactment of a federal renewable portfolio standard. Finally, the Company argues UIEC only recommends the Company bear the downside risk for the value of RECs over time; no proposal is made for when the value of a REC is higher.

We accept the value of REC's forecasted by the Company in this case. We recognize the REC market is only emerging and this is the first litigated case in which the subject of REC forecasting and allocation to states has been raised. We do not accept the UIEC proposal at this point because it addresses the issue in isolation of a comprehensive solution for the forecasting and allocation of REC revenue. While the MSP workgroup addressing RPS issues has resolved REC allocation issues for reporting purposes, we understand the issues of forecasting REC revenue is left to state rate case determinations. We do not find the current record sufficient to comprehensively resolve issues regarding REC forecasting and inclusion in rates. Therefore, we accept the Company's proposal for the test period in this case and await further discussion in a future rate proceeding.

6. Capital Additions

In direct testimony, the Division proposes an adjustment to the Company's rate base to reflect that the Company spent approximately $144 million less on plant additions than forecasted in the Company's rate base for the time period between July 2007 through February 2008. The Division maintains that $144 million is a significant departure from the original forecast submitted by the Company and thus justifies adjusting the Company's forecasted rate base balance for the test year. This adjustment reduces the Utah revenue requirement by approximately $8.69 million using the Division's proposed rate of return on equity of 10.1 percent.

The Company agrees with the adjustment in principle and states that even if it invests what was forecasted in the rate case, but at a later date, the filed test period rate base will be overstated. The Company maintains that due to ever-changing business conditions it must continually assess what investments in the system must be made in order to best meet its obligation to serve. This process sometimes requires the Company to reallocate its investment budget to optimize the investments made to the system.

In rebuttal, in response to the Company's claim that the Committee's revenue requirement would not even cover the cost of capital investment that the Company has put in place to date, the Committee points out that it did not recommend a single adjustment to the Company's proposed capital additions included in the 2008 test year. The Committee further indicates that actual capital investments have been fully reflected in the Committee's position along with the Company's projected capital investments in this case.

The Committee's arguments in this matter go to the broader issue of supporting their total revenue requirement position in this case. Based upon the average-of-year methodology used in determining rate base in this case, we accept the Division and the Company's position on this adjustment.

7. Interjurisdictional Allocation Factors

UIEC argues the Company's load growth forecasts for Utah overstate actual growth. Thus, certain factors used to allocate total Company costs to each state in the Company's utility system overstate Utah's share of these costs.

UIEC provides data comparing weather normalized actual sales to weather normalized forecast sales to support its claim. Further, UIEC testifies the number of actual customers added in the July 2007 to January 2008 time period was 6,570 rather than the forecasted amount of 13,200. UIEC provides exhibits showing in the first quarter of 2008, weather adjusted actual sales are also below the Company's forecast and that weather adjusted actual sales in several of the Company's other state jurisdictions are, in most cases, above the Company's forecast. With respect to the departure of weather adjusted peak demand and the Company's forecast, UIEC argues the other states are significantly above their forecasts, while Utah is below or just slightly above its forecasts.

UIEC proposes Commission staff develop allocation factors using the updated load numbers. UIEC suggests an adjustment to loads could result in about $22 million in reduced Utah revenue requirement. UIEC contends it is entirely appropriate for the Commission to update loads based on the exhibits presented in this case, because the Company insists on using updated load curves to demonstrate its need for higher net power costs. If the Commission declines to adjust the interjurisdictional cost-allocation factors based on the evidence presented in this case, which UIEC concedes is only for a partial year, the Commission should take note of this potential revenue misallocation to Utah ratepayers and be conservative selecting among each of the other cost estimates in this case.

We decline to make any adjustments to the Company's load forecasts in this case. The arguments presented by UIEC underscore the difficulty in developing a future test period. While we can consider adjustments to load forecasts, and therefore cost-allocations factors, such adjustments must be supported by evidence demonstrating the Company's annual forecasts are unreasonable for the purposes of setting just and reasonable rates. Further, any proposed adjustment must be symmetrical for costs and revenues. The selection of a few months of data is inadequate support for this adjustment, just as it is inadequate support for a change in net power costs. The changes in Utah's forecast, possibly due to economic slowdown as noted by UIEC, is one of the reasons we directed the Company to use a forecast test period nearer in time than its originally filed request. Finally, we decline to use weather adjusted actual load numbers to develop new allocation factors as this is inconsistent with use of a future test period which is predicated upon forecasted loads, and we have no alternative forecast of growth for each of the states, and supporting rationale, upon which to base this forecast.

8. Income Tax Domestic Production Activities Deduction

UAE/Wal-Mart recommends the tax benefits associated with the Domestic Production Activities Deduction, sometimes referred to as the Section 191 Deduction, should be passed through to ratepayers. In surrebuttal testimony UAE/Wal-Mart proposes a formulaic approach to determining the Section 191 Deduction adjustment as follows. If the Company is awarded a revenue requirement increase of less than $15.8 million, there will be no adjustment for the Section 191 Deduction. If the Company is awarded a revenue requirement increase of $84.4 million the revenue requirement should be reduced by $0.996 million to account for the tax benefit of the Section 191 Deduction. If the Company is awarded a revenue requirement increase that is between $15.8 million and $84.4 million (before consideration of the Section 191 Deduction), the revenue requirement adjustment associated with the Section 191 Deduction should be set between zero and $0.996 million on a pro-rata basis. At hearing the Company accepts the adjustment proposed by UAE/Wal-Mart for this case.

Based on the approved revenue requirement prior to a Section 191 Deduction, $33.636 million, we calculate the Section 199 total Company adjustment is $0.258 million.

9. Summary of Revenue Requirement

Table 1 provides a summary of the Company's proposed Utah revenue requirement and all adjustments approved herein, for the future test period 2008. As shown, we approve a Utah revenue increase for the Company of $33.378 million.

C. REGULATORY POLICY ISSUES

The Division, Committee, UIEC, and IBEW Local 57 propose reporting and filing requirements, advocate major and minor policy changes, recommend studies and model changes pertaining to net power cost determination, and request guidance on specific issues.

1. Reporting Requirements

a. Company Forecasts and Actual Data - Variance Reports

The Division recommends the Commission order the Company to file a detailed semi-annual variance report with the Company's results of operation, which are filed semi-annually. The Division asserts the need for this information in order to monitor the Company's performance relative to its forecasts. In its direct testimony, the Division provides the detailed content of this semi-annual variance report.

The Committee supports the Division's recommendation for semi-annual variance reporting and the submission of a two-year forecast with the following additions. First, the Committee recommends that Administrative and General Expenses by FERC account and the two-year forecast both be provided on a total Company and on a Utah jurisdictional basis. Second, the Committee further proposes the actual and forecast monthly demand and energy usage by state, as filed under Tab 11 of the June 2007 Semi-Annual Report, continue to be provided and that the actual amounts also be provided on a weather normalized basis. The Committee contends this information would be useful in evaluating the Company's forecasting accuracy associated with the factors that are utilized to derive the system generation and system energy jurisdictional cost-allocation factors. The Company does not address these recommendations in rebuttal testimony or at hearing.

As we have stated on numerous occasions, the Company is the gatekeeper of information concerning its operations. We view the Division's request with the Committee's enhancements falls under the purview of the Commission's responsibility to ensure just and reasonable rates and instruct the Company to provide such information beginning with the timing of the December 31, 2008, semi-annual report. We direct the Division, the Company, and the Committee to develop a variance report template by November 30, 2008, to be used for future variance report filings with the Commission. We note the Company's semi-annual report is already a voluminous document and direct the variance report be filed with the Commission as a separate document.

b. Wind Generation

UIEC recommends the Commission require the Company to file periodic reports detailing the actual generation from and resulting capacity factor for each wind project so that the Commission may have an opportunity to make adjustments in future cases if it appears projects are failing to approach the capacity factors assumed in project justification.

The Company disagrees with this request and offers that it currently files semi-annual reports with the Committee, Division and the Commission. This process provides ample opportunity for parties to have reasonable access to actual generation information and there is no reason for the Commission to place additional reporting burdens on the Company. The Company argues the use of this information to determine future imputations is totally inappropriate. The Company contends UIEC's recommendation is not symmetrical and offers that wind resources are similar to hydro resources in that their actual generation outputs are weather dependent. The Company asserts UIEC is essentially recommending the Commission revisit the prudence of the Company's decision to pursue the resource during a future rate proceeding whereas the Company is requesting the Commission to determine prudence in this docket.

In reviewing the December 2007 Semi-Annual Report we observe that all plant-specific generation data, including wind, is normalized and reported for the projected time period of January through December, 2008, i.e., there is no plant-specific actual generation information provided. In addition there are no capacity factors listed for wind resources and the capacity factors listed for the thermal resources are all "1" with the exception of Gadsby which has a "zero" capacity factor. In short, the information requested by UIEC is not currently available in the semi-annual report. We find merit in UIEC's request, not for the purpose of imputation which we decline to address at the present time, but to provide a record of the actual operating characteristics of the Company's wind resources, and consequently of their effects on overall system operation and system integration costs. These data will also serve as the foundation for resource characteristics to be used in the GRID model. We view UIEC's request as reasonable, especially in light of the Company's representation that it is procuring "cost-effective" wind resources. We therefore direct the Company to provide a summary report, either within or as a separate addendum to the semi-annual report, indicating the name, nameplate capacity, actual generation and actual capacity by month and other supporting information, for each wind resource.

2. Rate Case Information

a. General Requirements

The Division and the Committee recommend the Commission order the Company to provide certain information when filing a general rate case. The Division proposes the requirements identified in the January 30, 2006, Discovery Task Force Report filed in Docket No. 04-035-42 and as presented in the Stipulation on Filing Requirements, Discovery, and Timing of Test Period Hearing in Docket No. 06-035-21 be made a permanent part of future general rate case filings. Alternatively, the Division recommends the Commission initiate a rule making proceeding to determine the filing requirements for both Questar Gas Company and PacifiCorp.

The Committee contends that in order for parties to effectively analyze and investigate the Company's filings, adequate information must be provided in a timely manner.

As the Company is in control of the information upon which it bases its case, it is the Committee's view that having adequate information, such as that contained in responses to Master Data Requests ("MDR"), at an early stage of the case is essential. While the Company, through stipulation, provided responses to MDRs in this and the previous rate case, there is no agreement to provide responses to MDRs beyond this docket. The Committee believes this information is essential as support for the Company's case and should be required with every application for a general rate case.

The Company argues the proposed modification to the amount of required filing information for a general rate case and the associated time period in which a general rate case must be completed would further delay recovery of costs, create even less opportunity for the Company to achieve its authorized rate of return and provide poor price signals to customers. Additionally, these modifications are inconsistent with the Utah State Legislature's direction that the Commission use a forward looking test period when appropriate.

The Division counters that its proposed scheduling and filing requirements do not preclude a forward-looking test period because the information sought is known up front and should be able to be prepared with the rate case filing. Rather, the Division contends its general recommendation should be interpreted as a recommendation to expedite the assessment of critical data.

The issue presented before us deals with the information to be filed with or provided to parties at the time of filing a general rate case. We disagree with the Company that the previously agreed to filing requirements would further delay recovery of costs. We find the Division's and the Committee's testimony on the filing requirement issue persuasive and direct the Company to provide the requested information on an ongoing basis or until such time that rules may be adopted.

b. Notification of Accounting Procedure Changes

The Committee recommends the Commission require the Company to explain and support, in direct testimony, any proposed substantive accounting change. While investigating this case the Committee became aware the Company changed the way it normalizes asset basis differences for deferred income taxes, changing from 40 percent to 100 percent normalization. The change was incorporated in the filing but was not accompanied by any supporting testimony notifying the parties of the change, the reason for the change or the affect of the change on revenue requirement. The Committee contends this requirement is particularly important if the change is not required to comply with Generally Accepted Accounting Principles or other readily known accounting requirements or guidelines.

We find this request reasonable and direct the Company to explain and support in direct testimony any proposed material accounting change that varies from its practice or method used in its last general rate case.

3. Ratepayer Safeguards

The Division recommends major projects be put in rates on a phased-in basis based upon milestones assigned to a specific project. In using a fully forecasted test period, the Division believes ratepayer safeguards need to be implemented in the event that actual costs in the areas of capital expenditures or operations and maintenance fall short of budgeted or forecasted amounts. Phasing in projects based on pre-determined milestones assigned to a specific project would assure ratepayers that they are not paying for a project which could be delayed, as well as keep the Company on a Company-determined time line for meeting each stage of the project.

While the Committee is supportive of the concept of appropriate ratepayer safeguards, such as when the Company agreed to meet certain spending levels for the Utah system maintenance and capital expenses in the stipulation in Docket 06-035-21, it would need to see greater detail to determine if it could support the Division's proposal.

Beyond the general concept, the Division provides no detailed analysis or specific proposal for its recommendation on safeguards and corresponding rate structure and rate change mechanism. We do not believe the existing record is sufficient to support adoption of the recommendation nor how it would be implemented as part of rate design in this docket.

4. Test Period Guidance

The Division requests further instruction from the Commission on how to determine the test period that best reflects the conditions the Company will face when rates go into effect such as the weight given to the factors relevant to selection of a test period in the October 20, 2004, Order Approving Test Period Stipulation in Docket No. 04-035-42. The Committee supports this request.

In responding to this request we refer to the above referenced order in which we list "some" - but not all - factors which need to be considered in selecting a test period. In this order we also state: "Each case needs to be considered on its own merits and the test period selected should be the most appropriate for that case. The test period selected for a utility in a particular case may not be appropriate for another utility or even the same utility in a different case." In making our decision on an appropriate test period, we use no pre-determined formula or weighting but consider the testimony and evidence addressing factors relevant to the case and how the proposed test period will result in just and reasonable rates. Our guidance is for parties to develop their positions using informed judgement regarding relevant factors based upon the most currently available information.

5. Service Quality and Reliability Standards

IBEW Local 57 recommends the Commission authorize the Service Quality Review Task Force, and interested parties, including IBEW Local 57, to evaluate current, proposed and improved performance and reliability standards in the distribution system to which the Company should be committed, in accordance with its original mandate.

On June 4, 2008, the Company filed a proposal to modify its performance standards and customer guarantees and we opened Docket No. 08-035-55, In the Matter of Service Quality Standards for Rocky Mountain Power. On June 10, 2008, we requested the Division investigate this proposal and provide us with its recommendation by August 21, 2008. We also direct the Company and Division to invite IBEW Local 57 to future meetings addressing service quality standards.

6. Net Power Cost Modeling and Information Issues

a. Hydro Modeling

The Committee recommends the Commission require the Company to include a conventional forty water year modeling study as part of the MDR information in the next general rate case. In its surrebuttal testimony, the Committee discusses a disputed hydro adjustment. The Committee maintains its adjustment is reasonable, however in this case it would be satisfied if the Commission required the Company to file the above-mentioned study as is required in Washington. The Committee contends the availability of this study as applicable to the test year would enable the Commission to determine whether the Company's approach is biased or not as the study is based on a proven technique and would resolve the controversy. The Company does not address this request at hearing but disagrees with the Committee's approach to hydro modeling.

To the extent this information may help resolve a disputed issue we find the Committee's request reasonable and direct the Company to provide this information if asked for in a data request.

b. Duct Firing Operation and Reserve Capability

The Committee recommends the Commission require the Company to develop a modeling enhancement for GRID that allows proper modeling of all modes of operation for combined cycle generators in its next general rate case. The Committee argues the Company models the duct firing capabilities of Currant Creek and Lake Side as generation resources independent of the underlying combined cycle plants. Thus, in the model, the duct firing capacity runs at times when the combustion turbines and steam generator are not running. In the case of Currant Creek, the Committee contends GRID frequently shows duct firing operation when the combustion turbines and steam generator are operating at their minimum loading, which is neither economic nor realistic. In addition, GRID does not allow the duct firing capacity of Currant Creek and Lake Side to carry spinning reserves, although they are allowed to carry ready reserves, which is again unrealistic. The Committee developed an interim solution by combining the resources into a single unit in GRID, however this issue was not included in the Committee's total net power cost adjustment.

The Company disagrees with the Committee's interim solution. By reducing the heat rate for duct firing to a level based on the heat rate equation used for the combined cycle plant, the efficiency of the duct firing is overstated thereby understating net power costs. The Company states GRID is not capable of reasonably modeling a combined cycle plant with duct firing as a single unit because the heat rate curve is developed using a polynomial heat rate equation which is unable to jump up to a higher heat rate when the duct firing is started. The Committee disputes this statement and emphasizes, based on the confidential response to data request CCS 7.5, that the heat rate equation used in GRID is based on operation of the plant in both its conventional and duct firing mode of operation.

The Company also indicates GRID would not be able to capture the start-up time required for using duct firing. The Company asserts it is not reasonable to delay a general rate case based upon the Committee's concerns over the modeling of duct firing.

We note the limitations of GRID for modeling many of the Company's operating permutations. We believe this issue merits further research and discussion in order for all parties to understand the subtleties of the different modeling approaches used to address specific operating modes, modeling limitations and manual "workaround" adjustments. We encourage interested parties to address these issues in future proceedings.

c. Commitment Logic and Non-Firm Transmission

The Committee observes the Company excludes non-firm transmission capacity in its GRID modeling and recommends the Commission require the Company to file non-firm transmission data for the 48-month period as part of the MDR information in the next general rate case. The Committee testifies GRID portrays the PacifiCorp system as being heavily constrained by firm transmission and market capacity limits. This modeling constraint prevents the sale of surplus generation resulting in generators running inefficiently at minimum loading levels in the model. The Committee contends that in actual operation these constraints may not exist because non-firm transmission capacity is often available. While the impact of including non-firm transmission is not large, perhaps $5 million on a total Company basis, the Committee argues it should be included in GRID modeling. The Committee states that the Commission, in Docket No. 03-035-14,[10] ordered the Company to include a 48-month history of non-firm transmission for purposes of computing avoided costs using GRID. Therefore, the Commission should require the Company to do the same in general rate cases.

The Company discusses the goal of normalized rate-making, the limitations of the GRID model, and the prudence standard with respect to net power cost determination. The Company states, as a matter of prudence, it will generally seek to optimize its system but there are limits on what the Company can achieve in this regard in real-time operation. The Company submits the Commission should not hold the Company to a level of perfection in its operation of

[10] In the Matter of the Application of PacifiCorp for Approval of an IRP-based Avoided Cost Methodology for QF Projects Larger than One Megawatt.

its system that is impossible for any utility to achieve. The Company disagrees that it is appropriate to model transmission which might or might not be available to the Company. The impact of speculative modeling of non-firm transmission would be to assume an even higher level of perfection in the Company's system operations than is currently the case in the model and further exacerbate the disconnect between modeled and actual net power costs.

We recognize there are instances in the analysis of power costs when it may be inappropriate to include non-firm transmission capacity, for example in capacity expansion planning. However, since the use of non-firm transmission is normal in the operation of the Company's system, we are persuaded by the Committee's testimony on this matter and direct the Company to include non-firm transmission in the GRID model and to use an average of the 48-month history as is done in the calculation of avoided costs.

D. SPREAD OF RATE CHANGE AND PHASE I RATE INCREASE

The Company proposes the revenue requirement change ordered in Phase I of this docket be applied through a uniform percentage tariff rider rate, applied to all tariff customers' bills prior to the Commission's determination of costs of service rate spread and rate design in Phase II of the docket. The Company states this tariff rider rate would be similar to the Schedule 95 Credit that was applied in Docket No. 06-035-21 and which expired on May 31, 2007. The tariff rider rate would be applied to customers' bills as a line item for service on and after the effective date of the Phase I order through the effective date of the Phase II order. The Division agrees with the Company's proposal providing it is applied to an entire class rather than individual customers.

We approve the Company's proposal for the Phase I rate change. It is our understanding the tariff rider will identify the percentage change per rate schedule, as requested by the Division.

IV. ORDER

Wherefore, pursuant to our discussion, findings and conclusions made herein, we order:

1. The Company to file appropriate tariff revisions increasing Utah jurisdictional revenues by $33,377,525, effective August 13, 2008.
2. The tariff revisions shall reflect the determinations and the decisions contained in this Order. The Division shall review the tariff revisions for compliance with the terms of this Order.
3. Additional reports, studies, tasks and other requirements ordered herein, do not alter previous Commission requirements for filing Semi-Annual Results of Operations.

This Report and Order constitutes final agency action on the Company's December 17, 2007, Application. Pursuant to U.C.A. §63-46b-12, an aggrieved party may file, within 30 days after the date of this Report and Order, a written request for rehearing/reconsideration by the Commission. Pursuant to U.C.A. §54-7-15, failure to file such a request precludes judicial review of the Report and Order. If the Commission fails to issue an order within 20 days after the filing of such request, the request shall be considered denied.

Judicial review of this Report and Order may be sought pursuant to the Utah Administrative Procedures Act (U.C.A. §63-46b-1 et seq.).

DATED at Salt Lake City, Utah, this 11th day of August, 2008.

/s/ Ted Boyer, Chairman

/s/ Ric Campbell, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#58526

TABLE 1: 2008 Test-Period Revenue Requirement

	Company Position	$74,455,745
	Commission Rate of Return on Equity	(17,007,740)
	Remove Company NPC Adjustment 11.16	2,918,308
2.a	Call Options	(84,397)
2.b	SMUD Leap Year	(14,806)
2.b	SMUD Normalizing	(1,137,287)
2.b.	SMUD Repricing	(3,287,014)
2.c.	West Valley Uneconomic Operation	(268,465)
2.c.	Currant Creek Uneconomic Operation	(4,929,669)
2.c.	Lake Side Uneconomic Operation	(3,421,800)
2.c.	Incremental Start-up Costs	4,039,062
2.d	Planned Outage Schedule	(4,796,076)
2.e.	Unplanned Outage Rates	390,235
2.g.	Thermal Ramping	(771,271)
2.h.	Hermiston Losses	(454,490)
2.i.	Biomass Non-Generator Agreement	(190,228)
2.j.	Sunnyside QF Contract	(1,577,535)
2.k.	Schwendiman Contract Deferral	(53,317)
2.l.	Goodnoe Hills Transmission	(460,201)
2.l.	Transmission Escalation	(670,674)
2.l.	Borah Brady Transmission	164,567
2.l.	Transmission Imbalance	(382,298)
2.m.	Tesoro and Kennecott QF Contracts	(92,483)
2.o.	Currant Creek Outage Rate	(96,529)
2.p.	Self-Supplied Non-Owned Reserves	(847,832)
3.g.	Medical Costs	(514,210)
3.h.	Other Salary Overhead	(155,634)

4.a.	Relocation Expense	(203,919)
4.b.	Injuries and Damages	20,493
4.c.	Property Tax	(2,987,513)
4.e.	Generation Overhaul	(3,733,400)
4.g.	Office Reconfiguration	(119,520)
4.j.	Leaning Jupiter Warrantee	(94,381)
8.	Income Tax Domestic Production Activities	(258,198)
	Final Adjusted Results	$33,377,525