BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Ben Lomond to Terminal Transmission Line and the Dave Johnston Generation Unit 3 Emissions Control Measure	))))))))))	**DOCKET NO. 10-035-13** **Exhibit No. DPU 1.0** **Direct Testimony of** **Charles E. Peterson**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Direct Testimony of

Charles E. Peterson

April 26, 2010

CONTENTS

Direct Testimony of Charles E. Peterson

I. INTRODUCTION

Q. Please state your name, business address and title.

A. My name is Charles E. Peterson; my business address is 160 East 300 South, Salt Lake City, Utah 84114; I am a Technical Consultant at the Utah Division of Public Utilities (Division, or DPU).

Q. On whose behalf are you testifying?

A. The Division.

Q. Please summarize your educational and professional experience.

A. I earned my bachelor's degree in mathematics at the University of Utah in 1978 and my Master of Statistics degree through the Graduate School of Business in 1980. In 1990, I earned a Master's degree in economics from the University of Utah. In 2007, I earned the Certified Rate of Return Analyst (CRRA) accreditation from the Society of Utility and Regulatory Financial Analysts (SURFA).

I have worked as an economic and financial consultant in various capacities for approximately thirty years. I joined the Division in January 2005 as a Utility Analyst and was later promoted to my current position as a Technical Consultant. I have worked primarily in the energy section of the Division. My resume is attached as DPU Exhibit 1.1.

Q. Have you previously testified before the Utah Public Service Commission (Commission)?

A. Yes. I have testified before the Commission on numerous occasions regarding cost of capital issues and cost of equity in several general rate cases. I have also testified on behalf of the Division in the Phase I formal hearing on PacifiCorp's (Company) request for an energy cost adjustment mechanism (ECAM). In addition, I provided written and oral testimony regarding the acquisition of the Chehalis power plant, the acquisition of the Company by MidAmerican Energy Holdings Company (MEHC), and many other cases.

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

A. My testimony presents the Division's analysis, discovery, and policy recommendations to the Commission regarding the Company's application for alternative cost recovery for the construction of its Ben Lomond to Terminal transmission line (Line) and the construction of a new "environmental improvements" scrubber at Dave Johnston unit 3.[1]

---

[1] Rocky Mountain Power (RMP) is an operating division of PacifiCorp primarily performing the retail distribution operations of PacifiCorp in the eastern part (i.e. Utah, Wyoming and Idaho) of PacifiCorp's system. RMP runs no electric generators; it has no debt, no preferred stock and no common stock. The fact that PacifiCorp files with the Commission under the name Rocky Mountain Power, doesn't change the fact that any plant additions are system plant and not just RMP division assets. Therefore, throughout this testimony I will primarily refer to PacifiCorp, rather than RMP.

II. SUMMARY

Q. Please outline the Division's understanding of the Company's Application before the Commission.

A. Pursuant to Utah Code Annotated §54-7-13.4 PacifiCorp in an Application dated February 1, 2010, requested a Commission order putting the capital costs of two projects into the Company's rate base and issuing an accounting order deferring the rate increase of the resulting revenue requirement of this additional rate base until "approximately January 1, 2011."[2]

Q. What are the amounts the Company is asking to be included in rate base?

A. PacifiCorp estimates that the total capital investment of the Ben Lomond to Terminal transmission segment will amount to $268 million and the total capital investment for the Dave Johnston unit 3 "environmental improvements" (scrubber) will amount to $293 million; the total amount is $561 million. The Utah allocated portions are estimated at $109.3 million and $112.6 million, respectively, totaling $221.9 million.[3]

Q. What is the annual revenue requirement the Company is asking to be deferred?

A. Originally PacifiCorp was requesting the deferred revenue requirement be $33.7 million,[4] but this was later reduced to $33.0 million.[5] The reduced request came in Supplemental Direct

[2] Application, pages 3-4.
[3] Application, page 4; Direct Testimony of Steven R. McDougal, pages 8-10.
[4] $33,672,406 per RMP Exhibit SRM-1, page 1.
[5] $33,018,593 per RMP Exhibit SRM-1S, page 1.

Testimony filed by Company witness Steven R. McDougal on March 25, 2010. Mr. McDougal's supplemental testimony incorporated the cost of equity ordered by the Commission on February 18, 2010 in the Company's general rate case, Docket No. 09-035-23. The Division understands that besides cost of equity, Mr. McDougal evaluated other adjustments resulting from this Commission Order, but concluded that these other adjustments had an immaterial effect. The Division also believes these have an immaterial affect but included them in its evaluation described below.

Q. Please outline the Division's activities in evaluating this Application.

A. The Division staff has reviewed the filings made by the Company including the Attachments included with the Application pursuant to Commission Rule R746-700-30, parts A-E. Division audit staff evaluated the accounting the Company proposes for the two projects. While the Division does not recommend changes to the Company's accounting in this matter, the Division has some concerns that are discussed below.

The Division contracted with Slater Consulting, Atlanta, Georgia, (Slater) to review the net power cost (NPC) adjustments the Company proposed and to review the capital expenditure costs for both the transmission line and the scrubber projects. The Division and Slater issued 12 sets of data requests to PacifiCorp as of April 13, 2010. We have considered the Company's responses to our data requests as well as the responses to data requests by other intervening Parties. The Division and Slater have had several informal meetings with the Company and Division staff has reviewed highly confidential documents at the Company's offices. Slater has provided two letter reports to the Division that are included as Exhibits

DPU 1.2 and DPU 3.2. Slater's review and conclusions regarding the Company's NPC calculations are discussed in DPU 1.2; Slater's review of the project costs of the Terminal to Ben Lomond transmission segment and the Dave Johnston unit 3 scrubber is described in Mr. Ken Slater's Direct Testimony DPU 3.0 with attached exhibits. Mr. Evans and Mr. Slater's résumés are attached as DPU Exhibits 1.3 and 3.1, respectively.

Q. Does the Division anticipate further revisions to the annual revenue requirement in this matter?

A. Yes. In response to the Office of Consumer Services revised data request 3.1 received on March 22, 2010, PacifiCorp acknowledged error in the NPC calculation which should result in a downward adjustment of the system revenue requirement by approximately $634,000. The Division is also recommending a further reduction in the revenue requirement due to changes to the Company's jurisdictional allocation model (JAM) for this Docket only and for the use of the incorrect base revenue requirement resulting from the Commission's recent Order in the Company's general rate case as described above. Division witness Matthew Croft details this adjustment in DPU Exhibit 2.0 and supporting exhibits. In addition to the adjustments mentioned above, Mr. Croft has included the rate base adjustments made in Mr. Ken Slater's Direct Testimony, DPU Exhibit 3.0.

The Division is recommending the annual revenue requirement be set at $31,612,292.

Q. What are the Division's preliminary conclusions and recommendations?

A. As will be discussed in more detail below, with the exception of the revenue requirement adjustments described above, the Company's capital expenditure costs for each of the two projects appear to be within a reasonable range given the time period of construction and the geographical issues faced by the transmission line. The purpose of this Docket is to evaluate the prudence of the costs of the Ben Lomond to Terminal transmission segment and the general prudence of the Dave Johnston unit 3 scrubber and the associated costs of both projects. The Division believes any issue of the general need, necessity and of the Terminal to Ben Lomond transmission segment was resolved when the Commission issued a Certificate of Public Convenience (CPCN) and Necessity on September 4, 2008 in Docket No. 08-035-42.

As described in more detail below, the Division believes the installation of the new scrubber at Dave Johnston unit 3 is prudent due to the need to comply with EPA emissions standards issued in 2005, and, to a lesser extent, due to the Commission's approval of the Acquisition of PacifiCorp by MidAmerican Energy Holding Company (MEHC) in 2006, which approval included Commitment 43.[6]

[6] Docket 05-035-54, Second Amended Stipulation dated April 20, 2010; Commitment 43 states "Working with the affected generation plant joint owners and with regulators to obtain required approvals, MEHC and PacifiCorp commit to install, to the extent cost-effective, the equipment likely to be necessary under future emissions control scenarios at a cost of approximately $812 million. Concurrent with any application for an air permit, MEHC and PacifiCorp will discuss its plans regarding this commitment with interested parties and solicit input. While additional expenditures may ultimately be required as future emission reduction requirements become better defined, MEHC believes these investments in emission control equipment are reasonable and environmentally beneficial. The execution of an emissions reduction plan for the existing PacifiCorp coal-fueled facilities, combined with the use of reduced-emissions coal technology for new coal-fueled generation, is expected to result in a significant decrease in the emissions rate of PacifiCorp's coal-fueled generation fleet. MEHC represents that the investments to which MEHC is committing are expected to result in a decrease in the SO_2 emissions rates of more than 50%, a decrease in the NO_x emissions rates of more than 40%, a reduction in the mercury emissions rates of almost 40%, and no increase expected in the CO_2 emissions rate.

The Division concludes that the requested increment to PacifiCorp's rate base, less the rate base adjustments cited in Mr. Slater's Testimony, and the revised revenue requirement of approximately $31.6 million are just and reasonable and in the public interest. This conclusion assumes that the capitalized costs that finally go into rate base are the actual costs of the two projects under consideration. Therefore the Division recommends that the Commission approve the addition to PacifiCorp's rate base in Utah by the amounts of approximately $102.0 million and $112.6 million representing the Utah portion of the capital expenditures for the Terminal to Ben Lomond transmission segment and the Dave Johnston unit 3 scrubber, respectively, as being just and reasonable and in the public interest. The Division also recommends that the Commission conclude that the incremental revised revenue requirement of $31.6 million is just and reasonable and in the public interest and issue a deferred accounting order for that amount.

III. DPU ANALYSIS OF THE COMPANY'S APPLICATION.

A. Net Power Costs.

Q. Please describe the Company's original request for NPC relief and what has subsequently occurred.

A. Initially the Company, through its witness Dr. Hui Shu, requested relief for approximately $1.6 million in addition NPC, primarily for the Dave Johnston scrubber. However, in data request 3.1 the Office questioned the calculation of the NPC. In the revised response to this data request PacifiCorp admitted that the original calculation was wrong due to the incorrect heat rate being applied to unit 3. The correct NPC increase should be about $1.0 million or $634,000 less than originally claimed.

Q. Has Slater evaluated the Company's NPC adjustment?

A. Yes. George Evans, the analyst for Slater who performed the NPC analysis studied the NPC issue including the revision suggested by the Office and accepted by the Company. As described in DPU Exhibit 1.2, Mr. Evans calculated NPC based upon some slightly varying assumptions, which in turn gave slightly different results. However, the results approximated a $1.0 million increase in NPC.

Q. What is the conclusion Slater and Mr. Evans reached regarding the NPC?

A. Mr. Evans and Slater Consulting have concluded that an NPC amount of $1.0 is within a reasonable range. Consequently, the Division accepts the adjustment proposed by the Office and accepted by the Company of a reduction of $634,295 for NPC.

B. The Ben Lomond to Terminal Transmission Segment.

Q. Please describe the Ben Lomond to Terminal Transmission Segment project.

A. The Terminal to Ben Lomond transmission project is a segment of the larger Terminal to Populus transmission project. This transmission project is constructing a 345 kV transmission line from the Terminal substation on the west side of Salt Lake City to the new Populus substation in Idaho. This transmission line ties into other substations at intermediate points including the Ben Lomond substation in Weber County, Utah. The Terminal to Ben Lomond segment is approximately one-third of the total project. This transmission segment went into service on March 23, 2010.[7] The remainder of the project, that is the Ben Lomond to Populus segment, is expected to go into service in August 2010.[8]

Q. What did the Division do to evaluate the prudency of the costs of the Terminal to Ben Lomond transmission segment?

A. In addition to reviewing the documents provided by the Company at the time of the filing, the Division has issued data requests and held informal meetings with the Company. The Division contracted with Slater to evaluate the reasonableness of the construction costs of the transmission segment. DPU Exhibit 3.0 sets forth Slater's testimony and analysis of the Ben Lomond to Terminal transmission segment project. Kenneth Slater, owner and principal of Slater Consulting, led the Slater team that analyzed this project and the Dave Johnston unit 3 scrubber project.

Q. What were the results of the Division's own investigation of the Terminal to Ben Lomond segment?

A. The Division had earlier concluded that the Terminal to Ben Lomond transmission segment was needed and in the public interest.[9] In this Docket, the Division reviewed the accounting of the project costs including AFUDC and contingencies. The Division auditors and analysts became concerned with the size of the change orders and an $8.5 million item the Company

[7] UIEC DR 1.26
[8] Direct Testimony of Seven R. McDougal, page 11, line 248-250.
[9] Direct Testimony of Dr. Joni Zenger, Docket No. 08-035-42, filed August 1, 2009. The Commission essentially agreed with the Division's position in its Order dated September 4, 2009 in that Docket.

called "Forecast Risk." In answer to DPU DR 8.4 dated April 8, 2010, PacifiCorp explained that "Forecast Risk" was not a contingency but represented any changes in AFUDC or PacifiCorp overhead until the end of the project. The Division has followed up on this answer requesting further clarification in its data request set 11. In response to DPU DR 11.2, PacifiCorp now shows "Forecast Risk" as zero. The Company provided a new listing of the change orders in response to DPU DR 11.3. The change orders now total about $16.8 million.

As of December 31, 2009, change orders for this project amounted to over $19 million[10] Four of the changes are for amounts of about $1 to $5 million each. The Division has asked for further clarification of these items. The Company provided a new listing of the change orders in response to DPU DR 11.3. The change orders now total about $16.8 million. A partial explanation of the 230 kV outage resequencing is given in the Company's response to DPU DR 12.2 that was received in the DPU e-mail box late April 22 and distributed to staff on April 26, 2010.

Q. What conclusion has the Division reached based upon its own investigation?

A. Other than the rate base items discussed below the Division accepts the costs of the transmission line segment as reasonable.

Q. What were the results of the Slater investigation?

A. As detailed further in DPU Exhibit 3.0 and accompanying exhibits, in addition, Slater had concerns with the change orders and the "Forecast Risk." Slater also had concerns that the

[10] Direct Testimony of Darrell T. Gerrard, Exhibit RPM-DTG 2.

costs for roadways and construction staging. This latter issue appears to have been resolved with the Company's explanation in response to DPU DR 8.6 which was that there were added costs due to construction in a wetlands environment that require that the roadways be removed and remediated after construction at a particular site. Slater raises other issues regarding change orders and microwave costs. Based on Slater's recommendation the Division recommends rate base deductions for microwave cost items amounting to $3,162,878 and the change orders related to the 230 kV outage resequencing in the amount of $14,778,072 as detailed in Slater's Testimony, DPU Exhibit 3.0,

However, Slater has concluded that based upon its research and comparison with similarly-sized projects that the other project costs are within a reasonable range.

C. The Dave Johnston Unit 3 and Unit 4.

Q. The Company filed for recovery for costs associated with the Dave Johnston unit 3 scrubber. Is the unit 3 scrubber a standalone project?

A. No. The environmental project associated with Dave Johnston unit 3 is part of a larger project that includes a similar scrubber to service Dave Johnson unit 4. Roughly half of the requested cost recovery for unit 3 is for common facilities.[11] The common facilities include the actual scrubber (each unit will have its own bag house), lime processing facilities, a new, common smokestack, and some common electric facilities and piping. In its filing, PacifiCorp included the costs of the common facilities, reasoning that they are required in

[11] Confidential response to DPU DR 6.6.

order for unit 3 to be "used and useful." Ultimately, when unit 4 is also in service, approximately half of the total cost will be booked to unit 3 and half to unit 4.[12]

Q. Did PacifiCorp inform the Commission, and by extension the other parties, that its requested recovery for Dave Johnston unit 3 included the common costs for unit 4 as well in its Application?

A. No. In neither its application nor its supporting testimony and exhibits by Company witnesses Messrs. McDougal, Cupparo, Gerrard, Teply and Williams, or in testimony filed by Dr. Shu is there any mention of unit 4. In a meeting with the Company representatives on February 9, 2010 to review the Application, approximately one week after the Application was filed, there was no mention of unit 4 by the Company representatives.

Q. When did the Division first realize that the Dave Johnston unit 3 project was simply a subset of a larger project?

A. Almost a month following the February 9 meeting, when Division staff had had the time to review the voluminous supplemental information filed pursuant to Commission Rule R746-700-30, parts A-E, the Division found references to unit 4 in the Engineering, Procurement and Construction (EPC) contract and other documents. The timing is indicated by the Division's third data request set which was issued on March 9, 2010. The Company's silence on this matter is inexplicable: with several opportunities, the Company failed to plainly inform the Division of this material aspect of the Dave Johnston project.

[12] Company's response to Confidential OCS Data Request 4.22

Q. What is the significance of the Company's failure to plainly and accurately describe the true nature of the Dave Johnston project in its initial Application and filed testimony?

A. First, the Division staff and its consultant were delayed in understanding the true nature of the Dave Johnston project when we were already in a statutorily constrained time frame. This required the Division and its consultant to spend additional time in March participating in additional meetings and in issuing data requests that could have been handled much earlier. Second, and perhaps more important, the realization that unit 3 was part and parcel to a larger project raised and continues to raise questions about the process the Company went through to begin construction on the unit 3 and unit 4 scrubber and common facilities.

Q. What are some of those questions?

A. I will first describe the overall project as it eventually has come to be understood by the Division. Following the acceptance of the winning EPC bid, the contractor began construction of the unit 3 and unit 4 common facilities and both the unit 3- and unit 4-only facilities. The unit 3 facilities along with the common facilities are now essentially completed and are expected to be placed in service during the May 2010 planned outage of unit 3. The unit 4 facilities are also mostly completed now, but will not be connected to unit 4 and placed in service until 2012 when unit 4 has a scheduled outage. From now until 2012 the completed construction on unit 4 will earn AFUDC and accumulate additional, primarily maintenance expense, until the final portion of construction that will connect the scrubber facilities to unit 4 in 2012.

With this background the following questions have been considered by the Division and its consultant: Did the Company perform a benefit/cost analysis that indicated that nearly completing unit 4 in early 2010, but delaying connection until 2012 was a least cost/least risk strategy? Was it possible for the Company to schedule its generator outages so that the unit 4 scrubber would come on line sooner than 2012, thereby reducing some of the AFUDC and interim maintenance costs? What is the correct accounting of the project costs? Is it reasonable that rate payers pick up the entire tab of the common facilities now, when they will only be roughly 50 percent used and useful for two years? Answers to these questions may give rise to a question about the reasonableness of the unit 4 accumulation of AFUDC and interim costs. I point out again that consideration of these questions was delayed by the Company's failure to clearly inform the Division of the true nature of the Dave Johnston project in its Application rather than requiring the Division (and other intervening parties) discovering it in the voluminous supplemental documents.

Q. The unit 4 costs are not before the Commission in this Docket. Why are they important?

A. The common facilities have been sized to handle unit 4 and those costs are before the Commission in this Docket. Further, it is somewhat arbitrary to distinguish between unit 3 and unit 4 since it is clear from the EPC contract that it is a single project. The Division, intervenors, and ultimately the Commission have to view the unit 3 costs in the Application in the context of the total project.

Q. Did the Company perform a benefit/cost analysis such as you mentioned above?

A. No. The Company has indicated that such an analysis was never contemplated [redacted] In addition, the Division has no indication that the bidding process was not an open arms-length process which would presumably yield the best available options. Further, the Division's consultant, Slater, has opined that building units 3 and 4 together results in significant cost saving compared with the likely costs for building two separate projects.[13] Therefore, while the Division is somewhat disappointed that a benefit/cost analysis was not performed, the Division is not recommending any adjustments due to construction of unit 4 at the same time as unit 3.

Q. Could the Company have scheduled an earlier outage of unit 4 to attach the scrubber facility to it?

A. In answer to DPU data request 8.7 in which this question was asked, the Company said that the majority of its coal-fueled power plants are on a four year maintenance cycle and that it was not economic to shut down unit 4 simply to connect the scrubber. The Division and its consultant still question these assertions. The Division notes, for example that the Company's document "Dave Johnston Plant Heat Rate Improvement Plan" dated March 31, 2009, showed Dave Johnston unit 4 had scheduled outages in 2009 and 2012, which does not appear to be a four year difference. The Division is not convinced that with better planning the Company could not have reduced the time the unit 4 scrubber would have to essentially

[13] DPU Exhibit 3.2, p. 5

sit idle. While the Division is not making an adjustment in this Docket for the length of time between near-completion of unit 4 and its actual in-service date, the Division may visit this issue again when the Company applies for rate recovery of unit 4 costs.

Q. What were the accounting issues and have they been resolved?

A. Following the discovery of the common costs and unit 4 part of the project, PacifiCorp representatives orally told the Division that it was proper and accepted accounting to apply 100 percent of the common costs even when only 50 percent of the common facilities would be used and useful. The Company has not yet provided authoritative documentation of this claim. Neither has the Division been able to discover authoritative support for accounting all common costs to unit three as the Company's Application implies. Instead the proper accounting is the 50-50 accounting admitted to in the answer to OCS DR 4.22 mentioned above.

The justification for cost recovery of all common costs now as opposed to a *pro rata* share with unit 4, is an economic and not a technical accounting or even an engineering one. As seen above, the support for the reasonableness of such a recovery, from the Division's viewpoint, is the competitive bidding process and Slater's opinion that one project should result in significant savings over two separate ones. Based upon these indications, the Division does not oppose putting all of the common costs in rate base as requested by PacifiCorp in this Docket. However, as suggested earlier, the Division may revisit some of these issues as they apply to unit 4, such as the amount of AFUDC and the operating expense that will accrue while the unit's new environmental facility is largely idle, at the time the Company requests the inclusion of the unit 4 costs in rate base.

Q. What does Slater conclude about the Dave Johnston unit 3 costs and common costs?

A. Slater concludes that the overall construction costs appear to be "not unreasonable."[14]

Q. What is the Division's conclusion with respect to the requested cost recovery relative to unit 3?

A. The Division is not recommending any adjustments to the actual construction costs being put into rate base.

D. Issues of General Prudence for the Dave Johnston Project.

Q. Why is PacifiCorp installing the unit 3 pollution control equipment at this time?

A. PacifiCorp needs to meet regional air quality standards promulgated by the federal Environmental Protection Agency (EPA) which, in the case of the Dave Johnston units, are administered by the State of Wyoming. The Company needs to meet the SO_2 and particulate regional emission standards no later than about 2014. It would seem to be impractical and likely impossible to wait until 2013 or 2014 to upgrade all of PacifiCorp's coal burning units all at once to meet these standards. It is reasonable for the Company to upgrade the environmental controls on one or two units each year in order to meet the standards.

[14] Ibid., p. 5

Q. Has the Company chosen the "Best Alternative Retro-fit Technology" (BART) for Dave Johnston units?

A. PacifiCorp hired consulting engineers Sargent & Lundy in 2006 to evaluate various options for meeting the emissions standards promulgated by the EPA in 2005. Subsequently, Sargent & Lundy's report was reviewed and updated by CH2M Hill. Based upon the analyses of Sargent & Lundy and through consultations with the Wyoming Air Quality Division staff, the Company determined that the selected technology was BART. Of various options examined the Company chose the lowest cost option that was BART.

Q. What does the Division conclude with respect to the overall prudence of the Dave Johnston project?

A. Given the requirement to meet EPA standards, the Division believes that Company's program to add pollution control equipment in a steady, measured fashion over the next several years is reasonable and prudent. The Division accepts the unit 3 costs as being reasonable and prudent based upon the analysis described above. Disagreements, if any, with unit 4 costs will await a future Docket. Therefore, the Division concludes that the unit 3 portion of the Dave Johnston pollution control project costs are prudent and reasonable and in the public interest.

E. Revenue Requirement.

Q. You discussed above the prudence of the capital costs for the Ben Lomond to Terminal transmission segment and the Dave Johnston unit 3 environmental equipment. These costs are translated into a revenue requirement. What is the revenue requirement requested by the Company?

A. Based upon the Supplemental Direct Testimony of Steven R. McDougal, PacifiCorp is requesting an incremental Utah revenue requirement of $33,018,000 (based upon rolled-in plus 1 percent interstate allocation methodology).

Q. Does Mr. McDougal's Supplemental Direct Testimony consider all known adjustments?

A. No. Mr. McDougal has not included the error in NPC found in Dr. Shu's testimony. I discussed this NPC issue in Subsection A above.

Q. Are there other adjustments that the Division is recommending?

A. Yes. Division witness Matthew Croft has analyzed the Company's application of its JAM. Mr. Croft's analysis is detailed in separate testimony as DPU 2.0 plus supporting Exhibits. The Company through Mr. McDougal admits that it fixed the income before tax, or "IBT," factor at its value in its rebuttal case in the most recent general rate case (Docket No. 09-035-23). The IBT factor is usually allowed to vary with different inputs in the JAM and relates to the calculation of income taxes. The explanation given for this modification of the JAM is that the IBT factor gave non-intuitive results in this application. Further, the Company set the starting revenue requirement at the projected revenue based upon previous rates in effect and not the revenue requirement determined by the Commission in its revenue requirement order in Docket No. 09-035-23. Other adjustments made in the rate case were thought by the Company to be immaterial by the Company for purposes of this Docket. The only adjustment made by the Company as a result of the Commission rate case order was to reduce the allowed return on equity from 11.0 percent to the 10.6 percent ordered by the Commission. The Company offered no explanation for keeping the revenue requirement at a pre-Commission Order value.

Mr. Croft shows that when the JAM is corrected for Commission-ordered revenue requirement and restores the IBT factor to a variable, the incremental revenue requirement is reduced to approximately $31.6 million when combined with the previously mentioned NPC adjustment.

As mentioned above, the Division is recommending a reduction in the addition to rate base for the Ben Lomond to Terminal transmission line. This adjustment amounts to $17,743,675 on a system basis and approximately $7,298,049 on a Utah allocated basis. This rate base adjustment also affects the revenue requirement that Mr. Croft has estimated to be about $1,005,000.

Based upon these adjustments, the Division recommends an incremental revenue requirement of approximately $31.6 million based upon a rolled-in plus one percent allocation method This revenue requirement will likely alter again somewhat as the Company comes up with final actual costs for the projects under consideration. As the Company requested, the

Division recommends the Commission enter a deferred accounting order for the $31.6 million incremental revenue requirement.

F. Interstate Jurisdictional Allocation.

Q. What is the current method for determining the Company's revenue requirement in Utah?

A. The current allocation method is referred to as "Revised Protocol." In its order in Docket No. 02-035-04, the Commission adopted a stipulation (Stipulation) among Utah parties and the Company. The Stipulation specifies that, subject to certain conditions, for Utah the Company's revenue requirement is the lesser of (1) rolled-in plus a rate mitigation cap or (2) Revised Protocol plus a rate mitigation premium. While the rate mitigation cap and premium changed over time, currently, the rate mitigation cap is one percent (1%) and the rate mitigation premium is a quarter percent (0.25%). Since adoption of the Stipulation, Rolled-In plus the rate mitigation cap has always given the lower result.

Q. What are the interstate allocation issues associated with the interstate jurisdictional allocation methodology derived from the Multi-state Process (MSP)?

A. For two reasons, the Division does not believe that interstate allocation is an issue in this case. First, while the Division is making certain adjustments to the Company's revenue adjustment request, the Company's filing is consistent with the Stipulation. According to the Division's adjustments to the Company's filed position with the Rolled-in revenue requirement, including the cap, is approximately 1,538,274,369 while the Revised Protocol revenue requirement, including the premium, is approximately $1,555,177,179. Since the Company filed for deferral of an amount based on Rolled-In plus the rate mitigation cap of one percent, the Division believes the Company's filing in this case is consistent with the Stipulation.

Second, the Company's application for recovery in this case asks for deferral of the appropriate amount and not for a rate change.

Q. Why does the Division make a distinction between a rate change and deferral?

A. The Division makes this distinction based on the Commission's recent orders in the Company's general rate case, Docket No. 09-035-23. The expectation when adopting the Stipulation was that in the early years Revised Protocol would be greater than Roll-In, but that over time the results of Rolled-In and Revised Protocol would converge and reverse. Indeed, this was one of the conditions cited by the Commission in its order adopting the Stipulation. This condition has, to date, not been met and, given the analysis to date, there are indications that this condition probably will not be met in the foreseeable future.

In the Company's 2009 general rate case, Docket No. 09-035-23, the Commission ordered the Division, and invited other parties, to respond to two questions:

1. "Are the continued use of the 2004 Stipulation terms for the development of the Utah revenue requirement in this case in the public interest?" and

2. “whether there are alternatives, such as the use of the Rolled-In method without the revenue requirement adjustments contained in the 2004 Stipulation terms, which would be just and reasonable in this case.”[15]

The Commission subsequently stayed this order but stated that, “we intend to have inter-jurisdictional allocation issues addressed and the reasonableness of any allocation established prior to our approval of any future change in RMP’s rates.”[16] However, in a subsequent order clarifying its order to stay the two questions, the Commission stated that, "We note that an application for alternative cost recovery of major plant additions under [Utah Code 54-7-13.4] does not necessarily result in rate changes coming at the end of that application's proceeding. A deferral is also possible and in all cases the Commission may apply conditions which are necessary to ensure the public interest is obtained."[17]

Based on the Commission's statements, and given that the Company is asking for a deferral and not a rate increase, the Division believes there is no interstate allocation issue to address in this case.

IV. CONCLUSION AND RECOMMENDATIONS

Q. What conclusions have you reached?

[15] “Order,” Docket No. 09-035-23, October 19, 2009, p. 3.
[16] “Order Staying October 19, 2009 Order,” Docket No. 09-035-23, November 9, 2009, p. 2.
[17] "Order on Request for Clarification or Reconsideration of November 9, 2009, Order," Docket No. 09-035-23, November 25, 2009, p. 5.

A. The Division has concluded that the costs for the Dave Johnston unit 3 scrubber are reasonable. The Division accepts the project costs of the Ben Lomond to Terminal transmission segment except for the 230 kV outage resequencing and the microwave items. These two items total $17,743,675 on a system basis and $7,298,049 on a Utah allocated basis.

In addition to the effects on revenue requirement due to the disallowance of the two rate base items mentioned above, the Division is recommending two other adjustments to the Company's revenue requirement. The Company is currently requesting of approximately $33.0 million as explained in Mr. McDougal's Supplemental Direct Testimony. First, the Company has acknowledged that an approximately $634,000 reduction in NPC is required to correct a misspecification of heat rates for the Dave Johnston unit 3. The Division has determined that the Company made inappropriate changes to its jurisdictional allocation model and did not correctly specify the beginning revenue requirement in that model; correcting these errors results in a reduction in the incremental Utah revenue requirement of $1,406,600. Together these adjustments, along with the rate base adjustments, reduce the Company's incremental revenue requirement to $31,612,292.

Q. What do you recommend?

A. The Division recommends that the Commission accept the actual project costs of the the Dave Johnston unit 3 scrubber into rate base. The Division recommends that the Commission accept the actual project costs of the Ben Lomond to Terminal transmission segment after reducing them by $17,743,675 on a system basis and approximately $7,298,189 on a Utah allocated basis. The Division recommends that the Commission accept the adjusted $31.6 million revenue requirement and issue a deferred accounting order for the revenue requirement.

Q. Does this conclude your testimony?

A. Yes.