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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations	Docket No. 09-035-23 POST HEARING MEMORANDUM OF THE DIVISION OF PUBLIC UTILITIES

The following is the Post Hearing Memorandum of the Division of Public Utilities (Division or DPU) in the 2009 Rocky Mountain Power (Company or RMP) rate case.

INTRODUCTION

In response to the Company's most recent request for a rate increase in the amount of $53.3 million, the Division is recommending an increase in rates of approximately $16.7 million. This is based on a return on equity of 10.5%, an equity ratio in the Company's capital structure of 50.5% and a variety of adjustments to the Company's results of operation. It is the Division's position that this amount of rate increase will produce just and reasonable rates and will provide the Company with an opportunity to earn its authorized rate of return.

In evaluating the reasonableness of the DPU's proposed rate increase, the Company, during the hearings, raised a number of questions that it may argue should influence the Commission in evaluating the various proposals of the parties. First, the Company may argue that it has not been able to earn its authorized rate of return in the past and, therefore, the Commission should use this fact in evaluating the reasonableness of adjustments proposed by the parties. The Company presented RMP Cross Exhibit 1, which is the Company's monthly report on earnings provided by the DPU to the Commission. Each rate case except one during the entire period reviewed by RMP Cross Exhibit 1 was settled.[1] In the settlement of the 2008 rate case, the Company agreed that the stipulation was in the public interest, that, considered as a whole, it would produce fair, just and reasonable Utah rates, and that the stipulation provided the Company a reasonable opportunity to earn its rate of return.[2] It is not reasonable for the Company to argue that it does not have a reasonable opportunity to earn its authorized rate of return when most past rates cases have been settled with the Company as a signing party. Second, the Company has indicated through a number of witnesses that this rate case must provide sufficient revenues to sustain operating expenses through September 2011 (the earliest date new

[1] Docket No. 07-035-93 was not settled.
[2] Docket No. 08-035-38 Stipulation regarding revenue requirement, paragraph 25.

general rates can take effect).[3] The Commission should not give any weight to the fact that the Company cannot file a general rate case until January 2011 because the Company in the test year stipulation approved by the Commission in June of this year agreed not to file any new general rate case until January 2011.

The Division's recommendation of $17 million dollars may appear to be a small rate increase when compared to past rate cases, but one must remember that two additional single item rate increases will be filed this year with a total potential rate increase of close to a $100 million.[4] Additionally, the Company has requested an energy cost account (ECAM) in a separate docket.[5]

THE COMMISSION SHOULD NOT ADOPT EITHER THE OFFICE'S OR THE COMPANY'S PROPOSAL ON HOW TO ADDRESS CORRECTIONS, UPDATES, AND/OR NEW INFORMATION FILED LATE IN THE PROCEDING

In the 2007 rate case the Commission ruled against RMP's attempt late in the proceeding to propose updates to its forward price curve. The Commission found that the Company's proposal was "untimely and not well supported."[6] The Commission ruled that changes by the Company to its forecast late in the proceeding are subject to a high standard of review. The Commission also noted that the regulatory "known and measurable" standard cannot be readily applied to forecasts.[7]

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[3] See for example RMP Duvall Rebuttal Testimony page 2 and Wilson Rebuttal Testimony page 7 specifically urging the Commission to address the reasonableness of adjustments based on the Company will not have another opportunity to raise rates until September 2011.

[4] TR 175-178. The possibility of an ECAM in 2010 is also a possibility, which could, if the Company's proposal is adopted, allow additional rate relief in 2010 for any increases in net power costs.

[5] Docket No. 09-035-15.

[6] Docket No. 07-035-93, Order p. 51. See OCS 4S page 3.

[7] Id.

Additionally, in the Stipulation in the 2008 rate case, the parties addressed the issue of updates specifically. The Stipulation provided that:

> The parties agreed that the discussions and comments submitted in connection with rulemaking that will be undertaken pursuant to Senate Bill 75 will also address appropriate rules governing the introduction of updates to filed positions during a general rate case proceeding, including, without limitation, symmetry, timing, and fairness to parties. The parties will jointly ask the Commission to issue rules on such issues.[8]

However, no proposal came out of the Senate Bill 75 rulemaking and the issue as to what to do with updates still exists. In this proceeding, the Division believes that the Commission has provided additional guidance on the "corrections and update issue." In its November 12, 2009 order denying RMP's Motion to Strike DPU testimony, the Commission noted that parties should make the existence of an error known as soon as possible. Second, the Commission evaluated the new information both in light of the timing of the presentation and possible prejudice to the Company. The November 12, 2009 order clearly recognized the fact that RMP has greater access to information that this needs to be taken into account in evaluating the issues of updates or corrections in information. The Commission noted that the "basis and supporting data upon which the revision is based was known by RMP and the adjustment level reasonably calculable prior to the DPU even filing the supplemental testimony."[9]

The Division still supports rulemaking as the appropriate way to address corrections and updates. This rate case proceeding should not serve as the

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[8] Docket No. 08-035-38 Stipulation on Revenue Requirement paragraph 16.
[9] Docket No. 09-035-23 Order on Motion to Strike, November 12, 2009 page 12.

basis of making general policy conclusions and rules that would apply to future dockets.

The Division offers these comments on the Office's and the Company's proposals. The Division supports neither the Office's proposal to allow no net power cost (NPC) updates, nor the Company's proposal to either allow complete and symmetrical updates or not allow them at all.[10] Both the Company and Office's update recommendations appear to focus exclusively on net power costs. However, the issue of updates and corrections permeates all areas of the rate case. Not only are there net power costs update issues but updates also have occurred in the non-net power costs revenue requirement and in the cost of service portions of the case. Some of these updates and corrections are in dispute and some are not. For example, the McFadden Ridge Wind project cost was updated to its actual costs and the Company accepted these updates.[11] Updates were made and accepted by the Company for PERCO (issue 40) and generation overhaul expense (issue 37). Also, all plant additions and retirements were updated with actual results through August (issues 50, 51, 52, and 53), the Trapper and Bridger mine portion of rate base was updated with actuals through August (issue 49), and the lead lag study was also updated (issue 55). It appears that both the Company and the Office accepted all of these updates. Other changes accepted or proposed by the Company include: an update to use

[10] Mr. Duvall, the Company's NPC witness, also proposes that the Commission establish a clear timeline allowing updates up to the time intervening parties file their direct case. Further, the Company wants the Commission to clarify that updates can be made by all parties and can either increase or decrease costs. Duvall Rebuttal Testimony page 5.

[11] On the revenue requirement side, the Company has not apparently objected to using the actual costs of the McFadden wind project but on the NPC side, Mr. Duvall apparently would object to recognizing the effect of the earlier start date on net power costs. See issue 28. See also Duvall Rebuttal Testimony page 4.

the June 30, 2009 forward price curve; updates to use the more current BPA wind integration charges; updates to include new special contracts, QF contracts and other new arrangements for Kennecott, U. S. Magnesium and Tesoro; and more current coal prices (issue 34).[12] Corrections were also accepted or made by the Company without any objections. These are outlined in Mr. Duvall's rebuttal testimony.

Office witness Mr. Falkenberg has demonstrated the problem of updates where the Company has superior knowledge over all information about its operations.[13] He pointed out many issues that could have been updated by the Company but were not.[14] These include: a more current forward price curve than June 30, 2009;[15] a variety of updates that occurred in the recent Oregon rate case docket including short term firm and a more current forward price curve that reduced net power costs (NPC) on a total Company basis by $3.5 million;[16] updates of certain wholesale contracts for Southern California Edison, San Diego Gas and Electric, and PG&E which reduced NPC by at least $2 million;[17] reduction of the Cal ISO wheeling fees from $12 million to $7 million;[18] and failure to update reserves for the wind integration study that reflects the June

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[12] The Company supports these updates to its NPC information only if certain of its selective updates are also accepted. These updates that the Company has selectively placed in the record are the wheeling contract with Idaho Power and BPA, and the Grant County purchase contract. See Duvall Rebuttal Testimony page 7.

[13] See OCS 4S.

[14] Mr. Falkenberg asserts in his testimony that many of the updates the Company left out violate its proposed standard that updates be permitted up to the time interveners file their direct testimony. OCS 2S pages 4-6.

[15] Forward price curves are updated daily and an official new forward price cure is updated quarterly. OCS 2S page 4.

[16] Id. page 5.

[17] Id. page 5. Mr. Falkenberg assets that information on these contracts was available to the Company prior to the November 12 filing date.

[18] Id. page 5.

forward price curve.[19] Moreover, UIEC Cross Ex. 1 indicates that the Company has entered into a new contract (which it did not previously disclose) for the sale of renewable power with NV Energy that will take place during 2010.

After reviewing the updates the Company has not made to NPC, the OCS recommends that all NPC updates be excluded, even those presented by parties other than RMP. The OCS withdraws its NPC update presented by Mr. Hayet. As stated previously the DPU opposes both the Company's and the OCS's proposal on how updates should be handled in this case. Furthermore, the DPU believes that there should not be a hard and fast rule that would accept or reject an update or correction as proposed by both the Company and OCS. Some updates or corrections can be easily dealt with and verified. Some updates come from standard information normally made by the Company, and some are available in sufficient time to allow all parties to address the merits of the correction or update, but some are made so late in the proceedings with such a significant impact that the parties are not able to address the issues on the merits.

In this case, the DPU would urge the Commission to look at each contested update the Company has made and to evaluate each update individually. In making those decisions the Commission should consider three factors: 1) the availability (or lack thereof) of the data to all parties, 2) the complexity and amount of analysis required to evaluate the new information, and 3) the timeliness and the prejudice to parties that exists as a result of the new information. For example, late changes that rely on publicly available information

[19] Id. page 6.

and are relatively simple might be included (e.g. a rate base item entering service earlier than expected). However, if the underlying data are complex and difficult to analyze, this fact prejudices some parties more than others and might be excluded.

In addition, as noted by the Commission in the 2007 order, updates by the Company to its uncontested issues late in the proceeding must meet a high standard of review. This high standard of review is consistent with the burden of proof placed on the Company. This high standard of review is also consistent with the fact that the Company controls all information about its operations and, as has been shown above, has not included all updates to the revenue requirement in this case.[20] When applying these standards to the Company-proposed updates that appear to be currently in dispute, the DPU believes the Commission should not make adjustments based on those updates.

A brief review of what issues the DPU sees currently in dispute on updates and corrections may be helpful. The Division offers three specific examples.

First, although the Company agrees with the amount of the coal price update (issue 34), it seems to object to the update occurring since it was made in supplemental testimony and not in the DPU's direct testimony. It is hard to understand how the Company objects to this information. It did not object to the supplemental direct testimony of Mr. Evans, as it did to other DPU supplemental

[20] In the past, the Commission gave as one of its reasons to exclude post test year adjustments the Company's unequal access to information allowing it to propose post test year adjustments statically instead of providing complete post test year changes. That concern applies to updates where the Company late in the process proposes significant updates or changes that are either difficult to address on their merits or where it appears that not all updates have occurred.

testimony, because of "difficulties Mr. Evans had in obtaining spreadsheets and other information related to the coal costs adjustment he proposed."[21] This is a prime example of how the Company's control of information affects whether an adjustment can be timely under the Company's proposed standard or untimely because the DPU witness had problems getting the right information from the Company.

The second update that is of concern relates to the BPA peaking contract, the Grant County purchase contract, and the Idaho Power and BPA wheeling contract.[22] It appears to the DPU that updates to these issues should not be allowed for reasons similar to those recognized by the Commission in the 2007 rate case. These issues were raised late in the proceedings when the Company could have provided the updates earlier in the proceedings.

The third update or correction that is of concern relates to the significant changes in the cost of service results that the Company made late in this docket. This update is a prime example of information that requires extensive time for analysis. It is the DPU's position that these changes should not serve as the bases for rate spread in this case. Instead, the DPU recognizes these changes in the deviations from the actual cost of service results presented by the DPU witnesses.

In conclusion, it is important to remember who has the burden of proof and which party is most likely to know what changes have occurred in the Company since it filed its case. Updates the Company proposes should be made when

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[21] Motion of RMP to Strike Pre-Filled Supplemental testimony of the DPU dated November 9, 2009 page 2.
[22] See DPU Ex. 6.0SR pages 12-14.

known and, given the complexity of the updates, made in time so that the updates can be adequately addressed by the parties. Further, the DPU believes that the issue of updates is not a NPC issue alone, but also applies to other revenue requirement issues and cost of service. It is inconsistent for the Company and the Office to accept updates in one part of the case and to oppose them in another. The updates and corrections made by the Company should be viewed individually based on the reasons given by any party for objecting to the correction or update and the suggested standards given above.

THE COMMISSION SHOULD ADOPT THE DIVISION'S RECOMMENDATIONS ON THE COMPANY'S HEDGING PRACTICES AND ORDER THE COMPANY TO FILE ITS POLICIES IN A SEPARATE DOCKET

The issues surrounding the hedging practices of the Company have been on the periphery of rate cases for a number of years. The importance of reviewing the Company's hedging practices resulted in the parties in the stipulation in the 2008 rate case asking the Commission to open a docket, issue a protective order, allow discovery and hold a technical conference to review the Company's policies and procedures on natural gas price risk management.[23] As a result of this 2008 Stipulation, Docket No. 09-035-21 was opened. The technical conferences and related activities in that docket were to be held before this rate case so that the information obtained in that proceeding could be used in this rate case. Several technical conferences were held in that docket.

In its NPC for this rate case, the Company has included $174.2 million in natural gas swaps and $187.8 million of revenues from electric swaps. In this rate case, the DPU hired a consultant, Blue Ridge Consulting Services, to both

[23] Docket No. 08-035-38, Revenue Requirement Stipulation paragraph 12(b).

review the hedging practices of RMP and to present the Commission with a general overview of how other commissions throughout the country have addressed the reasonableness of hedging practices of utilities under their jurisdictions. Division witness Mr. Wheelwright also put forth testimony concerning PacifiCorp's hedging practices. The DPU's consultant and witness propose no adjustments, but do make certain recommendations to the Commission. The DPU requests that these recommendations be addressed by the Commission in its decision in this rate case. The Company's response to these important issues consists of two pages in Mr. Duvall's testimony, with only eight lines actually addressing the recommendations. The Company's proposal is that "it believes the Division's recommendations cannot get the full consideration they deserve until the Commission has ruled on the structure of an ECAM for Rocky Mountain Power."[24] While an ECAM and hedging issues can affect one another – for example, a greatly reduced volume of hedging could justify more costs flowing through an ECAM – the Company's hedging practices are likely to continue with or without an ECAM. The Division opposes delaying a decision by the Commission to establish what role it wishes to have in the Company's hedging practices. The Division recommends that the Commission specifically set up or designate a docket to address hedging issues, perhaps the existing Docket No. 09-035-21, and that the Commission order the Company to provide the information and studies recommended in Mr. Wheelwright's

[24] RMP Duvall Rebuttal Testimony pages 46-47.

testimony and the recommendations made by Blue Ridge Consulting.[25] The end result of the hedging specific proceeding should be the Commission approving guidance and standards for the Company's hedging strategies.[26]

NET POWER COST ADJUSTMENTS

Wind Integration Costs (issue 21)

In this rate case, the Company is proposing to include approximately $28 million in wind integration costs, amounting to $6.62 per MWh at each of the Company's wind facilities.[27] These increases in wind integration costs constitute a dramatic increase over what is currently in rates. In the last rate case, the Company's wind integration costs were $1.16 per MWh or approximately $6.1 million.[28] Over the past few years, the Company has been committing ratepayers to a significant amount of wind resources. Mr. Higgins for UAE indicates that with this dramatic increase in integration costs proposed in this rate case, the costs of integrating wind into the Company's system are approaching the per MWh costs of some of the Company's coal plants.[29] The new charges presented in this case are based on the analysis done in the Company's 2008 IRP, which was filed with the Commission in May of this year. The $1.16 MWh cost[30] used in the 2008 rate case was based on the 2007 IRP and was limited to

[25] DPU Ex. 12.0 pages 16-17 and DPU Ex. 3.8, which contains specific recommendations, pages 12-21.
[26] DPU Ex. 12.0 page 16, recommendation 2.
[27] DPU 6.0 page 13. The $6.62 per MWh reflects the rebuttal position of the Company which reduced the inter-hour wind integration cost to $1.79 per MWh.
[28] UAE Ex. 1 page 13.
[29] UAE Ex. 1 page 12.
[30] The 2007 rate case included a cost of $1.14 per MWh. In that case the Company argued that the $1.14 was needed to support 2000 MW of wind. The Commission in its Order accepted the $1.14 charge but commented that it "recognized that the Company has limited experience to date in forecasting integration costs as the Company adds greater amounts of wind resources …" The

an estimate of the intra-hour forecast deviations. The new costs for this rate case include three additional elements: regulate up and regulate down for intra-hour costs and inter-hour costs, which are made up of day ahead and hour ahead system balancing.

In its direct testimony, the Division did not challenge the inter-hour wind integration costs of $1.79 MWh. Although the Division recognized that there are intra-hour costs, it concluded that the assumptions and analysis performed by the Company were so fatally flawed that the Commission should reject them and only allow inter-hours costs. Division witness Dr. Powell reviewed the statistical assumptions used by the Company in its intra-hour study to arrive at the amount of incremental reserves. He concluded that the assumption used by the Company that the data were normally distributed was not correct and thus the use of the 1.96 Z score was invalid. This conclusion undermines the entire statistical conclusions reached by the Company's study.[31] In addition to the Commission's inability to rely on the statistical study of the Company, the Commission cannot rely on any historical data to demonstrate that the amount of incremental reserves needed by the Company exists.[32] Other concerns raised by Dr. Powell and Mr. Evans include an assumption by the Company that additional reserves are needed for the wind resources without evaluating the actual levels of reserves that would be carried without the wind,[33] use of a limited

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Commission invited future discussion of the best way to calculate, forecast, and reflect in rates wind integration costs. Docket No. 07-035-93, Order page 53.

[31] DPU Ex. 11.0 page 12.

[32] DPU Ex. 6.0SR page 6. Additional concerns of the DPU about this study are also reviewed.

[33] DPU Ex. 6.0 page 14.

amount of wind data in the analysis,[34] and failure to take into account loads in its analysis of needed reserves. As a result of these flaws, the DPU concluded that the Company had failed to meet its burden of proof necessary to include the intra-hour charges proposed.[35]

Recognizing that there are intra-hour costs, despite the imperfect data, in surrebuttal testimony Dr. Powell proposed that the Commission allow an intra-hour cost of $3.02 per MWh or total wind integration costs of $4.81 per MWh. The DPU's rationale for adopting this figure is explained in much more detail in Dr. Powell's surrebuttal testimony. [36] The $3.02 cost figure is proposed by Mr. Higgins of UAE. As the Commission is aware, the Company's proposal was presented in its 2008 IRP, which is currently pending before the Commission. In many instances, the Division's concerns in this case were also presented in its IRP comments. In either this docket or in the IRP docket, the DPU urges the Commission to provide its input on what changes need to occur in the Company's wind integration studies.

GRID Start Up Energy (issue 12)

Standard utility modeling packages such as PROMOD include start up energy produced in their modeling. The Company's GRID model, which imputes the costs of fuel to start up units but excludes the energy produced from those units during start up, is an outlier and should not be accepted by the

[34] DPU Ex .6.0 page 16. The wind data used was from September 2008 to April 2009, and did not include any summer data. Also data from new wind facilities are not included.

[35] Mr. Duvall in rebuttal testimony failed to respond to the fundamental flaws pointed out by the Division but instead argued that the Company's results are reasonable in spite of its concessions that its study can be further refined and is based on a limited amount of information. RMP Duvall Rebuttal Testimony page 42.

[36] For an explanation of how Dr. Powell arrived at the $3.02 MWh, see his testimony DPU Ex. 11.0SR page 7.

Commission. Both the DPU and OCS propose that the energy produced during startup be taken into account in developing NPCs. The issues that exist between the parties relate to the valuation of the amount of startup energy that exists, not to the undisputed conceptual fact that there is startup energy. This startup energy needs to be taken into account in arriving at NPCs. The main difference between the DPU and the OCS is how the credit should be given for energy produced. The DPU proposes to use savings of average fuel costs at the Company's coal fired power plants while the OCS uses a market-based approach.

In conclusion, the DPU urges the Commission not to reject the inclusion of the startup energy produced when gas units ramp up. Energy produced at startup, as well as the startup fuel, should be included.

Planned and forced outage rates (Issue 22)

Although this is a relatively small dollar issue, it is brought up to highlight that the planned outage schedule in GRID must be more closely aligned with actual historical outages. In his November 12th rebuttal testimony, Mr. Falkenberg adopted Mr. Evans' adjustment to coal plants that he believes produces a more realistic planned outage schedule for coal plants. The only response by Mr. Duvall was that the DPU proposal was arbitrary and allows gaming. Aligning historical planned outages more closely to GRID assumptions is not arbitrary and one cannot game the system if you are aligning the model with what is actually happening.

ACCOUNTING ADJUSTMENTS

Uncollectible Account Expenses (issue 38)

The amount of uncollectible expense can vary significantly from year to year. In order to normalize that expense for ratemaking and also to forecast the level for the test year, the DPU and OCS both recommend that a three-year average be used. At some point over the years, the Company and other parties moved away from using an average,[37] and instead the Company in this case escalated its base period results forward and moved its results to the end of period to arrive at its test year estimate.[38] With this methodology the Company proposed an uncollectables rate of 0.352%. This level is well above historical levels. Recognizing this, the Company in rebuttal testimony proposed to use its target rate of 0.27%. This significantly narrowed the dispute between the DPU's three-year average of 0.24% and the Company's revised recommendation. Both the DPU and OCS recognize that the use of an average is a reasonable way to normalize this expense and recommend that it be used in this case. The Company raised a concern that if the Commission prefers an average in this case, an average should also be used in the future. The Division has no objections to using an average as a means to normalize this expense in future rate cases.[39]

[37] In the Company's 1999 rate case, the last contested rate case before 2007, both the Company and others used averages to arrive at a test year result. The Commission also noted that in the 1997 rate case it decided the issue using a three-year average. See Docket No. 99-035-10, Order page 51.
[38] DPU Ex. 8.0 lines 178-184.
[39] Because of anomalies in the bad debt expense data, part of the dispute in the 1997 and 1999 cases included which years to include in the average. If an average methodology is adopted care should be exercised to eliminate such anomalies in the future from the average calculation. See Docket No. 99-035-10, Order page 51.

Generation Overhaul Expense (issue 37)

In direct testimony, through Ms. Salter, the Division recommended that the Commission follow its decision in the 2007 rate case on generator overhaul expenses. Ms. Salter made a similar adjustment in the 2008 rate case. The specific issue presented is whether an escalation rate should be included in an average of historical levels when estimating a test year level using that average. In the decision in the 2007 rate case, the Commission noted that this was the first time escalation within an average had been proposed. The Commission[40] was not persuaded that this was an appropriate approach and was concerned that the practice could get extended to other expenses that are calculated using an average.

As a result of the analysis in the surrebuttal testimony of Dr. Powell, the DPU altered its position on this issue, and instead accepted the Company's method of calculating this expense. The Office does not agree either with the results of Dr. Powell's analysis or its timing. The DPU, however, believes that when it has concluded that its adjustment is not appropriate, it immediately should bring that to the Commission's attention, and not hold on to an adjustment that has been made by the Division in the past. The Division urges the Commission to review Dr. Powell's analysis and reach its own conclusions. No matter what is done in this case, the Commission could choose to leave the issue open for more discussion, if needed, in future cases without making any broad policy decisions here. We recommend, however, that the adjustment that was adopted in the 2007 rate case not be made in this case.

[40] Docket No. 07-035-93, order page 81.

CWIP Write Off (issue 73)

In the surrebuttal testimony of DPU witness Mr. McGarry, the amount of this adjustment decreased significantly. However, the principal behind the adjustment is still present. The DPU believes this is the first case in which this issue has been presented to the Commission. The basic position is that CWIP for projects that are cancelled for reasons outside the direct control of the Company should be included in rates, while projects that are cancelled for budget, funding, or management approval reasons wholly within the Company's control are most closely related to abandoned projects, should be written off to FERC account 426.5, which is a below the line account and is not included in rates.[41] In the future, if the Company wants recovery of CWIP on projects that fit the above criteria for inclusion in rates, it should specifically make that request to the Commission in an appropriate general rate case or other relevant proceeding.

Wind Project Issues

In the past few years and continuing into the future, the Company plans to acquire and build a significant amount of wind resources. In this and future rate cases, the Commission will be asked to rule on the prudence of these wind projects. In this case, the Company was specifically asking to include the McFadden Ridge 1 project in rate base. Dr. Zenger was the DPU witness who performed that review and as a result made recommendations to the Commission addressing concerns outlined in her testimony. Although there is no

[41] DPU Ex. 3.0 page 18.

specific dollar adjustment being proposed,[42] the Division asks the Commission to address the concerns presented by Dr. Zenger. This section will address some of those issues.

The most significant issue raised by Dr. Zenger is who should bear the risk of contingency forecasts included in a wind project cost estimate in a rate case before actual costs are known. The DPU believes that the Company should bear that risk rather than ratepayers. It is a risk that will cease to exist as soon as actual costs of the project are known, and a new rate case incorporates those actual costs. McFadden Ridge can be used as an example of this issue. When the Company filed its Application, it proposed its estimate of the cost of the project be included in rates. Part of that cost estimate included a contingency that can be found on page 4 of DPU Ex. 10.0 SR (which is a confidential exhibit). With the proposal as stated in the Company's application, if the cost of the project were not known during the rate case and the project was found prudent, the estimated costs of the project, including the contingency, would be included in rate base, allowing the Company to earn a return on that estimate. With McFadden Ridge, the actual costs were significantly under the estimated costs but only the actual cost amount is being requested to be included in rate base in this case. No contingency was needed. The DPU's position is that the risk of incorrectly estimating the cost of wind projects that is represented with the contingency should rest with the Company, and not with ratepayers. After actual

[42] In Dr. Zenger's direct testimony she proposed a $1.1 million rate base adjustment to remove the contingency included in the Company's estimated project costs. However, actual costs for the project are now known, and that actual amount is now being requested to be included in rate base.

costs are known, those costs can be incorporated into rates. In other words, the DPU has no objection to the Company earning a return on the reasonable and prudent estimated costs made by the Company, but does object to the Company earning a return on the contingency that may or may not be needed to cover the actual costs of the project.

Addressing a few other issues would assist the DPU and the Commission in reviewing future wind projects. Two issues relate to information to be provided, and two other issues relate to future discussions that are needed to better understand the Company's wind acquisition strategy.

First, the DPU asks that the Company provide notification of when wind projects come into service. In his rebuttal testimony, Company witness Mr. Lasich referred to certain wind purchase agreements of which the DPU was not even aware.[43] With the significant amount of wind resources planned, this does not seem like a burdensome request, but rather an important tool to be made available. Second, when the Company makes a request to include a wind project into rate base, its testimony should include the detailed costs of the project rather than just a lump sum estimate. In this case, numerous data requests had to be made that could have been avoided if more up front information was provided.

The Division also recommends that the Commission require the Company to make a presentation at a technical conference on two issues: First, a presentation justifying the Company's recent tendency to build 99 MW wind projects that appear on the surface as a way to avoid Oregon bidding

[43] DPU Ex. 10 SR page 9.

requirements, and second, a presentation on how the Company is obtaining diversity of its wind projects to maximize their benefits. Mr. Lasich in his rebuttal testimony indicates that he has no objections to making presentations to the DPU.[44] The DPU asks that these presentations be done in a technical conference or other public forum where all parties and the Commission can attend if they wish.

<u>Coal Inventory Adjustment (issue 44)</u>

During 2008, the base period in this rate case, the Company began to increase significantly the coal inventory levels at the Utah coal plants, in particular, at the Hunter plant. The increases occurred as a result of the Electric Lake Settlement and the West Ridge Agreement.[45] It is the Division's position that the coal inventory levels at the Utah coal plants are excessive. There do not appear to be any plans to bring the inventory levels back to more normal levels. Of note, the inventory levels at these plants far exceed both past RMP historic inventory levels and agreements with state commissions as to target inventory levels and inventory levels for other utilities.[46] As a result of these facts, an adjustment is appropriate. The effect of the adjustment would be to reduce rate base to an inventory level that, even with the adjustment, exceeds historical inventory levels and the targets the company EVA and state regulators had agreed to use as targets.[47] The Division's witness on this issue was Mr. McGarry

[44] RMP Lasich Rebuttal Testimony pages 17-18.
[45] RMP Lasich Rebuttal Testimony pages 3-6.
[46] See DPU Cross Ex. 4. This exhibit is a NERC document that shows that at the coal inventory levels at the Utah plants are significantly above levels in other parts of the country including the west.
[47] See the confidential coal procurement policy statements attached to Mr. McGarry's rebuttal testimony.

and the Company's witness was Mr. Lasich. Much of the information on this issue is confidential. This section of the memorandum will avoid reference to material that is confidential but instead will ask the Commission to specifically review the exhibits that contain the necessary information.

We would ask the Commission to review the documents that represent the Company's coal inventory policy.[48] These exhibits demonstrate that the interjurisdictional task force retained an outside consulting firm to review the coal inventory policies of the Company. As part of the consulting firm's review, coal inventory targets were recommended. Both the Company and the state regulators accepted these recommendations. These targets have been in effect for years,[49] and are far below the proposed inventory levels at the Utah coal plants. Those schedules also show that the inventory levels at the Utah plants exceed historical levels. The DPU is not suggesting that the Company reduce inventory levels to the targets agreed to between the Company and regulators, but instead to reduce the inventory levels down the levels portrayed on RMP's ARL Ex. 1, included in Mr. Lasich's rebuttal testimony. It is the DPU's position that the Company, in its direct case, should have raised with the Commission the high inventory levels at these plants and that the Company planned to exceed the agreed-upon targets. Instead, Mr. Lasich's direct testimony was silent on this change. The Company argues that if opportunities arise to purchase below market price coal, it will take advantage of those opportunities. The Company

[48] The most recent policy statement is DPU Cross Ex. 3. The historical inventory policy statements can be found in Mr. McGarry's surrebuttal testimony. Theses historical inventory policy statements are dated May 16, 2007, June 1, 2007, and March 13, 2008.
[49] The reviews by the outside consultant took place in 1991 and 1995, shortly after the merger between Utah Power and Light and PacifiCorp.

argues that those actions are consistent with its coal policy. The Company notes that this additional inventory benefits ratepayers approximately $12 million.[50] Two aspects of this exhibit bring into question the Company's conclusions. First, the analysis only looks to the end of 2010. The Company has indicated that it has no plans to reduce the inventory levels at those plants in the future. With the carrying charges caused by the high inventory levels, it will only take a year or two to eliminate any benefits associated with the high inventory level. Second, the benefits assumed in the exhibit are based on the assumptions in the exhibit, the market prices in particular, that the Company claims it would have to pay for substitute coal. It was Mr. McGarry's position that the market prices were high and that they did not represent the cost at which the Company could actually purchase this additional coal.[51]

During the hearings, an issue was raised involving corrections to Mr. McGarry's calculation of the adjustment. Reference should be made to Mr. Lasich's Rebuttal Ex. 1 entitled "Corrections to DPU fuel stock analysis." The Division accepts the first correction which takes into account the joint ownership of the Hunter plant with other Utah entities. The effect of this correction on the coal inventory levels at the Hunter plant can be seen in correction 2 on Mr. Lasich's exhibit. The second correction in the exhibit addresses the 2008 burn levels at the Utah coal plants that were incorrectly provided by Mr. McGarry in his testimony. The actual 2008 burn levels reported in the Company's FERC Form 1

[50] See DPU Cross Ex. 2.
[51] DPU Ex. 3.0 SR page 11.

are included in the record.[52] The effect of this error is small. (See correction 1, which includes the actual 2008 burn levels and amounts to a change of approximately $100,000).[53] Note, correction 1 includes the actual 2008 burn levels but uses a 13-month average versus the Company's proposed use of a beginning and ending balance. The final correction suggested by the Company is to remove the high ash coal from the calculated adjustment to reduce inventory levels. The DPU does not accept this correction. The high ash coal is included in rate base. Ratepayers are paying a return on that inventory level. It should be included in the calculation since ratepayers are paying and will continue to pay a return on that coal for the indefinite future.

These corrections should not divert the Commission's attention from the issue before it - whether the high inventory levels at the Utah plants are justified both now and into the future. It is the DPU's position that the high inventory levels are not and an adjustment is warranted.

RATE OF RETURN AND RELATED ISSUES

Introduction

In this case, the testimony of Division witness Mr. Charles E. Peterson, with its comprehensive analysis, survives challenges from Company witnesses Mr. Bruce N. Williams and Dr. Samuel C. Hadaway. Mr. Peterson testifies that an appropriate rate of return for the Company is 10.50%, with an overall cost of capital of 8.26%, and with a 50.5% common equity ratio. In light of the evidence

[52] TR 369-371. Mr. McGarry advised the Division that he inadvertently placed 2007 burn levels in his calculation rather than 2008 burn levels.
[53] Correction 1 is the difference between a 13 month average inventory level and the Company's beginning and ending balance of inventory levels.

presented in this case, the percentages set forth by Mr. Peterson are just, reasonable, and in the public interest and should be accepted by the Commission.

The Commission has applied the leading cases of FPC v. Hope Natural Gas Company[54] (Hope) and Bluefield Water Works v. PSC[55] (Bluefield). Evidence concerning business risk, financial models and proxy companies plays an important part in the ratemaking process. The Commission discussed the importance of a rate of return decision giving investors the opportunity to earn a return comparable to that from an investment with similar risk. However, not only must the ratemaking process provide opportunities for investors as noted above, but also ratemaking must protect “ratepayers from exploitative rates”[56] requiring the Commission to “examine the effects of the proposed expenses upon ratepayers and shareholders.”[57] The Commission exercises “broad discretion in setting the rate of return on equity.”[58] The Commission stated that, “The allowed return, in short, must be reasonable, and be fair to shareholders and to ratepayers. Within this ranges, all returns are by definition reasonable.”[59]

In evaluating the evidence, the Commission emphasized that it is important for it to “ascertain that each witnesses judgments are finely and carefully made” utilizing financial model data and other information because a

[54] 320 US 591 (1944).
[55] 262 US 659 (1923).
[56] Stewart v. Utah Public Service Commission, 885 P.2d 759, 767 (Utah 1994).
[57] US West Communications Inc. v. Public Service Commission of Utah, 901 P.2d 270, 276 (Utah 1995).
[58] See Mountain Fuel Supply Company v. Public Service Commission, 861 P.2d 414 (Utah 1993).
[59] Questar Gas Company 2002 General (Distribution Non-Gas) Rate Case, Docket No. 02-057-02, December 30, 2002 at page 20.

"rate of return analysis is a subjective exercise" that requires the Commission to "assess witnesses' judgments carefully."[60]

Capital Structure

Mr. Peterson has proposed a 50.5% common equity ratio in this case,[61] lower than the Company's request for 51.0%.[62] To arrive at a percentage he believes appropriate, Mr. Peterson relied upon the Company's balance sheet from its June 30, 2009 SEC Form 10-Q, the Company's response to the DPU's confidential data request 3.1, and his own estimate of the Company's net income for the six months ending December 31, 2009.[63] Importantly, the balance sheet as of December 31, 2009 is assumed to represent the average for the test year and falls at the midpoint of the test year.

The Company's requested common equity percentage is unsupportable. Primarily, the differing percentages proposed by Mr. Peterson and Company witness Mr. Williams result from the difference between the recent actual results used by Mr. Peterson to calculate retained earnings, and the Company's budgeted forecast net income, used by Mr. Williams. There is a significant material difference between the two figures.[64] Mr. Peterson rejected the Company's forecast for the last half of 2009 because "the Company's forecast was prepared prior to the June 30, 2009 quarterly 10-Q report and had a forecasted earnings amount that was higher than the actual result for that quarter

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[60] Id. at pages 19-20.
[61] DPU Ex. 1.0 lines 323-324. See also November 10, 2009 TR p. 86, lines 14-20.
[62] RMP Williams Direct Testimony line 40.
[63] DPU Ex. 1.0 lines 323-328.
[64] DPU Peterson Surrebuttal Testimony (confidential) lines 195-203, where the two figures are presented. At the hearing, Mr. Peterson corrected certain numbers in his surrebuttal testimony, but the corrections should not be seen as changing the validity of his conclusions.

ended June 30, 2009."[65] Because the forecasted earnings were higher than the actual earnings, Mr. Peterson concluded that a downward adjustment of the earnings forecast was warranted.[66] The downward adjustment was further supported by reduced MWh sales in 2009 as compared to 2008, with revenues being quite flat for the first six months of 2009 as compared to 2008. Moreover, the then-latest data from Energy Information Administration (EIA) support Mr. Peterson's conclusions and downward adjustment.[67] Mr. Williams' comments regarding the five-quarter average method in his rebuttal testimony, which mirrored his comments in his direct testimony, did not alter Mr. Peterson's conclusions.[68] Additionally, when Mr. Peterson used confidential information provided in Mr. Williams' rebuttal testimony, the result did not support Mr. Williams' proposed figures. The calculation using the revised figures, and certain critical assumptions such as forecasts being exactly correct, resulted in a capital structure of 50.75% common equity.[69] The Division believes that an increase in the equity percentage structure is "neither likely to result in an increase or decrease in the Company's bond rating, either as part of MEHC or on a stand-alone basis, nor is it likely to result in any measurable change in cost of debt."[70] Contrary to Mr. Williams' concerns that an equity ratio of 50.50% would not necessarily maintain an A3 bond rating, notably Moody's criterion for an A3 rating is a range of 40 to 60%.[71] Additionally, changes that the Company or MEHC

65 Id. at lines 341-345.
66 Id. at lines 344-345.
67 DPU Ex. 1.0SR. lines 227-231.
68 Id. lines 237-241.
69 Id. (confidential) lines 193-219.
70 DPU Ex. 1.0 lines 305-321.
71 Id. at 318.

make, such as MEHC's anticipated equity capital contributions from MEHC,[72] will affect the Company's equity structure.[73] Of note, according to Mr. Williams, percentage of equity structure is "only one of the four key financial metrics that Moody's uses to assess utility credit ratings," with the other three being cash flow metrics.[74] Mr. Williams acknowledged that the Company's credit ratings benefit from "ownership by MEHC and its parent, Berkshire Hathaway."[75] Despite Mr. Williams comments, the Division's witness Mr. Peterson stated that his estimate remains "justified and reasonable; indeed it may turn out to be optimistic."[76]

The Division recommends that the capital structure for preferred stock remain at the established level of 0.3%.[77] Using the recommended 50.5% of common equity, and 0.3% level for preferred stock, results in long-term debt percentage of 49.2%.[78]

The Division urges the Commission to adopt the Division's recommendations set forth above.

Cost of Debt and Preferred Stock

The Division does not dispute the Company's embedded cost of long-term debt of 5.98% or the Company's cost of preferred stock rate of 5.41%.[79] The Division noted that PacifiCorp has indicated it does not plan to pay common

[72] RMP Williams Direct Testimony pages 3 and 7.
[73] DPU Ex. 1.0 lines 347-355.
[74] RMP Williams Rebuttal Testimony lines 88-96.
[75] Id. at 58-61.
[76] DPU Ex. 1.0SR (confidential) lines 237-246.
[77] DPU Ex. 1.0 lines 357-359.
[78] Id. at lines 357-361.
[79] Id. at lines 366-373.

stock dividends in the new year and has not indicated that it will be offering new preferred stock in the future.[80]

Cost of Common Equity

Through the use of multiple models and extensive analysis, the Division concluded that an appropriate point estimate for cost of equity for the Company is 10.50%. The Division's cost of equity estimate is set forth on DPU Exhibit 1.5, detailing the results of the single stage DCF models, two-stage DCF Models, and other models resulting in a reasonable range of 10.1% to 10.8%. Additional detail is provided in DPU Exhibit 1.5a and subsequent exhibits. The Division's recommended cost of equity is lower than the initial "conservative point estimate of 11.0" proposed by Company witness Dr. Hadaway, which remained unchanged after he reduced his DCF and risk premium cost of equity estimates by 30 to 50 basis points.[81]

The Division offered the Commission a robust analysis and many models including single stage and two-stage discount cash flow models and risk premium models to review and weigh regarding the appropriate cost of equity. With regard to the DCF models, the Division considered both single stage and two-stage models with varying growth rates, and also coupled with two types of risk premium models.[82] Each model is described and assessed by Mr. Peterson.[83] As part of his DCF analysis, Mr. Peterson used the 75% weighting on earning growth estimates and the 25% weighting on dividend growth

[80] Id. at lines 371-373.
[81] RMP Hadaway Rebuttal Testimony lines 27-32.
[82] DPU Ex. 1.0 lines 426-431, 753-828 (single stage DCF) and 830-875 (two-stage DCF).
[83] Id. at lines 437-529.

estimates set forth by the Commission in its 2002 Questar order.[84] Mr. Peterson gave more weight to the two-stage DCF models than he had in previous dockets due to the use by others of historical GDP growth rates to estimate long term growth for electric utilities.[85]

Additionally, the Division used the CAPM risk premium model and a model based upon Value Line financial strength ratings in its analysis, presenting both a description of the models and their strengths and weaknesses. Mr. Peterson concludes that he ultimately gave little or no weight to the results of the CAPM model because the results appeared unreasonable to him. As to the Value Line model, the Division offers that it does not necessarily expect the Commission to rely upon this model, but that the Division witness has personally used the model for many years and compares its results with other estimates.[86]

The Division selected comparable (proxy) companies that were generally comparable to those used by the Company[87] but did not use some companies identified by the Company because the Division determined that the suggested proxy companies were too small or had other characteristics that made them undesirable.[88]

Dr. Hadaway's analysis and models produced results that when analyzed do not persuasively support the Company's requested cost of equity. Dr. Hadaway uses past GDP growth rates in his models that are "far different from

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[84] Id. at lines 488-497.
[85] Id at lines 523-539.
[86] DPU Ex. 1.0 lines 531-687.
[87] Id. at lines 690-740.
[88] Id. at lines 1001-1016. The Division used nine companies used by Dr. Hadaway in the Division's analysis, and added three more companies to create a meaningful proxy group.

the current situation."[89] The growth rate of 6.2% offered by Dr. Hadaway is calculated as a "weighted average of change in nominal GDP back to 1947, basically the post World War II period."[90] No basis is given "for the weighted average historical GDP growth rate's relevance to expected future growth rates for regulated electric utilities."[91] Obtaining and using long-range forecasts instead of an average of past GDP growth rates would have better served the Commission."[92]

Additionally, use of EIA forecasts and those provided by the Congressional Budget Office (CBO) would have reduced the results of Dr. Hadaway's DCF models about one full percentage point lower than he offers in his direct testimony.[93] Dr. Hadaway's comments rejecting the use of the CBO and EIA forecasts fail to recognize that investors contemplate deviation of the future from the past, and that the future is not always a linear projection of the past. Growing competition from rising third-world economies, especially China and India, and likely higher energy prices in the future are among the foreseeable factors that will likely dampen future U.S. growth rates.[94] Furthermore, if political motives influenced EIA and/or CBO forecasts as stated by Dr. Hadaway, it would seem more likely that instead of "fairly mediocre real growth rates of about 2.5%," the forecasts would be "relatively rosy."[95]

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[89] Id. at lines 1061-1070.
[90] Id. at lines 1020-1023.
[91] DPU Ex. 1.0SR lines 114-117.
[92] DPU Ex. 1.0 lines 1035-1036.
[93] Id. at lines 1033-1047.
[94] DPU Ex. 1.0SR lines 132 –139.
[95] Id. at lines 141-145.

Dr. Hadaway also used two risk premium models incorporating authorized rates of return and average public bond yields. However, published authorized rates of return as estimators of expected market returns are of doubtful reliability because authorized rates of return are frequently the result of negotiated settlements involving tradeoffs with many other rate case items, Furthermore, the same argument may hold in litigated cases as well, which may also be affected by policies embraced by different jurisdictions. These factors call into question the persuasiveness of this portion of Dr. Hadaway's analysis.[96] Another third risk premium model used by Dr. Hadaway suffers from the use of Ibbotson/Morningstar data from 1926 to the present, which "includes business and economic conditions that are far different from the current situation."[97] For this type of risk premium model, it would be better to use the Company's current market cost of debt.[98] Dr. Hadaway and Mr. Peterson also differ in their opinions regarding the current economy's effect on the cost of equity.[99] An analysis comparing the Company's long-term borrowing rate with Mr. Peterson's recommended cost of equity supports the persuasiveness of the 10.50%.[100] Dr. Hadaway's criticisms regarding this point are unfounded and unsupported.

The Division's recommended cost of equity of 10.50% sits well within the estimates arrived at using standard financial models and forecasts derived from market participants. Evidence supports a Commission finding that the Division's

[96] DPU Ex. 1.0 lines 1049-1070.
[97] Id. at lines 1061-1067.
[98] Id. at lines 1067-1070.
[99] DPU Ex. 1.0SR lines 81-83.
[100] Id. at lines 153-167.

point estimate of a 10.50% cost of equity is just, reasonable, and in the public interest.

The capital structure, cost of debt, and cost of equity proposed by the Division will result in just, reasonable rates that are in the public interest, and should be adopted by the Commission.

Cost of Service and Rate Design

The Division's witnesses offered insight regarding the cost of service and rate design in this docket. Mr. Mancinelli stressed that there must be consistencies between the JAM and the RMP COS study with regard to functionalization and classification, and that there is slightly more flexibility regarding allocation of costs. Mr. Nunes addresses load research data and related issues. In his surrebuttal testimony, Dr. Brill presents the Division's final rate spread, based upon the analysis the Division conducted throughout the proceeding.

Classification of Fixed Production Costs

Mr. Chernick's suggestion that the Equivalent Peaker Method should be used to classify all generation costs as energy related, or at least 50% energy related and 50% demand related, confuses market pricing structure and the utility's underlying cost structure. This method does not reflect cost of service from an embedded or marginal cost perspective, and should not be adopted.[101]

The used and usefulness of a generation asset must be taken into account when it is classified. Classifying all generation units as 100% demand is

[101] DPU Ex. 5.0R lines 95-120.

inaccurate, and does not take into account the generation assets contributions to the system from a planning and operational perspective. Mr. Brubaker's suggestions ignore these facts, and a simple illustration can demonstrate the superiority of applying the used and useful method of classification. If a baseload generation unit has an annual capacity factor of 70%, it is appropriate to classify the plant as 70% energy related and 30% demand related because, over time, demand looks a lot like energy.[102]

Generation costs

The AED method of allocating costs proposed by Mr. Brubaker is a simple method which allocates each customer class demand-related costs based upon a mix of energy and capacity, using a class non-coincident peak. This method does reflect that generation resources provide all day value to all customer classes. However, this method penalizes classes with poor load factors, regardless of their contribution to the system peak by not incorporating seasonal diversity between the classes. Not only is seasonality not recognized, but also the AED method does not reflect cost differentials because it is applied uniformly to all generation resources. Although the AED method seems similar to the equivalent peaker method proposed by Office witness Mr. Chernick, the two methods have significant differences regarding allocation of demand-related costs.[103] Nonetheless, because of its simplicity, the AED method may be

[102] Id. lines 52-85.
[103] Id. lines 201-205.

acceptable as an alternative to using planning and operating characteristics to determine allocations to individual generation assets.[104]

Mr. Chernick's proposal to use the Equivalent Peaker Method to classify all generation costs primarily as energy related, or at least 50% energy related and 50% demand related may be fine for some baseload costs, but not all generating assets. Mr. Chernick does not recognize the impact of market pricing structure.[105]

However, because of uniqueness of generation assets, and the need to match the unit's used and useful value from a planning and operational perspective, a single classification approach may not be appropriate. Therefore, Mr. Mancinelli, the Division's witness, recommended that the Commission charge a working group to study and make recommendations concerning cost classification of various generation resources.[106]

Transmission costs

If RMP's production and transmission systems are truly integrated, it is appropriate to continue to classify and allocate the transmission function similarly to the production function. RMP is currently doing this, and Mr. Brubaker proposed this as well.

RMP COS Model

The RMP COS model presents challenges. For example, the "hot sheet" doesn't recognize underlying cost causation explicitly; this information is implicit,

[104] DPU Ex. 5.0SR lines 166-191.
[105] DPU Ex. 5.0R at lines 95-120.
[106] Id. at lines 219-232.

and is often difficult to discern.[107] In his surrebuttal testimony, Mr. Mancinelli adequately addresses Mr. Paice's comments concerning these matters.[108]

<u>Agreement of JAM with COS</u>

Functionalization and classification of costs must remain as constant as possible between the JAM and RMP's COS. However there may be some flexibility within the boundaries of cost causation. For example, because RMP has a more pronounced summer peak than the system as a whole, it may be appropriate to use a 3 or 4 CP rather than the 12 CP used at the jurisdictional level.[109] This issue was discussed by Division witness Dr. Abdulle in rebuttal testimony but, as was concluded, needs further study before a decision can be reached. Also, automatic application of the F10 factor produces results that are out of line with the resource. Cholla, with its seasonality, illustrates the issues with this application.[110] Thus, it is appropriate to revisit allocation issues between the JAM and RMP COS at this time, not withstanding prior Commission orders on this issue. The inquiry could determine or address consistencies, and inconsistencies, between the JAM and the RMP COS. The inquiry could take place through one or more technical conferences. The MSP allocation issues would need to be taken into account when the results of the technical conference indicate update and revision of allocation issues with the JAM and the RMP COS.[111]

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[107] DPU Ex. 5.0Rt lines 82-102.
[108] DPU Ex. 5.0SR lines 82-102.
[109] Id. lines 112-190.
[110] See DPU Ex. 5.0SR and related discussion.
[111] DPU Ex. 5.0SR lines 191-303.

Allocation of Wind Resource

RMP's approach to allocation of wind resources does not recognize the unique nature of that resource which makes it appropriate to classify wind resources as 100% energy. It is inappropriate to classify these resources as proposed by RMP using the F10 factor. Even RMP's witness Mr. Duvall acknowledged the distinction between wind and traditional resources, stating that "Generation from wind resources is both non-dispatchable and uncertain."[112] Only Mr. Mancinelli and Mr. Higgins address classification issues pertaining to wind resources. Mr. Higgins proposal to classify wind resources as 20% demand related and 80% energy related to be consistent with RMP's investment decisions, but this is not a definitive answer because it looks only at the planning, not operation, characteristics of the resource. It is appropriate, as proposed by Mr. Chernick to allocate renewable energy credits and green tag revenues consistently with wind resources, recognizing the investment.

Effect of RMP's COS Changes Presented in Its Rebuttal Testimony

In its rebuttal testimony, RMP made significant changes to both the revenue requirement and associated allocation factors. While, due to the late presentation of these changes, the Division was precluded from a thorough analysis, Mr. Mancinelli was able to make some preliminary observations. These updates increase the residential COS and, except for the schedule applicable to mobile homes, decrease the COS for the other classes. With the change to coincident peaks implement by RMP in these late updates, the residential class' contribution to the system peak increased approximately 25% from the original

[112]RM{ Duvall Direct Testimony page 17 lines 380-383.

RMP COS. This is a dramatic change. Customer C also experienced a dramatic change, but in the opposite direction from the residential customers. Customer C's contribution to system peak was reduced 28% in the COS accompanying RMP's rebuttal.[113] A comparison of class contribution to system demand between the updated COS information and information from other RMP rate cases, demonstrates the potential unreliability of the updates.[114] Because of this unreliability, and the other updating issues articulated herein, the Company's COS updates should not be accepted.

<u>Customer, Sales, and System Load Forecast</u>

Certain aspects of the Company's customer, sales, and system load forecast are problematic. For example, scrutiny of the residential class forecast was impaired by unresponsive data request responses. Also, there were problems with the methodology used for the industrial class.[115] A subjective process was used for the industrial class forecast and is thus not subject to replication or adequate scrutiny.[116]

To improve the industrial forecast for the industrial customers, the reliance upon subjectivity exclusively should be eliminated. An objective independent forecast based upon econometrics or end use, would be much more transparent and could serve as a benchmark or supplement, at the least, to the current methodology. This also would bring the forecast more in line with the objective process used with the other customer classes. Additionally, utilizing information

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[113] DPU Ex. 5.0SR lines 394-401.
[114] Id. lines 407-421.
[115] Mr. Nunes initial concern that sales were overstated were contradicted by a Company study, and thus he did not have enough evidence to support his alternative to the Company's forecast.
[116] DPU Ex. 9.0 lines-51 163-179.

on the economy or industry outputs from Global Insight should be incorporated into the forecast process. A revised methodology would provide better forecast data.[117]

Load Research Program

The estimates resulting from the Company's load research program lack precision. They do not meet the PURPA standard, and the program should be altered to produce more accurate results. Currently the results are outside of appropriate confidence levels. Monthly differences between estimates of class energy and actual billed energy exceed the stated purported confidence level. This may be due to many factors. The Company's suggestion to use annual comparisons instead of monthly differences to determine the discrepancy between estimated and actual class energy would take away the consistency that arises from using monthly differences in both the class load and in the class allocation process. To improve the load research program, the sample design can be altered and the stratification process changed. A working group to study the issue would be appropriate.

Neither Mr. Brubaker nor Mr. Higgins offer compelling arguments and evidence to support their adjustments concerning the class load issue. Mr. Brubaker did not conclusively support his assertion that the discrepancies between the jurisdictional peak demands and class coincident peaks resulted from load research estimates, which makes his cost of service study unpersuasive. Mr. Higgins does not support his assertions adequately. Focusing only on a single observation, Mr. Higgins lacks sufficient data to

[117] DPU Ex. 9.0SR lines 41-55.

support his claim that the residential class sample size was too small[118]. Also, Mr. Higgins does not establish a persuasive connection between errors in energy estimates and errors in coincident peak demand estimates. His assertion that load demand errors caused the discrepancy between jurisdictional peak demand and the sum of the class coincident peaks demands is not supportable because other factors such as weather normalization affect this discrepancy. Because Mr. Higgins uses jurisdictional peaks instead of the sum of class demands in his cost of service analysis for Schedules 8 and 9, his study should be disregarded. RMP's study would be improved by weather normalizing monthly class coincident peaks consistent with jurisdictional peak demands. It would be appropriate to establish a working group to determine appropriate revisions.[119]

Company witness Mr. Thornton is equally unpersuasive in his defence of the Company's load research samples. Mr. Thornton's efforts to support the load research sample were unconvincing because he failed to account for monthly differences. Additionally, Mr. Thornton's statements regarding the age of the sample design do not eliminate concern about the appropriateness of the current sample. The Division suggests that it would be appropriate to establish a working group to determine appropriate revisions to the Company's load research methods and samples.

Conclusion

The Division's positions have evolved throughout this case as it obtained additional information and engaged in additional analysis. In particular, the

[119] DPU Ex. 9.0R lines 94-145.

Division's position changed as a result of the larger recommended overall increase. Division Witness Dr. Thomas Brill presented the final Division position regarding rate spread in his surrebuttal testimony; the Division's revised rate spread proposal is found in Dr. Brill's DPU Exhibit 2.0SR and is discussed in more detail in the surrebuttal testimony of Mr. Mancinelli. Because of the deficiencies and questions with the COS study, rate changes should be carefully implemented in this case. Rate spread changes should be carefully tailored to these particular peculiar circumstances.   The irrigation class' share increased notably, but still remains under the cost of service, and any additional subsidy should be borne equally by the other classes if the entire increase is not ordered. The remaining classes should proportionately share the remaining revenue increase.

CONCLUSION

For the reasons set forth above, the Division requests the Commission to adopt the Division's positions as set forth above.

RESPECTFULLY SUBMITTED, this 11th day of January 2010.

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CERTIFICATE OF SERVICE

I hereby certify that I caused a true and correct copy of the foregoing to be served upon the following by electronic mail to the addresses shown below on this 11th day of January 2010.:

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