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PRELIMINARY EVALUATION OF PACIFICORP'S EBA PILOT PROGRAM

To: Public Service Commission

From: Division of Public Utilities

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Date: May 22, 2014

Docket: Docket No. 09-035-15: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

INTRODUCTION

In its Corrected Report and Order in Docket No. 09-035-15, dated March 3, 2011 (Corrected Order), the Public Service Commission (Commission) ordered the Division of Public Utilities (Division) to "file a written preliminary evaluation of the pilot program per item 4, including the identification of issues or concerns with the program, within four months after the conclusion of the second calendar year of the pilot."[1] Upon request of the Division the Commission extended the due date of the preliminary evaluation to May 22, 2014. The "Item 4" referenced above is the following direction from the Commission:

[1] Corrected Report and Order, Docket No. 09-035-15, March 3, 2011, page 79.

4) The pilot program shall evaluate, at a minimum:

a) The sharing mechanism;
b) which net power cost components are controllable and which are uncontrollable and whether the sharing element should be eliminated from the uncontrollable costs in the EBA;
c) the effects of the EBA on the Company's resource portfolio;
d) whether the EBA includes the appropriate net power cost components;
e) the effects of the EBA on the Company's hedging decisions and level of market reliance on net power cost;
f) parties' incremental costs to audit the balancing account;
g) unintended consequences resulting from the EBA; and,
h) monthly vs. annual accrual differences.

Subsequent to this Corrected Order, the Division filed an evaluation plan with the Commission. In its order dated June 15, 2012, the Commission accepted the Division's evaluation plan with the following comments:

> For the EBA Pilot Program Evaluation Plan, the Division proposes evaluating the following issues: auditing, monitoring, and assessing the EBA; EBA agreement or disagreement by the Division and interveners; net power cost variability; electric rate variability; effect on Company return on equity; Company plant and power usage and performance; and other issues. The Division will evaluate whether the Company and customers are better or worse off and lists various issues or criteria it will evaluate…
>
> We accept the Division's evaluation plan as an addendum to item 3 of our EBA Order subject to the following guidance. We direct the Division to: 1) expand its evaluation of changes to integrated resource planning to include the issues identified by the Office; 2) work with the Office to develop baseline performance metrics for evaluation of plant performance under the EBA; and 3) include evaluation of a dynamic composite NPC allocator as discussed in our May Order. Finally, we take note of the Division's intent to examine Security Exchange Commission ("SEC") reports to evaluate the effect of Utah's EBA on the Company's earnings. We look forward to understanding how the Division will determine the Company's earned return in Utah from total company SEC financial reports. We understand the Company's earned return

> in Utah can be determined only through the Company's semi-annual results of operations reports. We remind the Division Utah ratepayers are not responsible for the earnings results PacifiCorp experiences in other jurisdictions. The pilot program evaluation plan items are summarized at a high level and included in the Attachment.[2]

In preparing this report the Division has consulted with the Office of Consumer Services (Office), solicited comments from intervenors in the Docket, and submitted data requests relevant to preparing this preliminary evaluation to PacifiCorp (Company, or Rocky Mountain Power, or RMP). The preliminary report set forth below is divided into the following Sections.

- SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS
- COMMENTS FROM INTERVENORS AND PACIFICORP
- DIVISION'S COMMENTS AND ANALYSIS OF EVALUATION PLAN ITEMS
- DIVISION'S COMMENTS ON ITS AUDIT EXPERIENCE TO DATE
- CONCLUSIONS AND RECOMMENDATIONS
- APPENDIX 1, Survey instrument
- APPENDIX 2, Confidential Exhibits

SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

The Division has approached the EBA pilot program as a learning experience for it, the Company and other interested parties. In this regard the Division and its consultant have tried to work with the Company on developing solutions to many problems that it initially faced in order to improve the process going forward. While some issues remain, the Division believes that there has been substantial progress toward developing a smoothly running program.

The Division has analyzed and commented on each of the topic areas delineated by the Commission in the attachment to its June 15, 2012 order in Docket 09-035-15. The Division has

[2] Report and Order on EBA Filing Requirements and Pilot Program Evaluation Plan, Docket No. 09-035-15, June 15, 2012, pages 4 and 11.

also obtained comments from two parties to the original EBA docket and comments and data, particularly data on generation plant operations, from the Company. The Division is unable at this time to attribute changes in the Company's operations of its generation plant or in its plans as set forth in its IRP to the functioning of the EBA. In some cases the lack of attribution may be due to the shortness of the time period since the implementation of the EBA for any effect to show up; but in many, or perhaps most, cases the lack of attribution may remain systemic since many other factors in the Company's decision making are at work in addition to the EBA and the effect of the EBA may be lost in the "noise" of the other factors.

Two intervenors responded to a Division survey and the Company answered data request questions that were similar to the questions posed to the intervenors. One intervenor is decidedly critical of certain aspects of the EBA; the other intervenor essentially indicates that it does not have enough information at this time to have an opinion about most of the issues the Division asked it about, although it believes that the 70/30 sharing mechanism provides some protection to ratepayers. The Division continues to generally share this opinion regarding the 70/30 sharing mechanism.

The Division's experience with the EBA audit process has been mixed. There have been several issues regarding access to information (i.e. the Company's positions on confidential information) that were initially difficult and exasperating, particularly in light of the brief review period allowed by the Commission. These seem to have mostly been worked out. However, the Company's failure to maintain some records related to its transactions has made prudency reviews of those transactions more difficult. The Division believes that the Company has been working to improve its record keeping. The Division realizes the depth of post-hoc review of transactions required by the EBA is one with which the Company is unaccustomed. The Division is encouraged that the Company has been responsive to Division concerns regarding record-keeping issues. The Division notes that the EBA has had a major impact on its staffing resources and has required it to expend significant funds for consultants. The Company claims that it has incurred no incremental costs. A portion of this expense is necessary because of the compressed time during which the Division must review the EBA filing. The Division continues to believe this compressed time is not necessary and that an interim rate process would provide for relatively contemporaneous payments to either customers or the Company while allowing thorough review and subsequent reconciliation. The Division notes too that at least one intervenor reports expenditure of sizable resources in tracking the annual EBA process. Probably at least some other parties, including the Office, have devoted some resources tracking the EBA. These are resources that would otherwise be used elsewhere.

The Company makes some recommendations for changes to the EBA. These recommendations and issues include:

- Use a single EBA calculation / allocation method.
- Eliminate duplicative filing requirements.
- Issues resolved in the general rate cases should not be re-litigated in the EBA.
- A process for expanding the EBA to include other related costs on an as-needed basis should exist.
- Remove the EBA SAP accounts from the tariff.
- Consider unbundling EBA costs from base rates
- Remove the sharing band.

While the Company and any party may petition the Commission to make changes to the EBA at any time, the Division believes that any changes should be held in abeyance until the end of the pilot program when presumably we will all have more information and experience from which to draw. Therefore, the Division's recommendation is to continue the EBA pilot program as it currently exists.

COMMENTS FROM INTERVENORS AND PACIFICORP

Intervenor Survey

As part of its evaluation, the Division sent a survey to intervenors in Docket No. 09-035-15. A copy of the survey instrument is attached as Appendix 1. The Division received two responses. One respondent attempted to answer the questions of the survey, the other, only responded to the Division's generalized request for "any other" issues.

The first respondent's answers to the survey are summarized as follows:

1. The 70-30 sharing band is fair and reasonable and should be continued.

2. a. has no basis to recommend changes to the EBA components

   b. understands that the utility cannot control market forces or prices, but believes that the utility's management has a variety of tools to "help control and mitigate costs and cost variability."

3. Has no basis to conclude that the EBA has affected PacifiCorp's IRP, but notes that "an EBA has the potential of affecting resource portfolios by insulating a utility from some of the consequences of its decisions and actions."

4. Has no basis to conclude that the EBA has affected the Company's hedging program, but that it has the "potential of affecting the hedging decisions by insulating a utility from some of the consequences of its hedging decisions.

5. Similar to the above responses, this respondent believes that the "EBA has the potential of affecting market reliance by insulating a utility from some of the consequences of its market purchasing decisions and actions."

6. Respondent has no opinion at this time whether or not the EBA has produced unintended consequences.

7. Respondent believes it has a good understanding of the EBA and EBA process.

8. Respondent has no opinion regarding the level of dispute in the EBA and presently has no suggestions for how the process might be done differently.

9. Respondent estimates that it expends 200-300 hours annually in the EBA true-up process.

10. Respondent currently has no opinion regarding whether or not PacifiCorp is making reasonable efforts to reduce net power cost variability.

11. At this time the Respondent has no other issues to bring to the Division's attention.

This respondent asserts for each of 3 through 6 above, that the "30% sharing percentage helps to restore some of the proper incentives and consequences."

The second respondent outlined its concerns as follows:

1. The EBA Results in a Double Capacity Payment.

2. The EBA Ignores Time of Use and Seasonality of Costs.

3. Truing-up Against Forecasted Rather than Actual Costs Is Contrary to the Statute and Allows for Gamesmanship.

4. The Carrying Charge Applied to the Balance in the EBA Should Be Based on the Prudent Rate of Short Term Debt.

The Division will not recite the extensive arguments made by the second survey respondent regarding these points. The Division understands that this respondent has distributed its comments to PacifiCorp and to the service list in the original EBA docket. There will be other occasions for this respondent to present its views in order to persuade the Commission to make any changes to the EBA. The second respondent concludes its comments to the Division with the following statement.

> At this point, the parties should ask themselves how to proceed. Are the rate payers better off as a result of taking on the additional risk of this EBA? How have the rate payers been rewarded for assuming this larger risk? Has the return on equity been lowered as a result of the EBA?[3] Is the Consumer seeing fewer general rate cases as a result of the EBA? Is the Company engaging in more prudent energy cost management? It appears that the rate payers have taken additional risk, but it is business as usual for the

[3] While it is true that the return on equity has been lowered, the arguments to do so did not center on the fact that the Company has an EBA and therefore has less risk. The EBA should mean an even lower return on equity than is presently allowed. (Footnote in the original).

> Company. Should the Company be required to make a showing that the EBA is in the public interest? This is, after all, a prerequisite for an EBA.

PacifiCorp Data Request Response

The Division asked the Company through a data request many of the same questions it asked in its intervenor survey. The Company's responses are summarized below.

The Company was asked if it had suggestions for the annual EBA true-up process. The Company responded with three suggestions:

1. Use a single EBA calculation / allocation method. In addition to the method stipulated to in the last general rate case which is used to set the EBA collection rate, the Company files the Commission-approved method and two additional methods to determine the Utah EBA deferral.

2. Eliminate duplicative filing requirements. Currently the Company provides both the original EBA filing requirements and the additional EBA filing requirements with the annual EBA filing. Duplicative filing requirements should be eliminated.

3. Issues resolved in the general rate cases should not be re-litigated in the EBA. While parties should have the opportunity to generally review all of the Company's actual EBA costs for the previous year, issues that were resolved in the general rate case that established base net power costs, such as prudence of specific contracts, should not be re-litigated in the annual EBA true-up process. Pursuant to Tariff Schedule 94, the EBA provides for a review of the difference between base net power costs and actual net power costs, as those costs are defined under the Tariff Schedule 94.

When asked whether or not the current components of EBA were appropriate, PacifiCorp indicated that one item that was excluded should be added and another should be added due to the Company's prospective participation in the California Energy Imbalance Market. The Company stated:

> A process for expanding the EBA to include other related costs on an as-needed basis should exist. At a minimum, the following components should be added to the current EBA true-up:
>
> 1. Generation costs that vary with MWh production, but not currently included in NPC such as costs of chemicals and reagents which increase significantly with the addition of new environmental controls at the Company coal plants.
>
> 2. Variable costs associated with the Company's participation in the Energy Imbalance Market (EIM). While it is anticipated that essentially all of the benefits of EIM will flow through NPC, not all of the variable costs of EIM will be recorded in accounts that are included in the EBA. Including the variable costs of EIM in the EBA will provide consistent treatment of both the costs and benefits of EIM.

The Company was asked what specific efforts it has made to control and reduce net power cost variability over the last three years. In response the Company made the following extensive comment.

> PacifiCorp's net power cost (NPC) variability from plan occurs primarily due to changes in the volume of energy to be balanced and changes in market prices.
>
> PacifiCorp cannot control the weather driven variability affecting the volume of retail load, wind generation and hydro generation. However, PacifiCorp works to reduce the volume variability through the use of forecasts of load, wind and hydro, and by managing thermal resource availability. For more than the past three years PacifiCorp has produced forecasts for load, wind generation and hydro generation each day. Wind generation forecasting improvements are ongoing and continuous and are occurring on many levels. PacifiCorp is now sending near real time, turbine level data for all of the wind farms in its control area to its forecasting vendor. With this data, the forecaster is able to calibrate and train its model on every model run. Further, computing capabilities have improved such that a new forecast can

be generated every five minutes. A relatively new forecasting product called "ramp forecasts" is also available to predict, within certain risk tolerances, when sharp increases or decreases in wind generation will occur. On a larger scale, the National Oceanic and Atmospheric Administration (NOAA) recently released a vastly improved global atmospheric model; global atmospheric models provide the input data that wind generation forecast providers use to drive their models. In 2013 PacifiCorp committed to developing and implementing an energy imbalance market (EIM) with the California Independent System Operator (CAISO). As part of this market, the CAISO will be providing a load forecast of the PacifiCorp balancing authority areas which will provide PacifiCorp with incremental improvement by having two forecasts to compare. It will also enable more efficient dispatch of PacifiCorp's system and take advantage of diversity across a much wider footprint to further reduce costs and improve situational awareness within and outside of PacifiCorp's borders.

PacifiCorp cannot control market prices, weather, wind and hydro generation, among other things, which is why net power costs are largely outside of its control. With regard to market prices, PacifiCorp attempts to maximize the number of counterparties with which it can transact, pursuant to the terms of the PacifiCorp Energy Commercial &Trading (C&T) Risk Management Policy, in order to maintain a deep market. In addition, PacifiCorp uses its forecasts of load, wind and hydro to attempt to minimize the amount of balancing required in the less liquid real time market. PacifiCorp continues to use forward hedges of natural gas and electric power to reduce NPC volatility due to forward market prices. These hedges are consistent with PacifiCorp's hedging policy and guidelines that resulted from the Utah hedging collaborative. The hedging policy reflects Utah stakeholders' risk tolerance and their desire to leave a level of exposure to the market so that customers can benefit from potential favorable market movements, while also incurring the risk that market movements could be unfavorable.

The Division asked the Company, as it did in the intervenor survey, an open-ended question to discuss anything else that it wanted to bring to the Division's attention. Below is the Company's response.

While the EBA is generally satisfactory, is working well mechanically and should continue, there are some areas in addition to those listed in response to DPU 19.1, where it could be improved. The Company makes the following recommendations:

1. Remove the EBA SAP accounts from the tariff. Identification of SAP accounts could still be provided annually with the EBA filing, but including all of the accounting detail in the tariff makes the tariff too detailed for the typical customer.

2. Consider unbundling EBA costs from base rates. While EBA costs are differentiated by month, prices in the retail schedules do not change by month. This makes measuring actual recovered EBA costs problematic.

3. Remove the sharing band. The EBA pilot is currently in its third calendar year. The parties and the Commission now have two full years and four months' worth of experience with the EBA and several developments have occurred that support removing the sharing band.

   First, while the Company strives to reduce NPC volatility, as of December 31, 2013, PacifiCorp had PPAs for 869 MW of wind capacity, including 415 MW of wind QFs. In addition, the Company has provided over 1,000 MW of solar QF avoided cost indicative price responses to developers in Utah since the Commission's order on avoided costs methodologies in Docket No. 12-035-100. The Company has little to no control over the inherent volatility that these non-Company projects/potential projects will have on system net power costs.

   Second, the Company has implemented certain notable programs/policies that are worth mentioning. With considerable input from Utah stakeholders and other interested parties, the Company changed its hedging policy consistent with the DPU guidelines resulting from the 2011 Utah hedging collaborative. This policy requires the Company to maintain a specified amount of exposure to natural gas and power market prices, which influences NPC volatility, and over which the Company has no control. As the DPU is aware, the Company has filed detailed semi-annual hedge reports beginning in 2012, also resulting from the 2011 hedging collaborative, which describe hedges transacted since the previous report and planned hedges.

> Comments from the DPU and OCS have affirmed hedging compliance and have been non-controversial.
>
> Third, the Company has committed to participate in the EIM, which is scheduled to go live October 1, 2014. The EIM will automate and optimize dispatch of resources on a least cost basis every five minutes to serve load within reliability and transmission constraints. The EIM therefore removes any need for a purported sharing band incentive to influence company behavior related to balancing and dispatch.
>
> Other examples of the Company's efforts in its response to DPU 19.10 to improve its ability to manage NPC volatility and minimize costs to customers are not due to any argued incentive from the 70/30 sharing band, but rather are due entirely to Company management's expectations reflected in its core principles and the expected need to demonstrate prudence. These efforts are on-going and continuous improvements to the Company's business practices.
>
> Finally, the Company's resource portfolio, which establishes part of the NPC risk, is determined as a result of robust IRP, RFP and rate case processes which are all transparent proceedings that are subject to focused and rigorous scrutiny by parties and the Commission. Customers benefit from the resource diversity and this reduces NPC volatility. However, NPC volatility remains that is out of the Company's control due to wholesale market prices and depth; weather affecting customer load, wind generation, hydro generation, PPA volumes; and forced outages of Company resources.

The Company was asked several additional questions. The Company stated that the EBA has had no effect on the Company's Integrated Resource Plan, its hedging program, or its reliance on front office transactions. The Company believes that there have been no unintended consequences from the EBA. Finally, the Company claims that it has not incurred any incremental labor costs in administering the EBA.

DIVISION'S COMMENTS AND ANALYSIS OF EVALUATION PLAN ITEMS

The Division filed its initial plan for topics to be covered in the EBA evaluation with the Commission on March 1, 2012. The Commission generally accepted, with some amendments the Division's plan as set forth in its June 15, 2012 report and order. The plan included 21 topics that were listed as "a" through "u" on the attachment to the June 15, 2012 Report and Order. The Division uses this list to organize its comments below.

a. The Sharing Mechanism

The EBA pilot program provides for a 70-30 sharing percentage of the differences between the baseline and actual NPC. That is, if NPC is higher than the baseline the Company recovers only 70 percent of the difference. If NPC is less than the baseline, it has to refund to customers only 70 percent of that difference. As indicated above, the Company believes that the sharing mechanism should be eliminated (effectively making it a 100-0 sharing percentage). The first respondent to the Division's survey supports the application of the 70-30 percentage. In developing the EBA, the Division supported the 70-30 sharing mechanism to mitigate, among other things, the potential for moral hazard should the Company perceive that it is essentially guaranteed recovery of costs even if the Company makes mistakes in incurring those costs. The Division's experience to date in auditing the EBA supports the view that after-the-fact prudence reviews are, at best, imperfect mechanisms to protect ratepayer interests. (See discussion below). The Division concludes that it is premature to discuss making changes to the 70-30 sharing mechanism.

b. Controllable versus uncontrollable elements in the EBA.

The Company points out that it cannot control the weather and does not control the prices in the wholesale markets; these factors will always be a source of variability in the actual versus forecast net power costs. As described above, the Company expects to add wind and solar capacity through QF power purchase agreements, which will potentially add to the volatility of the Company's net power costs. On the other side, the Company is attempting to manage net power costs better by, participating in the EIM in California, by improving load and weather forecasting, and through its hedging program. The Division is pleased that the Company has these various efforts underway. However, given the apparent widening in the difference between the baseline and actual NPC as evidenced in the latest EBA filing, the Division looks forward to the realization of positive results in these efforts. The Division also expects the Company to continuously look for other prudent ways to reduce NPC both in absolute terms and in the variability of actual costs over baseline.

c. The effects of the EBA on the Company's resource portfolio.

Division has not been able to discern any effect of the EBA on the Company's resource portfolio to date. Topics related to this issue are discussed under items "p" and "q" below.

d. Appropriate Components of the EBA.

The Division generally believes that the current EBA tariff contains the appropriate EBA components.[4] During EBA filings the Division reviews SAP account additions proposed by the Company. The Division's understanding of these additional SAP accounts is that they are merely a subset of the broader GRID-type costs that are included in a general rate case filing.
There are certain situations in which a certain type of cost or revenue has GRID-type characteristics and non-GRID-type characteristics. An example of this kind of situation is the GP Camas adjustment which was included in Docket No. 12-035-67. Division witness Matthew Croft stated the following in his direct testimony in that docket.

> In the EBA filing the Company has made an adjustment to FERC Account 555 to include purchased power expenses in the Accounting EBAC for GP Camas or James River Paper Company. This adjustment to Accounting EBAC dollars is needed since the GP Camas expenses are included in base NPC amounts. PacifiCorp receives rental revenues from GP Camas based upon the Company's lease of the generating plant at the mill site to GP Camas. The revenues associated with GP Camas or James River are not included in Base NPC but they are included in general rate

[4] The Division may ask the Commission to reconsider the inclusion of wholesale wheeling revenues as part of the EBA since the Division believes that the nature of these revenues is distinct from net power costs.

> case filings.[5] Since these revenues are not included in Base NPC it would not be appropriate to include them in Actual NPC.
>
> Furthermore, the treatment of these rents in NPC is consistent with the Division's view on wheeling revenues.[6] Wheeling revenues are rents the Company receives on its transmission system. The Division believes the Company has accounted for the expenses and revenues for the GP Camas contract correctly and does not believe that the definition of NPC should be expanded to include rents on facilities. Even if the definition of NPC were to be expanded, it would have to take place in a general rate case since that's where Base NPC are set.

In summary, costs from the James River Paper Company contract are included in the EBA while revenues are excluded. To the Division's knowledge, the Company has never advocated that the revenues from James River should be included in the EBA. Interestingly however, the Company does appear to be advocating the inclusion of non-GRID-type EIM costs in the EBA since the anticipated benefits will be included in GRID-type NPC. Why the Company would treat the EIM different from the James River contract is unclear. In order to be consistent with the treatment of the James River contract, one would expect the Company to include GRID-type costs or revenues from the EIM in the EBA but exclude non-GRID-type costs or revenues.

e. The effects of the EBA on the Company's hedging practices and front office transactions.

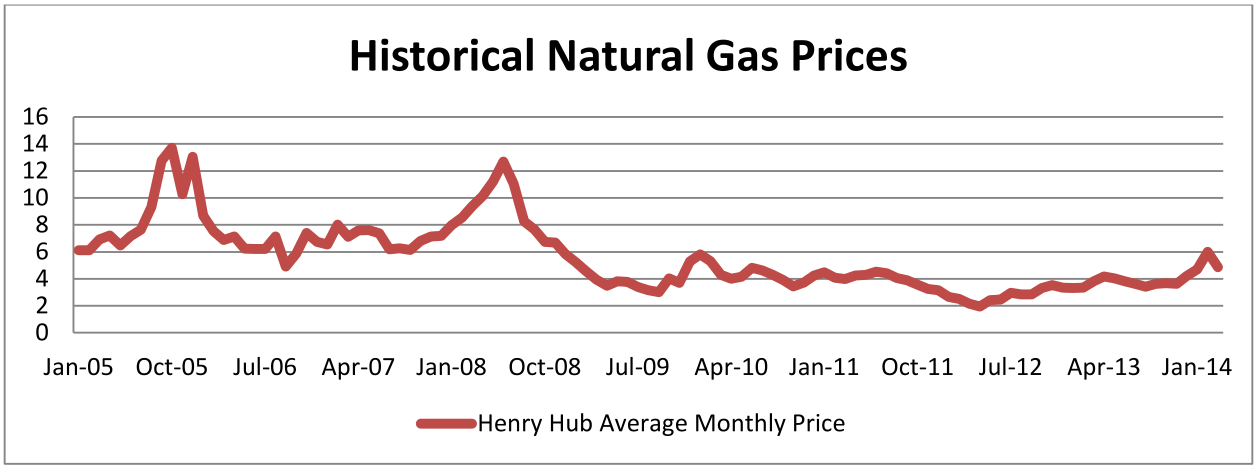
Issues relating to the Company's hedging program were discussed and have been a concern for parties in Energy Balancing Account or EBA (09-035-15), previous general rate cases (09-035-23 & 10-035-124) and in the Natural Gas Price Risk Management docket (09-035-21). In each of these cases parties have provided testimony and expressed concern with the amount and the methods used to hedge the forecast natural gas requirement. As part of the stipulation agreement under Docket No. 10-035-124, parties agreed to convene a collaborative process to discuss appropriate changes to the Company's hedging practices. The collaborative process resulted in revised guidelines for hedging natural gas which were outlined in a report to the Commission

[5] RMP General Rate Case Docket No. 11-035-200, McDougal Exhibit SRM-3, page 5.2
[6] RMP ECAM Docket No. 09-035-15, Peterson Exhibit 3.0SR (Confidential), October 13, 2010, page21, lines 454 - 463

dated March 30, 2012. Since the stipulated changes to the hedging strategy and the EBA implementation cover the same time period, the Division has not been able to determine if the EBA has had an impact on the Company's hedging decisions.

The current market conditions have also impacted hedging decisions. Since the implementation of the EBA program, the price of natural gas has remained fairly stable compared to previous years.

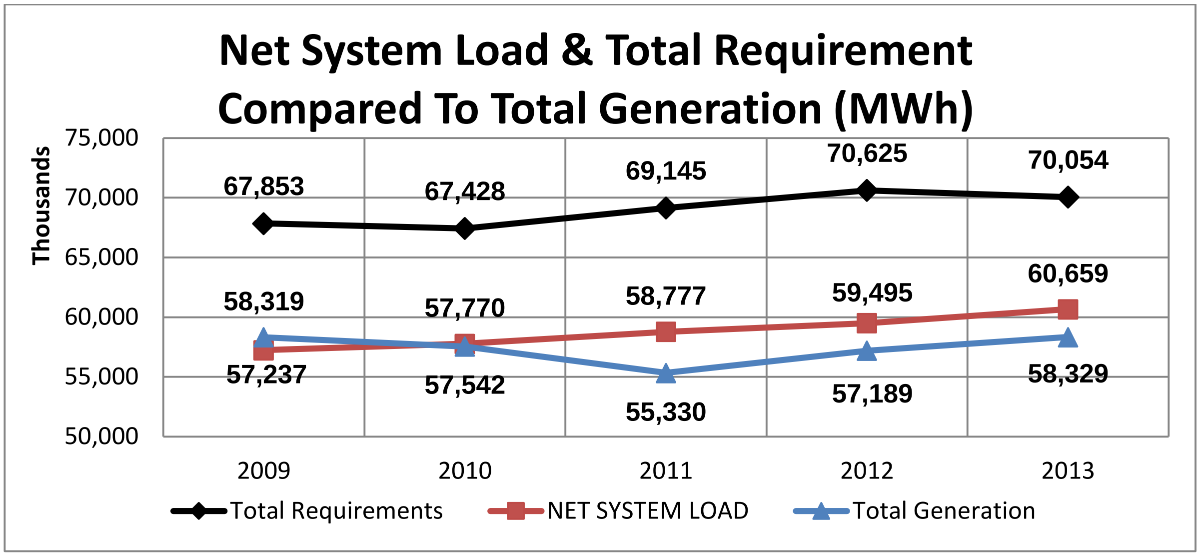
Figure 1



One of the factors that has changed in the day-to-day operations of the Company's hedging program is the relationship of gas hedging and electric hedging. In previous testimony, the Company has indicated that there is a strong correlation with the price of electricity and the price of natural gas. The excess power and long electric position creates a natural hedge for the short natural gas position. Over the last few years that position has changed with less excess power generated by the Company, while the short natural gas requirement has remained relatively stable. This natural offset between the two commodities and natural hedge as represented by the Company does not appear to be as beneficial as it has been in previous years.

In recent years, the Company has relied more on purchased power and front office transactions compared to self generation. While the Company is using more purchased power, the reasons may be a function of market prices and not the result of the EBA. Below is a chart that shows the total Company generation compared to the net system load. For the past several years the Company has relied on purchased power to meet the balance of the system load requirement.

Figure 2



While there has been an increase in the the net system load and the total requirement, there has been very minor change when comparing the volume of total generation in 2009 with the total generation in 2013. Historically the growth in the requirement has been satisfied with purchased power. The Division is unable to determine if the decision to increase the reliance on market purchases has been influenced by the EBA. Further, because the Company's decisions appear to be market driven, rather than based on any regulatory program, the Division does not believe, at this time, that there are implications for capacity or demand charges.

f. Parties' incremental costs to audit the EBA.

In response to the Division's survey, the first respondent indicated that there was an annual cost of 200 to 300 hours in what are likely consultant and attorneys' fees. These are resources that the respondent could redirect elsewhere if there were no EBA. The Division has no information on any other party. As discussed later, the Division has expended much more than 200-300 hours and many dollars in performing its EBA functions.

g. Unintended Consequences of the EBA.

As indicated above, neither the Company nor the first respondent to the Division's survey is aware of any particular unintended consequences. The Division is unaware of unintended consequences as the Division understands the usual meaning of the term. There is a consequence of the EBA as it is currently implemented that arguably is unintended, but it was known going into the EBA pilot program: the situation where the EBA period extends beyond, usually by about six months, the test year of the most recent rate case. Thus there is no specific EBA baseline for those months. The baseline months used are the previous calendar months for which there was a baseline. In a period of generally rising costs, this means that there will likely always be an under-collection of NPC during the EBA period due to this situation. One solution would be for the Company to forecast NPC for multiple years in a rate case, but then the forecast would have to be put into effect in multiple years to reduce the effect on the annual EBA adjustment. This seems to be undesirable from the perspective that customers would have to endure more rate changes.

One noteworthy realization concerning EBA has arisen in general rate case proceedings. For a given revenue requirement in a general rate case proceeding, customers' incentives are to set an NPC figure artificially high and the Company to set the figure artificially low. At any given revenue requirement, an artificially low NPC figure allows the Company greater recovery (or less liability) in EBA proceedings. The reverse is true for customers. This can invert parties' positions on adjustments to NPC items. The 70/30 sharing band and the interest accrual in the EBA may mitigate these incentives.

h. Monthly vs. Annual accrual differences.

This particular item originated from the Commission's March 3, 2011 Corrected Report and Order in Docket No. 09-035-15. The Division is unsure of the Commission's specific intent or purpose with regards to this item. However, the Division notes that the two main differences between calculating the EBA accrual on a monthly or annual basis revolve around interest expense and allocating total Company EBAC to Utah.

Using a monthly accrual enables interest to be calculated on a more precise basis. If the EBA accrual was calculated on an annual basis, interest would be calculated on a single amount that is either positive or negative. Such a calculation assumes the accrual was positive or negative for the entire year while in reality the accrual balance may have been positive for some months of the year but negative for others.

Calculating the EBA accrual on a monthly basis does create more complexity in deciding how costs should be allocated to Utah. Four methods currently exist to allocate total Company actual NPC to Utah. These methods have been described in the Company's EBA filings as the "Scalar" method, "A2 Method", "Commission Order Method", and the "A3 Method." Table 1 shows a comparison of these methods using information from the Company's most recent EBA filing.

Table 1

ACTUAL NPC ALLOCATION - DOCKET 14-035-31

SE Related NPC

				"A3 Method"		"A2/Commission Order Method"		"Scalar Method"						
		Total	Total	Monthly Factors		Annual Factors		Total		SE		Total		Total
	UT	Company	Company	Applied Monthly		Applied Monthly/Annually		Company	Monthly	Allocated		Company	UT	UT
Month	MWH	MWH	NPC	SE	UT	SE	UT	NPC	SE	NPC	Scalar	$/MWH	MWH	NPC
Jan-13	2,289,624	5,538,025	94,403,380	41.34%	39,029,848	42.89%	40,487,133	133,659,007	41.34%	55,259,576	1.00252	24.13	2,289,624	55,398,601
Feb-13	1,958,995	4,694,153	87,573,752	41.73%	36,546,863	42.89%	37,558,085	116,188,681	41.73%	48,488,637	1.00252	24.75	1,958,995	48,610,627
Mar-13	2,002,424	4,775,925	92,048,804	41.93%	38,593,720	42.89%	39,477,317	122,299,255	41.93%	51,276,964	1.00252	25.61	2,002,424	51,405,970
Apr-13	1,863,136	4,444,207	85,020,466	41.92%	35,642,965	42.89%	36,463,047	110,236,400	41.92%	46,214,192	1.00252	24.80	1,863,136	46,330,460
May-13	1,989,009	4,718,856	87,055,279	42.15%	36,694,004	42.89%	37,335,725	119,488,604	42.15%	50,364,727	1.00252	25.32	1,989,009	50,491,437
Jun-13	2,259,640	5,114,425	87,905,711	44.18%	38,838,236	42.89%	37,700,453	129,963,629	44.18%	57,420,138	1.00252	25.41	2,259,640	57,564,599
Jul-13	2,606,694	5,754,894	102,272,204	45.30%	46,324,452	42.89%	43,861,865	176,029,837	45.30%	79,733,157	1.00252	30.59	2,606,694	79,933,754
Aug-13	2,534,176	5,501,806	103,768,299	46.06%	47,796,517	42.89%	44,503,501	157,274,954	46.06%	72,442,115	1.00252	28.59	2,534,176	72,624,369
Sep-13	2,078,648	4,699,007	106,086,059	44.24%	46,928,119	42.89%	45,497,528	139,287,264	44.24%	61,614,969	1.00252	29.64	2,078,648	61,769,983
Oct-13	1,998,854	4,735,308	104,577,099	42.21%	44,143,773	42.89%	44,850,374	124,259,043	42.21%	52,451,857	1.00252	26.24	1,998,854	52,583,818
Nov-13	2,029,355	4,828,482	102,613,866	42.03%	43,127,417	42.89%	44,008,395	124,573,043	42.03%	52,356,604	1.00252	25.80	2,029,355	52,488,326
Dec-13	2,309,262	5,631,850	105,302,650	41.00%	43,177,888	42.89%	45,161,544	166,275,377	41.00%	68,178,908	1.00252	29.52	2,309,262	68,350,436
Total	25,919,817	60,436,938	1,158,627,570	42.89%	496,843,802		496,904,966	1,619,535,095		695,801,843			25,919,817	697,552,380
UT NPC From A2 Method										697,552,380				
Scalar										1.00252				

Note: It appears the Company's deferral calculations in RMP Exhibit BSD-1 (14-035-31) inadvertently used the scalar from the previous EBA filing (13-035-32). The Division assumes the scalar will be corrected in Docket 14-035-31 to show the 1.00252 scalar shown here.

SG Related NPC

		Total			Monthly Factors		Annual Factors	
	UT	Company		Total Company	Applied Monthly		Applied Monthly/Annually	
Month	MW	MW	SC	SG Related NPC	SG	UT	SG	UT
Jan-13	3,702	8,825	41.95%	39,255,627	41.80%	16,408,413	43.53%	17,089,198
Feb-13	3,231	8,052	40.12%	28,614,929	40.52%	11,596,029	43.53%	12,456,971
Mar-13	3,012	7,780	38.72%	30,250,451	39.52%	11,955,480	43.53%	13,168,964
Apr-13	2,960	7,338	40.33%	25,215,934	40.73%	10,270,586	43.53%	10,977,282
May-13	3,890	8,033	48.42%	32,433,325	46.86%	15,196,783	43.53%	14,119,237
Jun-13	4,704	9,637	48.81%	42,057,917	47.65%	20,042,462	43.53%	18,309,123
Jul-13	4,931	10,292	47.91%	73,757,634	47.26%	34,857,165	43.53%	32,108,997
Aug-13	4,525	9,415	48.06%	53,506,655	47.56%	25,449,312	43.53%	23,293,115
Sep-13	4,306	8,597	50.08%	33,201,205	48.62%	16,143,291	43.53%	14,453,519
Oct-13	2,998	7,512	39.91%	19,681,945	40.48%	7,968,154	43.53%	8,568,164
Nov-13	3,099	8,176	37.90%	21,959,176	38.93%	8,549,055	43.53%	9,559,514
Dec-13	3,700	9,336	39.63%	60,972,727	39.98%	24,374,546	43.53%	26,543,329
Total	45,058	102,994	43.75%	460,907,526	43.53%	202,811,276		200,647,414

	Total Company	"A3 Method"	"A2/Commission Order Method"	"Scalar Method"
Total NPC	**1,619,535,095**	**699,655,078**	**697,552,380**	**697,552,380**

A summary of these four methods is shown on Table 2 below.

Table 2

Actual NPC Allocation Summary

Method	14-035-31 UT NPC	Description
A2 Method and Commission Method	$ 697,552,380	Applies the **annual** SG and SE factors to total company monthly NPC.
Scalar Method	$ 697,552,380	A scalar is applied to monthly total company $/MWH which is then applied to Utah's load. The scalar is derived by dividing the total UT monthly SE allocated costs by the total UT allocated NPC calculated in the A2 method.
A3 Method	$ 699,655,078	Applies **monthly** SG and SE factors to total company monthly NPC.

The A2/Commission Order methods and the Scalar method yield the same total actual Utah NPC for a given year but the amounts for the individual months will be different. Thus, the only impact on the EBA will be the interest costs which are calculated monthly. The A3 method yielded a total NPC result that is 0.3 percent higher than the other methods. In Docket No. 13-035-32 the A3 method was 0.5 percent lower than the other methods. From an overall EBA deferral perspective, the A2, Commission Order, and A3 methods from Dockets 13-035-32 and 14-035-31[7] have differed from the Scalar results between -$1.2 million and +$2.9 million. Given that: a) each method has both positive and negative aspects; b) each method yields relatively similar results and c) the fact that there are only two full years to compare, the Division sees no convincing reason at this time to change the Scalar method that is currently used to calculate the EBA deferral.

i. Quantitative and qualitative assessments of the effect of EBA monitoring on Division staff and resources.

Since the inception of the EBA, the EBA filings have required the greatest collective time and resource commitment of Division staff compared to any other project, with the exception of general rate cases. The complexity of the EBA has also required the Division to retain the services of La Capra Associates to assist in the audits. The Division believes that with time, the amount of hours required to review the Company's EBA may decrease. Although it is not

[7] The A2, Commission Order, and A3 methods were not part of the Company's filing in Docket No. 12-035-67. The Division also notes that the EBA period for that case was only three months.

entirely certain at this point of time, the potential may exist for the Division to conduct future EBA audits without the assistance of outside consultants. To bring the entire EBA audit "in-house" may require the Division to bolster its staff with expertise in the engineering and possibly other fields. Whether or not the Division could do this at some point is an open question.

j. The level of comprehension by the Division and interveners.

The Division has no indication that the EBA process is not generally understood by interested interveners.

k. The level of dispute among parties during the true-up process.

Likewise, the Division does not perceive that the annual EBA true-up process is subject to more (or less) disputation than it would normally expect.

l. Company progress in smoothing variability of net power cost in addition to the EBA.

As discussed above, the Company reports making positive efforts to improve weather forecasting and is proposing to enter into the EIM in California, among other initiatives. The Division expects the Company to seek other ways to reduce NPC variability and improve forecasts.

Also, see under "t" below.

m. Changes in Company hedging and front office transactions.

See under "e" above.

n. Swings in the Company's electricity rates.

The Division has performed an initial analysis of the historical and going-forward swings in the Company's rates to determine if the EBA resulted in reduction in the rate variability. This requires the Division to compile historical data on rates for all Schedules before and after the introduction of the EBA program. This data will then be subjected to a Chi-Square test to compare the variability in rates before and after the EBA. Collecting this data requires retrieving information from the archives is time consuming and has not been completed. Below is an initial review of Schedule 1 (residential) customers which may roughly reflect the experience of customers on other rate schedules.

For the purpose of this report, the Division used historical data from the Commission's web site pertaining to rate changes over time for a typical residential customer.[8] A descriptive statistical analysis of this data shows that the standard deviation of the percent changes of rates for the period before and after the introduction of the EBA were 3.86% and 1.6%, respectively. However, there is not enough data to determine whether or how much of the change in variability can be attributed to the EBA. Unless more data becomes available and an attribution test is conducted, the Division cannot tell whether or not the EBA had any impact on the variability of rates.

Table 3

	Bill Percent Change	
	Before EBA	***After EBA***
Count	30	13
Mean	1.07	0.93
Median	0.24	0.23
Population variance	14.86	2.55
Population standard deviation	3.86	1.60
Minimum	-11.33	-0.48
Maximum	9.40	5.23

8 http://www.psc.utah.gov/utilities/electric/Rate%20Changes/Rate%20Changes%20Electric%20November%201%202013.pdf

o. Return on Equity

One measure of the overall financial health of the Company is the return on common stockholders' equity, a profitability measure which, at its simplest level, is calculated by dividing the annual net income attributed to the common stock by the book value of the common stock. Consistent earnings and earnings growth are measures that are important to both debt holders and stockholders. PacifiCorp has had a history in recent years of not earning its authorized rate of return, as accounted for either on a regulatory basis, or on an SEC basis. Table 1 sets forth the Company's returns on equity since 2006; the first year the Company was owned by Mid American Energy Holdings Company (recently renamed Berkshire Hathaway Energy).

Table 4

PacifiCorp
Realized Return on Equity Calculations
2006-2013

		Rocky Mountain Power, December Report of Operations		
Year	SEC Form 10K 1/	System	Utah, unadjusted	Utah, adjusted
2006	9.76%	8.17%	6.13%	7.84%
2007	9.79%	8.62%	8.56%	7.47%
2008	8.37%	8.70%	7.77%	7.71%
2009	8.62%	8.78%	8.45%	8.45%
2010	8.08%	8.44%	9.22%	6.70%
2011	7.61%	8.24%	7.80%	7.61%
2012	7.19%	8.49%	7.89%	8.71%
2013	9.05%	9.84%	9.57%	9.17%
Mean	8.56%	8.66%	8.17%	7.96%

1/ DPU estimates based on the current net income attributable to the common stockholder divided by the average of the common equity balance as of December 31 of the current year and December 31 of the preceding year.

Sources: Rocky Mountain Power, December Report of Operations
To the Public Service Commission, various years.
PacifiCorp SEC Form 10K, various years.
http://www.sec.gov/cgi-bin/browse-edgar?action=getcompany&CIK=0000075594&owner=exclude&count=40&hidefilings=0

As can be seen on Table 4, the Company reached a low in the 2011-2012 time frame when the EBA was first being implemented in Utah. Actual payments to the Company from Utah ratepayers did not begin until late 2012. Some form of an EBA is available to PacifiCorp in other states. Contributing to the relatively low profitability in 2011-2012 is related to the timing of rate cases in Utah and the other states as well as residual effects from the 2008-2009 recession. In 2013 the reported system return on a regulatory basis approximates the Company's authorized return on equity not only in Utah, but also in the other jurisdictions the Company operates in. In 2013 there was improvement in the return on equity on an SEC basis and on a Utah regulatory basis. At this point, there are too little data to attribute (in part) the improvement to the Company's return on equity to the EBA, either in Utah or its other operating jurisdictions.

In its Corrected Order, the Commission questioned the value of reviewing return on equity saying in part that Utah ratepayers are not responsible for what goes on in other states. Because PacifiCorp operates as an integrated system, the Division believes that this is only partly true. In the case of return on equity and cost of capital generally, the SEC results form the basis for the Company's debt ratings and consequently cost of debt. Less directly, but still consequentially, the cost of equity determined in rate cases is also derived from SEC-based results. For example, the Company is compared to the guideline or proxy companies based upon their SEC filings: the relative risk and hence the expected return is based upon the integrated system. Thus, for better or worse, the results in other states impact Utah ratepayers.[9]

p. Changes to the Company's pre-EBA IRP preferred portfolio and implementation of the Company's IRP action plan.

One of the assumptions in the establishment of the EBA was that the EBA would not affect the Company's efforts to establish a least-cost/least risk generation portfolio. The IRP is developed with public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, and other stakeholders throughout a two-year process. The preferred portfolio selection is determined using system modeling tools that consider cost, risk, supply reliability, uncertainty, and government energy resource policies. The pre-EBA IRP that the Division considered as the baseline was the Company's 2011 IRP, filed on March 31, 2011, with an update filed on March 30, 2012.[10] The post-EBA IRP was filed on April 30, 2013, with an updated filed on March 31, 2014.[11]

The Division considered the 2011 IRP preferred portfolio as well as the 2013 IRP preferred portfolio. As noted above, the Company's hedging practices and front office transactions have changed in the Company's 2013 IRP after the EBA went into effect. However, those changes as well as the preferred portfolio outcomes cannot be directly attributed to the EBA. As one of the survey respondents noted above, there is the possibility that the Company's exposure to risk could be minimized, and therefore there is a potential that the EBA could impact changes to the IRP. However, at this time the Division cannot attribute changes in the Company's IRP to the EBA.

[9] Another area where other states' actions affect Utah ratepayers is transmission and generation resource planning. Utah ratepayers are impacted through PacifiCorp's efforts to reflect the demands and wishes of other jurisdictions in its generation and transmission portfolios.
[10] Docket No. 11-2035-01.
[11] Docket No. 13-2035-01.

q. Generation Performance Baselines

As set forth in the Introduction, the Commission ordered the Division to "work with the Office to develop baseline performance metrics for evaluation of plant performance under the EBA…." As a result of discussions with the Office, the Division requested certain information on plant performance from the Company. This is also item "q" in the attachment list of the June 15, 2012 Report and Order.

The data are collected into tables and charts set forth in Appendix 2. One reason why the Commission and intervenors would be interested in these performance data is the concern that the Company may become lax in maintaining and operating its plants at the highest levels of efficiency given the automatic recovery of net power costs through an EBA. Alternatively, as pointed out by the Office's representative, the Company might actually have the incentive to maintain and operate its plants at the highest levels of efficiency in order not to jeopardize its EBA. In any case, a detailed discussion of these data follows. The overall conclusion is that to date there is no evidence of the EBA affecting plant performance.

The Division received monthly heat rate data by thermal plant from the Company. These data are summarized on Exhibit A2.1. Besides the Gadsby plants, there are only a handful of instances where the differences between the pre- and post-EBA periods appear noteworthy: the Hayden and Craig plants, Johnston 1, Lake Side 1, and Hunter 2. There were also a handful of anomalous monthly readings (plus Gadsby) that were removed in Exhibit A2.2. Removing these anomalies significantly reduced the variability. The differences between the two periods appear to be more or less random fluctuations. Therefore, the heat rate data do not at this time suggest that there is a real difference between the pre- and post-EBA periods.

Exhibit A2.3 together with some charts, summarize the thermal plant availability and achieved capacity factors. The availability factors actually improved slightly overall between the pre- and post-EBA periods. However, the achieved capacity was lower in the post-EBA period versus the pre-EBA period. This difference appears to be real; that is, the differences are not random fluctuations. The Company operated its thermal plants differently in the two periods. The actual dispatch of the thermal plants can be affected by a number of factors that are probably more important than the existence, or non-existence, of the EBA such as weather variation, variation and location of demand, availability of renewable generation, and relative prices of fuel and wholesale electricity. At this time the Division cannot attribute the reduced achieved capacity factors to the EBA.

Exhibits A2.4 and A2.5 provide data on forced outages at thermal plants. In the post-EBA period a number of relatively extreme outage events occurred in 2013, although the total number of outages and the number of operator errors were not exceptional. Given the limited number of years (two), 2013 may be a random fluctuation and cannot be attributed to the EBA.

Exhibits A2.6 and A2.7 present data on wind generation mechanical availability and forced outages, respectively. The Company only began collecting wind forced outage data in 2012, so that there is no pre-EBA data to compare it to. The availability data suggests that there is no real difference between the pre- and post-EBA periods. Therefore, the data available do not indicate a systematic deterioration in reliability of the wind generation assets.

Finally, hydro resource data is summarized on Exhibit A2.8. There appears to be a drop in hydro availability after 2011 when the EBA was in effect. Also, there was an increase in the number of forced outage events; however, the total number of outage hours was lower in the post-EBA period. Given that there is only two years worth of post-EBA, it is difficult to say whether this constitutes a trend, whatever the cause might be.

While some statistical differences exist between the pre- and post-EBA periods in the Company's generating plant; there is little evidence at this time to suggest that the differences highlighted above are systematic. For a variety of reasons, one cannot expect two, relatively short periods to be identical.[12] The value of this exercise is that over time trends might emerge that then could be investigated for their root causes. At this point the Division makes no attribution to the EBA for the variability in the data cited above.

r. The implicit capacity price.

See under "e" above.

s. Revenue growth by measuring absolute differences between the base and actual net power cost to assess profitability.

See under "t" below.

t. The accuracy of GRID in monthly versus annual forecasting.

In order to assess the accuracy of GRID, the absolute differences between base and actual NPC, and the smoothing of NPC variability, the Division compiled data from the previous two general rate cases (Docket Nos. 10-035-124 and 11-035-200) and all three EBA filings (Docket Nos. 12-035-67, 13-035-32, 14-035-31). A summary of those results is shown in the two graphs below. Note that the graphs below show NPC as opposed to EBAC which includes net power costs and offsetting wheeling revenue. The two graphs represent two different perspectives of comparing actual NPC to base/forecasted NPC.

[12] Differences in weather, changes in load, differences in relative fuel and wholesale prices and forced outages all could contribute to one period being different to another.

Figure 3

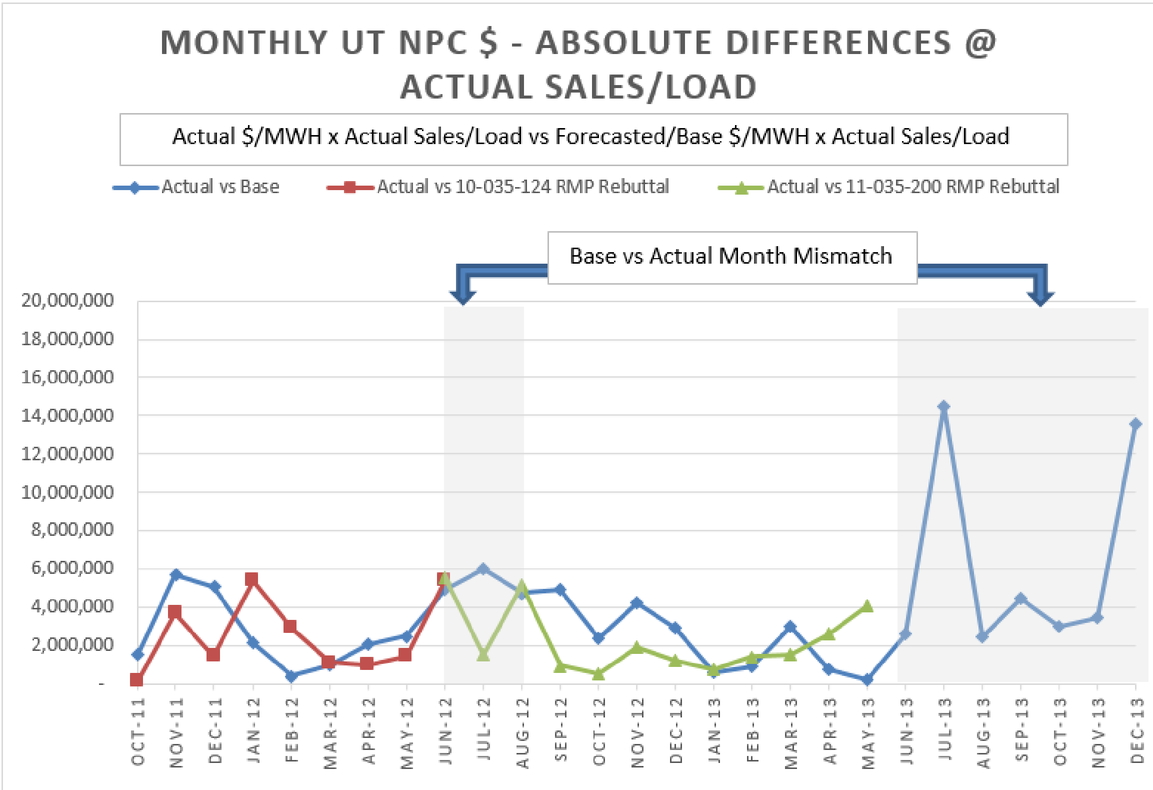
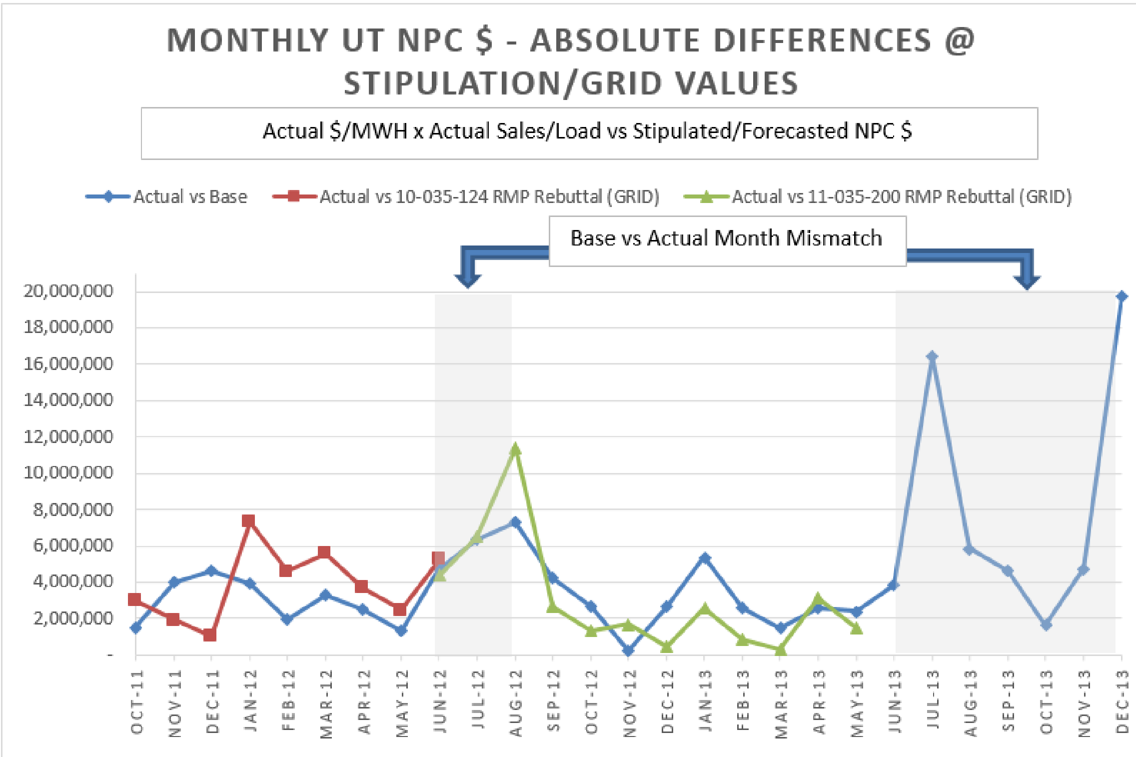

MONTHLY UT NPC $ - ABSOLUTE DIFFERENCES @ ACTUAL SALES/LOAD
Actual $/MWH x Actual Sales/Load vs Forecasted/Base $/MWH x Actual Sales/Load
Actual vs Base
Actual vs 10-035-124 RMP Rebuttal
Actual vs 11-035-200 RMP Rebuttal
Base vs Actual Month Mismatch
20,000,000
18,000,000
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
-
OCT-11
NOV-11
DEC-11
JAN-12
FEB-12
MAR-12
APR-12
MAY-12
JUN-12
JUL-12
AUG-12
SEP-12
OCT-12
NOV-12
DEC-12
JAN-13
FEB-13
MAR-13
APR-13
MAY-13
JUN-13
JUL-13
AUG-13
SEP-13
OCT-13
NOV-13
DEC-13

Figure 4



As can be seen from the graphs above, there is very limited data available to assess the accuracy of GRID. There are essentially only two GRID runs that can be evaluated against actual NPC. These two GRID runs are the Company's rebuttal positions in Dockets 10-035-124 and 11-035-200. Based on the data that are available for these two forecasts, it is not clear whether the Company's monthly forecast improved between rate cases. In comparison to base NPC (which have been stipulated to by the various parties), the Company's rebuttal positions have had less variability to actual NPC about 50% of the time. The graphs above show extreme variability between base NPC and actual NPC in July 2013 and December 2013. The Division believes this to be the result of the months being "mismatched." For example, under the current EBA structure, December 2013 actuals are compared to base NPC for December 2012. The Division expects the potential for more extreme variation to continue from January 2014 through August 2014 due to the fact that base NPC will not be "reset" into rates until the beginning of September

2014. Hence, actual NPC for any month in the 2015 EBA (calendar year 2014 data) will be compared to base NPC that are more directly tied to months in 2012 and 2013. For example, July 2014 actual NPC will be compared to July 2012 base NPC. July 2012 base NPC were determined in Docket 11-035-200 which had a June 2012 to May 2013 test year. The Division considers the mismatch in months to be the greatest concern in the current EBA structure.

In addition to a review of monthly NPC data, the Division also reviewed NPC in total for time periods covering much more than one month. The graphs below show a summary of this analysis.

Figure 5

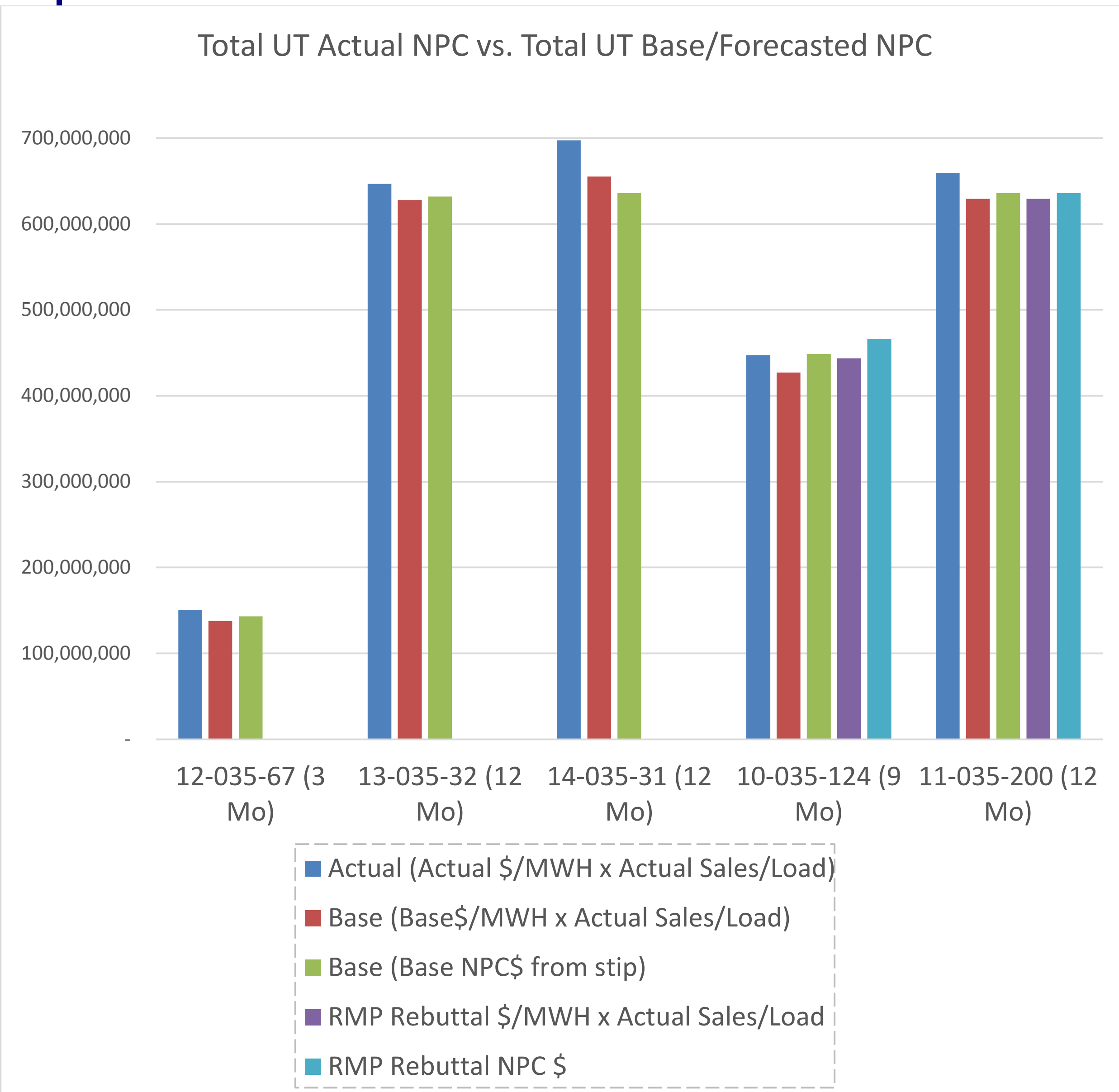
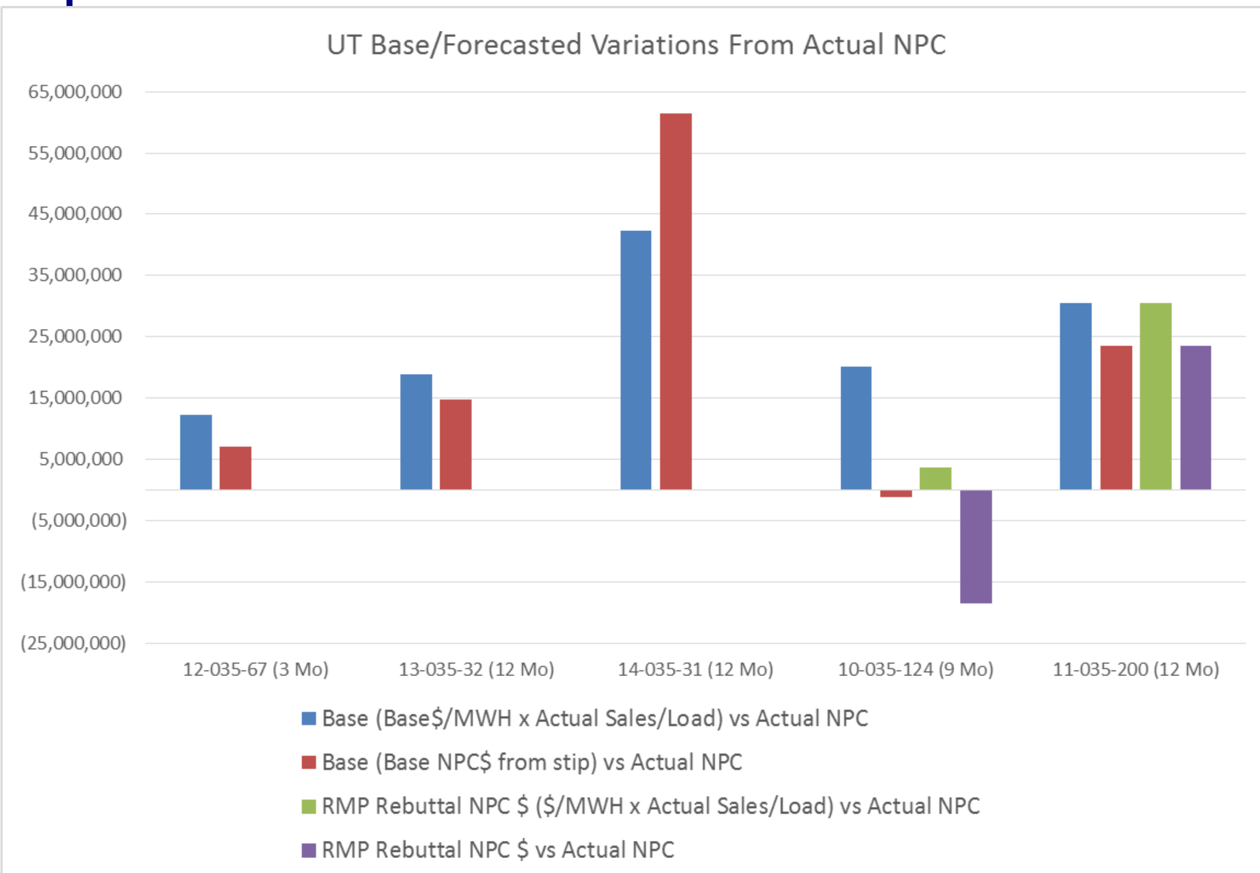

Total UT Actual NPC vs. Total UT Base/Forecasted NPC
700,000,000
600,000,000
500,000,000
400,000,000
300,000,000
200,000,000
100,000,000
-
12-035-67 (3 Mo)
13-035-32 (12 Mo)
14-035-31 (12 Mo)
10-035-124 (9 Mo)
11-035-200 (12 Mo)
Actual (Actual $/MWH x Actual Sales/Load)
Base (Base$/MWH x Actual Sales/Load)
Base (Base NPC$ from stip)
RMP Rebuttal $/MWH x Actual Sales/Load
RMP Rebuttal NPC $

Figure 6



Similar to the monthly analysis previously presented, there are relatively few data points to compare. The data points that do exist are characteristically dissimilar. For example, there is one 3 month EBA period and two 12 month EBA periods. For comparing rate case forecasts to actuals there is only one 9 month period and one 12 month period. Furthermore, some periods are based on loads, some are based on sales and others still are based on a combination of the two. Thus, any comparative analysis of the total NPC for each of these periods is problematic. Generally, the Division believes that there are: a) not enough data; and b) not enough characteristically similar data to draw any meaningful conclusions with respect to trends in total Utah actual NPC or total Utah NPC variability for extended time periods (e.g. one year).

The Division has no recommendation to solve the mismatch problem discussed above. However, one possible type of solution would require the Company to make a long-term NPC forecast that would extend months, or years, past the end of the test period in a general rate case. The NPC after the end of the test period would somehow go into rates "automatically" and could be trued-up in the annual EBA process. Such a procedure would likely face statutory as well as practical objections.

u. The quantitative differences and relative advantages of using a static or dynamic composite allocator for allocating EBA accruals to rate schedules.

The issue of what method to use to spread EBA deferrals among the various rate schedules and special contracts was litigated and decided by the Commission in Docket No. 11-035-T10. The Office proposed a method referred to as the "NPC Allocator," which the Commission adopted as its EBA allocation method and ordered that the method be applied to EBA deferrals beginning October 1, 2011.

In theory and practice the NPC Allocator differs from a simple energy allocator and represents a more accurate method for spreading EBA deferrals to the rate schedules and special contracts. First, the NPC Allocator reflects the way base NPC accounts are allocated to rate schedules and special contracts in the Company's class cost-of-service model in general rate cases (GRC). Second, the NPC Allocator includes NPC elements that are spread on the basis of both demand and energy. Third, the NPC Allocator tracks changes in the energy-demand weighting, which varies in each GRC as the composition of NPC elements (fuel expense, purchase power expense, wheeling expense, wholesale revenue, etc.) changes.

The Division continues to support the NPC Allocator as long as it was used in the most recent prior rate case. If the NPC Allocator was so used, then it is the more precise and dynamic method for spreading EBA deferrals.[13] As the class-specific allocation of NPC changes from

[13] The Division understands that the Office of Consumer Services also continues to support the NPC Allocator as the preferred method for spreading EBA deferrals.

one GRC to the next, those differences will be reflected in the NPC Allocator used for spreading EBA deferrals.

DIVISION'S COMMENTS ON ITS AUDIT EXPERIENCE TO DATE

The Division's experience with the EBA audit has been mixed. The EBA audit consumes substantial Division staffing resources and funds for outside consultants. As highlighted below there have been problems with both the lack of documentation and access to existing documents, particularly of front office transactions. There have been several issues regarding access to information that were initially difficult and exasperating for both parties. These seem to have mostly been worked out. The Division has approached the EBA audit process as a learning experience for it, the Company and for other parties. The Division believes that progress has been made and that further progress can be made.

The Division has assessed the internal controls over the accounting cycles associated with the EBA. Based on the Division's experience to date in this area, the Company has in place adequate internal controls.[14] The DPU can move with some assurance, based on its review of the numbers provided by the Company, that they are accurate and the accounting is done properly.

The Division has reviewed outages, both forced and unforced. Using accounting review methods, outages were highlighted that required additional investigation. These outages were reviewed by the Division's consultants, La Capra Associates. Adjustments to the EBA due to outages have been recommended by La Capra. While up to this point the Division has relied heavily on its consultant, outages is one area in which the DPU staff may have some confidence on its ability to do in-house prudency reviews in the future. This prudency determination could be done by the DPU because on most unforced outages the Company does assessments and reviews by in-house and outside experts and consultants on the cause of the unforced outage. A

[14] Docket No. 13-035-32, Utah Division of Public Utilities Audit Report of Rocky Mountain Power's Energy Balancing Account (Highly Confidential), pages 9-11.

review of those reports gives one the ability to determine if the outage was due to prudent or imprudent activities of the Company. There may be times, however, when a review of the prudence of an outage requires engineering expertise, which the Division does not currently possess. Given state procurement rules, the Division may or may not be able to obtain outside technical assistance on a timely basis.

With respect to the Division's review of the coal (fuel review), the Division can report that the Company in the last review provided very good supporting documentation for the basic coal transactions and demonstrated clearly how the transactions rolled to total numbers in the EBA. In other words, the accounting appeared proper and well documented. However, the Division lacks the expertise in coal procurement practices or the day to day proper management of coal inventories and other such non-accounting matters as to coal activity, to assess the prudency of the inventories and management activities. The Division must rely on outside consultants to assist it in the prudency determinations of these transactions and the related operations.

Of course, in the EBA during the year, there are thousands of back office and front office transactions affecting the EBA throughout the year. The Division is concerned that it may be virtually impossible to meaningfully assess the prudency of daily trading transactions because of a lack of contemporaneous written and verifiable source documentation supporting and justifying the trades made. In the first two EBA audits, the Division identified several supporting documentation issues related to front office transactions. If the Company improves its written documentation, the Division will be able to more adequately assess the prudence of these front office transactions. Even with supporting documentation, the Division resources limit it to reviewing small samples and rely on the expertise of its consultant to make a prudency determination.

One of the major arguments put forth by the Company for having an EBA-type mechanism was that it would reduce the number of rate case filings by the Company since it would reduce financial shortfalls from a major component of the Company's cost structure. So far, the

Division has not perceived a reduction in the frequency of rate cases due to the EBA. Since the EBA has not reduced the frequency of rate case filings, to date the work load on the Division has been to do both the EBA review and the rate case work in tandem; thus the Division's workload has generally increased. The Division has relied heavily on the resources and expertise of its consultants in order to perform the expected work.

There have been some positive developments in the conduct of the EBA process as both the Division and the Company provide feedback to each other. The documentation provided by the Company and the cooperation of certain sections of the Company have improved with each additional EBA cycle; the Division has improved its understanding of the Company's systems and data sets, making some parts of the annual review more routine for the Division. As the process is refined and further insight developed, the benefits to the customer and the Company, hopefully, will become more equitable. The time allowed to accomplish the tasks in the past has been less than ideal however; as the procedures are repeated and refined the time frame required by the Division will probably be shortened. The increased filing of available information throughout the year (now done on a quarterly basis by mutual agreement of the Company and the Division) by Rocky Mountain Power will provide increased review time making the process somewhat more manageable.

As the EBA periods are reviewed the process will also bring refined measurement of elements that should be included as well as those that should not. As this experience brings the refinement of the includable elements the reporting will also become more understandable and meaningful to all parties involved. There has been significant improvement and standardization in the reporting as the EBA process has developed. There are continuing efforts to develop standardized reporting formats and refinement of the filing requirements.

While the Division was generally supportive of the Company having an EBA in Docket No. 09-035-15, the Division also expressed concern about the Division's ability, based on its staff size and expertise, to be able to do a proper prudency review on the EBA. As discussed above, working with the consultants has given the Division some assurance related to prudency checks on outages and to a lesser degree, other areas of net power costs. The Division continues to have concerns about determining transaction prudency. The Division relies on the 70/30 sharing split to give it some confidence that the Company will generally act with prudence because of the potential for loss to the Company outside of the threat of a formal prudence disallowance by regulators.

CONCLUSIONS AND RECOMMENDATIONS

As highlighted above, there is generally not enough information to attribute differences in the Company's operations to the EBA, and perhaps there never will be due to the effects of various other factors. As expected, performing the EBA audit is a challenge to the resources of the Division. It is unsurprising that there are differing, sometimes opposing views, concerning the EBA among the Company, the Division and the intervening parties. However, the Division believes that many issues with the Division's audit program have been worked out and that much of the EBA program is running as expected.

While there are recommendations for changes to the EBA from the Company and others, the Division recommends that these changes wait the completion of the pilot program when it can then be assessed from a position of additional information and experience.

CC David Taylor, Rocky Mountain Power
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Service List

APPENDIX 1

Division's Survey Instrument to the Intervening Parties

APPENDIX 2

Confidential Exhibits