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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.	**COMMENTS OF UIEC ON THE DIVISION OF PUBLIC UTILITIES' FINAL EVALUATION REPORT ON THE EBA PILOT PROGRAM** Docket No. 09-035-15

Pursuant to the Utah Public Service Commission's ("Commission" or "PSC") Scheduling Order, Notice of Hearing and Notice of Public Witness Hearing, issued in this docket on June 22, 2016, the Utah Industrial Energy Consumers intervention group ("UIEC")[1] hereby submits these Comments on the Final Evaluation Report of PacifiCorp's EBA Pilot Program ("DPU Report" or "Report"), which was filed by the Division of Public Utilities ("Division" or "DPU") on May 20, 2016.

The UIEC commends the Division for its effort in preparing the Report and recommendations, and offers the following Comments on the limited topics addressed below. To

[1] The UIEC was granted intervention in this docket on May 4, 2009, at which time the intervening parties were identified as Holcim, Inc., Kennecott Utah Copper Corp., Kimberly-Clark Corp., Malt-O-Meal, Praxair, Inc., Proctor & Gamble, Inc., Tesoro Refining and Marketing Co., and Western Zirconium. These Comments are submitted on behalf of only Tesoro Refining and Marketing Co., Malt-O-Meal, and Holcim, Inc. The remaining intervening parties do not participate in these Comments.

the extent these Comments do not address a topic on which the Division has reported, the UIEC reserves the right to take a position on those topics in response to the direct testimony and/or comments of other parties, or in reply comments submitted in accordance with the Commission's Scheduling Order.

I. INTRODUCTION

In its Corrected Report and Order in Docket 09-035-15, dated March 3, 2011 (Corr. Rep. and Order"), the Commission required the Division to submit a "final evaluation of the pilot program … [which] will include the Division's recommendation as to whether the program should be continued as is, modified or discontinued." Corr. Rep. and Order at 79. The resulting Report from the Division notes that there is no agreement on whether Senate Bill 115 ("SB 115"), enacted during the 2016 Legislative session, had the effect of extending the EBA pilot program through 2019. Report at 3. At the same time, the Division apparently presumes that "the Commission seems to accept that the SB 115 Legislation effectively extended the EBA pilot program through 2019." Report at 7.

The UIEC does not agree that SB 115 necessarily requires a three-year extension of the EBA. In comments filed in Docket 16-035-T05, the UIEC expressed the view that "the enactment of SB 115 does not … guarantee that the EBA should continue or obviate the need for the Commission to monitor vigilantly any changes in circumstances that would make the EBA contrary to the public interest." Comments of the UIEC, at 4, Docket No. 16-035-T05 (May 2,

2016) (hereinafter, the "T05 Comments").[2] The UIEC also emphasized the importance of the Division's completing the pilot program review:

> The Pilot Program evaluation is essential in informing the Commission about the consequences of the EBA so that the program can be terminated as inconsistent with the public interest or so that adjustments can be made going forward to ensure that ratepayers do not become the guarantors of the Company's risky policies and practices or of the resource decisions of other jurisdictions that affect the allocation of power costs to Utah.

T05 Comments at 5. In light of the conclusions reached in the DPU Report, and for the reasons discussed below, the UIEC believe that the EBA in its current form, as it has been modified by SB 115, cannot be found to be in the public interest. It should therefore be eliminated.

If, however, a means can be found to sufficiently modify the EBA so that it becomes consistent with the public interest and can be retained, the UIEC proposes several structural changes to the EBA (see part III of these Comments) and recommends that the Commission consider implementing them.

II. THE EBA IS NOT IN THE PUBLIC INTEREST AND SHOULD BE ELIMINATED.

The enactment of SB 115 has changed the balance of the risk and the benefits of the EBA by eliminating the 70/30 sharing bands. As a consequence, ratepayers are now at risk for 100 percent of Rocky Mountain Power's ("RMP" or "Company") prudently incurred net power costs. Because this represents a fundamental reassignment of risk and reward, the Commission should undertake a thorough evaluation of the benefits and negative impacts of the EBA on ratepayers

[2] As the DPU's Report quoted selected sections from the UIEC's T05 Comments, the UIEC requests the Commission take administrative notice of the full text of UIEC's T05 Comments and incorporate them herein.

before deciding whether the EBA should be retained. If the Commission concludes that it should be retained, it should give careful consideration to the form that the EBA should now take.

The inquiry relevant to determining whether the EBA should continue is prescribed by the statute itself, which provides that "[a]n energy balancing account shall become effective upon a commission finding that the energy balancing account is: (i) in the public interest; (ii) for prudently-incurred costs; and (iii) implemented at the conclusion of a general rate case." Utah Code Ann. § 54-7-13.5(2) (2010). In the context of a regulatory statute, the term "public interest" "takes its meaning from the purposes of the regulatory legislation in question." *Ellis-Hall Consultants, LLC v. Pub. Serv. Comm'n*, 342 P.2d 256, 261 (Utah 2014) (*quoting NAACP v. Fed. Power Comm'n*, 425 U.S. 662, 669, 96 S.Ct. 1806, 48 L.Ed.2d 284 (1976)).[3]

The Commission illuminated the meaning of "public interest" in the context of the EBA statute, by setting out three essential criteria that would be necessary to find that an energy cost adjustment mechanism is in the public interest:

> To serve the public interest and to ensure just and reasonable rates, most importantly this new mechanism must [1] fairly allocate risk between customers and shareholders, [2] maintain incentives to operate efficiently, both in the long-run and short-run, and [3] satisfy the requirements of the Energy Balancing Account statute.

[3] For example, in the context of considering an application for approval of a merger under Section 54-4-28, the public interest standard has been interpreted to require the Commission to ensure that "the applicants show that the transaction provides a *net positive benefit* to the public." *In the Matter of the Merger of the Parent Corps. of Qwest Communications Corp., LCI Int'l Telecomm. Corp. and US West Communications, Inc.* ("*Qwest Merger*"), Report and Order at 14, Docket No. 99-049-41, 2000 WL 873341 (Utah PSC, June 9, 2000) (emphasis added). *See also In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock*, Report and Order at 26-27, Docket No. 98-2035-04 (Utah PSC Nov. 23, 1999) (The Commission "is to consider [all positive benefits and negative impacts], giving each its proper weight, and determine whether on balance the [proposal] is beneficial or detrimental to the public.").

Corr. Rep. and Order, at 67-68. Because the energy cost adjustment mechanism that was originally filed by RMP did not fairly allocate risks or provide incentives to the Company to operate efficiently, the Commission found that "it [did] not meet the statutory requirements for our approval of an energy balancing account." *Id.* at 67. It failed all three criteria for being "in the public interest." After a lengthy proceeding in which the Commission took testimony and held hearings on RMP's proposed energy cost adjustment mechanism, the Commission ultimately approved the mechanism embodied in the "EBA pilot program," conditioned upon changes that would be necessary for it to serve the public interest:

> As in the past, we will continue to rely on prudence reviews during rate setting proceedings to determine the extent to which the Company is providing least-cost, risk-adjusted service to its Utah customers, consistent with integrated resource planning and competitive solicitation analyses. We recognize, however, *relying solely on prudence reviews will shift too much of the risk for suboptimal planning and operation currently borne by the Company, who is in the best position to manage this risk, to customers, who are not.* Therefore, the balancing account we adopt requires both Company customers and shareholders to remain at risk for a portion of the actual net power cost which deviates from approved forecasts. This decision recognizes the value of Company management having *meaningful financial incentives* to minimize net power cost in the short-run and long-run, regardless of the extent of net power cost volatility. *We find a sharing mechanism is the best method, at this point, to ensure customer and shareholder interests are aligned and the public interest is maintained.*

Id. at 69-70 (emphasis added). The 70/30 sharing mechanism was essential to the Commission's conclusion that risks could be fairly allocated, and the Company would have a meaningful financial incentive to minimize net power costs.

The enactment of SB 115 has altered the outcome of the analysis of whether the EBA in its current form is in the public interest. The dilemma is now, as it was then, that the risk of actual costs differing "detrimentally and substantially from forecasted costs" is a "zero sum game, where all benefits flow to one group (customers or shareholders) at the expense of the other." *Id.* at 70. But, with the elimination of the 70/30 sharing mechanism, regulators must now rely solely on prudence reviews to balance that risk, which the Commission has already recognized "will shift too much risk for suboptimal planning and operation" from the Company "who is in the best position to manage the risk, to customers, who are not." *Id.*

The DPU's Report acknowledges the inadequacy of prudence reviews. Having put forth heroic efforts to audit the EBA during the pilot period, the Division "continues to have concerns about determining transaction prudence" (DPU Report at 44), and warns of the moral hazard that will result "should the Company perceive that it is essentially guaranteed recovery of costs." *Id*. at 17. The Division concludes that "the removal of sharing bands is a significant shift in risk to ratepayers not only in the raw dollar amounts involved but in the manifest lessening of the incentives aligning the Company with ratepayer interests." *Id.* at 18. Without the sharing bands, it appears highly unlikely that risk will be fairly shared, or that the incentives will be adequate to protect ratepayers from losing this zero-sum game.

The Division reports that the EBA benefits only the Company, and that "ratepayers are worse off both in higher rates, but also in terms of risk that the Company was able to shift to them." *Id.* at 50. The Company is earning its authorized rate of return (even with the 70/30 bands in place) (*id*. at 31), yet the EBA has not resulted in any reduction in energy rates, rate volatility, or the need for annual rate increases. *Id.* at 29. At the same time, it has placed an additional burden on regulators, who state that they have not achieved any confidence that they can meaningfully assess the prudence of the Company's daily transactions, nor would they be able to do so even with improved documentation. *Id.* In the Division's words, it appears "virtually impossible" to reasonably ascertain "prudently incurred" actual power costs. *Id.*

The enactment of SB 115 did not expressly mandate an extension of the EBA pilot period, or amend the Commission's statutes in any way that would change the analysis for determining whether an energy balancing account is in the public interest. It did remove the 70/30 sharing bands (codified at Utah Code Ann. § 54-7-13.5(2)(d)), and it does require the Commission to report to the Legislature at the end of years 2017 and 2018 about whether allowing the Company to recover 100 percent of its costs is in the public interest. Utah Code Ann. § 54-7-13.5(6). But there is nothing in SB 115 to suggest that the Legislature found that 100 percent EBA cost recovery would be in the public interest. Nor is there anything to suggest that the EBA need no longer be in the public interest, or that it must continue through 2019 if the Commission finds before then that it is not in the public interest. The original statutory requirements remain: any EBA initially must be in the public interest (Utah Code Ann. § 54-7-13.5(2)(b)); an EBA must be "formed *and maintained*" in accordance with the requirements of Section 54-13.5 (which includes the "public interest" requirement) to avoid constituting impermissible retroactive ratemaking (*id.* at § 54-7-13.5(4)(c) (emphasis added)); rates charged to utility customers must be just and reasonable (*id.* at § 54-3-1); and every unjust or unreasonable charge of a public utility must be prohibited (*id.*). In short, SB 115 does not require the pilot program to continue if it does not result in just and reasonable rates or is not in the public interest.[4]

[4] SB115 must be read to be consistent with other provisions of Section 13.5 and of Title 54. *Mountain States Tel. & Tel. Co. v. Payne*, 782 P.2d 464, 467 (Utah 1989); *see also Olsen v. Eagle Mountain*, 2011 UT 10, ¶ 12, 248 P.3d 465; *Sullivan v. Scoular Grain Co. of Utah*, 853 P.2d 877, 880-81 (Utah 1993); *Clover v. Snowbird*, 808 P.2d 1037, 1045 (Utah 1991). Furthermore, when the legislature amends a portion of a statute but leaves the other portions untouched,

Allowing the Company to recover 100 percent of its net power costs when the prudence of its transactions cannot be reliably ascertained is precisely what prevented the Commission from finding that the originally proposed energy balancing account was in the public interest. With the enactment of SB 115, the regulators are again in the "virtually impossible" position of "relying solely on prudence reviews" to incentivize efficiency, which the Commission has already found is inimical to the public interest because it "will shift too much of the risk for suboptimal planning and operation currently borne by the Company, who is in the best position to manage this risk, to customers, who are not."

The current EBA does not fairly allocate risk between customers and shareholders, or maintain incentives for the Company to operate efficiently, or satisfy the requirements of the EBA statute. Under the circumstances and in light of the DPU's Report and the applicable law, the Commission may have little choice but to conclude that the current EBA is *not* in the public interest and that it should therefore be eliminated or substantially restructured.

It is not clear that restructuring would salvage the EBA. After the Company's original energy balancing account proposal, some parties suggested the Commission "establish predefined or pre-approved levels of hedging, market purchases, energy efficiency programs, renewable resources or low-cost resource operating characteristics," and other methods to provide incentives to the Company's behavior. Corr. Rep. and Order, at 68-69. The Commission declined to adopt any of the suggested proposals. It stated:

> Based on the recommendations of several parties, we conclude an EBA design which includes risk-sharing during regulatory lag, coupled with prudence review, is superior to predefined standards

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the unchanged portions must be interpreted to be adopted by the legislature with no implicit repeal or change in meaning. *Christensen v. Indus. Comm'n*, 642 P.2d 755, 756 (Utah 1982).

> or preapproved levels of hedging, market purchases, energy efficiency programs, renewable resources or low-cost resource operating characteristics.

*Id.*at 69. [5] The risk sharing mechanism was the only measure the Commission found that would be effective in fairly allocating risk and adequately encouraging efficiency.

It is not inconceivable that structural changes to the EBA could provide some assurance that risk could be fairly shared between ratepayers and the Company, or that adequate incentives could be imposed.[6] Ultimately, however, it is not up to the regulators or interested private parties to propose a solution that would satisfy the public interest requirement. The EBA statute requires RMP to bear the burden of proof to demonstrate that the EBA is in the public interest. Utah Code Ann. § 54-7-13.5(2)(d); *see also Utah Dep't of Bus. Regulation v. Pub. Comm'n*, 614 P.2d 1242 (Utah 1980). The Company should be required to propose changes to the EBA, and to provide evidence demonstrating that, as amended by SB 115, the EBA continues to fairly allocate risks between the Company and ratepayers; provides an adequate incentive to the Company to minimize

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[5] The Commission explained its reasoning:

> [W]e decline to adopt the proposals to establish standards or targets, or to set limits on components of power costs. First, we agree with the Division, rate change proceedings provide a better venue to examine data and make a determination on prudent levels of market reliance and use of other resources to serve the public interest. Second, setting pre-determined levels as suggested by the parties may impede the Company's flexibility to manage its resources wisely. As this record demonstrates, market conditions change and it is not our intention to micro-manage the Company's operations. Third, the record identifies a more effective means of providing the required incentives [*i.e.*, risk sharing through the 70/30 mechanism].

Corr. Rep. and Order at 68-69.

[6] If deviations from base net power costs were accrued, reconciled and billed monthly, for example, overruns in favor of customers could be covered immediately as refunds or reduced surcharges, while overruns in favor of the utility could be covered later (without carrying charges) but only after a thorough investigation of the reasons for the overruns, the prudence of the utility's actions that led to the overruns, and the actions taken by the utility to minimize or reduce net power costs.

short-term and long-term net power costs; and complies with the applicable statutes. Unless it can do so, the Commission should discontinue the EBA.

III. IF THE EBA IS RETAINED, IT SOULD BE SIGNIFICANTLY MODIFIED.

If the Commission does not completely eliminate the EBA, it should require significant modifications to the current EBA to reduce some of the harm that the EBA now inflicts on Utah ratepayers. The UIEC offers the following suggestions for modifications, without conceding that the implementation of any of them (or all of them in the aggregate) would bring a post-SB 115 EBA in line with the public interest.

A. The EBA Should be Restructured to Eliminate Annual Averaging of Deviations, Recognize Time of Use and Seasonality of Costs, and Provide Price Transparency to Customers.

The UIEC has testified in prior proceedings before the Commission that EBA costs should be allocated to customer classes in the month that they were actually incurred. *See, e.g.,* Direct Test. of Jonathan Lesser at 37, Docket No. 11-035-200 (June 22, 2012). Power costs may vary significantly from hour to hour, day to day, and month to month, and some customer classes have greatly varying consumption from season to season. Although the current EBA method of allocation appears to be tracking time of use and seasonality, those data are not used to allocate to customers the deviation from the base power costs. While underlying base rates may reflect these differences to some extent, the smearing together of all monthly deviations into one annual average ignores these important cost-related differences, defeating the purpose of time of use and seasonal rates. *See* Rebuttal Test. of Maurice Brubaker, Docket 09-035-15 (Sept. 15, 2010). The aggregation of real-time EBA deviations is distorted by this method of assignment of costs, which obscures pricing signals so that customers lose the ability to know (or respond to) the price of power at the time they consume it. Thus, the EBA allocation methodology fails in two important aspects of rate design – to shape and modify consumer behavior, and to spread costs to the customers (or class of customers) that cause the costs.

The DPU's Report states that although "calculating the EBA accrual on a monthly basis does create slightly more complexity in allocating costs to Utah," it also enables the carrying charge on EBA balances to be calculated more precisely. DPU Report at 25-26. Nevertheless, the Division makes no recommendation on the issue. Meanwhile, RMP acknowledges that "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." DPU Report at 13 (quoting comments received from RMP). Both parties, therefore, cite certain advantages to monthly accounting of EBA costs.

The UIEC recommends, as it has from the inception of the EBA, that customers should be billed, as nearly as possible, the actual energy costs incurred by the utility at the time the customer consumes the energy. Power cost deviations should be accrued monthly by rate schedule (and special contracts), one-off costs should be booked in the month incurred, and costs should be allocated and billed to customer classes on a monthly basis. The allocation to Utah may be "slightly more complex," but the data necessary for monthly accrual and billing is readily available. While monthly accrual and billing does not begin to solve the overarching problem of risk sharing and incentives that render the current EBA fatally objectionable, it would result in better price signals and a fairer allocation of costs to cost causers, and would also make carrying charges unnecessary.

B. The EBA Reconciliation Proceedings Should True-up Against Actual Costs Rather than Forecasted Costs.

The EBA statute provides the Company an opportunity to recover "[p]rudently incurred actual costs in excess of revenues collected," and requires a refund of "[r]evenues collected in excess of prudently incurred actual costs." Utah Code Ann. § 54-7-13.5(2)(f)–(g) (emphasis added).[7]

EBA reconciliation proceedings currently compare actually incurred net power costs against base rates set by projecting the Company's needs at the time of the most recent general rate case. Unless there is a general rate case every year to re-set base rates based on more current forecasted data, the amount of net power costs in base rates is likely to bear an ever diminishing relationship to the Company's actual power costs. Moreover, as the Division points out, the mismatch between the test year used in general rate cases and the calendar year used in EBA reconciliation proceedings builds in additional inaccuracy in times of generally increasing (or decreasing) power costs. Finally, given the Company's abysmal forecasting ability,[8] continuing to set base rates on GRC forecasts opens the possibility for the Company to take advantage of "perverse incentives" inherent in the current method of setting base rates. DPU Report at 24-25.[9]

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[7] It should be noted that the use of the EBA is restricted to "actual power costs," which are enumerated as "fuel, purchased power and wheeling expenses." Utah Code Ann. § 54-7-13.5(2)(b). The UIEC oppose any attempt to expand the EBA to include other types of costs, and submit that it would be unlawful to do so without legislative action amending the statute.

[8] *See* DPU Report at 35-38 (from Oct. 2011to Dec. 2015, forecast error for net power costs was over 6 percent). When the Commission first determined that an EBA could be in the public interest, it noted that the Company's ability "to accurately forecast system-wide net power cost in future test periods, even one year ahead, is questionable." Corr. Rep. and Order at 65.

[9] The Division observes that because the Company collects a carrying charge on the EBA balance, it has an incentive to under-forecast base net power costs. DPU Report at 25. On the other hand, by over-forecasting base net power costs, the Company could avoid ever making a refund to customers even if there may have been overcharges resulting from earlier forecasted power costs.

RMP recognizes that "unbundling EBA costs from base rates" would likely facilitate more accurate measuring of EBA costs. DPU Report at 13. The UIEC believes it would also improve the ability of customers to understand and respond to the actual cost of the energy they consume.

If the EBA is to continue, the Commission and regulators should consider de-linking the EBA from general rate cases. The Division suggests that the Company's forecasts could be updated concurrent with its annual EBA filing, but recognizes that adjusting base rates by updated forecasts could amount to an impermissible "partial rate case each year." *Id.* at 25. As an alternative, the Commission could consider doing away altogether with forecasting net power costs, and using instead the actual, historic net power costs from one year as the base for the following year.[10] If base power costs were reset at the end of each EBA proceeding using a historical calendar year (*e.g.*, the previous year's actuals), the "mismatch" problem could be solved, inaccuracies and perverse incentives inherent in projections could be avoided, actual costs would be trued up against actual costs as the statute requires, and there would be no need for a general rate case each year to reset base rates.

C. The Carrying Charge Applied to the Balance in the EBA Should Reflect the Company's Actual Risk and Be Based on the Prudent Rate of Short Term Debt.

One of the core principles of ratemaking is that utilities are allowed to achieve a rate of return, or "profit" on their capital that is authorized by the Commission through the investigative and determinative means of a general ratemaking case. However, the authorized rate of return, and thus the authorized profit, is not guaranteed. Rather, it carries an inherent risk that the Company might not achieve that profit or rate of return. The presence of this risk may justify a

[10] That may require a period of time where there can be an appropriate review of cost overruns by the utility.

somewhat higher potential rate of return on the Company's investment than may be realized under market conditions.

However, the rate of return applies only to the Company's net investment on facilities. Deferred purchased power and fuel costs are not capital investment but are costs that are passed through to customers on a dollar-for-dollar basis. Although the Company is entitled to be made whole with respect to the costs related to financing those fuel and power purchases, it is not, and should not be, entitled to profit by virtue of the EBA mechanism. That is apparently what is happening with the currently effective carrying charge.

The DPU's Report recommends that in light of the incentive to under-forecast net power costs created by elimination of the sharing bands, "it would be appropriate to reduce the carrying charge to a short term rate, or eliminate it altogether." DPU Report at 7-8. The UIEC agrees. At the current rate of 4.45%,[11] the potential amount of interest that could accrue on temporary EBA balances is substantial and represents a rate that is significantly higher than the short-term borrowing rate.[12]

Not only does the current authorized carrying charge allow the Company to profit through the deferred energy account balances (rather than simply recover its costs), it essentially *guarantees* that RMP will receive a set amount of *profit* from the carrying charges associated with that deferred energy balance. Especially with the elimination of the 70/30 sharing bands, the

[11] Tariff Approval Letter from the Commission, Docket No. 15-035-69 (Feb. 26, 2016).

[12] The UIEC has raised this concern several times during the pilot period. *E.g.*, Brubaker Rebuttal Test., Docket No. 11-035-T10 (March 15, 2012); Brubaker Surrebuttal Test., Docket No. 11-035-T10 (Apr. 5, 2012).

Company should not be permitted to profit on a deferred account for its fuel and purchased power costs since it carries *no* risk by incurring those charges.

While it is true that the utility may at times be required to raise capital to fund fuel and purchased power costs until recovery through either a deferred or general ratemaking case, nothing about that situation is inconsistent with allowing a utility to only recoup the net effective costs of procuring such capital at whatever rate is required to cover the utility's actual costs of financing the deferred balance. The Company is statutorily only allowed to recover its actual costs. It is not authorized to recover the perceived or hypothetical opportunity costs associated with tying capital to the deferred account. Consequently, the carrying charge should be restricted to the *actual cost* of the debt, and not to the amount the Company might otherwise receive as a return on a hypothetical investment without the deferred account requirement.

The carrying charge should reflect, at a maximum, only the *net effective interest rate* of the prudent debt required to fund the fuel and purchased power costs incurred in the deferred EBA. This is especially true since utilities, unlike their customers, are also able to take advantage of the federal tax deductions that arise from funding the deferred energy balances.[13] Resetting the carrying charges in line with these suggestions would help prevent the Company from profiteering on the carrying charges.

D. <u>The EBA Should Be Revised to Eliminate Double Capacity Charges.</u>

There is included in the price of all firm market energy an amount to compensate the selling generator for its capacity. Although not separately stated in the price, capacity costs are included

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[13] In addition, any carrying charges should be calculated net of associated accumulated deferred income taxes ("ADIT"). The failure to offset the ADIT results in what essentially becomes "free capital" to the Company.

in the market energy that is purchased by RMP (as well as by all market energy purchasers). Allowing this capacity cost to be passed through to the ratepayers results in ratepayers paying twice for capacity–once for the fixed costs of an RMP generator, and again for the demand component of purchased power. When a plant is down due to an outage, ratepayers still pay a capacity payment on the steel, but then are also charged the capacity payment in the market energy purchased to compensate for that outage. In general rate cases, this duplication can be accounted for and eliminated. However, with the EBA as currently designed, ratepayers are forced to pay twice for capacity.

Similarly, the impact on the EBA of the Company's use of a "75/25" allocator, which allocates fixed generation and transmission costs, in part, based on energy consumption, has never been addressed. It appears that because of that allocator, there is some level of fixed costs in the EBA (contrary to the EBA statute) which has the effect of further exacerbating RMP's fixed cost recovery shortfall. And because of that shortfall, RMP continues to make adjustments that require retail ratepayers to bear all of the risks of the Company's recovery of fixed costs (which by statute may not be recovered through the EBA). The skewing of fixed cost recovery is both inequitable and inefficient because it fails to align risk and reward, and presents another moral hazard by insulating RMP from its own investment decisions regardless of market changes.

The Commission has ordered "the Company and Division to evaluate this issue further during the pilot period of the EBA to determine if it should be addressed differently in a permanent program." Corr. Rep. and Order, at 73. As far as the UIEC can tell, nothing has been done in response to this directive from the Commission. If the EBA is to continue, the Company should be required to either demonstrate that capacity costs are not being flowed through the EBA, or propose a means to capture and eliminate them from the EBA.

E. **<u>Recent Legislative Changes and Plans to Join the CAISO Require Reconsideration of the Allocation of Risk for Power Costs</u>**

Oregon has recently passed legislation that will require Utah ratepayers to underwrite Oregon's resource choices. S.B. 1547, 78th Leg. Assem. Reg. Sess. (Ore. 2016). RMP was successful in passing SB 115 in Utah, which will allow for early retirement of coal plants pursuant to the Oregon legislation. The legislation in both of these states will almost certainly result in higher power costs, which RMP will likely seek to recover through the EBA to avoid any risk that it will not fully recover those increased costs. The Utah Commission and regulators should consider how the political decisions that have been forced upon Utah (as a result of other state's legislative actions) should affect the way we view the EBA in Utah. It does not seem to be in the public interest to remove the energy cost risk from RMP resulting from legislative developments in other states.

Likewise, before extending the EBA the Commission and regulators should consider the effect of RMP joining the CAISO in a regional ISO. In a few years, RMP will be buying forward, daily and hourly power as a price taker from the power pool, and expecting to recover its deficiencies through the EBA. Moreover, it has been reported that there is a "retropricing" problem in CAISO where buyers will not know the price they are paying for power until, in some cases, 60 days after the purchase. *CAISO Bus. Practice Manual* § 2.3.2 (Vers. 17, May 12, 2016). If RMP is able to recover its CAISO costs through the EBA, not only will it have no incentive to minimize power costs, it may not even know the price it is paying for power. And Utah ratepayers will be fully covering RMP's blind power purchases through the EBA.

While the impact of recent Oregon legislation and of RMP's joining the CAISO is unknown, it is clear the world will be different and that the power cost risks will likely be greater. The UIEC does not believe the EBA should continue without the Commission and regulators making a serious attempt to understand the impact of RMP sponsored legislation in other jurisdictions and the nature and magnitude of the CAISO risks.

F. The Commission Should Not Establish Interim Rates for EBA Cost Recovery.

The Division recommends that the time period for performing an audit of the EBA should be extended to one year, and that "interim rates should be established until the Division can complete its audit." DPU Report at 7, 49; Test. Charles Peterson, 2:42-44, 7:162-163 (Sept. 21, 2016). The UIEC appreciate the impact that the Division's EBA audits have had on its time and resources, and recognize the importance of the audits, especially because with the advent of SB 115, prudence reviews apparently have become the only means to control inefficient behavior by the Company. The UIEC, however, cannot support the Division's proposal of implementing interim rates for one year to extend the time for an audit. This question of whether an interim rate should be put in place for the EBA has already been before the Commission and extensively litigated by the parties. *See* Order on EBA Interim Rate Process, Docket Nos. 12-035-67, 09-035-15, 11-035-T10 (Aug. 30, 2012). The UIEC continue to hold the view that there exists no process for "interim" rate relief for EBA cost recovery. Costs the Company wishes to recover through the EBA cannot be incorporated into rates until after the Company has demonstrated by substantial evidence that the costs were prudently incurred.

G. If Rate Payers Must Accept More Risk for Price Changes, They Should Be Given the Ability to Avoid these Risks through Smart Meters.

With the enactment of SB 115, the EBA now transfers to consumers 100 percent of the risk that actual power costs will exceed base net power costs. At the same time, the structure of the EBA withholds from consumers the information needed to ameliorate that risk. This harm could be reduced by, among other things, providing customers with real-time, accurate information about their consumption and pricing.[14]

Smart meters could provide consumers with near-real time energy usage information about how much, when, and in some cases at what price, they use energy. Armed with this information, consumers could better control their energy consumption and their monthly bills. Unfortunately, in Utah, consumers are frozen into the use of obsolete radio-controlled meters even though better, smart metering technology is available. This is because RMP has been allowed to select the technologies to be implemented and to freeze them in place until it has fully recovered its costs, unlike private businesses that often incur losses to keep pace with technological changes. If consumers must bear virtually all of the risk of energy prices, they should have the ability to control some of those risks through, among other things, the implementation of smart meters.

H. The Company's Rate of Return Should Be Reduced to Reflect Its Risk.

Over the last several years, the Company has been instrumental in passing legislation that greatly reduces its risk (*i.e.*, future test years, separate major plant addition cases, an energy balancing account, *etc.*). With the enactment of SB 115, the 70/30 sharing band of the EBA has been eliminated, and the recovery of other costs associated with implementing the legislation has

[14] Monthly billing would also reduce the risk.

been removed from the Commission's discretion. As a result, as the DPU's Report concludes, the Company is now in a position where it is likely to earn a greater return than allowed. If the EBA is to continue, the Company's return on equity should be reduced to reflect the true resulting risk. The Commission should seriously consider this in RMP's next general rate case, or instigate a general rate case to significantly reduce the Company's return on equity.

CONCLUSION

The UIEC encourage the Commission to fully review the risks and benefits of an EBA in light of SB 115's requirement that the Company recover 100 percent of the deficiency in its net power costs. Without some mechanism to share the risk and to incentivize the Company to efficiency, the Commission has already correctly determined that an EBA cannot be in the public interest. If the EBA is to continue, it will require extensive restructuring to develop other means to ensure that it is in the public interest and that it produces just and reasonable rates.

The UIEC do not contend that any or all of the revisions to the EBA that are proposed above would enable the EBA to again serve the public interest, but request that these proposed measures be considered in any undertaking to restructure the EBA.

Date this 16th day of November, 2016.

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