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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.	**POST HEARING BRIEF OF UIEC** Docket No. 09-035-15

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Pursuant to the order of the Utah Public Service Commission ("Commission" or "PSC") issued on November 2, 2010, at the close of hearings in this docket, the Utah Industrial Energy Consumers ("UIEC"), an intervention group, submits this Post Hearing Brief for the purpose of summarizing the issues, the evidence, and the law with respect to Rocky Mountain Power's ("RMP" or the "Company") proposed energy cost adjustment mechanism.

INTRODUCTION

While this is RMP's first attempt to propose a cost adjustment mechanism under the recently enacted Energy Balancing Account ("EBA") statute, Utah Code Ann. § 54-7-13.5 (2009), it is not RMP's first attempt at finding some method to pass costs through to customers without having to file a general rate case. In November 2005, for example, RMP filed an application for an order approving a proposed "Power Cost Adjustment Mechanism" ("PCAM") and later withdrew it when faced with a motion to dismiss on the grounds that the proposed PCAM was not authorized by statute. Order Granting Voluntary Withdrawal and Dismissal, Docket No. 05-035-102 (December 22, 2006). With the enactment of the EBA statute in 2009, the Company has again applied for balancing account treatment of certain costs. Even though there is now a statute in place that would authorize some kinds of costs to be collected through an energy balancing account, the statute is more narrowly drawn than the Company's proposed cost adjustment mechanism. Many of the costs that RMP proposes to collect through a balancing account are simply not authorized by the statute. Also, the statute requires that the Commission find that the establishment of an energy balancing account is in the public interest—the Company's proposal is not. In addition, the Company's proposal would not result in just and reasonable rates and is otherwise fraught with problems that make its implementation not only unlawful, but impractical as well. For the reasons discussed in this Brief, the UIEC urge the

Commission to reject the Company's Application and to deny any cost recovery through an energy balancing account.

ARGUMENT

I. <u>THE ECAM, AS PROPOSED, DOES NOT MEET THE STATUTORY REQUIREMENTS FOR COMMISSION APPROVAL OF AN ENERGY BALANCING ACCOUNT.</u>

A. <u>The Commission's Regulatory Authority Is Limited by the Powers Granted by the Utah Legislature and the Generally Accepted Rules for Ratemaking.</u>

> It is well established that the Commission ***has no inherent regulatory powers other than those expressly granted or clearly implied by statute***. . . . When a specific power is conferred by statute upon a . . . commission with limited powers, the ***powers are limited to such as are specifically mentioned***. . . . Accordingly, to ensure that the administrative powers of the [Commission] are not overextended, ***any reasonable doubt of the existence of any power must be resolved against the exercise thereof***.

<u>Heber Light & Power Co. v. Utah Pub. Serv. Comm'n</u>, 231 P.3d 1203, 1208 (Utah 2010) (internal citations omitted) (emphasis added) (ruling that Utah Public Service Commission acted beyond its limited grant of statutory authority). Furthermore, despite the broad language of Section 54-4-1, the Utah Supreme Court has held this statute "does not confer upon the Commission a limitless right to act as it sees fit, and [the Court] has never interpreted it as doing so." <u>Hi-Country Estates Homeowners v. Bagley & Co.</u>, 901 P.2d 1017, 1021 (Utah 1995) (citing <u>Mountain States Tel. & Tel. Co. v. Pub. Serv. Comm'n</u>, 754 P.2d 928, 930 (Utah 1988)). The Commission must exercise its authority consistent with the rules and precedent for ratemaking, including the general prohibition against retroactive ratemaking. <u>See</u> <u>Utah Dep't of Bus. Regulation v. Pub. Serv. Comm'n</u>, 720 P.2d 420, 420 (Utah 1986) ("EBA Case").

Under the applicable rules of statutory construction, we first look "to the statute's plain language to determine its meaning." <u>Heber Light</u>, 231 P.3d at 1208 (internal citations omitted). "We presume that the legislature used each word advisedly and give effect to each term

according to its ordinary and accepted meaning." C.T. v. Johnson, 1999 UT 35, ¶ 9, 977 P.2d 479 (citation and internal quotations omitted) (emphasis added). Furthermore, "'statutory construction presumes that ***the expression of one should be interpreted as the exclusion of another***[,]' . . . we should give effect to any 'omission in the [statute's] language by presuming that the omission is purposefu1.'" State v. Jacobs, 2006 UT App 356, ¶ 7, 144 P.3d 226 (quoting Carrier v. Salt Lake County, 2004 UT 98, ¶ 30, 104 P.3d 1208) (internal quotations omitted) (emphasis added). "Where a general statutory term is followed by the word 'include,' the primary import of words following that word indicates 'restricted meaning' to the general term, which came before it." Edmondson v. Pearce, 91 P.3d 605, 640 (Okla. 2004). In addition,

> The doctrine of *ejusdem generis* applies in instances where an inexhaustive enumeration of particular or specific terms is followed by a general term or terms that suggest a class. The doctrine declares that in order to give meaning to the general term, the general term is understood as restricted to include things of the same kind, class, character, or nature as those specifically enumerated, unless there is something to show a contrary intent.

Utah ex rel. A.T. v. A.T., 34 P.3d 228, 232 (Utah 2001).

B. The Proposed ECAM Seeks to Shift Risks to the Ratepayers and Recover Costs Not Authorized by the Utah Legislature.

In this case, the EBA statute provides in part:

> (b) "Energy balancing account" means an electrical corporation account for some or all components of the electrical corporation's incurred ***actual power costs***, including:
> (i) (A) fuel;
> (B) purchased power; and
> (C) wheeling expenses; and
> (ii) the sum of the power costs described in Subsection (1)(b)(i) less wholesale revenues.

Utah Code Ann. § 54-7-13.5(1)(b) (emphasis added).

The statute allows recovery through an EBA of the enumerated categories of costs. The statute is unambiguous in stating that an EBA must be for actual cost components of fuel, purchased power, and wheeling. Based on the rules of statutory construction explained above and the types of actual power costs listed in the statute, it is clear that the Legislature meant to include only costs for the physical commodities—fuel and purchased power—and for the wheeling costs to deliver the power. Any other items that might be included must be restricted to the same type, kind, class, character, or nature as these. See Utah ex rel. A.T., 34 P.3d at 232.

For the sake of clarity, this Brief will refer to these costs as "F&PP."[1] Costs related to financial products, resource availability, changes in load, or effects of political events cannot be included in an EBA.

1. The Company's Proposed Cost Would Place on Customers Risks that Are Not Authorized under the Statute.

The effect of an EBA is to shift certain risks from the Company to ratepayers. However, the statute allows that shift only with respect to the delivery of physical products (fuel or purchased power). The Company proposes that ratepayers should assume the costs and risks of financial products to hedge natural gas and certain power purchases (*i.e.*, derivatives), plant availability, and as some parties have advocated, load growth. Because RMP's proposal would shift these costs and risks, which are not components of actual power costs, it should be rejected

a. The Statute Does Not Allow the Company to Shift Risk of its Swaps or other Financial Products to Ratepayers.

In Phase II Part I of this Docket, the parties presented evidence on the Company's natural gas purchasing practices. The Company's natural gas purchasing strategy is to fix the total cost of its natural gas supply for some substantial period of time by using financial products ("derivatives") and then to buy physical products periodically at index prices. TR (Bird) 240:7-

[1] Rocky Mountain Power and some of the parties have consistently referred to something called "net power costs," or "NPC" without specifically defining what kind of costs might comprise NPC. Because the statute unambiguously designates the kind of costs that can be considered for recovery under an EBA, this Brief will refer to these costs as fuel and purchase power or "F&PP." As used in this Brief, F&PP may include natural gas, coal, steam, biomass, other fuels, and also wheeling revenues and expenses.

10.[2] The Company uses derivatives, exclusively in the form of fixed-for-floating swap transactions ("swaps"),[3] to mitigate the price risk on its supply of natural gas.

The EBA statute permits the cost of the physical contracts for gas or purchased power to be included in an energy balancing account because those contracts are for the delivery of fuel and power. However, even though RMP may record the settlement cost of derivatives in a fuel or purchased power account, it does not acquire any fuel or power for those costs, or even any security of supply. TR (Duvall) 51:9-19; 52:9-17 (Aug. 17, 2010). Its use of derivatives does not ensure that it obtains its fuel and power supply at the least cost, but instead, only "reduces volatility" in the price of fuel and power. Id. at 53:21-24; 58:18-23. The derivative is simply a bet on the direction of a price. And, as the data show, the Company has been wrong about that over the past several years. Confidential DPU Ex. 2.1SR (Wheelwright, Phase I, Part I) (Aug. 10, 2010).

The settlement cost of swaps is not inconsequential. Id. In addition, the abuse in the market for swaps and other derivatives has recently prompted federal legislation that is likely to subject utility hedging practices using swaps to additional regulation including possible margin obligations.[4] As a result, the use of derivatives to mitigate price risk will likely become even

[2] References to the Transcript of Hearing are cited as TR (Witness) [page #]:[line #]. Unless otherwise noted, citations to the hearing transcript refer to the Phase II, Part 2 hearing, that took place on Nov. 1-2, 2010.

[3] "A fixed-for-floating financial swap transaction is a transaction in which one party pays a fixed price in exchange for a floating index price. With respect to natural gas, the floating index price could refer to beginning of the month index prices, or daily index prices. With respect to power, the floating index price normally refers to daily index prices." Duvall Reb. (Phase I) 459-462, n.2 (July, 20, 2010).

[4] In 2010, Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"). Pub.L. 111-203, H.R. 4173 (2010). Dodd-Frank implements a profound increase in regulation of the financial services industry, giving, among other things, the Securities Exchange Commission ("SEC") and the Commodity Futures Trading Commission ("CFTC") authority to regulate over-the-counter derivatives. It requires central clearing and exchange trading for derivatives that can be cleared and provides a role for both regulators and clearing houses to determine which contracts should be cleared. Data collection and publication through clearing houses or swap repositories will be required as well as capital and margin requirements on swap dealers and major swap participants.
http://banking.senate.gov/public/_files/070110_Dodd_Frank_Wall_Street_Reform_comprehensive_summary_Final.

more costly in the future than it has been. It is questionable whether the Company's use of derivatives (to the exclusion of all other financial products, for the extent of time over which RMP purchases them, and to the extent of its portfolio for which they are used) is a prudent[5] gas or power acquisition strategy.[6]

Whether or not it is prudent, however, the use of "derivatives" or "swaps" or "financial products" for the "reduction of price volatility" is not listed in the enabling EBA statute, and is not similar to any kind of cost that is listed. Because financial products are not for any physical commodity or for the delivery of any commodity, the Commission should find that they are not a component of actual power costs for which the Utah legislature has allowed the risk to be shifted to ratepayers by allowing recovery through an energy balancing account. If they are to be recovered at all, it must be in a general rate case when all necessary information is available for analysis.

b. The Statute Does Not Allow the Company to Shift Risk of Plant Availability to Ratepayers.

Thermal plants, wind plants, and hydro plants all have different levels of availability. When these resources are unavailable, the Company must resort to the use of other resources or

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pdf. It is expected to produce market dislocations, increase the cost of certain swap transactions, and adversely affect certain types of investment funds and structured finance transactions. http://blogs.law.harvard.edu/corpgov/2010/07/21/dodd-frank-act-becomes-law/.

[5] There is also a question as to whether the Company's physical purchases at index are prudent.

[6] In 2006, the Public Utilities Commission of Nevada ("PUCN") approved a stipulation whereby NV Energy and the parties to NV Energy's IRP agreed that the gas hedging strategy would be: (i) to leave open 25% of the Company's projected financial gas exposure for each season; (ii) to hedge 50% of the Company's projected financial gas exposure with fixed price products for each season; and (iii) to hedge 25% of the Company's projected financial gas exposure for each season with collars. PUCN Docket No. 06-07010, Order, Stipulation ¶ 1, Oct. 5, 2006. In 2008, NV Energy proposed to expand its natural gas hedging strategy to hedge 100% of its projected financial gas exposure for the three months of July, August, and September. It proposed to hedge 67% of projected financial gas exposure with fixed price products and 33% of projected financial gas exposure with collars. Its current hedging strategy would remain in place for all other months. PUCN Docket No. 08-0831, Order ¶ 191, Dec. 17, 2008. The PUCN denied NV Energy's request, stating that NV Energy's "existing hedging strategy balances the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of the plan." Id. ¶ 197.

must purchase power to meet its load requirements. The Company's proposed ECAM takes into account the fuel and purchased power that must be used to make up for the unavailability of thermal, wind and hydro generation resources. Thus, it places this risk of availability onto ratepayers.

For example, if through the Company's inadequate maintenance, one of these generation facilities becomes unavailable (as was the case with the Hunter outage several years ago), the Company would have to replace the lost power with power from another resource or with power purchased from the market.[7] Unless the energy acquired to replace the lost power is equal to or less than the Company's average cost of production, as proposed, Utah ratepayers will pay the difference. In other words, the Company's proposed ECAM would make the ratepayers take the risk of unavailability of the Company's thermal, wind, and hydro resources regardless of the reason that those resources may become unavailable.

While the Utah statute allows actual power costs such as fuel and purchased power to be recovered under an EBA, it does not contemplate passing the risk of plant unavailability on to Utah ratepayers who are not (and should not be) the underwriters of the performance of the Company's thermal, wind, and hydro plants. There should be an availability benchmark established for each resource, and any costs related to unavailability beyond that established benchmark should be borne completely by the Company. The Company could seek recovery of those costs in a general rate case where they can be properly scrutinized, but they should not be flowed through the energy balancing account.

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[7] See the Settlement and Order in Docket No. 01-035-23 (May 1, 2002). As a result of inadequate maintenance, PacifiCorp had to replace 400 megawatts of power with purchases from the wholesale market between November 2000 and May 2001.

c. <u>The Statute Does Not Allow the Company to Shift Risk of Changes in Load to Ratepayers.</u>

Changes in load should not be addressed in an EBA, but instead in a general rate case. RMP uses forecasted test years in its general rate cases. This allows the Company to make a projection of what its load will be in the future. Allowing the Company to then collect for changes in load in an EBA, is in essence allowing the Company the chance to fix its poor projections. It gives the Company a level of risk mitigation never contemplated by the statute—a forecasted test year as well as an energy balancing account.

RMP has confessed that it would be willing to give up a future test year for setting base F&PP to receive some comfort in the form of an EBA. Mr. Duvall testified in Phase I of this proceeding that "RMP has an interest in recovering its prudently incurred net power costs and is willing to abandon forecasts of net power costs in favor of allowing the Commission to determine if net power costs incurred by RMP are prudent." Duvall Reb., 3:59-57 (Dec. 10, 2009).[8]

However, if the Commission does allow both forecasted test years and an EBA that addresses changes in load, some type of load-growth adjustment must be used. It should be used only to offset increases in costs due to load growth but not decreases in revenue from declining load. *See* Brubaker Reb., 19:3-20 (Sept. 15, 2010).[9] Utah ratepayers should not have to bear the risk that the Company may experience declining sales, no matter what the reason.

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[8] To avoid confusion in citing testimony from the various phases of this Docket, citations in this Brief are in the following form: [Witness] [Dir. Reb. or SR], [page]:[line] (date).

[9] UIEC recommends that if a load growth adjustment is permitted in an EBA (which it should not be), it should be used only to offset increases in costs due to load growth and not decreases in revenue from declining load. The Company has criticized UIEC's proposal as one-sided. Duvall SR 8:162-67. The Company believes that a load growth adjustment that works to offset increases, but does not make adjustments for reduction in load "fails the equity test." <u>Id.</u> Apparently, it is the Company's position that if the Commission allows revenue from fixed costs due to load growth to offset increases in net power costs recoverable through an energy balancing account, there should be a credit for a decline in sales revenues due to economic downturn or weather-related events.

The load growth adjustments proposed by some of the parties have the potential to compensate RMP for economic downturns, weather conditions (*e.g.*, when heating degree days and/or cooling degree days depart from normal), and even for revenues lost as a result of demand-side management ("DSM") programs. Allowing the Company to add a surcharge so that ratepayers pay for DSM programs, and then allowing the Company to make adjustments for the loss of load that resulted, at least in part, from the DSM programs is tantamount to requiring ratepayers to pay twice for DSM. Utah ratepayers would arguably be better off with no DSM and an increasing load.

Furthermore, none of these factors are permitted to come into play in an EBA. Taking a credit for declining revenue clearly falls outside the ambit of costs that the statute provides can be recovered through an EBA. The Company acknowledges that if a change in Company revenue from declining load is compensated through an EBA it would be a form of decoupling. TR (Duvall) 51:12 – 52-18. The purpose of the statute is not to decouple costs, or to guarantee any certain level of cost recovery, but to allow the Company a reasonable opportunity to recover the enumerated types of its actually incurred, prudent fuel and purchased power costs.

d. <u>The Statute Does Not Allow the Company to Shift Political Risks to Ratepayers.</u>

Likewise, power costs shifted to Utah customers as a result of public policy choices in other PacifiCorp jurisdictions should not be a part of any EBA. For example, if sales decline (or increase) in Oregon and the marginal cost of energy delivered departs from the average cost, the Utah ratepayers could be obligated for part of the differential in costs. Sales volumes could also change due to differences in public policy (as with open access and the renewable portfolio standard in Oregon), or could change on a region-wide basis because of an economic recession. The EBA statute allows the pass-through of costs reflecting changes in the incurred actual cost of power, not changes in sales volume or changes in public policy that result in changes in sales volumes. Those costs should be considered in a general rate case.

e. Conclusion.

In summary, the Commission should reject the Company's proposal to recover costs and to shift risks that are not authorized under the EBA statute. The risk of the Company's use of derivatives, the availability of its thermal, wind and hydro plants, and the costs attributable to changes in load should not be part of the Company's proposed ECAM or any other form of energy balancing account.

C. The Proposed ECAM Does Not Meet the Statutory Bases for Commission Approval.

The EBA statute 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 Phase I of this docket the Commission found that some kind of energy cost adjustment mechanism *could* be in the public interest. Report & Order at 1 (Feb. 8, 2010). The Commission continued to Phase II for the purpose of considering whether the cost adjustment mechanism proposed by RMP met the requirements of the EBA statute. Id. at 2. Even if only used to recover the costs allowed by the statute (fuel, purchased power, and wheeling), as discussed above, RMP's proposal does not meet the public interest standard. In fact, it is likely that it may harm the public interest.

The Company's proposal is not in the public interest primarily because it succeeds only in reducing RMP's risk of recovering its fuel and purchased power costs by shifting those risks to its ratepayers. It provides no net benefit to customers; it fails to provide an adequate mechanism by which the Commission and regulators can determine whether the costs that it proposes to recover through an energy balancing account were prudently incurred; and its implementation is premature. If there is a cost adjustment mechanism that would comply with the requirements of the EBA statute, the Company's proposed ECAM is not it.

1. The Proposed ECAM Does Not Provide a Net Benefit to the Public.

The public interest standard requires 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 Corporations of Qwest Communications Corporation, LCI International Telecom Corp. and US West Communications, Inc. ("Qwest Merger"), Report and Order at 14, Docket No. 99-049-41, 2000 Utah PUC LEXIS 228, (Utah PSC, June 9, 2000) (emphasis added). 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." In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock, Docket No. 98-2035-04, Report and Order at 26-27 (Utah PSC Nov. 23, 1999).

Therefore, to find that PacifiCorp's proposed ECAM is in the public interest, the Commission must consider its positive and negative impacts on the public. The Commission may find it to be in the public interest only if it concludes there is a "definable net benefit" to the public. See Qwest Merger, 2000 Utah PUC LEXIS 228 at _____, (citing Utah Code Ann. §§ 54-4-28, 54-4-29 and 54-4-30). The EBA statute requires that RMP bear the burden of proof as to whether a proposed EBA is in the public interest and it has failed to do so in this instance. 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 stated purpose of RMP's proposed ECAM is to allow the RMP to recover the difference between what it calls "net power costs" ("NPC")[10] in rates as a result of the most recent rate case ("Base NPC"), and its actual, prudently-incurred "net power costs." *See* Duvall Dir., 2:36-3:49 (Mar. 16, 2009). The amount by which the actual NPC deviates from Base NPC is the amount (positive or negative) the Company proposes be reconciled through the proposed ECAM ("ECAM Costs"). The purpose of the proposed ECAM, therefore, is to make the Company whole for the set of costs referred to as NPC. However, the Company has not shown that recovery of those costs through an energy balancing account is in the public interest. Aside from *claiming* that full cost recovery *may* enhance the financial strength of the utility, the Company has failed to offer any evidence to show that the ECAM would provide a "definable net benefit" to the public.

In its initial Application, and in the testimony supporting it, the Company failed to make any showing that its proposed cost adjustment mechanism would provide any benefit to the public. In fact, it initially did not even attempt to make such a claim. The Company represented instead only that the Company "has been prudent in the management of its NPC, the volatility of NPC is primarily related to factors outside the Company's control," and that it does not have "a reasonable opportunity to recover its actual and prudently incurred NPC for service in Utah." Application at 2-3 (March 16, 2009); see also Duvall Dir. (March 16, 2009) (failing to mention

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[10] As explained above, it is not clear precisely what costs RMP has included in "NPC." "Net power costs" has no conventional meaning. It varies from time to time and from one jurisdiction to another. The Utah Legislature wisely avoided stating that the utility could shift all risks for recovery of "net power costs" to the ratepayers. Thus, the Company's proposals and expectations as they relate to some group of costs the Company calls "net power costs," as a whole, are not permitted by the EBA statute. See Utah Code Ann. § 54-7.13.5 (1)(b). There are only certain narrowly drawn types of costs for which the Company has been permitted to shift its risk of recovery, and those are fuel, purchased power, and wheeling. Id. Thus, even though in this section UIEC discusses NPC, that is only because NPC is discussed in the Company's proposal.

whether a cost adjustment mechanism would benefit the public); Griffith Dir. (March 16, 2009) (same).

In testimony subsequently filed in Phase I of this case, Company witness Dr. McDermott, offered two reasons that the Company's proposed ECAM would be in the public interest. Dr. McDermott stated the first reason as follows:

> Providing utilities with a reasonable opportunity to recover prudently incurred costs helps create an environment in which capital can be obtained on more favorable terms in order to provide safe, reliable, and reasonably priced electric services on an on-going basis.

McDermott Supp. Dir., 15:314-17 (Aug. 17, 2009) (emphasis omitted). In other words, the ECAM would "create an environment" that would be good for the Company's financial health. The second reason Dr. McDermott gave was:

> Second, consumers, and indeed, society, benefit when the price of electricity reflects the cost of production. This promotes the right amount of consumption on the part of consumers and provides benefits by directing consumers to consume only that incremental amount of electricity that provides them an equal incremental benefit.

Id. at 15:328-32. If it were the case that the Company's proposed ECAM rates were designed to reflect the cost of production, then there might be some benefit to customers in having appropriate price signals so that they could adjust their consumption. In fact, the opposite is true here. As discussed in Section II.B below, one of the conspicuous failings of the Company's proposed ECAM is that the surcharge imposed to recover the costs in excess of Base NPC masks the true costs of production and precludes informed decision making because the surcharge will bear no relationship at all to the ***cause*** of those costs. It does not reflect time of use or seasonality in a way that gives customers any information about the incremental cost of the electricity. Even if that information were implicit in the amount of the surcharge, customers would not receive the information until the following year—after the annual reconciliation and far too late for customers to respond to price signals. In short, the proposed ECAM provides no benefit to consumers in establishing proper price signals as posited by RMP's witness.

Apart from mentioning the notion that customers somehow indirectly may benefit if the Company fully recovers its claimed NPC costs without risk, the Company has not identified, much less provided, any evidence to demonstrate that its proposed ECAM provides any benefit to the public. More importantly, the Company has not offered to reduce its rate of return if its proposed ECAM is implemented and therefore, it is more than likely that harm, not benefit, will occur to the public.

The Commission's Order in Phase I of this docket did ***not*** make any findings or conclusions that the proposed ECAM (or any ECAM for that matter) would provide a net benefit to the public. Instead, the Commission's Order states: "we do not believe the evidence presented precludes a conclusion that *one could design an ECAM* and use it consistent with the public interest." Report & Order at 1. It was on that basis that the Commission determined to move to Phase II of this docket to take a closer look at RMP's proposed ECAM. In Phase II of this proceeding, the Commission must examine the ECAM as proposed by the Company to determine whether it provides a net benefit to the public interest—not whether, in the abstract, some EBA mechanism could be in the public interest. The Company has failed to meet its burden to demonstrate that, on balance, the proposed ECAM provides a net benefit to the public. In fact, as discussed in the following sections of this Brief, the evidence indicates that it is far more detrimental than beneficial to the public. Because there is no definable, positive net benefit, the Commission should reject the Company's currently proposed ECAM and dismiss the Application.

2. The Proposed ECAM Does Not Provide for a Sufficient Prudence Review.

The second requirement that must be met before the Commission can approve an EBA is that the Commission must find "that the energy balancing account" must be for "prudently-incurred costs." Utah Code Ann. § 54-7-13.5 (2)(ii).

Whether RMP's proposed ECAM will be only for prudently incurred costs is unknown because the Company has failed to provide any mechanism or process for an adequate prudence review in connection with reconciliation of the balancing account. It does not attempt to provide procedures or standards, or to set informational requirements for a prudence review, no guidelines for hedging natural gas or electric power purchases, no standards of conduct for operation and maintenance of its low-cost generation plant—in short, no framework on which to determine whether the costs it may seek to recover were prudently incurred.[11]

At the same time, the Company has resisted any suggestion that the Commission should set guidelines for natural gas hedging and front office transactions (Duvall Reb., 6:110-15 (July 20, 2010)), and has opposed the UIEC's proposal that the Company should be required to either meet performance standards for its low cost generation resources or explain, as part of a prudence review, why those standards were not met. Duvall Reb., 19:426-20:442 (Sept. 15, 2010). Either proposal, if adopted, or especially both in combination, could make the prudence review more effective. Because the Company has failed to propose any standards for determining prudence or any practical method for accomplishing a prudence review, the Commission can have very little confidence that regulators will be able to determine whether the

[11] The Company apparently expects the Division, as well as any interested parties, to audit hundreds of transactions for purchased power and natural gas, including hourly transactions involving purchases and sales, decisions about the acquisition of fuel supplies, preventive maintenance practices, and decisions affecting the speed and cost of recovering from forced outages. See Brubaker Dir., 5:10-18 (Aug. 4, 2010); TR (Peterson) 379:5-380:7. A "rigorous audit of electric utility generation and purchased power costs is much more difficult to accomplish" than a similar audit for a natural gas utility. Brubaker Dir., 5:17-18 (Aug. 4, 2010).

costs presented for recovery were prudently incurred. Until there is a process in place to ensure that only prudently incurred F&PP costs are recovered,[12] the Commission should not allow any EBA to be implemented.

3. No ECAM Should be Authorized Before the Conclusion of the Next General Rate Case.

The final statutory requirement for the Commission to approve an energy balancing account is it can only be implemented "at the conclusion of a general rate case." Utah Code Ann. § 54-7-13.5 (2)(iii).

RMP filed its Application for approval of its proposed ECAM on March 19, 2009. One month later, on April 16, 2009, it filed a notice of intent to file a general rate case, and followed with an application for an increase in rates and charges filed on June 23, 2009. Docket No. 09-035-23. While the Company may have intended that its proposed ECAM would go into effect at the end of the 2009 rate case, neither RMP, the parties, nor the regulators could have anticipated the complexity of the issues involved in developing the evidence in this ECAM docket. When the Commission issued its order in the general rate case on revenue requirement, cost of service and spread, on February 18, 2010 (meeting the statutorily imposed time limit), the ECAM docket had barely progressed through Phase I. See Report & Order (Feb. 8, 2010) (Phase I). At the end of the last general rate case, therefore, there had been no evidence presented on natural gas hedging or front office transactions, and no evidence presented on RMP's specific proposal, including what elements, if any, should be included in an energy balancing account. It was

[12] UIEC's suggestions related to prudence reviews are discussed in Section III.B below.

therefore impossible to implement the proposed ECAM at the conclusion of the last general rate case.[13]

Moreover, the last general rate case should not be used as a basis for setting costs for recovery through an energy balancing account. None of the issues that are under consideration in this docket were determined in the last general rate case, which in any event was fraught with bad load data and allocation errors. Loads were not set in the last general rate case; nor were performance levels. The Commission's order was not of sufficient granularity and did not make the specific findings that are relevant to the implementation of an EBA.

The Company has given notice that it intends to file another general rate case on or about January 17, 2010. Letter to PSC from RMP, December 1, 2010. That rate case will provide an opportunity for the Commission to consider and set costs consistent with the kinds of costs that the Commission might allow to flow through an EBA. Thus if an EBA is to be implemented, it should take effect upon the conclusion of the 2011 rate case.

In summary, the Company's proposed ECAM should be rejected because even if it were designed to recover only the actual F&PP, as authorized by Section 13.5(1)(b) of the EBA statute (which it is not), it still fails to comply with Section 13.5(2) of the EBA statute because it is not in the public interest; it cannot presently be implemented in a way that ensures only prudently incurred costs are recovered; and, in any event, it should not be implemented until the conclusion of the next general rate case.

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[13] As a result of a Stipulation among the parties on May 4, 2010, the Commission issued an order allowing the Company "to defer incremental NPC, commencing February 18, 2010, pending the Commission's final determination of the ratemaking treatment of the deferred balance." Docket Nos. 09-035-14, 09-035-15, Report & Order at 4 (July 14, 2010). At the same time, however, the Commission's Order specifically did not guarantee that the Company would be allowed to recover the deferred balance. The Commission stated that "the deferred accounting order[ ] do[es] not create any presumption regarding future ratemaking treatment of the deferred amounts." Id. at 5. The Parties to the Stipulation agreed no presumption could be made regarding future ratemaking treatment of the deferred amount. Docket Nos. 09-035-14, 09-035-15, Stipulation and Joint Motion for Deferred Accounting Orders, ¶ 14, May 4, 2010.

II. <u>THE PROPOSED ECAM DOES NOT PRODUCE JUST AND REASONABLE RATES.</u>

In addition to applying the standards in the EBA statute, which have not been met in this case, the Commission must consider whether the Company's proposed ECAM would result in just and reasonable rates. Before any rates or charges for any commodity or service furnished by a public utility can be approved, the Commission must find that they are "just and reasonable." Utah Code Ann. §§ 54-3-1; 54-4-4. The Commission has stated:

> Two polar constitutional principles fix the parameters for rate regulation for natural monopolies: the protection of utility investors from confiscatory rates and, ***of equal importance, the protection of ratepayers from exploitive rates***. . . . To avoid confiscatory rates on the one hand and exploitive rates on the other, ***the Commission must determine what a just and reasonable rate is*** under Utah Code Ann. § 54-4-4 ***by applying a standard that is based on a utility's cost of service***. . . . In both rate-of-return and rate-base cases, the issue is what economic factors the Commission may consider in determining what rates should be charged ratepayers for the benefit of shareholders. . . . ***Just and reasonable rates are necessarily based on cost of service and cost of capital***, whatever the particular formula used.

<u>Stewart v. Utah Pub. Serv. Comm'n</u>, 885 P.2d 759, 767, 770-71 (Utah 1994) (internal citations omitted) (emphasis added); <u>see also</u> <u>U.S. Magnesium, LLC v. Utah Pub. Serv. Comm'n</u>, 110 P.3d 165, 168 (Utah Ct. App. 2005). As discussed below, the proposed ECAM surcharge would result in rates that are virtually unrelated to the costs that the Company incurs in providing service at any given time. The Company has made no attempt to allocate the excess fuel and purchased power costs to the customers or classes of customers who cause the excess costs. Thus, even if, contrary to all the evidence available, the Commission were to determine that there is some net positive public benefit in allowing cost recovery through an EBA, and were it to find that there is an adequate means to determine whether EBA costs were prudently incurred in compliance with the statute, and were it to find that it is appropriate to implement an EBA right

now, even in light of the infirmities of the last general rate case, it should still reject the proposed ECAM because it does not produce just and reasonable rates.

A. The Proposed ECAM Results in a Mismatch between Cost Allocation in Base Rates and Allocation of Costs Recovered through an Energy Balancing Account.

The Company proposes to track deviations from base F&PP costs on a "per kWh" basis. Yet, some of the elements of F&PP are allocated in base rates on a 75/25 demand/energy basis. The inconsistency creates a mismatch, the impact of which is unknown. The effect of this "75/25 mismatch" has not been adequately explained or accounted for. But, it could result in an allocation of costs that grossly skews the relationship between cost causation and cost recovery, resulting in rates that are neither just nor reasonable.

The Company has tried to suggest that the error caused by the 75/25 mismatch is negligible or *de minimis*.[14] Yet, the Company acknowledges that it has no idea what the actual impact would be on the various customer classes of ignoring the 75/25 mismatch, or the extent of its disproportionate effect on some classes.[15] Furthermore, the 75/25 allocator is currently a point of contention in other dockets, and its viability is in question. The recent reports filed with the Commission raise serious concerns about the use of the 75/25 allocation factors, which promises to be an important issue in the current Multi-State Protocol ("MSP") case. See Report of DPU on Work Groups I-II, Docket No. 09-035-23 (Nov. 30, 2010); Utah Work Group III, Consistency of Allocation Factors between JAM and Class COS, Docket No. 09-035-23 (Nov.

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[14] Mr. Duvall testified that, in the last general rate case, "all of the components of NPC allocated on the System Generation ("SG") and other factors netted to a reduction to base NPC of $98 million." Duvall SR, 10:211-13 (Oct. 13, 2010). He stated that in the last general rate case, the difference between the Utah SG factor and the Utah SE factor was only 0.13%, concluding that the 75/25 mismatch in allocating NPC "would likely produce a small number, which could either increase or decrease the allocation of actual NPC to Utah." Id. at 11:218-20.

[15] UIEC Cross Exhibit 2 indicates that while the 75/25 mismatch produces a difference of 0.13% for Utah, it produces a difference of 1.93% for Schedule 9, an amount 14.8 times higher than the 0.13% that Mr. Duvall used to claim the mismatch was insignificant. TR (Duvall) 64:23-66:1; TR (Griffith) 177:22-178:2.

30, 2010). It is unknown what allocation factors will be proposed in an interjurisdictional allocation methodology, but it cannot be assumed that the use of a 75/25 allocator will continue indefinitely.

The Company has failed to consider, let alone have a firm understanding of, how the 75/25 mismatch would affect rate schedules or individual customer rates. Because the effect of the proposed allocation is unknown, it cannot be expected to result in just and reasonable rates.

B. The Proposed ECAM Results in a Double Payment of Capacity.

No accounting has been proposed for the capacity costs implicit in purchased power. Seasonal purchases include a capacity recovery component to pay the selling generator for its capacity. Until and unless there is some method to back out the capacity charges from purchased power costs flowed through the EBA, customers could be paying twice for capacity—once for the fixed costs of an idle Company generator, and again for the demand component of purchased power to replace the idling generator.

The Company's proposed method to recover EBA costs cannot be just and reasonable because it is not based on the cost of providing service to customers, because the impact of the 75/25 mismatch is unknown but potentially substantial, and because it could result in double charging customers.

C. The Proposed ECAM Ignores Time of Use and Seasonality of Costs.

The Company's proposal to allocate ECAM costs does not result in just and reasonable rates because it ignores time of use and seasonality of the costs it proposes to recover through the ECAM, disregarding the varying responsibility of customer classes for consumption in individual months. The UIEC have criticized the Company's ECAM design as ineffectively tracking the cause of the excess power costs and failing to allocate those costs to the classes of customer that caused them. Brubaker Reb., 10:6-12:2 (Sept. 15, 2010).

Currently, some rate schedules, including Schedule 9, provide for time of use and seasonal rates. Those rate structures are meant to reflect the variation in costs based on time of day and the season in which customers use the power. Based on the on-peak/off-peak and summer/winter/spring-fall rates, customers can schedule their power usage to save during the periods of higher cost power and to ameliorate for all customers the consequences of increased system peak demand. The Commission has found that those time-of-use and seasonally adjusted rates are just and reasonable.

Under the Company's ECAM proposal, the time-of-use and seasonal variability in costs is lost because the costs to be recovered through the proposed ECAM are masked in the surcharge. The Commission has ordered that the Company must track data "in sufficient detail and granularity to permit whatever ratemaking treatment may be ultimately ordered by the Commission for all or any part of the deferred NPC and REC revenues," including time-of-use and seasonal rates. See Report & Order on Deferred Accounting Stipulation at 5 (July 14, 2010).[16] While RMP may be tracking time of use and seasonality in its deferred account, it does not propose to use that data in allocating the deviation from its base F&PP. TR (Griffith) 190:12-192:15. Instead, RMP proposes to accrue only the deviation from base F&PP that occurred during the month, without distinction as to time of use.

The monthly deviation loses its seasonal character as well. Although RMP states that it will accrue the deviation monthly, it does not propose to allocate the costs monthly. Instead, at the end of the year, all of the monthly deviations are to be added together to produce one sum reflecting the annual deviation. Id. This annual deviation is collected (or refunded, as the case may be) through a flat surcharge (or refund) on base rates, adjusted for line losses. Griffith, Ex.

[16] The Parties to the recent deferred accounting order stipulation also agreed no presumption could be made regarding future ratemaking treatment of the deferred amount. Docket Nos. 09-035-14, 09-035-15, Stipulation and Joint Motion for Deferred Accounting Orders, ¶ 14, May 4, 2010.

2.2SR. The Company contends that rates are "shaped" to follow time of use in seasonality in a recovery of F&PP costs. But, while a customer's base rate may reflect time of use or seasonality, the surcharge is spread evenly among all classes, adjusted only for losses based on the voltage at which the customer takes service. The surcharge is shaped only to base rates, and thus bears no relationship to the cause of F&PP costs. There is no attempt to allocate costs to the classes of customers who have caused the costs, either in the time of use or seasonality.

The lack of seasonality can have a significant impact on rates. Based on the cost of service study for the 12 months ending June, 2010 (which UIEC contends already overstates Schedule 9's contribution), Schedule 9 is allegedly responsible for 14.4% of the excess power costs incurred during the month of July. UIEC Cross Ex. 2; TR (Griffith) 193:13-19; 194:23-195:2. Thus, if the Company were to allocate its ECAM surcharge monthly, Schedule 9 would get 14.4% of the excess power costs incurred in July. By summing monthly excess power costs and setting the surcharge based on the annual total, the seasonality is lost. Schedule 9 customers who caused 14.4% of excess power costs in July would receive a surcharge of 16.6% (id.), which would apply not only to their July bill, but also to their bill in every other month of the year. By totaling the monthly deviations into one annual sum and then smearing them across base rates as a surcharge on all consumption in every month and season, the Company has effectively negated time-of-use and seasonal rates for all costs recovered through its proposed ECAM.

Principles of cost recovery suggest that, to the extent possible, customers who cause costs should be allocated those costs. At least, customer classes should be billed each month based on the class's monthly energy usage and contribution to peak. Costs recoverable through an EBA should be no different—any surcharge should reflect the behavior of the class. At the very least, those costs should be accrued monthly by rate schedule (and special contracts), and allocated on a monthly basis, with deviations accumulated into the periods of summer, winter, and spring/fall, and reconciled in the subsequent corresponding calendar time period. One-off costs should be booked in the month incurred.

Many Utah ratepayers, residential and industrial, currently face time of use rates and seasonably adjusted rates, which are intended to bear some relationship, scant though it may be, to costs. Yet, even that scant relationship would be lost in the Company's proposed ECAM, which takes the change between forecasts in Period A and forecasts in Period B and smears the deviation across all schedules on the assumption that present rates reflect prospective costs in some fashion (in effect allocating last year's costs on this year's usage). The Company's proposed spread precludes even the most sophisticated customers from understanding what the costs are for the energy at the time they consume the energy.

If rates are to be used as a tool for moderating behavior to assure that ratepayers are prudent in their use of electricity rather than ensuring RMP's corporate earnings by smearing deviations between forecasts indiscriminately across customer classes, the time and expense invested in devising and implementing an EBA would probably be better spent in investigating smart meters to provide customers real-time information about their use and moving to dynamic pricing. Customers should be billed, as nearly as possible, the actual cost of the energy incurred by the utility at the time the customer consumes the energy. Anything else is inadequate to capture time-of-use and seasonal variations. The Company's proposed ECAM should be rejected because it ignores long-standing principals of cost causation, sends the wrong price signals, and ultimately results in unjust and unreasonable rates because the rates bear no relationship to the costs of serving the customer classes.

D. **Authorizing an ECAM that Uses a Forecasted Test Year for Based Rates Can Lead to Gamesmanship.**

As long as F&PP rates are set using a forecasted test year, cost recovery through an EBA will only encourage the Company to set ever increasing forecasted F&PP in general rate cases. That is because if the Company estimates higher than actual costs and over-collects in the first year, it can cover any refund to customers from the excessive rates collected during the second year. It is possible that the Company could ensure it receives more in rates than the amount of its actual F&PP, and then pay the refund from the customer overcharges, thus always over-collecting.

Reconciliation of the proposed ECAM account occurs annually with the surcharge or refund to be collected or paid during the following year. If base F&PP costs are set using a forecasted test year, then by simply forecasting ever increasing costs of energy, RMP might never become obligated to make any refund to customers even if there are overcharges resulting from earlier forecasted F&PP. Moreover, because any surcharge imposed on customers would reflect the difference between forecasted and actual costs, customers will never have the opportunity to understand the actual cost of the energy they consume.

RMP's Application under consideration in this docket does not propose to abandon a future test year for setting base F&PP. The Commission should take RMP at its word, require base F&PP to be set using a historical test period, and wait until the conclusion of the soon-to-be-filed general rate case before implementing an EBA, if an EBA is otherwise found to be in the public interest and to result in just and reasonable rates. Nevertheless, at present, the Commission should reject the proposed ECAM because, among other things, it would allow recovery of forecasted costs in contravention of the statute.

III. THE PROPOSED ECAM HAS OTHER INFIRMITIES THAT MUST BE RECTIFIED BEFORE IT IS IMPLEMENTED.

The Company's proposed ECAM is not complete in form or content. There are mismatches in the ECAM as filed, which individually or in combination, unnecessarily complicate it and should preclude it from being approved.

A. The Proposed ECAM Reduces RMP's Incentive to Act Efficiently and Prudently and Provides No Substitute Besides Prudence Reviews.

Under traditional ratemaking principles, rates should be set so that a utility has a reasonable opportunity to recover its prudently incurred costs. Cost recovery is not guaranteed, but if the utility acts efficiently and prudently, it can, in theory at least, earn its authorized rate of return. The absence of guaranteed cost recovery acts as an incentive for the utility to make prudent decisions and to minimize costs wherever possible, by putting the utility at risk for cost recovery. The incentive to act prudently and efficiently (and thus to control costs) is substantially diminished when an utility is allowed to pass-through costs to customers. Brubaker Dir, 2:12-13 (Aug. 4, 2010).

Instead of putting the Company at risk if it fails to control costs, a pass-through under the EBA statute puts the ratepayers at risk. The Company is at risk only if the regulators detect imprudently incurred costs. Utah Code Ann. § 54-7-13.5 (2)(b). With pass-through of its F&PP costs, RMP is essentially absolved from the consequences of its inefficient actions if the regulators do not discover imprudence. As discussed below, the task of auditing the Company's proposed ECAM reconciliation will be formidable, and is likely to be less effective at curbing imprudent actions than placing the Company directly at risk for F&PP recovery. Rather than providing an incentive to act efficiently, the Company's ECAM simply incentivizes the Company to not let regulators discover imprudent conduct.

RMP has stated that it intends to do nothing differently if its ECAM is adopted, but it has not satisfactorily explained how the adoption of its ECAM would not change behavioral incentives to the detriment of its customers. It has not included any mechanism or proposal designed to incentivize, maintain or improve its productivity and efficiency. And it has resisted the attempt of regulators and parties to bring its purchasing and hedging practices into the light of regulatory oversight. Because there can be no substitute as powerful to the Company as its risk of loss, as it stands now, the Commission can be fairly certain that the approval of the proposed ECAM would result in reduced incentives to act efficiently and prudently, to the detriment of customers.

B. Performance Standards Should be Adopted to Ensure that Costs Recovered through an EBA Are Prudent and to Ease the Burden on Regulators to Audit F&PP.

Some parties are suggesting the use of a 70/30 sharing mechanism and/or a dead band. While these mechanisms may provide incentives for prudence by leaving the Company partially at risk, they leave unanswered the necessary element of auditing standards. Auditing standards are separate from and should be considered in addition to any type of incentives.

No EBA should be implemented before there is a practical way to perform a prudence review of F&PP. The task would involve reviewing fuel expenses, power purchases and sales, and looking at whether the operation, maintenance and management of low-cost generation resources was prudent. TR (Peterson) 378:18-380:7. The Division testified that it believes it would not be appropriate "to carve out one resource or group of resources from the system and look at their output in isolation." Peterson Reb., 5:91-93 (Sept. 15, 2010); TR (Peterson) 381:1-382:5. Thus, unless there is some way to narrow the prudence inquiry, regulators would have to audit all transactions and all resources every year. The Division has expressed serious concern about its ability to perform an adequate audit of the Company's proposed ECAM with its current staff and work load. Peterson Dir., 9:189-10:194 (Aug. 4, 2010). At the same time, because cost recovery through an EBA removes risk of F&PP cost recovery, thus reducing the Company's financial incentive to minimize F&PP, an audit becomes an essential process in determining whether the costs the Company seeks to recover through its proposed ECAM are allowed under the EBA statute. See Utah Code Ann. § 54-7-13.5(2)(b).

The Division has stated that it would expect the Company to deliver a "certain amount" of information with its annual EBA cost recovery filing, and would probably expect monthly filings as well for its ongoing review. TR (Peterson) 377:21-378:17. But, unlike filing requirements for general rates cases or major plant addition cases, there are no filing requirements addressing the kind of information that must be provided in an EBA cost recovery proceeding. Moreover, because it is anticipated that there would be monthly filings, it is important to have informational requirements in place before any EBA is implemented.

Even with informational requirements, the task of performing a prudence review would be difficult. It should probably be conducted by an experienced, independent, third party chosen by the Commission and funded by RMP's stockholders.

To focus the prudence inquiry and to alleviate some of the burden on regulators, UIEC has recommended that the Commission include as part of the informational requirements, certain minimum performance standards for RMP's lowest cost resources—its coal generation plants, wind resources and output from Company-owned coal mines. Brubaker Dir., 5:19-6:2 (Aug. 4, 2010). If the total generation from RMP's coal fleet does not meet minimum performance standards (which is recommend to be set at the average annual generation from the previous five years), RMP would not be allowed to collect the costs incurred to replace the output shortfall unless it provided information to show that it operated the resource prudently and that it acquired a substitute resource on a least cost basis. Id. at 6:11-15. The same would be the case for wind resources if they did not achieve 90% of the output that RMP used to justify the acquisition of the wind resource. Id. at 16-21. Likewise, the performance standard for coal production would be the five year output from Company-owned mines. Id. at 6:22-26.

These are merely auditing standards or benchmarks that can be used for true-up in a general rate case if there is a need to justify an excessive cost. The failure of RMP to meet any performance standards would not necessarily result in the disallowance of costs. It would simply require the Company to identify the shortfall, and to demonstrate that it operated, maintained and managed its resources prudently, and obtained replacement power at least cost. Id. at 7:3-7.

Requiring performance standards would also restore some of the financial incentive for the Company to minimize F&PP. Moreover, it would make the task of the regulators somewhat lighter by placing the burden on the Company to identify underperforming resources and to offer, in the initial informational filing, an explanation for the underperformance. That saves the regulators time and the expense of having to independently discover that information from the Company's documents. As the Division acknowledges, the Company "always knows more about the company than any regulators do." TR (Peterson) 395:13-15. The Company should be required in the first instance to produce information that it contends justifies the underperformance of its resources, rather than require the regulators to ferret out that information, especially because it may be the case that the regulators will not even know that such information exists. See TR (Peterson) 393:25-395:15.

No cost recovery mechanism under the EBA should be implemented until there is a process by which the Commission can be confident that regulators can ascertain whether F&PP costs have been prudently incurred. As a practical matter, part of that process should include some type of auditing standards requiring that the Company meet reasonable performance standards and to bear the burden of demonstrating prudence in a general rate case when those standards have not been met.

C. Other Recommendations

1. Pilot Program, Rate Cases, and True-up Filings.

If an EBA is adopted, it should be designated as a pilot program for a specific period of time with a sunset provision and a requirement to re-justify its continued existence in its then-current or modified form. An EBA would be a significant change in rate recovery methodology in Utah and should not be implemented without a trial period first.

With the implementation of an EBA, the Company's F&PP expenses can be recovered through periodic EBA reconciliation proceedings. Likewise, the Company has recently settled two cases to allow recovery of major plant addition costs. Because major expenditures can be recovered through proceedings other than a general rate case, the Company should not be allowed to file a general rate case during the pilot period and, if an EBA is permanently adopted, no more frequently than every three years.

True-up filings should not be made on December 15 if an EBA is approved, but rather should occur sometime in the middle of the calendar year. This allows the Company's Form 1 filing and other such reports to be available to third parties. It also avoids the busy holiday season and accommodates a seasonal reconciliation approach.

2. Transmission and REC Revenues Should be Tracked and Deferred Separately, Outside of ECAM.

a. Transmission Revenues Should be Tracked and Deferred.

Changes in the level of revenues from the sale of transmission services must be tracked and deferred to prevent the benefits from being lost to customers between rate cases. Revenues from non-firm and short-term firm products will be lost to the ratepayers due to their temporary nature and the rule against retroactive ratemaking if they are not tracked and deferred for later recovery, regardless of whether an EBA is adopted. Some type of mechanism must be established so that transmission revenues can be tracked and deferred for later recovery. This recovery should be made as an offset in a general case or in a major plant addition case.

b. RECs Should be Tracked Outside of the ECAM.

RECs are created as a result of investment in renewable energy projects that are supported by customer rates. Customers are entitled to the full benefit of the REC values. The Commission has issued a deferred accounting order for REC revenue, which may or may not fully account for the REC revenue actually received. Nevertheless, UIEC agrees that it is appropriate to establish a tracking mechanism and deferred accounting for RECs, regardless of whether an EBA mechanism is adopted. Otherwise, the customers could lose the benefit of the REC value.

The Company has stated that if RECs are deferred, they should be included in its ECAM. Duvall SR at 3:50-53. But that position ignores the statutory authorization to collect only F&PP costs (offset by wheeling revenues) through an EBA. RECs are not fuel or purchased power or wheeling. They are more like a regulatory asset created from renewable generation that can be used to offset rate increases. As such, they should be tracked outside of the EBA. The recent settlement approved in Docket No. 10-035-89, RMP's second major plant addition application in 2010, is an example of how these regulatory assets can be used and why it is so important to have a mechanism for tracking them.

IV. LEGAL ISSUES:

The Commission has requested that the Parties address three legal issues: (1) whether the Commission has the authority under its general powers to order that an EBA be created similar to what is assumed to have occurred with the Questar balancing account so that the Commission would not be bound by the strict reading of Utah Code § 54-7-13.5; (2) whether the phrase "some or all components" in the definition of "energy balancing account," found at Utah Code § 54-7-13.5(1)(b), can be read to allow the 70/30 sharing and dead band mechanism proposed by the Division; and (3) whether the Company's REC revenues that pre-date the Commission's order approving a REC-revenue deferral account can be considered for refund to the ratepayers.

As set forth above in Section I.A, the Commission's regulatory authority is limited by the powers granted by the Utah Legislature and the generally accepted rules for ratemaking. Heber Light & Power Co. v. Utah Pub. Serv. Comm'n, 231 P.3d 1203, 1208 (Utah 2010) (internal citations omitted) (ruling that Utah Public Service Commission acted beyond its limited grant of statutory authority). Furthermore, despite the broad language of Section 54-4-1, the Utah Supreme Court has held this statute "does not confer upon the Commission a limitless right to act as it sees fit, and [the Court] has never interpreted it as doing so." Hi-Country Estates Homeowners v. Bagley & Co., 901 P.2d 1017, 1021 (Utah 1995) (citing Mountain States Tel. & Tel. Co. v. Pub. Serv. Comm'n, 754 P.2d 928, 930 (Utah 1988)). The Commission must exercise its authority consistent with the rules for ratemaking, including the general prohibition against retroactive ratemaking. See Utah Dep't of Bus. Regulation v. Pub. Serv. Comm'n, 720 P.2d 420, 420 (Utah 1986) ("EBA Case").

A. The Commission Cannot Rely on Questar's 191 Account or PacifiCorp's Prior Energy Balancing Account as Authorization for a Generic Energy Balancing Account.

In the past, the Commission has allowed "balancing accounts" for utilities to pass through certain fuel or energy costs over which the utility allegedly has no control. For Questar Gas Company ("Questar"), the Commission approved the "191 Account." Report & Order, Docket No. 78-057-13 (Apr. 3, 1979). The 191 Account allows Questar to pass-through its actual cost of purchased natural gas. This account and the underlying tariff are unique to Questar. The 191 Account is narrowly tailored for natural gas costs, contrary to RMP's proposed ECAM, which includes many more types of costs than even those specified in the statute. Furthermore, Questar's use of the 191 Account has never been challenged and it is accepted due to its long-term use.[17]

PacifiCorp's predecessor, Utah Power and Light ("UP&L") had an "Energy Balancing Account" ("EBA") that was approved by the Commission. As with the 191 Account, PacifiCorp's use of this account was never challenged, and the question of whether the Commission ever had authority to approve it was never formally asked or answered in court. Neither the EBA nor the 191 Account was tested for authorization under any known provision of Title 54, and neither could be approved today unless they conform with Utah Code § 54-7-13.5.

Moreover, the existence of Utah Code § 54-7-13.5 precludes the creation of any type of EBA other than that defined in the statute.

1. The Existence of the 191 Account Does Not Provide Authority for the Commission to Approve an ECAM Different from that Proscribed by Utah Code § 54-7-13.5.

Even though there is no statute that explicitly or clearly implies authority to approve the 191 Account, Questar has been permitted to maintain it for the simple reason that the Commission's order approving it was never challenged. It is now accepted due to long-term use because under the Utah Administrative Procedures Act, the Commission cannot depart from prior practice without full justification of the inconsistency. Such is not the case here.

The Commission approved the 191 Account in 1979. Report & Order, Docket No. 78-057-13 ("Mountain Fuel Order"); Questar Gas Co. v. Pub. Serv. Comm'n, 34 P.3d 218, 221

[17] See subsection A.1 that follows.

(Utah 2001). In doing so, the Commission noted that it would follow a procedure "'similar to that used in the current pass-through procedure.'" Id. at 222 (quoting Report & Order, Docket No. 78-035-13 at 5 (April 3, 1979)). Although the Commission appears to have remarked in its Mountain Fuel Order that rate changes made in a 191 proceeding "will be made pursuant to procedures that comply with statutory and regulatory requirements," it never identified the statutes and regulations that it thought might apply. Id. (quoting Report & Order, Docket No. 78-057-13 at 5). The Commission's Mountain Fuel Order is thus unclear as to the source of its authority to allow rate changes pursuant to the 191 Account.

In the Questar case of 2001, the Utah Supreme Court had occasion to consider the 191 Account on appeal from the Commission's order in the CO_2 case. Questar, 34 P.3d at 218. The Commission had concluded that Questar's CO_2 processing costs were not eligible for treatment under the existing pass-through statute. Id. at 221. Questar argued to the court that the 191 Account was not tied to the pass-through statute and the costs were eligible to be recovered through the "separate procedures" that had been established for the 191 Account. Id. The court, after examining the Commission's 1979 Mountain Fuel Order approving the 191 Account, agreed with Questar, ruling that proceedings relating to the 191 Account did not fall under the pass-through statute. The court, however, still did not identify the source of the Commission's authority to approve the 191 Account. Instead, it stated:

> We ***presume***, as we did in [the EBA Case] . . . that the Commission implemented this rate-changing mechanism under its "ample general power to fix rates and establish accounting procedures." Id. at 424 n.4; see also Utah Code Ann. § 54-4-1 (2000). We recognize that this power is not unlimited, and as we stated in the EBA case, the Commission has authority to set rates "only in general rate proceedings . . . [and has] limited authority to permit interim rate changes which are necessary because of unexpected increases in certain specific types of costs." 720 P.2d 420 at 423.

Questar, 34 P.3d at 222-23.

As support for this presumption, the court cited the EBA procedures, and the longstanding Commission practice of using the 191 Account, even though the procedure is different than is prescribed in the pass-through statutes.[18] Id. It noted that under Utah's Administrative Procedures Act, an agency's action may not be contrary to its "prior practice, unless the agency justifies the inconsistency by giving facts and reasons that demonstrate a fair and rational basis for the inconsistency."[19] Id. at 224 (citing Utah Code Ann. § 63-46b-16).

It is also critical to realize that "[a]s a general rule, claims not raised before the [Commission] may not be raised on appeal." State v Holgate, 10 P.3d 346, 350 (Utah 2000) (citing State v. Marvin, 964 P.2d 313, 318 (Utah 1998)). In addition, "[i]t is well established that an appellate court will decline to consider an argument that a party has failed to adequately brief." Valcarce v. Fitzgerald, 961 P.2d 305, 313 (Utah 1998). This means that an appellate court such as the Utah Supreme Court will not address an issue that has not been raised in the proceedings below and fully briefed in the appellate proceedings.

Because the Commission had used the 191 procedure over a long period of time, because the 191 Account considers matching costs and revenues, and because the court was not asked to consider whether the 191 Account was authorized in the first place, the Questar Court simply "presumed" that it was authorized so that the court could address the issues before it.

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[18] In addition, the court found that because the 191 Account adequately considered costs and revenues on both sides of the equation, it could serve as a type of abbreviated proceeding "that should result in just and reasonable rates." Questar, 34 P.3d at 223. That logic is not available here because we have a statute that prescribes the requirements.

[19] By the time the court decided Questar in 2001, the Commission had been allowing Questar to recover specified costs through the 191 Account for nearly twenty-two years. "Because it ha[d] been the Commission's ***prior practice*** to enable Questar to recover gas costs through this procedure," and because the Commission's refusal to do so was not sufficient to "demonstrate a fair and rational basis for the inconsistency," the court set aside the Commission's order. Id. at 224 (emphasis added).

2. The Former "EBA" Does Not Provide Authority for the Commission to Approve an ECAM Other than that Authorized by Utah Code § 54-7-13.5.

Just as there is no clear authority for the Commission to have initially approved the 191 Account, there is no authority for its approval of UP&L's now defunct EBA. In the EBA Case, 720 P.2d 420 (Utah 1986), the court considered whether PacifiCorp should be allowed to transfer surplus funds out of the EBA to the benefit of shareholders. In its analysis, the court reviewed the background of the EBA and the source of the Commission's authority to approve it. The court concluded:

> There is nothing in the pass-through legislation that sanctions the establishment of an EBA. . . . The only relation that we can discern between the pass-through legislation and the EBA is that in between general rate-making proceedings the PSC uses pass-through proceedings to adjust the fuel cost component of the EBA. We find no authorization for the establishment of EBA's in the pass-through legislation; rather, we ***assume*** that the EBA order was promulgated under the Commission's ample general power to fix rates and establish accounting procedures.

Id. at 423 n.4 (emphasis added).

As with Questar's 191 Account, because the issue of whether the Commission had been authorized to establish the EBA was not raised in the proceedings below nor fully briefed before the Utah Supreme Court at any time, either when established or on appeal, the court declined to rule on whether the Commission was so authorized. Instead it stated:

> ***We decline to determine the overall validity of the PSC's order establishing the EBA*** and the propriety of the PSC's determination that certain costs and revenues . . . should be segregated from a utility's general account and held in the EBA.

Id. at 424 (emphasis added).

Thus, there is no explicit or implicit statutory authority or judicial confirmation that the Commission ever had the authority to establish the EBA. Like the 191 Account, any validity the

EBA might have acquired could only have been derived from the Commission's long-term use of it in light of the requirement in the Utah Administrative Procedures Act that the Commission's orders may not be contrary to its prior practice. Utah Code Ann. § 63.46b-16. Notwithstanding any momentum the EBA may have acquired due to its habitual use, however, it clearly lost it when the Commission, upon PacifiCorp's urging, abolished it in 1990.

3. The Legislature's Enactment of Utah Code § 54-7-13.5 Precludes the Implementation of Any Alternative F&PP EBA.

"'It is well settled that a more specific [statutory] provision ***always*** takes precedence over a more general [statutory] provision.'" Taghipour v. Jerez, 26 P.3d 885, 887 (Utah Ct. App. 2001) (emphasis added) (quoting State v. Hinson, 966 P.2d 273, 277 (Utah Ct. App. 1998)) (ruling that specific requirements of statute governing limited liability company managers' approval of contracts must prevail over the general restrictions of statute governing authority of limited liability company managers); see also Hess v. Blackstock, 65 P.3d 305, 306-07 (Utah Ct. App. 2003) (ruling that in DUI case, statute specifically outlining hearing procedures for DUI charges prevails over statute outlining general administrative hearing procedures); Hansen v. Eyre, 74 P.3d 1182, 1186 (Utah Ct. App. 2003) (ruling that traffic statute that specifically addressed direction of travel required or allowed on a roadway must prevail over traffic statute that generally addressed vehicle travel on a roadway but did not mention direction of travel required or allowed on a roadway).

In the instant case, Utah Code § 54-7-13.5 is a specific statute passed by the Utah Legislature detailing how an energy balancing account for an electrical corporation must be implemented. Under Utah law, this specific statute must prevail over any general authority that the Commission has under Utah Code § 54-4-1.

B. <u>The Phrase "Some or All Components" in the Definition of an EBA Likely Authorizes the Commission to Allow a 70/30 Sharing and Dead Band Mechanism.</u>

A 70/30 sharing mechanism and a dead band mechanism are both tools proposed by the Division of Public Utilities that the Commission could use to encourage prudence. With the dead band, it is anticipated that only costs that are above 2% be recovered or refunded. In the 70/30 sharing mechanism, it is proposed that recovery of actual costs between 2% and 30% would be shared based on the Company's attainment of certain goals. In both cases, the statute would require that the percentage of recovery or refund be based on actually incurred power costs.

Pursuant to Utah Code § 54-7-13.5, an "energy balancing account" is defined as:

> [A]n electrical corporation account for some or all components of the electrical corporation's incurred actual power costs, including:
>
> (i) (A) fuel;
>
> (B) purchased power; and
>
> (C) wheeling expenses; and
>
> (ii) the sum of the power costs described in Subsection (1)(b)(i) less wholesale revenues.

Utah Code Ann. § 54-7-13.5(1)(b).

Under the applicable rules of statutory construction, we first look "to the statute's plain language to determine its meaning." <u>Heber Light</u>, 231 P.3d at 1208 (internal citations omitted). "We presume that the legislature used each word advisedly and give effect to each term ***according to its ordinary and accepted meaning***." <u>C.T. v. Johnson, 1999 UT 35, ¶ 9, 977 P.2d 479</u> (citation and internal quotations omitted) (emphasis added). Furthermore, "'statutory construction presumes that ***the expression of one should be interpreted as the exclusion of another***[,]' . . . we should give effect to any 'omission in the [statute's] language by presuming that the omission is purposefu1.'" State v. Jacobs, 2006 UT App 356, ¶ 7, 144 P.3d 226 (quoting Carrier v. Salt Lake County, 2004 UT 98, ¶ 30, 104 P.3d 1208) (internal quotations omitted) (emphasis added).

Based on these rules of statutory construction, and keeping in mind that when a specific power is conferred by statute upon the Commission, the powers are limited to such as are specifically mentioned, an EBA can likely be designed so that a 70/30 sharing mechanism or dead band is used to determine what portion of the electrical corporation's incurred actual power costs are recovered or refunded.

The ordinary and accepted meaning of the word "component" includes: "a part; a constituent; an ingredient." Webster's New Universal Unabridged Dictionary at 372 (2d ed. 1979). Therefore, an EBA is an electrical corporation account for some or all of the parts or constituents or ingredients of the electrical corporation's fuel, purchased power, wheeling expenses, and the sum of these particular costs, less wholesale revenues.

A 70/30 sharing mechanism and a dead band would allow a part of the fuel, purchased power, and wheeling expenses to be accounted for in an EBA. Thus, the statute allows the Commission to implement these mechanisms in determining what components of fuel, purchased power and wheeling costs should be included in an EBA.

C. The Company's REC Revenues that Pre-date the Commission's Order Approving a REC-revenue Deferral Account Can Be Considered for Refund to the Ratepayers.

In July 2010, the Commission issued its order approving for establishment of a deferral account beginning February 22, 2010, for the REC revenues recovered by RMP in excess of the REC value utilized in Utah rates in the last general rate case. Subsequently, interested parties discovered that RMP had recovered substantial revenues that pre-date the February 22, 2010, start-date of the deferral account ordered by the Commission. Based on the two exceptions to the rule against retroactive ratemaking, unforeseeable, extraordinary events and fraud on the Commission, justice and equity require the Commission to make appropriate adjustments in future rates to offset these extraordinary financial consequences.

Utah law prohibits the Commission from permitting a utility to recover past costs or unrealized revenues. In the EBA Case, the Utah Supreme Court stated:

> [***As a] general rule [] . . . all ratemaking must be prospective in effect*** and rates may be fixed only in general rate proceedings. . . . It is true that the PSC has limited authority to permit interim rate changes which are necessary because of unexpected increased in certain specific types of costs. . . . However, neither the pass-through legislation ***nor the Commission's general grant of regulatory authority permits a utility to have retroactive revenue adjustment in order to guarantee shareholders the rate of return initially anticipated***.

702 P.2d at 420 (emphasis added).

A "retroactive" rate adjustment is one that allows a utility to recoup from future rates "costs that were greater than projected" (MCI Telecomm. Corp. v. Pub. Serv. Comm'n, 840 P.2d 765, 770 (Utah 1992)), or "to order refunds of amounts collected by a public utility pursuant to . . . approved rates and prior to the effective date of a [C]ommission decision ordering a . . . rate reduction" S. Cal. Edison Co. v. Cal. Pub. Utils. Comm'n, 576 P.2d 945, 945-46 (Cal. 1978). The rule against retroactive ratemaking is not constitutionally mandated, but it is a well-established Utah rule based on "sound ratemaking policies." Stewart v. Utah Pub. Serv. Comm'n, 885 P.2d 759, 777 (Utah 1994). The purpose of the rule is "to provide utilities with some incentive to operate efficiently." Id. at 778 (citing EBA Case, 720 P.2d at 420).

The rule against retroactive ratemaking makes no exception for "overestimates" or "underestimates" of a utility's costs, or for mistakes in the ratemaking process based on the utility's inability to accurately forecast its revenues and expenses. Id. Nevertheless, there are two exceptions to this rule that are recognized under Utah law: (1) when "an unforeseeable event results in an extraordinary increase or decrease in expenses or revenues," and (2) when "a utility misleads or fails to disclose" relevant rate-making information. MCI, 840 P.2d at 771, 775.

1. Unforeseeable and Extraordinary Events.

An "unforeseeable" event is one which is "inherently unpredictable," and which is not a result of "company mismanagement or imperfect forecasts." Id. at 771. This type of exception is appropriate only when an event is sufficiently unpredictable that it would be impossible to account for its effect in a rate case, and only when the effects of the unforeseen event are so beyond expectation that it would be unjust and inequitable not to adjust rates accordingly. Id.; see also Stewart, 885 P.2d at 778 ("Because earnings or expenses caused by an unforeseeable event cannot be reasonably anticipated in the ratemaking process, justice and equity may require appropriate adjustments in future rates to offset extraordinary financial consequences.").

With respect to REC revenues, events happened in the market that were truly unforeseeable and beyond expectation that resulted in REC revenues for which it would be unjust and inequitable not to adjust rates.

2. Fraud on the Commission.

A utility that misleads or fails to disclose pertinent rate-making information "cannot invoke the rule against retroactive rate making to avoid refunding rates improperly collected." MCI, 840 P.2d 775. "The rule against retro active ratemaking was designed to ensure the integrity of the rate-making process, not to shelter a utility's improperly obtained revenues." Id.

With respect to the Company's REC revenues that pre-date the Commission's order approving a REC-revenue deferral account, both exceptions to the rule against retroactive ratemaking likely apply. Here, the Company knowingly failed to disclose in the last general rate case information that was directly relevant. Because of this, the Commission should initiate a proceeding to investigate the true nature of the conditions surrounding these prior REC revenues, make a determination of whether the exceptions to the rule against retroactive ratemaking apply, and if so, order a rate adjustment so that the ratepayers can receive these improperly collected revenues.

DATED this 14th day of December, 2010.

/s/ William J. Evans

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CERTIFICATE OF SERVICE

I hereby certify that on this 14th day of December, 2010, I caused to be e-mailed, a true and correct copy of the **POST HEARING BRIEF OF UIEC** of Docket No. 09-035-15 to:

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