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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	Docket No. 09-035-15 **ROCKY MOUNTAIN POWER'S PETITION FOR CLARIFICATION AND RECONSIDERATION OR REHEARING**

Rocky Mountain Power, a division of PacifiCorp ("Rocky Mountain Power" or "Company"), hereby respectfully requests, pursuant to Utah Code Ann. §§ 54-7-15 and 63G-4-302, and Utah Administrative Code R746-100-11.F, that the Commission clarify and reconsider or rehear its Corrected Report and Order issued March 3, 2011 in this docket as modified by the Errata to Corrected Report and Order issued March 16, 2011 ("Order"). Rocky Mountain Power sincerely appreciates the Commission's approval of an Energy Balancing Account ("EBA") for the Company. Nevertheless, the Company respectfully requests that the Commission reconsider or rehear certain aspects of the Order and clarify certain aspects of the Order and as follows:

A. Matters for Reconsideration or Rehearing

1. The Commission should reconsider its decision to exclude swaps from the calculation of both base and actual net power costs ("NPC") included in the EBA (*id.* at 72) because the premise that the decision is required by Utah Code Ann. § 54-7-13.5(1)(b) is incorrect and because the decision is contrary to established practice, sound hedging strategy and undisputed credible evidence and will have unintended and adverse consequences. If the Commission believes it needs additional evidence to reconsider this decision, the Commission should grant rehearing on this issue.

2. The Commission should reconsider its decision to require the Company to bear 30 percent of any difference between net power costs recovered as a component of base rates and actual NPC incurred in an annual period (referred to herein as the "30% Provision") (*id.* at 70) because it is inconsistent with the underlying rationale of the Order, in conflict with Utah Code Ann. § 54-7-13.5, and contrary to the weight of the competent evidence and the public interest.

B. Matters for Clarification

1. The Order states that "REC revenues can be banked." Order at 72. While renewable energy credits ("REC") can be banked in some states including Utah, REC revenues cannot. The Company requests that the Commission clarify the Order by correcting this incorrect statement and clarify any aspect of the Order that would be impacted its correction.

2. The Order excludes REC revenues from the EBA at this time. *Id.* The Company requests that the Commission clarify that this decision is not intended to preclude the Company or other parties from urging the Commission to adopt balancing account treatment for REC revenues in any other docket in the future.

3. The Order provides for a four-year pilot program for the EBA. *Id.* at 78. The Company requests that the Commission clarify that the term of the pilot program extends through December 31, 2015.

II. INTRODUCTION

A. Procedural History

The Company filed its application for approval of its proposed Energy Cost Adjustment Mechanism ("ECAM") on March 16, 2009. This was done in compliance with Commitment U 23 in Docket No. 05-035-54 and the statute authorizing energy balancing accounts, Utah Code Ann. § 54-7-13.5. The ECAM filing was timed specifically to allow the Commission to approve an ECAM which could be implemented in the general rate case ("GRC"), Docket No. 09-035-23 ("2009 GRC"), filed over three months later. The Commission resolved disputes regarding the adequacy of the application, scheduling of proceedings in this case and the 2009 GRC, and implementation of the ECAM at the conclusion of the rate case by assuring the parties that it had adopted a schedule that "can accommodate parties' interests in both dockets."[1]

The case proceeded through two phases, with the second phase later divided into two parts. In anticipation of this protracted proceeding and consistent with the August 4, 2009 Scheduling Order, the Company moved the Commission to establish a deferred account for incremental NPC effective February 18, 2010, the date rates set in the 2009 GRC would go into effect. This was done to preserve the Company's right to have the ECAM go into effect at the conclusion of the 2009 GRC. The Commission granted the motion along with an application for

[1] Scheduling Order, Docket No. 09-035-15 (Utah PSC Aug. 4, 2009) at 1.

a deferred accounting order for incremental REC revenues filed by the Utah Association of Energy Users ("UAE") in Docket No. 10-035-14 pursuant to stipulation of the parties.[2]

Following hearings in January, August and November 2010 and submission of post-hearing briefs in December 2010, the Commission issued the Order in March 2011.

B. Summary of the Company's Position

The Company appreciates the Commission's adoption of an EBA and its decisions rejecting recommendations to (1) include a deadband, (2) include a load growth adjustment unrelated to NPC and (3) require the EBA balance to be accounted for by rate schedule. The Company will file a revised tariff and work cooperatively as part of the EBA working group as directed by the Commission.

However, the Company believes the Commission should reconsider or rehear its decision to exclude swaps from the EBA because the Commission's rationale for the decision is in error and because exclusion of swaps is contrary to established practice, effective hedging and undisputed, competent evidence and will have adverse and unintended consequences contrary to the public interest. The Company also believes the Commission should reconsider the 30% Provision because it is inconsistent with the Commission's findings, in conflict with the statute, and contrary to the great weight of the competent evidence. Finally, the Company believes certain aspects of the Order require clarification, including the decision on REC revenues and the term of the pilot program.

[2] Report and Order on Deferred Accounting Stipulation, Docket Nos. 09-035015 and 10-035-14 (Utah PSC Jul. 14, 2010) at 1-2.

III. ARGUMENT

A. Matters for Reconsideration or Rehearing

1. Swaps

a. Under rules of statutory construction, it is clear that swaps are costs of fuel and energy and are permissible elements of the EBA

Section 54-7-13.5 of the Utah Code, the statute specifically authorizing energy balancing accounts such as the EBA, provides that:

> (1) (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).

When confronted with an issue of statutory interpretation, the Commission must first look to "the statute's plain language to determine its meaning,"[3] "presume that the legislature used each word advisedly[,] . . . give effect to each term according to its ordinary and accepted meaning,"[4] and read all provisions together attempting to give meaning to each part of the statute.[5] Utah courts have stated that the "plain language analysis is not so limited that we only inquire into individual words and subsections in isolation; our interpretation of a statute requires that each part or section be 'construed in connection with every other part or section so as to produce a *harmonious whole.*'"[6] Moreover, "'the purpose of the statute' has an influence on the

[3] *Heber Light & Power Co. v. Utah Public Service Comm'n,* 2010 UT 27, ¶ 19, 231 P.3d 1203.

[4] *C.T. v Johnson,* 1999 UT 35, ¶ 19, 977 P.2d 479.

[5] *See Nixon v. Salt Lake City Corp.,* 898 P.2d 265, 268 (Utah 1995) (stating an "important rule of statutory construction is that a statute should be construed as a whole, with all of its provisions construed to be harmonious with each other and with the overall legislative objective of the statute"); *State v. Redd,* 954 P.2d 230, 235 (Utah App. 1998) ("[A]ny interpretation of statutory language that would nullify other statutory provisions is improper.").

[6] *Anderson v. Bell,* 2010 UT 47, ¶ 9, 234 P.3d 1147 (quoting *State v. Maestas,* 2002 UT 123, ¶ 54, 63 P.3d 621) (citing *Sill v. Hart,* 2007 UT 45, ¶ 7, 162 P.3d 1099 (emphasis added). *See also State v. Schofield,* 2002 UT 132, ¶ 8, 63 P.3d 667.

plain meaning of a statute." [7] When interpreting a list of terms, the word "including" indicates that the list of terms following is not exhaustive, but that the list suggests the types of things to be included and that "including" extends or enlarges the list.[8] Lastly, the Commission can consider other applications of the terms in the statute and common usage when interpreting statutory language.[9]

Based upon these rules, it is clear that the Commission may include some or all components of NPC in the ECAM. These components include, but are not limited to, the enumerated items: fuel, purchased power, wheeling costs and wholesale revenues, and similar and associated items related to them under the umbrella of "actual power costs." Utah Code Ann. § 54-7-13.5(1)(b).

Swaps are similar to and associated with fuel and purchased power for several reasons. First, they are an integral part of the actual cost of fuel or purchased power as demonstrated by the uncontroverted evidence in this case. The combination of a forward index price physical purchase of natural gas or electricity and a fixed for floating swap transaction is identical to a forward fixed price physical purchase of natural gas or electricity.[10] In other words, swaps are simply a financial vehicle used as part of the forward purchase of natural gas and electricity to fix the price of the commodity. Thus, they are clearly part of the actual cost of fuel and purchased power.

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[7] *Anderson*, 2010 UT 47 at ¶ 9 (quoting *R & R Indus. Park, L.L.C. v. Utah Prop. & Cas. Ins. Guar. Ass'n*, 2008 UT 80, ¶¶ 23, 36, 199 P.3d 917.).

[8] *Checkrite Recovery Services v. King*, 2002 UT 76, ¶ 7, 52 P.3d 1265 ("[A] statutory definition of a term as 'including' certain things does not restrict the meaning to those items included." Rather, "the word 'include' is ordinarily used as a word of extension or enlargement.") (internal citations omitted).

[9] *See, e.g., State v. Holm*, 2006 UT 31, ¶ 19, 137 P.3d 726.

[10] Tr. (8/17/10) at 28, 36, 53, 62-63, 65-66; Bird Rebuttal Phase II-2 (9/15/10), Exhibit SAB-Phase II-2-1R; Tr. (11/1/10) at 248-250.

Second, the Order's conclusion that swaps "do not track well with the statutory definition of energy costs" (Order at 72), is incorrect as a matter of law. Under the principles of statutory interpretation articulated by Utah courts, if there is any doubt or ambiguity in the meaning of a statutory term, the Commission is then to consider the language of the statute in connection with other parts of the statute as well as common usage and legislative intent. Under these principles, swaps are clearly recognized as part of the cost of purchasing fuel and energy.

In the section immediately following the definition of "energy balancing account," the statute defines a "gas balancing account" as "a gas corporation account to recover on a dollar-for-dollar basis, purchased gas costs, and gas cost-related expenses." Utah Code Ann. § 54-7-13.5(c). Questar has included gas hedging costs, including swaps, in its gas balancing account.[11] Thus, the Commission has previously recognized that swaps are part of purchased gas costs.

Moreover, swaps have always been recorded without question in the fuel and energy accounts in the Uniform System of Accounts, Fuel Account Nos. 547 and 501, and Purchased Power Account No. 555. These accounts are accounts that the Commission has allowed for inclusion in the EBA. Swaps have been included in the Company's NPC examined in GRCs for many years. Again, no party has questioned the legitimacy of the cost of swaps as a component of NPC.

Nor is there any indication in the legislative history of Senate Bill 75 ("SB 75"), passed in the 2009 General Session of the Legislature, that the Utah Legislature intended to exclude the

[11] Direct Testimony of Alan J. Walker, Docket Nos. 04-057-04, 04-057-09, 04-057-11, 04-057-13 and 05-057-01 (Utah PSC Apr. 15, 2005) lines 456-465 ("Trading or buying natural gas using an index for the immediate pipelines interconnecting the supply area and market offers significant advantages in liquidity and trading partners. Some parties are unwilling to purchase or sell gas using fixed prices because they fear they may not get a fair deal during the transaction, their management is unwilling to risk missing the market or other reasons. Questar Gas buys most of its gas using index-related prices because its purchases extend far into the future. Trying to predict future fair market values is nearly impossible, so Questar Gas contracts for most gas on an index-related basis. *When the Company feels it is advantageous to swap the price on index-related gas, the Company will convert the contract with the supplier or use financial instruments.*") (emphasis added).

costs associated with swaps from EBAs. Rather, the Legislature expressed its intent to provide the Commission with the necessary authority to address the issue of volatility in the energy markets. More specifically, when expressing support for the bill's passage during floor debate in the House of Representatives, Representative Garn stated that the bill "provides additional authority and tools to the Public Service Commission to address the changing utility environment while balancing the interest of consumers and utility service providers."[12] During both Senate and House committee hearings and floor debates, the Legislature gave no indication that certain classes of costs, and costs related to swaps in particular, should be excluded from EBAs or that the Commission should be limited beyond the terms of the statute regarding the tools with which it can address the issue of volatility in energy markets. Given the broad legislative support for SB 75 and its various provisions and the lack of any indication to the contrary, there is no reason to believe that the Legislature intended for the Commission to exclude the cost of swaps from EBAs. Incidentally, the Company notes that the Commission's rationale that swaps "do not track well with the statutory definition of energy costs" (Order at 72) is selective, arbitrary and capricious. Wheeling revenues have never been recorded in the fuel and energy accounts in the Uniform System of Accounts, Fuel Account Nos. 547 and 501, and Purchased Power Account No. 555. Thus, using the Commission's rationale, an even stronger argument could be made against including wheeling revenues in the EBA; yet, the Commission included wheeling revenues in the EBA.

Third, not only do swaps track well with purchases of natural gas and electricity, they are an essential component of such purchases and understood to be cost of fuel in today's energy market place. They are commonly accepted tools used in the purchase and sale of fuel and

[12] Transcript of 2009 Utah Legislative Session, Day 44, re Senate Bill 75, Utility Amendments, March 11, 2009.

energy in the market. For example, a recent report on use of derivative accounting by Standard & Poor's indicates that of the sample of 25 U.S. utility holding companies reviewed, all use derivatives to hedge commodity exposure, all have a variation of a fuel and purchased power adjustment clause, and all but two (for which information was not available) receive authorized regulatory recovery of hedging costs including settled derivative gains and losses.[13]

Fourth, other states have included hedging and similar transaction costs associated with managing the volatility of fuel prices, including the costs of swaps, in EBAs as fuel or energy costs. Although the Company recognizes that regulatory decisions in other states are not controlling, the inclusion of swaps in EBAs in other states provides persuasive policy analysis and support for an industry and regulatory standard that should be considered by the Commission.

For example, the Florida Public Service Commission determined that swaps associated with hedging were appropriate as part of a utility's overall risk management plan for fuel procurement.[14] The Florida commission stated in particular that by including swaps and hedging costs, Florida's cost recovery clause "appears to remove disincentives that may currently exist for [investor-owned utilities] to engage in hedging transactions that may create customer benefits by providing a cost recovery mechanism for prudently incurred hedging transaction costs, gains and losses, and incremental operating and maintenance expenses associated with new and

[13] *See* Standard & Poor's, "New Accounting Standards Provide More Insight About the U.S. Electric Utilities' Use of Derivatives," *Global Credit Portal Ratings Direct* (Jan. 28, 2011) at Tables 2 and 5, attached for the convenience of the Commission as Appendix 1.

[14] Proposed Resolution of Issues, Docket No. 011605-EI (Fla. PSC Aug. 9, 2002) at 1 ("Each investor-owned electric utility shall be authorized to charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions for natural gas, residual oil, and purchased power contracts tied to the price of natural gas. Examples of such items include transaction costs associated with derivatives, gains and losses on futures contracts, premium on options, contacts, and net settlements from swaps transactions.").

expanded hedging programs."[15] Additionally, the Florida Commission regularly reviews for prudence the cost recovery of hedging gains or losses and approves these costs for recovery during fuel proceedings.[16]

Further, North Carolina's statute allows its commission to permit its public utilities to charge an increment or decrement as a rider to its rates that reflects "changes in the cost of fuel and fuel-related costs used in providing its North Carolina customers with electricity from the cost of fuel and fuel-related costs established in the electric public utility's previous general rate case." N.C.G.S. § 62-133.2(a) (2010). The North Carolina commission determined that "prudently-incurred direct, incremental, transaction-related costs of financial and physical hedging activities utilized by [the utility] to reduce the volatility of its natural gas costs and charged or credited to FERC Account No. 547 shall be treated as recoverable fuel costs pursuant to G.S. 62-133.2 subject to the same standards of reasonableness and prudence as other fuel costs incurred by the [utility]."[17]

Finally, the Illinois Commerce Commission likewise determined that utilities are allowed to recover hedging transaction costs through the commission's Uniform Purchased Gas Adjustment rule that allows a utility to apply for a uniform fuel adjustment charge to its filed rate schedule.[18] When the commission approved the Purchased Gas Adjustment rule, it also

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[15] Order No. PSC-02-1484-FOF-EI, Docket No. 011605-EI (Fla. PSC Oct. 30, 2002) at 2.

[16] *See, e.g.,* Order No. PSC-08-0824-FOF-EI, Docket No. 0800001-EI (Fla. PSC Dec. 22, 2008); Order No. PSC-08-0667-PAA-EI, Docket No. 0800001-EI (Fla. PSC Oct. 8, 2008) at 18 ("The Hedging Order authorized the IOUs to charge hedging gains and losses to the fuel clause and provided initial support for utility hedging programs."); Order No. PSC-08-0030-FOF-EI, Docket No. 070001-EI (Fla. PSC Jan. 8, 2008).

[17] In the Matter of Application by Carolina Power and Light Company for Authority to Adjust Its Electric Rates Pursuant to G.S. 62-133.2 and NCUC Rule R8-55, 2006 N.C. PUC LEXIS 1035 (N.C. PUC Sep. 25, 2006) at 48-49.

[18] Reconciliation of Revenues Collected Under Fuel and Gas Adjustment Charges with Actual Charges, 1998 Ill. PUC LEXIS 383 (Ill. Commerce Comm'n May 20, 1998) at 12; 83 Ill. Adm. Code § 425.10 - 425.30 (2011).

authorized the use of hedging strategies, and determined specifically "that the costs incurred in supply management and price management of gas are recoverable through PGA, subject to prudence review, as direct out-of-pocket non-commodity costs of gas."[19] Thus, the law of other states supports the view that swaps are a cost of fuel and should be included in fuel cost recovery mechanisms.

On the basis of the foregoing, there is nothing in the statutory definition of fuel and energy costs, in their common usage or in the legislative history supporting the conclusion that swaps should be excluded from the NPC calculation. Therefore, it is clear that swaps are costs of fuel and energy under section 54-7-13.5(1)(b) and are permissible elements of the EBA.

b. The Commission may not ignore uncontradicted, competent, credible evidence that all elements of NPC, including swaps, should be included in the EBA

The Commission may not ignore "uncontradicted, competent, credible evidence" presented in a proceeding before it.[20] In this case, all witnesses who addressed the issue ultimately recommended that all components of NPC should be included in the EBA because exclusion of any element would create perverse incentives and undesirable outcomes. Although some parties originally questioned whether all elements of NPC should be included in an ECAM, it was undisputed by the end of the case that exclusion of some elements of NPC from the ECAM would create perverse incentives. As explained by Dr. McDermott in Phase I:

> ECAMs are designed to be comprehensive, i.e., all relevant costs related to fuel and purchased energy are recovered on a level playing field. . . . The reason for this is simple: if some costs were treated one way, and other costs another, perverse incentives could be created. Comprehensive and symmetrical treatment provides an assurance that fuel and purchased energy are treated equally, meaning that a utility would not have an

[19] Reconciliation of Revenues Collected Under Fuel and Gas Adjustment Charges with Actual Charges, 1998 Ill. PUC LEXIS 383 (Ill. Commerce Comm'n May 20, 1998) at 13.

[20] *U.S. West Communications v. Public Service Comm'n*, 901 P.2d 270, 275 (Utah 1995).

> incentive to favor one over the other.[21]

After carefully considering the issue, by Phase II-2, Mr. Peterson agreed:

> [T]he major reason for backing away from specifying relatively narrow accounts for inclusion and exclusion is the effects such a design could have on Company incentives. For example, if short-term power purchases were treated favorably in the ECAM and long-term purchases were excluded, there would be an incentive for the Company to move more to short-term at the expense of long-term purchases. These could occur even if it were not in the best interests of ratepayers to do so.[22]

Specifically, with regard to hedging, Mr. Peterson testified that excluding hedging would create a perverse incentive for the Company to stop hedging entirely which would result in the full volatility of gas and electricity markets being flowed through to customers.[23] When explaining why excluding gas hedging costs would result in perverse incentives that would harm customers, Mr. Bird testified that the exclusion of these costs:

> …results in forcing increased NPC due to the perverse incentive for the Company to forego opportunities to run its natural gas generation resources more or make wholesale purchases at levels above the forecast used to establish rates even when it is economical to do so and would reduce NPC. . . . [T]he Company would incur the incremental cost of natural gas purchases, wholesale purchased power or both and receive no offsetting wholesale sales revenues, while customers would bear no incremental costs but receive all of the benefit of the incremental wholesale revenues.[24]

The only party that advocated exclusion of swaps did so based solely on legal argument without providing any evidence in support of its position. In its post-hearing brief, UIEC recommended that swaps be excluded based on a claim that they do not fit the statutory definition of elements that may be included in an EBA.[25] The error of that argument has already

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[21] McDermott Rebuttal Phase I (12/10/09), lines 359-441.

[22] Peterson Direct Phase II-2 (8/4/10), lines 207-240.

[23] *Id.* at lines 233-237.

[24] Bird Rebuttal Phase II-2 (9/15/10), lines 239-247.

[25] Post Hearing Brief of UIEC, Docket No. 09-035-15 (Utah PSC Dec. 14, 2010) at 6.

been demonstrated above. Notably, UIEC's own witness, Mr. Brubaker, did not recommend that swaps be excluded from the EBA, but rather recommended that the Commission adopt hedging guidelines in order to establish the parameters within which the Commission could evaluate the Company's hedging program.[26]

Therefore, the Commission's conclusion that swaps should be excluded from the EBA is contrary to the law and uncontradicted, competent, credible evidence and should be reversed on reconsideration.

c. Swaps are necessary to properly hedge price risks

Swaps are an integral part of the Company's price hedging program that ultimately benefits customers by reducing the volatility of NPC due to market price volatility as illustrated by the following examples:

1. Assume the Company wishes to sell 5,000,000 MWh of power to be delivered at a future date with a current market price of $50/MWh. If the Company uses fixed for floating swaps where the Company is paid at fixed prices now and pays market indexes at the time of delivery, the Company can lock in $250 million of revenues from this sale of power. At the time of delivery of the power, the revenues from selling the power and settling the swaps will have the following impact assuming the market price at that time is either $25/MWh or $75/MWh:

$m	$25/MWh	$75/MWh
Sales Revenues of Physical Product	125	375
Expenses of Swaps	(125)	(375)
Revenues from Swaps	250	250
Net Revenues	**250**	**250**

[26] Brubaker Rebuttal Phase II-2 (9/15/10) at 5, lines 12-15.

If the Company did not use swaps, its net revenues for this transaction at the time of delivery would be:

$m	$25/MWh	$75/MWh
Sales Revenues of Physical Product	125	375
Net Revenues	**125**	**375**

Thus, using swaps, the revenues from selling 5,000,000 MWh power are $250 million whether the market price is higher or lower at the time of delivery. Without using swaps, the revenues will fluctuate with the market prices at the time of delivery.

2. Assume the Company wishes to generate 5,000,000 MWh of power from gas-fired generating plants with an average heat rate of 8.0 MMBtu/MWh (i.e., 40,000,000 MMBtu fuel requirement) and the current market price of natural gas is $3/MMBtu. If the Company purchases fixed for floating swaps for the fuel requirement, where the Company pays fixed prices now and receives market indexes at the time of delivery, the Company locks in a $120 million expense for this transaction. At the time of delivery, the expenses from purchasing physical products and settling the swaps would have the following impact assuming the market price of natural gas at that time is either $2/MMBtu or $4/MMBtu:

$m	$2/MMBtu	$4/MMBtu
Purchase Expenses of Physical Product	(80)	(160)
Revenues from Swaps	80	160
Expenses of Swaps	(120)	(120)
Net Expenses	**(120)**	**(120)**

If the Company did not use swaps, its costs at the time of delivery would be:

$m	$2/MMBtu	$4/MMBtu
Purchase Expenses of Physical Product	(80)	(160)
Net Expenses	**(80)**	**(160)**

Thus, if the Company uses swaps, the costs of fuel for generating 5,000,000 MWh will be $120 million whether the market prices are higher or lower at the time of delivery. Without swaps, the expenses will fluctuate with the market prices at the time of delivery.

Because no one can reasonably predict market price volatility, customers benefit when the Company hedges its open positions. While, in theory, the Company could hedge equally effectively using fixed price physical transactions in lieu of fixed for floating price financial swaps, customers benefit when the Company uses fixed for floating price financial swaps for these practical reasons:

1. Financial markets are significantly more liquid than physical markets, thereby increasing market efficiency and lowering transaction costs.
2. Many more counterparties participate in financial swap markets than in physical markets.
3. Physical markets with which the Company can hedge price risk are around many specific points of delivery, of which only a limited number are connected to the Company's system.
4. Financial markets with which the Company can hedge price risk are structured around major trading hubs that provide benchmark pricing for many specific locations; thereby encouraging liquid markets.
5. Financially settled transactions can reduce transactional costs and risks related to price risk hedging activities.
6. Financially settled transactions do not require physical scheduling, whereas physical transactions executed expressly to hedge price risk need to incur scheduling costs.

7. The credit risk associated with physical transactions inflates to the nominal value of the commodity once delivery begins, whereas financially settled transactions are assessed credit risk only on the amount the transaction is in or out of the money.

d. Exclusion of swaps will have adverse and unintended consequences

Excluding financial swaps is arbitrary and will result in unintended consequences. The exclusion of swaps in the EBA results in an outcome where Utah customers are left nearly completely unhedged and exposed to volatile market prices. Approximately 90 percent of natural gas requirements and 50 percent of electricity sales in the 2011 GRC are accomplished with the use of natural gas and electricity swaps. However, if swaps are excluded from the EBA, then swap transactions approved in the GRC in effect convert from their intended purpose as a tool to hedge NPC and instead become speculative transactions where the Company and customer interests diverge. The following examples illustrate the unintended and adverse consequences that result from excluding swaps from the EBA:

1. Assume the Company's in-rates NPC are $1 billion, consisting of $200 million in forecast swap expense and $800 million in other forecast NPC, and that the combination of swaps and physical wholesale contracts perfectly hedge the forecasted generation and retail loads. Then assume that actual generation and retail loads during the rate-effective period match the forecast and the only change is that settlement market prices change. In such an example, NPC in total will remain $1 billion, but the mix of NPC between swaps and physical wholesale contracts will change, as illustrated in the foregoing section. Depending on the direction of market price movements, customers may be unintentionally harmed. For example, assume market prices move in a direction that causes swap expense to decrease by $200

million and other fuel, purchased power and wholesale sales to increase by $200 million. Applying the Commission's EBA will result in customers paying an additional $140 million (i.e., 70 percent of the $200 million expense) for a total NPC (excluding swaps) of $1.14 billion even though actual NPC was $1 billion. The Company's intent to use swaps as a hedge achieved its purpose by locking in actual NPC at $1 billion, but because the Commission excluded swaps from the EBA, the Company instead receives an additional $140 million windfall.

2. Conversely, assume the same example as above, but that market prices move in the opposite direction by the same amount, causing swap expenses to increase by $200 million and other fuel, purchased power, and wholesale sales to decrease by $200 million. Applying the Commission's EBA will result in customers receiving a credit of $140 million for total NPC of $860 million even though actual NPC was $1 billion. Again, although the Company's swaps achieved their intended hedge purpose to lock in NPC at $1 billion, because the Commission excluded swaps from the EBA, the Company arbitrarily loses an additional $140 million.

The unintended consequences in the examples discussed above are demonstrated further by applying the Commission's EBA to historical data for 2010. In 2010, the NPC component of base rates was $996 million, consisting of $2 million in forecast swap revenue and $998 million in other forecast NPC. Among other NPC impacts, settlement market prices were unfavorable to the forward price curve used to set rates, and actual NPC was $1.15 billion, consisting of $86 million in actual swap revenue and $1.24 billion in other actual NPC. Without the EBA, customers paid $996 million, while the Company incurred actual NPC of $1.15 billion[27]. If the

[27] For simplicity in this example, actual NPC was not adjusted for changes in actual load, which was lower than the load forecast in rates by approximately 574,000 MWh. The load forecast in rates was 58,344,264 MWh.

EBA had been in place during this period excluding swaps but including other elements of NPC, customers would have paid an additional $169.4 million, or total NPC of $1.165 billion, even though actual NPC was $1.150 billion.[28] If instead, swaps were included in the determination of base and actual NPC for purposes of determining the EBA, customers would have been credited $58.8 million (70 percent of the $84 million gain in swap revenue) and would have paid $1.104 billion total NPC[29].

e. Conclusion on swaps

The Commission should reconsider its decision to exclude swaps from the EBA. It is not necessary to exclude them based on a proper interpretation of section 54-7-13.5(1)(b), the uncontradicted, competent, credible evidence supports their inclusion, they are necessary for an effective hedging strategy and their exclusion will have adverse and unintended consequences. If the Commission believes it needs to review additional evidence to include swaps in the EBA, the Commission should grant rehearing to allow parties to provide that evidence.

2. Company Responsibility for 30 Percent of Any Difference Between NPC recovered in Base Rates and Actual NPC

a. The 30 % Provision is inconsistent with other findings in the Order

In the Order, the Commission accepted the recommendation of various parties that the Company not be permitted to recover all of its NPC costs even if such costs were prudent; this is

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The Company believes that incorporating the change in load in the calculation would not change the conclusion that customers would have been harmed with an EBA that excluded swaps.

[28] Customers would have been charged 70 percent of the difference between the $998 million forecast and the $1,240 million actual NPC, excluding swaps, plus the $998 million included in rates less the $2 million swap revenue included in rates. 70% * ($1,240,000,000 - $998,000,000) = $169,400,000, and $169,400,000 + ($998,000,000 - $2,000,000) = $1,165,400,000.

[29] Customers would have been charged 70 percent of the difference between the $996 million forecast and the $1,150 million actual NPC. 70% * ($1,150,000,000 - $996,000,000) = $107,800,000, and $107,800,000 + $996,000,000 = $1,103,800,000.

the effect of the 30% Provision. The rationale for this decision appears to be the following findings:

1. "[T]his new mechanism must fairly allocate risk between customers and shareholders, maintain incentives to operate efficiently, both in the long-run and short run, and . . . ." Order at 66 - 67.
2. "A primary objective . . . is to ensure sufficient incentive . . . to continue to make and implement prudent resource decisions . . . ." *Id.* at 67.
3. "[A]n EBA design which includes risk-sharing during regulatory lag, coupled with a prudence review, is superior . . . ." *Id* at 69.
4. "[The EBA] requires both Company customers and shareholders to remain at risk for a portion of actual net power cost which deviates from approved forecasts." *Id.* at 69.

Based on these findings, the Commission ordered the 30 % Provision.[30] Given that NPC is projected to be approximately $1.5 billion on a total Company basis in the 2011 GRC and the total Utah-allocated under-recovery from 2002 through September 2009 was approximately 14.2 percent higher than the amount included in rates during that time, 30 percent of the excess could be in the range of $60 million on a total company basis.

The Commission's determination to place 30 percent at risk suggests that the "risk" repeatedly referenced in the Order's findings is the risk of a difference between actual NPC and the forecast NPC approved by the Commission for inclusion in base rates in a rate case. Note

30 The Company interprets the Order as actually providing it the opportunity to recover and retain **more** than 100% of its prudent NPC. This would occur if revenues collected in base rates associated with NPC approved for EBA treatment exceeded actual NPC approved for EBA treatment in a particular calendar year. In other words, the 30% difference that the Company must bear is symmetrical and without dollar limit. If the Company is incorrect regarding the intent of the Order in this regard, the Company respectfully requests the Commission clarify this aspect of the Order as well.

that this is a different and separate objective from what the Commission found to be the "primary objective;" that primary objective being to ensure sufficient incentive to make prudent resource decisions (Order at 67).

The disconnect between the 30% Provision and the Order's acknowledged primary objective can readily be demonstrated by the following examples:

1. The Company could theoretically act imprudently but if NPC revenues matched actual NPC, the 30% Provision would not be triggered; any disallowance would occur as a result of the separate prudence review.
2. The Company's NPC forecast could theoretically match perfectly with the rate-effective period, but if the Commission does not approve that forecast, revenues will not match actual NPC regardless of the Company's prudence.[31]
3. Most importantly, the Company could act prudently but it will not matter if the revenue collected through the NPC component of rates does not match actual NPC; the 30% is triggered anyway. Prudence is not a factor. *There is no opportunity for the Company to offset the 30% by a showing that it has satisfied the primary objective of making prudent resource decisions.*

The Company recognizes that the Order contains provisions to prevent the first example above because it retains the prudence review element proposed by the Company. But that clearly demonstrates the lack of symmetry of the Order. If the Company is imprudent, it will (understandably) not be allowed to recover all its costs even if the revenues match actual NPC

[31] Prior to adoption of the EBA, parties representing customer interests had an incentive to assure that the NPC included in rates was as low as possible because the Company was exposed to any difference between in-rates NPC and actual NPC. Unfortunately, the decision to adopt the 30% Provision has not removed the incentive for parties representing customer interests to continue to attempt to forecast NPC much lower than the NPC actually expected. However, if the sharing mechanism is to truly balance risks between the Company and customers and provide an incentive to the Company as stated in the Order, the NPC forecast adopted by the Commission in rate cases must be unbiased, with an equal probability that actual NPC will be higher or lower than the forecast.

perfectly. But, if revenues do not match actual NPC perfectly, the Company will be at risk for 30 percent of the difference even if it is prudent. The Company fails to see how this encourages prudent conduct. <u>To reiterate a critical point, the Order provides no opportunity for the Company to offset the impact of the 30% Provision by a demonstration of prudence.</u>

Some parties, and perhaps the Commission, might contend that the objective of the 30% Provision is to encourage conduct that is more than prudent, perhaps best efforts. Obviously that is not the primary objective, because the Order specifically identifies what the primary objective is. And even if best efforts was *an* unstated objective, the disconnect between the 30% Provision and this objective remains. The Company's NPC forecasts do, in fact, assume best efforts will be made. But even with that assumption in the forecast and even if the Company, in fact, can demonstrate best efforts were made, the 30% Provision will be triggered oblivious to these factors if the revenues collected differ from actual NPC.

There is no nexus between the 30% Provision and the primary objective of the Order. The 30% Provision does little more than encourage the Company to improve *NPC revenue forecasting***.** While improvement in revenue forecasting may be a laudable pursuit, the Company suggests it should not be a primary or even secondary objective of an ECAM or EBA.

b. A sharing mechanism for components of NPC allowed in the EBA is inconsistent with the statute.

In the Order, the Commission adopted UAE's argument that Utah Code Ann. § 54-7-13.5 permits a "cost-sharing component of the EBA." Order at 71. The Commission reasoned that because the statute does not explicitly prohibit a cost-sharing mechanism and is "silent on the detailed operation of an energy balancing account," the Commission may impose a cost-sharing mechanism at its discretion. *Id.* Further, the Commission asserted that other states allow cost-sharing mechanisms, without any analysis of how those states' relevant statutes may be like or unlike Utah's statute. Finally, the Commission compared apples to oranges by stating that "if the ratemaking process can properly assign 100 percent of the risk or benefit of net power cost deviations . . . it can now also properly assign 30 percent of such risk to the Company." *Id.*

The Commission's reasoning ignores the plain language of the statue. Section 54-7-13.5, the statute specifically authorizing EBAs, provides that:

> (1) (b) "Energy balancing account" means an electrical corporation account for *some or all components of the electrical corporation's incurred actual power costs* . . . .
>
> . . . .
>
> (2) (g) Revenues collected in excess of prudently incurred actual costs *shall*: (i) be refunded as a bill surcredit to an electrical corporation's customers over a period specified by the commission; and (ii) include a carrying charge.
>
> (h) Prudently incurred actual costs in excess of revenues collected *shall*: (i) be recovered as a bill surcharge over a period to be specified by the commission; and (ii) include a carrying charge.
>
> . . . .
>
> (4) (a) *All* allowed costs and revenues associated with an energy balancing account or gas balancing account *shall* remain in the respective balancing account until charged or refunded to customers.

Utah Code Ann. § 54-7-13.5(1)(b), (2)(g) and (h), and (4)(a) (emphasis added).

In accordance with the accepted rules of statutory construction discussed previously, the Commission must first look to the plain language of the statute, presume that the Legislature used each word advisedly, give effect to each term and read all provisions together attempting to give meaning to each part of the statute. In addition, the word "shall" is mandatory rather than discretionary.[32]

[32] *See Pugh v. Draper City*, 2005 UT 12, ¶ 13, 114 P.3d 546 (stating use of the word "shall" is "usually presumed mandatory and has been interpreted as such previously in [Utah] and other jurisdictions"); *Diener v. Diener*, 2004 UT App 314, ¶ 12, 98 P.3d 1178 ("Ordinarily, the use of the word 'shall' in a statute creates a mandatory condition eliminating any discretion on the part of the courts.").

Based upon these rules and the plain language of the statute, the Commission may not disallow recovery or order a sharing of the components of actual NPC included in the EBA unless it finds them imprudent. Rather, *all* of the difference between actual prudent costs for the allowed components and the amount included in rates *shall* remain in the balancing account until charged or refunded to customers. "All" does not mean some portion or percentage of a component—it means all; and "shall" does not mean may—it means shall. Thus, the sharing mechanism is inconsistent with section 54-7-13.5.

c. Imposition of the sharing mechanism is inconsistent with the great weight of the credible evidence.

The Commission found that the primary objective of the EBA design was to ensure sufficient incentive to make prudent resource decisions. Order at 67. However, the Order is devoid of any rationale or evidentiary support for the implicit assumption that the 30% Provision will incentivize achievement of the primary objective. Indeed, the overwhelming weight of the evidence, as well as logic, indicates that the 30% Provision will not incentivize achievement of the primary objective.

The Company's evidence demonstrated that a sharing mechanism would provide no incentive at all to change behavior. First, one of the most critical elements of the NPC forecast is retail sales – a factor over which the Company has little control. Second, another critical element is weather, as it impacts load, energy usage, wind generation availability and hydro generation availability – again, not within the Company's control. Third, other elements of an annual NPC forecast over which the Company has little, if any, opportunity to modify during a single annual period include fuels supplies already under contract and power purchases and sales already under contract.

The element of the NPC forecast over which the Company is presumed to have control – and the element which appears to be the focus of the Order's primary objective -- is transactions by traders buying and selling gas and electricity to balance the Company's short-term load and resources. The evidence is undisputed that these traders will not be more likely to attempt to achieve better prices with a sharing mechanism than they would with no sharing mechanism. Traders don't refer to the NPC forecast when making procurement, including purchases and sales, decisions. They simply attempt to purchase or sell natural gas or electricity at the best prices available in the market at the time and for the location that these commodities are needed.[33]

Moreover, the extent of the Company's control over transactions to fill open positions is limited. The Company cannot choose whether to buy or sell depending on the market prices. It is obligated to acquire the resources necessary to meet the load required by customers.[34]

Logic supports the Company's evidence that the 30% Provision will not impact procurement decisions. To impact decisions, there must be a nexus between the conduct sought to be incentivized (here, prudent or best efforts procurement) and the incentive (here, the potential non-recovery of actual costs that vary from projected revenues, even if best efforts are made). Even if a trader or other Company employee responsible for resource procurement referenced the NPC forecast, how would the employee know how to modify her/his conduct on the first day of the forecast? The midpoint of the forecast? The last day of the forecast? The employee won't know what NPC revenues have been collected at that point, won't know exactly

[33] Duvall Rebuttal Phase II-2 (9/15/10), lines 121-127; Tr. 11/1/10 at 16, 22-23; Tr. 11/1/10 at 221 (Mr. Bird explaining what motivates traders). *See also* Graves Rebuttal Phase I (12/10/09), lines 486-494 (explaining why an ECAM would not cause a utility to become lax in its management of NPC); McDermott Rebuttal Phase I (12/10/09), lines 300-357 and McDermott Rebuttal Phase II-2 (9/15/10), lines 295-360 (discussing academic studies on the impact of an ECAM on incentives).

[34] Tr. (11/1/10) at 252.

how (and how much) the conditions in the year have varied from the averaged and normalized assumptions in the forecast, and probably won't know how costs outside her/his responsibility area vary from the forecast. The only logical action for the employee to take is to make the best decision she/he can to serve customers – which is what they will do with or without the 30% Provision.

On a broader scale, while exclusion of certain types of NPC from EBA treatment could create an incentive for the Company to favor acquisition or use of certain types of resources, the Company's goal is always to plan its resource mix and power acquisition strategy based on the mix of resources that it believes will achieve the lowest cost for customers at reasonable risk over the long term.[35] The purpose of the integrated resource planning process is to assure that the Company's plans are articulated, subjected to scrutiny and input, and ultimately, if acknowledged, provide a standard against which future conduct may be evaluated. None of this will change with an EBA. As Messrs. Duvall and Bird both testified, an EBA does not change the Company's incentives in any way. It is simply a vehicle for assuring that prudent NPC, no more and no less, is recovered in rates.[36]

Rather than providing a greater incentive for the Company to continue to perform its duty to provide safe, reliable and adequate service at the lowest reasonable cost to customers, the 30% Provision will simply assure that the Company will over-recover or under-recover its actual NPC which is contrary to fundamental principles of rate making and the regulatory compact.[37] The greater the sharing mechanism, the greater this deviation from appropriate rate making. The Commission certainly would not penalize the Company by slashing an arbitrary 30 percent from

[35] Tr. (11/1/10) at 222.

[36] *Id.* at 22-23, 251-253.

[37] *Id.* at 17, 42-43, 219.

the recovery of rate components found to be 100 percent just and reasonable, but that is precisely what the 30% Provision does.

d. The sharing mechanism is inconsistent with sound public policy and the public interest

The uncontroverted evidence submitted in the case was that the vast majority of power cost adjustment mechanisms approved by utility commissions in the United States do not have sharing mechanisms. Dr. McDermott provided the most comprehensive evidence of the design of mechanisms in other states. His evidence showed that most states have never had sharing mechanisms, but that of those states that have had them, the trend has been a narrowing or elimination of them, and that no state has increased its sharing mechanism.[38] His evidence further showed that sharing, when applied, is usually not applied to fuel and purchased power costs.[39] Of the 47 different operating companies selected because they were the comparable companies used by witnesses for estimating cost of equity in the 2009 GRC, only 3 have sharing mechanisms. Thus, over 93 percent of the companies do not have sharing mechanisms.

The fact that states that have been regulating electric utilities for many years utilizing power cost adjustment mechanisms do not have sharing mechanisms is a strong indication that they are not necessary to ensure that utilities have an incentive to operate in a reasonable manner.

e. Conclusion regarding the 30% Provision

The Company respectfully requests that the Commission reconsider whether the incentive mechanism that it has adopted in the Order is truly designed to incentivize the conduct that the Order identifies as the primary objective of the EBA design; to ensure sufficient incentive to

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[38] McDermott Rebuttal Phase II-2 (9/15/10), lines 136-146 and Exhibit KAM-Phase II-2-1R.

[39] *Id.* at lines 153-158. *See also* Exhibit KAM-Phase II-2-2R and Exhibit KAM-Phase II-2-3R (showing that in the few instances where sharing ratios are used they generally provide an upside incentive and do not restrict recovery of any portion of fuel and purchased power costs).

continue to make and implement prudent resource decisions. The Company suggests that the credible evidence of record proves there is no sound nexus between the incentive mechanism adopted and the conduct sought to be incentivized. The Company fears that in a period of increasing costs, combined with an admitted inability to control or predict retail sales perfectly, the 30% Provision will simply deny the Company any reasonable opportunity to recover its prudently incurred costs of serving customers and, as a consequence, deny it any reasonable opportunity to earn its authorized return. The Order at 70 and 71 suggests that was not the Commission's intent.

B. Matters for Clarification

1. Banking of REC Revenues

In discussing its reasons for not including REC revenues in the EBA, the Commission made an inaccurate statement that "REC revenues can be banked." Order at 72. While it is true that RECs can be banked under some state programs including Utah's, REC *revenues* cannot be banked. REC revenues must be recognized as income in the period in which they are received. The Company respectfully requests that the Commission clarify the Order by correcting this incorrect statement and clarify any aspect of the Order that would be impacted by its correction.

2. Future Balancing Account for REC Revenues

As noted previously, in the Order the Commission determined not to include REC revenues in the EBA at this time. Order at 70. REC revenues are a relatively new source of revenue for the Company. Over their short history, both the price and demand have been very volatile and difficult to forecast. The prices the Company realizes for them are dependent on decisions of legislators and regulators in several states, resulting in a market largely outside the control of the Company. As demonstrated by the evidence in this case, the most fair and appropriate ratemaking treatment for this type of revenue or expense is a balancing account.

Therefore, the Company respectfully requests that the Commission clarify that its decision to exclude REC revenues from the EBA at this time is not intended to preclude the Company or other parties from urging the Commission to adopt balancing account treatment for REC revenues in any other docket in the future.

3. Term of Pilot Program

The Commission recognized that the first period under the EBA would be a partial year and that the EBA reconciliation periods would be calendar years thereafter. *Id.* at 77. The Commission ordered implementation of the EBA as a 4-year pilot program with the start date of the pilot program being the first day of the month following the Commission's decision in the Company's current GRC, Docket No. 10-035-124 ("2011 GRC"). *Id.* at 78. The first day of the month following the Commission's decision in the 2011 GRC is likely to be October 1, 2011, because the 240-day statutory period for the Commission to make a decision ends on September 21, 2011. The Commission directed the Division to file a preliminary evaluation of the pilot program within four months of the conclusion of the second calendar year of the pilot program and a final evaluation within four months of the conclusion of the third year of the pilot program. *Id.* at 79. This direction is consistent with a view that the term of the pilot program is intended to extend through the end of the fourth calendar year of the EBA—December 31, 2015. The Company requests the Commission clarify the Order to provide that the term of the pilot program should commence as stated but extend to the end of the fourth complete calendar year of the program.

IV. CONCLUSION

Rocky Mountain Power sincerely appreciates the Commission's adoption of an EBA and its rejection of recommendations of parties that would have prevented the Company from any reasonable opportunity to recover the prudent costs it has incurred in providing service to customers for over a decade. However, the Company respectfully requests that the Commission reconsider and rehear its decisions with regard to exclusion of swaps from the EBA and adoption of the 30% Provision. Both of these decisions are contrary to applicable law, facts or public policy. Finally, the Company respectfully requests that the Commission clarify certain aspects of the Order to enable the Company to better understand the intent of the Order.

DATED: April 15, 2011.

Respectfully submitted,

ROCKY MOUNTAIN POWER

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CERTIFICATE OF SERVICE

I hereby certify that I caused a true and correct copy of the foregoing **ROCKY MOUNTAIN POWER'S PETITION FOR CLARIFICATION AND RECONSIDERATION OR REHEARING** to be served upon the following by electronic mail to the addresses shown below on April 15, 2011:

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