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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Load Surcharge.	Docket No. 07-035-93 **POST-HEARING BRIEF ON REVENUE REQUIREMENT**

Pursuant to the invitation of the Utah Public Service Commission ("Commission"), UIEC, a group of industrial customers of Rocky Mountain Power ("RMP" or the "Company"), present the following post-hearing brief on revenue requirement.

INTRODUCTION

This case represents the first entirely forecasted test year case for an electric utility rate case heard by this Commission. It should be kept in mind that legislation allowing consideration of forecasted data in setting rates was not deregulation legislation.

Most of the decisions to be made by the Commission in this proceeding involve determining which estimates of forecasted costs, if any, are reasonable.[1] Much of the testimony has been devoted to the methods used for estimating those future costs. The arguments are centered around which estimates are the more reliable and reasonable and the most likely to reflect reality going forward. The Commission must decide which estimate of future costs, if any, are reliable and reasonable, unconstrained by any presumption of correctness.

When selecting which estimate to rely upon, the Commission should consider what estimates or estimation techniques (a) are most reliable and believable; (b) will provide the most accountability; (c) will provide incentives for efficient and prudent management; and (d) will best reflect the actual costs given the circumstances existing at the time of the occurrence of those costs.

From the record in this case, it appears there is also reason to be particularly circumspect about the Company's estimated allocation of costs between the states, and to question the fairness of the interstate allocation made on those estimates. For example, it appears that the forecasted property tax costs used by the Company may penalize Utah ratepayers by imposing on them higher property tax rates that might be experienced in other states. The Company assumes Utah taxes will be higher than they are or have been. It also appears that current interstate allocation techniques may penalize Utah ratepayers by imposing on them higher medical costs than are, in fact, experienced in Utah. Again, this is based on the assumption that Utah costs will

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[1] Unlike cases based on historical data where prudency questions are presented as a basis for cost disallowance, here the question is the evidentiary reliability and reasonableness of the forecasted numbers. All of the witnesses, including the Company's witnesses, are mere soothsayers. The question is which soothsayer, if any, should be believed. There can be no presumption of correctness in the utility's favor, which may occur when actual historical data from the Company books and records is relied upon. See, e.g., Nevada Power Co. v. Publ. Utils. Comm'n of Nev., 138 P.3d 486, 498 (Nev. 2006) (citing Re Minnesota Power & Light Co., 11 FERC 61,312, 61,645, 1980 WL 100840 (1980). If the utility has failed to meet its burden of proof, then the application should be denied. The utility must meet the burden that its forecasts are reliable and reasonable or it is not entitled to a rate increase.

follow costs in other states. The renewable portfolio standards of other states appear to have been used to impose costs on Utahns not imposed by the Utah legislature (i.e., Oregon compliance costs imposed on Utahns when Utah has no mandated compliance legislation). Also, the bold unfounded estimates about the economic future growth of Utah upon which loads were forecasted will have the result of transferring disproportionate costs to Utah ratepayers—costs that indeed should be borne by other states given their comparative load growth. It appears that, for the first few months of 2008, loads in other states were up while loads in Utah were flat to declining. The forecast for the total Company may be accurate, but actual results in each state departs significantly from the Company's state forecasts.

Caution is advisable here because the excess costs imposed on Utah residents by these bold overestimates will never be recovered by Utah ratepayers. They will simply result in a subsidy by Utah ratepayers of RMP customers in other states. There cannot be, nor will there ever be, a true up, given the ban on retroactive rate making.

In this Brief, the UIEC presents arguments on only selected adjustments. That should not be interpreted to mean that other adjustments not mentioned herein are without merit. No negative inference should be drawn from the absence of comment.

ARGUMENT

I. RATE OF RETURN

UAE Cross Exhibit 1 (ROR) presents a very enlightening comparison of PacifiCorp's performance. Set forth below is a summary of the results of operations in each of the jurisdictions in which it operated for the year 2007.

	Total	**Utah**	**Utah Adjusted**
Return on Rate Base	7.460%	8.178%	7.518%
Return on Equity	8.005%	10.032%	8.723%

	Total	Oregon	Oregon Adjusted
Return on Rate Base	7.467%	7.970%	6.821%
Return on Equity	8.622%	9.621%	7.341%

	Total	Idaho	Idaho Adjusted
Return on Rate Base	7.467%	6.256%	7.360%
Return on Equity	8.730%	6.279%	8.515%

	Total	Wyoming	Wyoming Adjusted
Return on Rate Base	7.123%	6.696%	7.504%
Return on Equity	7.941%	7.092%	8.697%

	Total	Washington	Washington Adjusted
Return on Rate Base		4.490%	4.710%
Return on Equity		2.716%	3.153%

While the results may be criticized because the Company does not report results on a consistent basis in each jurisdiction, they nevertheless demonstrate that Utah ratepayers in 2007 probably underwrote the operations of RMP.[2] In determining a rate of return, therefore, the Commission should (a) not allow a rate of return on equity that is greater than the rate of return allowed by any other state, because RMP apparently has problems earning its allowed return and this arises not from Utah but from other states; (b) consider a rate of return that reflects the cost of capital only for 2008 because, in light of the Company's threat to file another rate case within the year, prospective changes in the cost of capital should not be included in this test year; and (c) consider that any rate of return granted should be based on the Company achieving

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[2] It might be appropriate for the Commission to order a report that shows jurisdictional results on a consistent basis for comparison purposes to overcome this reporting flaw.

comparable rates of return in other states. Utahns should not subsidize the residents of other states in rates of return given the potential for inequity of interjurisdictional rate allocation, especially as subsidization may already be occurring.

II. REVENUE REQUIREMENTS

Interjurisdictional Allocation. RMP forecasted robust growth in Utah for each rate class for the test year. (See UIEC Cross Exh. 7). That exhibit discloses new customer connections forecasted by month for the year 2008. By contrast, the actual results occurring during the year 2008 shows that the forecasted robust growth did not occur. UIEC Cross Examination Exhibit 9 shows, through the latest dates for which information was available (the first three months of 2008), growth in the number of customers, particularly residential customers, is approximately half the amount forecasted. More telling is UIEC's Cross Examination Exhibit 8, which discloses that for the first three months of 2008, actual kilowatt-hour and kilowatt sales in Utah, when weather adjusted, were below the amounts forecasted for Utah. During the same period, the kilowatt-hour and kilowatt sales for California, Oregon, and Wyoming were, in most cases, above the amounts forecasted.

Weather Adjusted Departure from Forecast
(Kwh)

	Utah	Wyoming	Idaho	Oregon	Washington	California	Total
2007 Totals	-0.7%	-.8%	2.7%	2.0%	-4.3%	2.8%	0.0%
Jan 2008	-2.7%	3.1%	-13.0%	1.8%	-8.1%	11.8%	-1.4%
Feb 2008	-5.4%	7.2%	4.4%	2.3%	-0.8%	8.4%	-0.2%
Mar 2008	0.4%	3.9%	-8.9%	-0.1%	-3.1%	11.3%	0.3%

(UIEC Cross Exh. 8). The non-weather adjusted Kwh loads show even greater departure of actual from the forecast. (See UIEC Cross Ex. 7.)

Similarly, UIEC Cross Examination Exhibit 8 shows the departure of weather-adjusted peak demand forecast in kilowatts for 2007 and the first two months of 2008. It shows Utah below or just slightly above the forecasted norms, while other states are ***significantly*** above their forecasts. Note, particularly, the 23.9% departure from the forecasts for Oregon.

	Utah	**Wyoming**	**Idaho**	**Oregon**	**Washington**	**California**	**Total**
2007 Peak	1.8	6.0%	21.0%	23.9%	8.0%	9.3%	9.3%
Jan 2008	-8.5%	1.8%	10.9%	24.4%	17.9%	23.3%	5.9%
Feb 2008	2.4%	7.7%	10.0%	10.3%	0.9%	23.4%	6.1%

(UIEC Cross Ex. 8)

In light of the actual load growth slow-down in Utah versus the forecasts for 2008, Witness Brubaker, in his surrebuttal testimony, explained that Utah sales as a percentage of total RMP sales are less than forecasted, and illustrated the impact of such forecasting errors on interjurisdictional factors. At pages 11 and 12 of his testimony, he stated:

> More specifically, the company has forecasted that in the first quarter 2008, Utah sales would be 41.3% of systems sales. In fact, the actual sales in the first quarter of 2008, after normalization by RMP, amount to 40.4% of the total RMP sales, considerably below the forecast suggested.

RMP witnesses, when asked to estimate the impact of such a 1% swing in allocation factors, were unwilling to give an estimate. (McDougal Cross Tr. 91-92; Eelkema Cross Tr. 157). Assuming a 1% shift in both the SG and SE allocation factors as a result of the less than forecasted growth in Utah and the greater than forecasted load growth in other jurisdictions, CCS Witness DeRonne estimated that a revenue transfer of about $22 million would occur from Utah ratepayers to the ratepayers of other states.[3] (DeRonne Cross, Tr. 620-621). The process of making the adjustment is complicated, but that adjustment could be made more precise by

[3] UAE Witness Higgins estimated an impact of near the same magnitude in the test year portion of this case. See Prefiled Direct Testimony of Kevin C. Higgins [Test Period] at 11-14, including exhibits cited therein.

Commission Staff using the updated load numbers available in the exhibits to develop allocation factors. (Falkenberg Cross, Tr. 532-33) (DeRonne Cross Tr. 620-621) It is entirely appropriate that the updated load numbers be used because the Company has insisted on using updated load curves to demonstrate its need for higher net power costs.

If the Commission chooses not to adjust the interjurisdictional allocation factors based on the evidence presented in this case, which is concededly for only a partial year, it should recognize the potential revenue misallocation to Utah ratepayers in excess of $20 million and should, therefore, be very conservative selecting among each of the other cost estimates in this case. An estimate of costs on the high end would compound the disproportionate burden on Utah ratepayers if the interjurisdictional allocation remains uncorrected.

III. OTHER REVENUE REQUIREMENT ISSUES

A. Medical Costs

The Division of Public Utilities ("DPU") advocates that the proposed medical costs of the company should be adjusted downward. It contends that the Company's estimation techniques are too aggressive. (Garrett Cross Tr. 321).

Furthermore, Utah, and maybe the whole RMP service territory, does not follow national trends and is not subject to cost pressures equal to that faced nationally. This is an additional independent basis for being conservative in estimating medical costs.

As the evidence in this record shows, medical costs on a per capita basis in Utah are the lowest of all the states in the Nation. (UIEC Cross Exs. 10 and 11). The actual rate of growth in medical costs in Utah is also considerably below that forecasted by the Company. (UIEC Cross Exh. 12.)

Therefore, independent of whether the Towers or Hewitt studies is the best basis for estimating national growth rates for future health care costs, the Commission should realize that

adopting the Company's estimates of future medical costs will result in the ratepayers of Utah subsidizing in their electric rates healthcare costs that are not experienced in Utah. There exists no good policy argument for assuming health care costs will rise to national levels in Utah or the rest of RMP's territory. Utahns should pay Utah costs in their rates, not the higher costs that flow through the allocation process. True, not all employees of RMP work in Utah, but one need not assume they all work in a place where health care costs are as high as the national averages.

B. Wind

A theme that sounded consistently during the hearing in this case with respect to wind resources was the need for accountability. (UIEC Exh. 2 (Brubaker)). This is because the economic feasibility of the Company's wind enterprise is dependent upon speculation, production tax credit savings, and revenues from the sale of renewable energy credits ("REC") at prices above those experienced heretofore by RMP. (UIEC Cross Exh. 5; UIEC Ex. 2 of Brubaker Conf. Test.). Utah does not have a renewable portfolio standard ("RPS") statute compelling the addition of wind. Rather than supporting the development of renewable resources by promoting particular technology and providing incentives in the form of an RPS set-aside (as Oregon may have done for wind), Utah's legislation addresses reducing carbon emissions from electric generation by whatever means. (Utah SB 202, 2008).

The UIEC do not advocate the disallowance of wind costs in this case. Rather, the UIEC ask the Commission to assure that the wind resources perform as RMP represents in its testimony. Without production tax credits and REC sales revenue, some wind is simply not economic. (UIEC Exh. 2 (Brubaker confidential)). Utah ratepayers should not be called to subsidize wind or pay a "renewables tax" because the Company must comply with some other state's statute. The Utah climate legislation does not so mandate. (*See* SB 202).

The Commission can best accomplish the objectives of Utah law by (1) requiring periodic reporting of the wind resources to assure that the availability, production tax credit offsets and green tag revenus used to determine the financial viability of a project are also used as the inputs for the production cost models used to determine the net power costs; (2) presuming wind resources will operate as the Company represented they would operate when it justified the decision to acquire the wind resources. The Company requires similar undertakings when, through a power purchase contract, it acquires electric energy from a developer with a wind farm. See, e.g., UIEC Cross Exh. 6 (Company's standard form contract leaves the developer at risk for the production tax costs and requires it to meet certain minimum standards of availability). The UIEC advocate accountability, not disallowance at this time. Because the Company is building the wind facilities to meet Oregon mandates, Utah should not pay any unnecessary costs that have been incurred just to meet Oregon mandates. The uneconomic costs from aggressively attempting to comply with another state's renewable resource statutes should never be passed on to Utah ratepayers. Accountability is required to appropriately allocate the unnecessary costs going forward.

C. Net Power Costs

An area of stark disagreement among the parties in this case is the estimated net power costs for the test year 2008. However, it would be purely coincidental if the Company's estimated net power costs are equal to the actual net power costs in the absence of sophisticated financial management by the Company's budgets at the allowed cost.

What we know from the testimony of Mr. Duvall is that the actual net power costs for the year 2007 were $975 million. (Duvall Cross Tr. 439) Some have complained that those costs have not been normalized to reflect the occurrence, in mid-year, of several significant events. Similarly, the Company argues that the actual net power costs for the 12-months ending March

2008 are actually $1.024 billion. (RMP Rebuttal Exh. GND-1R-RR). Again, some argue that those numbers do not reflect an apples-to-apples comparison because events occurring mid-year were not appropriately considered. (Duvall Cross Tr. 432-434.) The Company estimates net power costs to be in excess of $1.04 billion for 2008. (RMP Exh. GND-1R-RR).

The Company uses a homegrown model called GRID to estimate net power costs (RMP Exh. GND-1S). (Duval Cross, Tr. 445). The Company concedes in its rebuttal and surrebuttal testimony, and on cross examination, that there are several uncorrected modeling errors in GRID that must be "worked around." (Duvall Cross Tr. 440-41). The Company has purported to have designed several workarounds in trying to solve the problems discovered in the model's logic. (Duval Cross Tr. 441). However, assuming the workaround is reliable, it addresses the problem for the present case only. It will do nothing to prevent the use of the model in another case, which would require the expenditure of considerable time and effort to discover again similar deficits of the model. Indeed, GRID has had problems for years, but the Company persists in using it. (Duvall Cross Tr. 445)

Interestingly, the Company does not use the GRID model for its planning. (Duval Cross Tr. 446) It does not use it for dispatch. It is only used for estimating power costs for rate cases. Id. There are a number of commercial models, including the Promod model or the Henwood model, that could be used and, in fact, are used by the Company for its own purposes. They likely do not suffer from the "diseases" of the GRID model. (Duval Cross Tr. 446-47). Because the GRID model requires so many manual workarounds to correct the logical errors — as discovered by the parties in case after case — the UIEC suggest that the Commission be conservative and decline to accept the Company's estimate of net power costs based on the evidence in this record.

The differences between the Company's position and that of the Committee of Consumer Services ("CCS") involves a number of issues illustrated by the witness Falkenberg in the Testimony Summary Illustrative Exhibit of Randall J. Falkenberg. Given the observed errors in GRID, and the consequences of its overestimation of power costs in this case, the UIEC again encourages the Commission to be conservative in selecting an estimate for future net power costs.

As demonstrated in the testimony of Mr. Falkenberg, the Company has a habit of admitting an error in the GRID model, accepting an adjustment, but then suggesting another adjustment in the opposite direction for an entirely unrelated matter. (See RMP Exh. GND-1R-RR). For example, after correcting certain logical errors, the Company, for the first time, introduced costs relating to electric swap transactions of $1.3 million and index gas transactions of $1.7 million, and then also introduced completely new information, including ae March 2008 "official price curve" of $2.4 million. (Duvall Cross Tr. 446)

UIEC Cross Examination Exhibit 13 shows that on January 18, 2008, the Company's natural gas requirements were price hedged at 100% for the year 2008. (Duvall Cross Tr. 448). UIEC Cross Examination Exhibit 14 shows that the Company was also hedged in its electric position. The Company admitted an error, produced new power cost curves and then stated "the overall hedge price is the company's embedded costs which is below the March 2008 curve." (Duvall Cross Tr. 454) (UIEC Cross Exh. 14.) When asked to explain, the Company witness simply replied that he "does not know" what the costs are. (Duval Cross Tr. 450-52). If, indeed, natural gas prices were hedged, and if indeed the hedged price is below the March 2008 curve, why should the March curve be allowed as a basis for adjusting prices upward? Such testimony

does not meet the Company's burden of proof that its estimates of net power costs are reliable and reasonable.

DPU witnesses Dalton stated that GRID was populated with the hedged costs. (Dalton Cross Tr. 471). Yet, the Company now relies on the forward curves (Duval Rebuttal Test. at 10; Rebuttal Ex. GND-1R-RR). The hedged power is fixed, the forward curves move with the market prices. This is obviously inconsistent. So, it is impossible to understand the basis for the Company's power costs. It certainly cannot sustain their burden of proof with "I don't know."

Customers should face no expense greater than the expense actually to be incurred by the Company. Utah is, and has been for some years, an original cost state, not a market-based state. The regulatory scheme in Utah is that the Company is allowed to recover its reasonable and prudently incurred final purchased power costs, not costs based upon some guess about future market activity. If prices were fixed by hedge, then no market price should be allowed.

The most perplexing situation is presented in UIEC Cross Examination Exhibit 15, which indicates that the Company is engaged in significant hedging transactions through the use of derivatives, which add to or subtract from the Company's net power costs. In that same exhibit, it is shown that: "For those energy contracts that are probable of recovery in rates, the unrealized gains and losses in derivative instruments are recorded as net regulatory assets or liabilities." (UIEC Cross. Exh. 15 at 83).

The cost or benefit to the ratepayers of the Company's hedging and swapping activity on net power costs is not shown anywhere in this record. In light of this additional uncertainty, the UIEC submit that the most conservative estimate of net power costs is compelled. If future test years are to be allowed, more transparency and accountability must be required. Regulators and others must be capable of comparing costs actually incurred with those forecasted. The failure of

the Company to show net power costs with transparency and accountability is a failure to meet its burden of proof.

D. Rate Base (Cash Working Capital)

Considerable discussion occurred on the record concerning the appropriate level of cash working capital. One of the more significant debates was whether long-term debt interest payments should be included in cash working capital. (DeRonne Cross Tr. 585-593). The Commission should consider whether the Company can be entitled to any allowance for cash working capital in light of the age of its lead-lag study, which fails to take into consideration the advances in technology for billing and metering. The old study is likely not sufficiently reliable to find that the Company has met its burden of proof.

Logic compels the conclusion that changes in technology relating to billing and collecting affect cash flow timing, as does the payment of interest and dividends. These require careful evaluation of the amount of cash that should be allowed for working capital. The Company should not be permitted to ignore changes that reduce cost of working capital by using old-source lead-lag studies. The UIEC suggest the Commission find the Company has not met its burden and therefore, only the most conservative assumptions about the amount of cash working capital should be allowed, unless and until the Company presents an updated lead-lag study to justify its requested cash working capital.

E. Escalation Rates/Productivity Deductions

Considerable discussion occurred on the record concerning the escalation rates. Ms. DeRonne suggested that some of the escalation rates used by the Company needed to be stepped down based on her confidential exhibit. (DeRonne Cross Tr. 581-582) Mr. Garrett suggested that a productivity gain deduction ought to be made. (Garrett Cross Tr. 334-335) The UIEC agree that both of these adjustments are correct.

The escalation rates used by the Company are from Global Insight. (DeRonne Cross Tr. 581-582). Ms. DeRonne testified that she believes the escalation rates are too high because in many cases the Company's budget is lower than the cost as escalated by the Global Insight factors. (DeRonne Cross Tr. 581-582). Again, the problem is national averaged costs versus local costs. When the Company's own budget does not support the number resulting from a national forecast, the national forecast cannot be reliable in a state rate case. The Company's budget numbers impair the credibility of the national forecast. Numbers escalated by the Global Insight factors cannot be relied upon.

Moreover, when using a future test year and escalating historic costs by a percentage, there must be some deduction for productivity gains. Regulation of public utilities in general is intended to reduce the pricing power of monopolies that arises from their ability to restrain output and raise prices, as well as to realize super-normal profits. Rate-of-return regulation allows a public utility to earn a rate of return on the investments and to recover its costs. It offers few incentives to public utilities to constrain or reduce costs, but instead provides some measure of accountability. Accountability is never perfect because the utility controls all the information.

Performance-based rate making is an alternative to cost-based, rate-of-return regulation. It provides incentives for a utility to constrain and reduce costs between rate periods, but sacrifices accountability. The public utility keeps all of the gains between cases. Performance-based rate making usually contains a productivity deduction from anticipated earnings to incent efficiency and to allow regulators to pass along some of the potential productivity gains to customers. However, performance based ratemaking does not always withstand judicial scrutiny.

Cost-of-service based rates, using future test periods, share some of the positive and negative attributes of both these forms of regulation. Although the public utility's ROE is set, the utility is incented to constrain or reduce costs because it retains the benefit when it can beat its forecasted costs under a future test year. Thus, in cost-of-service regulation using a future test year, just as in performance based ratemaking to assure that the ratepayers share in the productivity gains, there should be an express productivity deduction. Establishing a reasonable deduction for expected productivity gains is not easy. But, it must be done to allow ratepayers to share in productivity gains, and to reduce the possibility that the utility will enjoy super-normal profit where accountability is compromised by allowing escalated prior period costs as a basis for regulation.

The regulatory schemes of other countries where rates are set for some period of time include explicit adjustments downward for productivity to encourage the efficiency of the company. A deduction for productivity gains is therefore both necessary and appropriate in the present case.

F. Rate Spread

The Company has testified eloquently that the most efficient and effective way to spread any allowed revenue increase is through a uniform percentage increase across all classes. We support that position and accept the Company's logic on that point. Any other system introduces complexity without a factual predicate to demonstrate that the spread basis is reliable. While the Company submitted a cost of service study that may be interpreted to show that a disproportionate increase is required for some classes, that study has not been subject to evaluation by the parties, nor viewed in the light of cross examination. Unless and until that critique occurs, the only presumptively correct rate is the existing rate. A uniform percentage

increase also minimizes the possibility of an untoward result pending the resolution of the spread portion of this case.

CONCLUSION

This is the first fully forecasted test year heard by this Commission. Most all of the numbers presented to the Commission are based on forecasts. We question whether the Company has met its burden of proof, unaided by presumptions, based on forecasted numbers. Because of the inherent inaccuracy of forecasted numbers, caution is advised. Numbers in the lowest part of the range of forecasts ought to be selected to minimize the consequences to rate payers of the inevitable forecasting errors and minimize the opportunity for the Company to overearn by using aggregate forecasts. Accountability should also be maintained by regarding the reports and comparisons the UIEC have suggested herein.

DATED this ____ day of June, 2008.

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CERTIFICATE OF SERVICE

I hereby certify that on this ___ day of June 2008, I caused to be e-mailed a true and correct copy of the foregoing **POST-HEARING BRIEF ON REVENUE REQUIREMENT** to:

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