- 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 | ) | DOCKET NO. 09-035-23<br><br>REPORT AND ORDER ON RATE DESIGN |

---

ISSUED: June 2, 2010

SHORT TITLE

**Rocky Mountain Power 2009 General Rate Case**
**Phase II Order on Rate Design**

SYNOPSIS

The Commission approves a Stipulation on Non-Residential Rate Design. It also decides rate design issues for residential Schedule Nos. 1, 2 and 3, and mobile homes, Schedule No. 25. The Stipulation and rate design decisions of Phase II are consistent with the spread of the $32.4 million, or 2.2 percent, overall revenue increase to rate schedules approved in Phase I of this proceeding.

For Schedule Nos. 1 and 3, the customer charge is increased to $3.75 per month and the remaining revenue increase is obtained by increasing the second and third blocks of summer energy rates by 3.7 percent. For Schedule No. 2, no change is made to the on-peak and off-peak summer energy rates. For Schedule No. 25, the revenue increase is obtained by increasing the energy rate by 2.7 percent.

---

# TABLE OF CONTENTS

**APPEARANCES:**

| | | |
|---|---|---|
| Yvonne Rodriguez Hogle, Esq.<br>Rocky Mountain Power | For | PacifiCorp |
| Patricia Schmid, Esq.<br>Assistant Attorney General | " | Division of Public Utilities |
| Paul H. Proctor, Esq.<br>Assistant Attorney General | " | Office of Consumer Services |
| Gary A. Dodge, Esq.<br>Attorney at Law<br>Hatch, James & Dodge | " | UAE Intervention Group |
| F. Robert Reeder, Esq.<br>Attorney at Law<br>Parsons Behle & Latimer | " | Utah Industrial Energy Consumers |
| Holly Rachel Smith, Esq. (via telephone)<br>Attorney at Law<br>Holly Rachel Smith, PLLC | " | Wal-Mart Stores, Inc., and Sam's West, Inc. |
| Sophie Hayes, Esq.<br>Attorney at Law<br>Law Office of Sophie Hayes | " | Southwest Energy Efficiency Program and<br>Utah Clean Energy |
| Steven S. Michael, Esq. | " | Western Resource Advocates |
| Elizabeth Wolf | " | Salt Lake Community Action Program |

## I. PROCEDURAL HISTORY

On June 23, 2009, PacifiCorp, doing business in Utah as Rocky Mountain Power ("Company"), filed an Application for General Rate Increase which included its direct testimony rate design proposal. On July 7, 2009, the Commission issued a Notice of Scheduling Conference to be held on July 14, 2009. On July 8, 2009, the Utah Industrial Energy Consumers ("UIEC") filed a motion requesting the Commission bifurcate this proceeding into two phases, a revenue requirement phase and a cost-of-service, rate spread and rate design phase ("Motion to Bifurcate"). On July 22 and 23, 2009, the Division of Public Utilities ("Division") and the Company, respectively, filed responses to UIEC's Motion to Bifurcate. On July 23, 2009, the Office of Consumer Services ("Office") filed a response in opposition to UIEC's Motion to Bifurcate. On July 27, 2009, the Utah Association of Energy Users ("UAE") filed a joinder in UIEC's Motion to Bifurcate. On July 27, 2010, UIEC responded to the comments provided by the Division, the Office, and the Company and to UAE's joinder.

On August 4, 2009, the Commission issued an Order on Motion to Bifurcate in which it decided to address rate of return, revenue requirement and cost of service in Phase I and to address rate design in Phase II. Also on that same day, the Commission issued a scheduling order, including the Phase II schedule outlined previously at a July 14, 2009, scheduling conference.

On August 11, 2009, the Office filed a request to establish a schedule for rate design testimony and hearings. On August 19, 2009, UAE filed a joinder in the Office's motion to amend the schedule. On August 20, 2009, the Company also filed a request to establish a schedule for rate design testimony and hearings. On August 27, 2009, the Division filed a request to vacate the existing schedule and to establish a schedule for rate design testimony and hearing (Phase II) or, alternatively, a request for a scheduling conference, and the Commission issued an Amended Notice of Hearing. On September 3, 2009, the Commission issued a Notice of Scheduling Conference to be held on September 9, 2009.

A scheduling conference was held September 9, 2009, wherein parties discussed modification to the schedule for Phase II of this docket. On September 21, 2009, the Commission issued an Amended Scheduling Order Changing Phase II Testimony Filing And Hearing Dates, setting hearing dates for March 23 through 25, 2010.

On November 12, 2009, the Company filed rebuttal testimony in Phase I of this case reflecting its updated revenue requirement proposal and including a revision of its rate spread/rate design proposal.

On January 11, 2010, the “Division” filed a motion requesting the Commission modify its Phase II scheduling order and scheduled hearing dates, which was unopposed. On January 14, 2010, the Commission issued an Amended Scheduling Order And Notice Of Hearing, setting the dates for filing direct testimony by intervenors and for filing rebuttal and surrebuttal testimony by all parties, and setting the hearing dates for April 12 through 13, 2010.

Phase I of this proceeding was completed with the issuance of the Commission’s February 18, 2010, Report and Order on Revenue Requirement, Cost of Service and Spread of Rates. Phase II of this proceeding, as represented by the following procedural history, sets rates consistent with the Phase I decision on the spread of the $32.4 million overall revenue increase to rate schedules.

On February 22, 2010, the following parties filed written direct testimony on rate design issues: The Division; the Office; UAE; Wal-Mart Stores, Inc., and Sam's West, Inc., (collectively, "Wal-Mart"); the Kroger Company ("Kroger"); the Southwest Energy Efficiency Project and Utah Clean Energy ("SWEEP/UCE"); Western Resource Advocates ("WRA"); and, the Salt Lake Community Action Program ("SLCAP").

On March 11, 2010, the Company filed testimony updating its rate design proposals to reflect the Commission's Phase I order on revenue spread. On March 23, 2010, parties filed rebuttal testimony on rate design.

On March 25, 2010, certain parties met for settlement discussions on all non-residential rate design issues. As a result of negotiations, the following parties agreed to the Stipulation on Non-Residential Rate Design ("Stipulation") dated April 1, 2010: the Company, the Division, the Office, UAE, UIEC, Kroger, and Wal-Mart. These parties did not, however, agree on the residential rate design or decoupling issues in this case. On April 6, 2010, the Company filed a motion requesting Commission approval of the Stipulation. Both the Stipulation and an attachment showing the stipulated rates were filed with the motion. These rates match the revenue spread decisions made by the Commission in Phase I for the non-residential rate schedules.

On April 7, 2010, the Company, the Division, the Office, UAE, SWEEP/UCE, and WRA filed surrebuttal testimony on residential rate design. On April 12, 2010, AARP Utah filed public comments and SWEEP/UCE filed corrected pre-filed direct testimony. On April 12 and 13, 2010, a duly noticed hearing was held to address the Stipulation and all other rate design issues. In addition, a public witness hearing on April 12, 2010, afforded non-parties the opportunity to comment on the matters addressed in this phase. Dr. Dianne R. Nielson, Ph.D., Energy Advisor to the Governor, provided sworn testimony supporting the Division's revenue decoupling proposal.

On April 14, 2010, SWEEP/UCE filed supplementary information. On April 19, 2010, SWEEP/UCE, as requested by the Commission during the April 13, 2010, hearing, filed a brief addressing the ratemaking authority of the Commission to adopt a decoupling mechanism or inverted block energy rates.

## II. STIPULATION ON NON-RESIDENTIAL RATE DESIGN

### A. Overview

Without modifying its terms in any way, the following is a brief summary of the Stipulation on Non-Residential Rate Design ("Stipulation"). The Stipulation and its Exhibit 1 are included as Appendix 1 and 2, respectively, to this order.[1] The Stipulation is entered into by the Company, the Division, the Office, UIEC, UAE, Kroger, and Wal-Mart ("Stipulation Parties"). The Stipulation Parties agree that the implementation of the rate increase granted to the Company shall be collected from all non-residential schedules as set forth in the stipulated rates attached to the Stipulation in Exhibit 1, Column B and Exhibit 2, Column G. These rates

[1] Due to its size and format, Exhibit 2 is not attached herein. Exhibit 2 of the Stipulation provides additional detail for each affected schedule including billing units, current and stipulated rates and test period revenues calculated using current and stipulated rates.

collect revenues equal to the rates approved for the non-residential schedules in Schedule No. 98, Tariff Rider Rate, effective February 18, 2010, implemented in Phase I.

For Schedule No. 6, general service, the terms of the Stipulation apply a uniform percentage increase to demand and energy charges and increase the customer service charge from $27 to $45 per month. For Schedule No. 8, large general service, and Schedule No. 9, high voltage general service, the monthly customer charge is increased from $27 to $55, and from $183 to $200, respectively. The remaining charges are increased by about the same percentage to achieve each class's revenue increase. For Schedule No.10, irrigation service, and Schedule No. 23, small general service, the stipulated rate design applies the rate changes uniformly to demand and energy charges and increases the monthly customer charges from $94 to $98 and from $6 to $8, respectively.

In addition, the Stipulating Parties agree to address the issue of moving customers from Schedule No. 25, mobile home and house trailer park service, to appropriate general service rate schedules in the next general rate case. The Company agrees to show the impacts of moving affected customers from Schedule No. 25 to any proposed general service schedules in its filing.

**B. Discussion, Findings and Conclusion**

Seven parties representing a diversity of interests signed the Stipulation. These parties state they participated in settlement conferences on rate design. These parties agree the Stipulation is in the public interest. The Company, Division, and Office provide testimony recommending the Commission approve the Stipulation. The Company, Division and Office testify the Stipulation is in the public interest and results in just and reasonable rates for the Company's non-residential customers. No party of record provides testimony opposing approval of the Stipulation.

Our consideration of the Stipulation is directed by Utah statutory provisions in U.C.A §54-7-1 that encourage informal resolution of matters brought before the Commission. After examining the Stipulation and the evidence contained in the record, the Commission concludes that its terms are just and reasonable and in the public interest, and it is just and reasonable in result. Based upon the foregoing, the Commission approves the Stipulation.

The Commission's approval of the Stipulation, as in similar cases, is neither intended to alter any existing Commission policy nor to establish any precedent by the Commission. We now turn to the only schedules for which rate design is disputed, residential and mobile home service. The following section addresses the Division's proposal to alter the relationship between revenue and usage for residential service, termed decoupling. Specific rates are then addressed in a subsequent section.

## III. RESIDENTIAL DECOUPLING

### A. The Division's Decoupling Proposal

In its direct testimony, the Company asserts the existing residential rate structure is inappropriate because it gives the Company an incentive to increase electricity sales in order to recover its fixed costs. Further, the Company argues this rate structure gives customers improper price signals regarding the cost of service and creates subsidies among customers within the class. The Company also notes the structure makes fixed cost recovery, to some degree at least, subject to weather and other factors that drive residential usage levels. The Company expresses concern about the resulting revenue volatility and the potential for the fixed costs of serving residential customers to be either under- or over-recovered in summer months.

In its direct testimony, the Division proposes a pilot “decoupling” mechanism seeking flexibility to design residential rates that promote energy efficiency while mitigating the Company’s foregoing concerns. Like the Company, the Division testifies rate structures designed to collect fixed costs through usage or energy rates potentially conflict with those designed to promote energy efficiency. The Division points to the current inverted block structure of residential energy rates. While encouraging customers to conserve and use electricity more efficiently, this structure increases risks to the Company of recovering its fixed costs due to changes related to weather. The Division notes this to be especially true for the existing third block, i.e., the tail block, of summer usage, where the Division asserts usage variations are largely weather driven.

The Division concurs with the Company that the risk of cost recovery, driven, in part at least, by factors beyond the Company’s control, creates incentives for the Company to promote sales, rather than encourage efficiency. Seeking to mitigate these incentives, the Division proposes a new tariff, as a three year pilot, in which the revenue the Company collects from residential customers to recover its fixed distribution costs is separated or “decoupled” from the amount of kilowatt hours (“kWh”) used by these customers. The separation allows the revenue actually collected to be tracked and periodically compared to the authorized revenue level and any under- or over-recovery amortized. The Division believes its proposed tariff ameliorates the risks the Company will fail to recover its fixed residential distribution costs or, in a period of unexpectedly high usage, customers will pay more than the allowed revenue level.

The Division testifies its primary reason for advocating the decoupling tariff is to mitigate the Company's concerns over fixed cost recovery so that energy rates may be increased in order to promote customer conservation. In pursuit of this objective, the Division proposes the customer charge remain unchanged and the summer first and second, and winter block energy rates be increased only 1 percent, while increasing the summer third block energy rate by 11 percent. The Division testifies economic theory holds higher rates promote conservation. The Division aims to send a meaningful price signal to residential customers whose energy usage levels extend into the third block.

Furthermore, the Division expresses confidence in the proposed mechanism because it is similar to the one in place for Questar Gas Company ("Questar") which, in the Division's view, has worked well. Finally, the Division offers a Rand Corporation study concluding the demand for electricity is relatively inelastic; therefore, in order to prompt a significant demand response, a substantial change in rates would be necessary. For the Division, the sharp increase to the third block energy rate is a necessary condition to its decoupling proposal. The Division estimates its proposed increase in the tail block energy rate would evoke a demand reduction of between 2.3 percent and 2.9 percent. Accounting for income effects, the Division testifies a 1.5 percent reduction could be expected in the short run and about a 3 percent decrease in the long run.

**B. Support for Decoupling**

The Company, SWEEP/UCE and WRA testify in general support of the Division's decoupling proposal. These parties offer separate rate design proposals for the residential class in their pre-filed direct testimony which do not include a decoupling component. Their pre-filed direct testimony was filed simultaneously with the Division's. Consequently, their expressions of support are offered in rebuttal and are made in the context of the rate changes each initially proposed. We will address their support for decoupling in this section and rule upon the substance of their respective rate design proposals in the following section. We note SWEEP/UCE and WRA accept decoupling and share the Division's intent to place the majority of the residential class revenue increase on the highest usage summer block. The Company's support for the decoupling mechanism, however, is conditioned on our rejecting the Division's proposed changes to the tail block energy rate.

In its rebuttal testimony, SWEEP/UCE strongly supports the Division's proposal and commends the Division "for its ingenuity in developing a cogent proposal that addresses the Company's concern about recovering its fixed distribution costs while promoting the important rate design goal of encouraging the efficient use of electricity." SWEEP/UCE testifies the mechanism would align the Company's financial interest with that of consumers regarding the implementation of energy conservation and DSM measures. SWEEP/UCE also contends adoption of the decoupling proposal is supported by federal energy policy, citing Section 410 of the American Recovery and Reinvestment Act ("ARRA"): "The applicable State regulatory authority will seek to implement, in appropriate proceedings for each electric and gas utility, ... a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provide timely cost recovery...."

SWEEP/UCE also offers its opinion concerning the consequences of removing the linkage between cost recovery and residential energy sales by having the Company recover more of its fixed costs in higher fixed charges. In the opinion of SWEEP/UCE, doing so would significantly diminish customers' incentive to save energy, just when they should be encouraged to do more. SWEEP/UCE testifies in rebuttal testimony: "If you raise the portion of the bill that is independent of energy consumption, you necessarily reduce the incentive to use less energy, while shifting costs from the heaviest users to the most sparing."

WRA commends the Division for its decoupling proposal and urges it should go even farther. In WRA's view, a more desirable mechanism would address all residential fixed costs, i.e., fixed generation and transmission costs, as well as fixed distribution costs. WRA is concerned the mechanism the Division proposes does not adequately reduce the disincentives it perceives result from the revenue reductions produced by the success of the Company's DSM programs. Nevertheless, WRA supports the Division's proposal as sufficient in the present case to facilitate the Company's acceptance of a rate design intended to encourage reduced usage.

In its rebuttal testimony, the Company expresses support for the Division's decoupling proposal as "an acceptable interim alternative to including the fixed costs in the customer charge component of rates." The Company sees value in the decoupling pilot as a vehicle to assess the effect of the mechanism on the Company's ability to recover certain fixed costs and to evaluate customer response to the mechanism. The Company asserts the Division's decoupling proposal, with clarifications and minor revisions, can be an effective method to address the volatility and uncertainty of fixed cost recovery it perceives to exist under the current residential rate structure.

The Company, however, opposes the conservation rationale underlying the Division's proposal. In surrebuttal, the Company characterizes the increases to the summer tail block energy rate upon which the Division's proposal centers as excessive, "disproportionate" and "not acceptable." In the Company's view, cost-based rates will provide proper pricing signals. It contends rates should not be set above cost in order to encourage conservation. Additionally, because the proposed mechanism only addresses distribution revenue recovery and the pass-through amounts are capped, the Company believes the mechanism does not afford the Company sufficient certainty of recovery to justify the tail block energy rate increase the Division proposes.

Moreover, the Company considers the Division's proposed tail block energy rate increase to be unsupported. The Company contends there is no evidence in the Division's presentation on whether customers understand the tail block energy rate and will respond to the price signal the Division proposes. Accordingly, the Company concludes implementing the decoupling pilot and simultaneously ordering a "disproportionate" tail block energy rate increase would hinder the Commission's ability to assess the effectiveness of the pilot mechanism and likely would result in a failed program.

**C. Opposition to Decoupling**

The Office opposes the Division's decoupling mechanism, asserting it is not in the public interest and would not lead to just and reasonable rates. The Office also notes the mechanism unduly discriminates against the residential class, and the Division has not demonstrated any need to decouple revenue recovery from sales levels. The Office believes the Division has proposed a complicated remedy for a perceived problem, one neither clearly understood nor empirically defined or supported. The Office also testifies the proposal of the decoupling mechanism in this phase is untimely and unfairly limits the parties' opportunity to examine the need for the mechanism and to explore alternatives.

The Office asserts a key design issue for many decoupling programs is an adjustment to the utility's return on equity, reflecting a reduction in its risk of fully recovering authorized revenues. The Office rejects the Division's reasons for not presenting evidence examining the specific risk impacts of its proposal on the Company's operations. The Division asserts such an examination is unnecessary because the change in the Company's risk profile generated by the decoupling mechanism could be positive or negative, and any change would be difficult to isolate and quantify. The Office discounts this reasoning as referring to hypothetical examples and testifies the Division's showing does not adequately address why and how its generalized observations about risk apply specifically to the Company's operations under the proposed mechanism. The Office finds it most troubling the Division has not performed an empirical analysis of the degree of revenue recovery risk its proposal shifts from the Company to residential customers and the corresponding costs and benefits to these customers. Without such a showing, according to the Office, there can be no assurance rates under the mechanism would be just and reasonable.

The Office also challenges the fairness of a decoupling mechanism focusing only on the residential class. The Office maintains this class has a history of providing revenue recovery at or above its cost of service. The Office believes decoupling residential class revenue recovery is inequitable, in the absence of evidence showing the rates of all customer classes are set to recover the full cost of serving each class. The Office considers the Division's proposal discriminatory because it does not address non-residential customer classes whose rates do not reflect the full cost of service. Additionally, the Office testifies the Division has presented no compelling evidence demonstrating revenue shortfalls will result from its proposed increase to the residential tail block. Consequently, the Office sees no justification to focus decoupling exclusively on the residential class.

The Office also raises the potential for the proposed decoupling mechanism to generate inequality within the residential class, because the mechanism would recover any revenue under-collection through the energy rates of all residential customers. The Office asserts this approach may be unfair to low-use customers who have already embraced conservation or whose usage is economically constrained. In the Office's view, the mechanism would assign to such low-use customers a portion of the revenue burden that is created solely by the reduced demand of high use customers in response to the tail block energy rate increase. In the opinion of the Office, such a result would unduly discriminate against these low-use customers.

The Office notes the importance of rate structures being simple and understandable to utility customers. The Office comments these principles are included among the objectives the Division articulates for its rate design. Nevertheless, in the opinion of the Office, decoupling would neither be simple nor understandable to the average ratepayer, and the Division has not made any showing to the contrary.

The Office discounts the claims of some decoupling advocates who justify the decoupling pilot as a way to eliminate disincentives for the Company to expand its DSM efforts. The Office testifies the DSM tariff rider has increased from approximately 2.1 percent to 4.7 percent. The Office concludes nothing in the Company's DSM program suggests further incentives are needed in this area. The Office believes, in fact, significant further DSM program expansion would be met with resistance by certain large customer groups. The Office also opines resource deficits, fuel price risk and potential carbon legislation facing PacifiCorp provide the Company ample additional motivation to ensure DSM continues to play a vital role in its resource planning.

The Division and other decoupling advocates place confidence in the proposed mechanism, in part, because it parallels the Questar decoupling tariff with which there is some operational experience. The Office does not share this confidence. The Office suggests the Division and others, ignore key differences between the two utilities that may affect the need for residential electric revenue decoupling. In supporting this position, the Office refers to differences in the relative levels of historical DSM activity, the degree of recovery of forecast revenues, and the percentage of customers subject to decoupling. The Office also references the possibility of significant differences in the comparison of marginal costs and marginal revenues of the two utilities that have not been explored. The Office believes the Division's decoupling proposal and associated rate design cannot be properly evaluated in the absence of such cost information.

The Office is also concerned because the deadline for filing interventions had long passed when the Division, the first party to raise decoupling in this proceeding, filed its initial showing. Consequently, others sharing the Office's desire to examine the potential reduction in business risk resulting from decoupling, or to propose alternatives, may have been precluded from participation. As noted above, the Office is particularly concerned about the absence of any opportunity at this stage of the case to examine the Company's cost of capital in light of any reduced business risk.

SLCAP also opposes decoupling and expresses several of the same objections raised by the Office. For example, SLCAP sees no benefits flowing from decoupling to low income customers, particularly because the timing of the Division's proposal precludes consideration of an appropriate adjustment to the Company's rate of return. Additionally, SLCAP notes the Commission authorized decoupling for Questar in the context of a history of declining natural gas usage per customer. In contrast, SLCAP testifies the Company has experienced steady growth in electricity usage per customer, prompted by increased use of central air conditioning for residential cooling and other electric appliances like large screen televisions. SLCAP also opposes decoupling because, in the instance of fixed cost under-recovery, the account balance will be recovered through the energy rates of all residential customers. In the view of SLCAP, this approach would conflict with the principle it advocates of maintaining an affordable first block of energy.

Despite the fact UAE members do not take service under residential schedules, UAE is concerned about the precedential effect of our decision. UAE opposes decoupling mechanisms, in general, as unwarranted applications of single-issue ratemaking. UAE also opposes the decoupling pilot presenting many of the foregoing arguments. For example, UAE also argues: 1) insufficient evidence is provided to establish any need for the mechanism; and 2) inadequate time was available for evaluating the Division's proposal or providing any alternatives, or for considering the affects of the mechanism on the Company's return on equity in this case.

Additionally, UAE strongly opposes application of the decoupling pilot to commercial or industrial customers. UAE characterizes the Division's decoupling mechanism as based on deviations in average usage per customer and contends such mechanisms are not useful in customer classes where demand is not relatively homogenous. UAE testifies wide differences in energy usage levels among commercial and industrial customers result largely from different business requirements, and are much less likely to be affected by individual consumption preferences than those of residential customers. Moreover, in UAE's view the presence of cost-based customer and demand charges in the commercial and industrial rate design further obviates the need for any form of decoupling for customers on these schedules. Accordingly, whether or not revenue decoupling is adopted for residential customers, UAE strongly opposes it for the commercial and industrial rate classes.

**D. Discussion, Findings, and Conclusions**

We place importance on continuing to implement rate structures encouraging the efficient use of energy and the conservation of scarce energy resources. We pursue this critical priority, not only in fulfillment of our regulatory responsibilities, but in accordance with executive and legislative directives. We likewise recognize, as do those who have provided us guidance, the rate levels and structures we authorize must be just and reasonable, and in the public interest.

We have examined the Division's proposed pilot decoupling mechanism with interest. It is offered to facilitate significant increases in the residential summer tail block energy rate thus theoretically providing a strong price signal to some customers to conserve energy. The Division testifies these increases will meaningfully reduce residential peak demand for electricity. While we find the goal laudable, we find the record inadequate to support implementation of the pilot at this time.

We agree with the Office and find the Division's proposal untimely. The Division first raised its decoupling proposal in its pre-filed direct testimony, distributed on February 22, 2010. No other party proposed or discussed a decoupling mechanism in its initial testimony. Consequently, the record before us consists entirely of the parties' views on the Division's proposal.

Several parties, including the Office, testify the timing of the Division's proposal, coming after the conclusion of the revenue requirement and cost of service phase, deprived them of the opportunity to fully examine the proposal and potentially to offer competing alternatives.

In particular, these parties testify implementation of the decoupling tariff has cost of capital implications which should have been raised for consideration in adopting the authorized revenue requirement. This position is consistent with our Order in Docket No. 05-057-T01, issued November 5, 2007, in which we found the changes in risk introduced by the Conservation Enabling Tariff ("CET"), Questar's decoupling tariff pilot, could only be considered adequately in the context of full rate case scrutiny. There, we ordered Questar to file a rate case to facilitate this scrutiny. Accordingly, the Division should have raised its decoupling proposal in time for the risk implications to be fully vetted in the revenue requirements phase of this proceeding.

The primary purpose the Division gives for proposing decoupling in this case is to mitigate the Company's concerns over fixed cost recovery concomitant with their recommendation that the tail block energy rate may be increased by 11 percent in order to promote conservation. In the opinion of the Division and the other proponents, the decoupling mechanism is necessary to mitigate the Company's cost recovery risk and reduce its incentive to promote sales. Unfortunately, this is an area where the record is under-developed. We find the Division has not adequately established a need to safeguard the Company against under-recovery of fixed residential distribution costs. In fact, the evidence in this case shows in recent years the Company has fully recovered the revenue requirement allocated to this class. Further, the Company does not appear to be promoting sales.

The Office and SLCAP also point to the absence of evidence concerning the likely impact on revenue recovery of the proposed tail block energy rate increase. While the Division offers some general observations about the elasticity of residential demand in its surrebuttal testimony, this information was not specific to the Company's customers or the proposed rates. Moreover, it was presented too late in the proceeding to be fully examined by the parties. Finally, we concur with the Company the tailblock energy rate proposed by the Division is not supported by marginal cost analysis and may not be cost-based. Additional evidence is needed on this issue.

For the foregoing reasons, we conclude the implementation of an electric revenue decoupling mechanism is not adequately analyzed in the record before us. We must have a well-defined problem supported by evidence and comprehensive evaluation of alternatives in order for us to appropriately balance important regulatory objectives including conservation, energy efficiency, cost-based rates, revenue adequacy, price stability, intra-class equity, inter-class equity, administrative simplicity and customer understanding and acceptance.

## IV. RESIDENTIAL RATE DESIGN

### A. Positions of the Parties

From our decisions in Phase I of this case, the revenue increase required of Schedule No. 1, residential service, and Schedule No. 3, the low-income lifeline residential option, is $12.55 million. The revenue increase required of Schedule No. 2, the residential time-of-day option, is about $5,100, and the increase required of Schedule No. 25, mobile home and house trailer park service, is about $185,700.

Six alternative rate design proposals are offered in this case. No party proposes any changes to the summer on-peak and off-peak energy rates in Schedule No. 2, the time-of-day option for residential customers. All other rates of Schedule No. 2 are related to corresponding rates in Schedule No. 1, and the revenue increase required of Schedule No. 2 is mostly met by the increases related to corresponding Schedule No. 1 rates. Only the Company and the Office propose changes to the rates of Schedule No. 25. We turn next to the positions of the parties regarding rates for residential Schedule Nos. 1 and 3.

Throughout this case the Company consistently proposes all of the revenue increase required of residential customers be collected through an increase in the customer charge, leaving energy rates unchanged. As noted earlier, the Company argues its proposal will promote intra-class equity. The Company proposes to increase the customer charge by $1.45 from $3.00 to $4.45 per month per customer. In the context of competing rate design objectives, the Company believes the overarching principle has been and should continue to be basing rates on costs. In its view, the fixed costs of the distribution facilities used to serve residential customers should be recovered through fixed monthly customer charges and not energy rates. According to the Company, these fixed costs are in excess of $23.00 per customer per month. The Company includes the following components in its $23.00 assessment of fixed costs: meters, service drops, poles and conductors, transformers, and retail service. The Company concedes these cost components go beyond the long-held Commission policy regarding the cost components to be included in a customer charge. For the Commission-approved cost components, the Division testifies a $3.83 customer charge is cost-based. In rebuttal testimony, the Company proposes to maintain the minimum bill for single-phase service at $3.78 per month.

Having rejected the Division's decoupling proposal, we now turn to the Division's alternative proposal for residential rate design. The Division proposes to increase the customer charge to $3.25. It proposes to eliminate the monthly minimum bill and to reduce the seasonal minimum bill from $47.36 to $39.00. The energy rates for the winter season and the first and second blocks of the summer season are increased by 1.0 percent, to 7.8789¢, 7.6046¢ and 9.0310¢ per kWh, respectively. The remaining revenue increase required of Schedule Nos. 1 and 3 is obtained through an 8.5 percent increase in the third or tail block energy rate of the summer season, to 12.0669¢ per kWh. The Division states this proposal respects the concept of gradualism by increasing slightly the customer charge and energy rates, and also promotes conservation and efficiency by further increasing the summer third or tail block energy rate.

The Office proposes to obtain about one-half of the revenue increase required of Schedule Nos. 1 and 3 through an increase in the customer charge and to spread the other half through the energy rates. Specifically, the Office proposes to spread about half of the revenue increase evenly between all energy rates but for the summer first block energy rate, which remains unchanged. The Office proposes to increase the customer charge to $3.75. Relying on Division testimony stating the cost of service for the customer charge is $3.83 per month, the Office argues its proposal brings this charge near its cost of service. Spreading the other half of the required revenue increase evenly to all energy rates but the summer first block energy rate results in a 2.2 percent increase to the summer second block energy rate, a 2.82 percent increase to the summer third block energy rate and a 0.75 percent increase to the winter energy rate. Hence the proposed summer second block energy rate is 9.1383¢ per kWh, the proposed summer third block energy rate is 11.4400¢ per kWh, and the winter energy rate is 7.8594¢ per kWh. The Office proposes to eliminate the minimum bill unless the ordered customer charge is less than $3.75 per month.

The Office supports its proposal by noting it comports with past Commission orders and achieves an appropriate balancing of key ratemaking objectives including cost causation, fairness, rate stability and energy conservation. The Office contends its proposal addresses the Company's concerns regarding its risk of recovering distribution fixed cost from residential customers through energy rates by allocating 50 percent of the class revenue increase to the fixed customer charge. The Office argues its customer charge increase is gradual as it is less than the dollar increase approved by the Commission in the last rate case. Further, the impact to low usage customers from the higher customer charge is mitigated by making no change to the first summer block energy rate. Finally, the Office recommends the Company prepare and file a Utah marginal cost study to guide rate design in the future. The Office understands the Company and Division support this recommendation and that the Company will file a Utah study in connection with its next rate case.

SLCAP proposes to increase the monthly minimum charge to $6.00, then obtains one-half the remaining revenue increase required of Schedule Nos. 1 and 3 through an increase in the customer charge and obtains the other half through an equal increase in the summer second and third block energy rates. The summer first block and the winter energy rates are not changed. This results in a monthly customer charge of $3.76 and an increase in the summer second and third block energy rates of 0.3436¢ per kWh. SLCAP opposes the elimination of minimum bills. SLCAP argues minimum bills are more effective than customer charges in ensuring extremely small usage customers pay for the cost of their facilities but also permit more costs in total to be recovered in usage-based energy rates, thereby enhancing efficiency. Further, increasing the minimum bill does not result in an extremely large percentage increase in the bill for those customers for whom SLCAP is most concerned (those low-income customers with lower-than-average usage).

SWEEP/UCE proposes to increase the customer charge to $3.25. To encourage efficiency, SWEEP/UCE proposes to replace the current, single, winter energy rate of 7.8009¢ per kWh with a two block energy rate design. The winter first block energy rate, for monthly usage up to 700 kWh, is reduced slightly to 7.6000¢ per kWh and the winter second block energy rate, for monthly usage above 700 kWh, is increased to 8.4000¢ per kWh. SWEEP/UCE also proposes to add in the summer season a fourth block to the current three block design of energy rates, for monthly usage above 2,000 kWh, and to increase rate differentials between blocks. The summer first and second block energy rates of 7.5292¢ per kWh and 8.9416¢ per kWh, respectively, are not changed. The differential between the summer third and second block energy rates is to be about one-third, resulting in an increase in the third block energy rate to 11.9714¢ per kWh. The new summer fourth block energy rate is then set to obtain the remaining revenues required of Schedule Nos. 1 and 3, resulting in an energy rate of 14.7235¢ per kWh. This rate is almost double the rate for the first block, yet SWEEP/UCE argues it is still less than the corresponding marginal cost.

To encourage more energy conservation and efficiency, WRA proposes a surcharge whose value varies by blocks of energy, termed a High Usage Surcharge, be introduced to obtain the revenue increase required of Schedule Nos. 1 and 3, leaving current rates unchanged. No surcharge is proposed on monthly usage up to 1,000 kWh. The surcharge starts at $2.50 for the block of monthly usage over 1,000 kWh and up to 1,500 kWh. The surcharge then increases by $10 for each additional 1,000 kWh block of monthly usage, up to a total monthly usage of 10,000 kWh. For monthly usage in excess of 10,000 kWh, the surcharge increases by $250 for each additional 2,500 kWh. To increase the incentive to conserve, WRA recommends the surcharge be a separate line item on a customer's bill and recommends the bill include an explicit explanation for the surcharge as well as information on energy efficiency programs the Company has available to residential customers.

UAE asserts any perceived benefits of using an inverted block energy rate structure or assigning a disproportionate increase to tail block energy rates for residential customers do not apply to commercial or industrial customers.

As stated previously, the revenue increase required of Schedule No. 25 is about $185,700, or 2.2 percent, which is the overall change in Utah revenue requirement. The Company proposes the demand, energy, and voltage discount rates be increased by approximately 2.2 percent and the remaining revenue increase required of Schedule No. 25 be obtained through an increase in the customer charge. The Office proposes all rates of Schedule No. 25 be increased equally by approximately 2.2 percent. The only difference between the two parties is the Company uses the customer charge to more closely achieve the required revenue increase, compensating for rounding errors in setting all rates in Schedule No. 25.

The Office recommends and the Company agrees to prepare and file a Utah marginal cost study in its next general rate case, anticipated to be January 2011. This marginal cost study should provide additional cost information to guide rate design for all classes in future rate cases. The Office requests a technical conference be convened two weeks after the rate case filing for the presentation by the Company of the marginal cost study and key results. If the next rate case is delayed past March 30, 2011, then the Office requests the Company file this study by April 15, 2011.

**B. Discussion, Findings and Conclusions**

All parties propose an increase in the customer charge and SLCAP proposes to increase the minimum bill for single-phase customers. We first decide these rate design components and then decide changes to energy charges.

**1. Background on the Customer Charge**

Since only residential rate design is contested in this phase of this case, and in order to place our decisions in the context of balancing long-standing rate design objectives, we provide here a brief history of the customer charge and its relationship to minimum bills in Utah. Throughout the 1960's and 1970's, residential rate design consisted of a declining block structure of energy rates and monthly minimum bills. The 1970's were marked by inflation and rising utility rates. As a consequence of the 1973 Arab oil embargo and ensuing turmoil in world markets, the Public Utilities Regulatory Policy Act became federal law in 1978. This law promoted efficiency, conservation, and renewable energy. It also provided standards to be considered in ratemaking. This led to a reexamination of rate design, with the purpose of increasing incentives toward efficiency and conservation.

Beginning in the 1980's, the declining block structure of energy rates for the Company was dismantled and the monthly customer charge was introduced to replace minimum bills. The residential customer charge was initially set at a value less than the residential minimum bill (for single-phase service) in order to mitigate impacts on low-use customers. Ultimately, the declining block rate structure was replaced by an inverted or increasing block energy rate structure in the summer.

During this time, the Company and the Division have consistently supported use of a customer charge and increasing it toward the value of, and eliminating, the minimum bill. The Office and other residential customer groups have previously opposed the introduction of, and subsequent increases in, the customer charge and instead have continued to support using minimum bills.

In 1982, the Commission first allowed the natural gas utility to introduce a customer charge instead of a minimum bill.[2] Then in 1984 the Commission first approved the costs upon which the customer charge for the natural gas utility was to be designed. These are the costs of the plant on the customer's premises and the expenses caused by every customer

---

[2] Order in Case No. 81-057-01, "In the Matter of the Application of Mountain Fuel Supply Company for a General Increase in Rates and Charges Incident to Natural Gas Service Rendered within the State of Utah," issued May 18, 1982, pages 7-8.

each month. Costs which generally increase with the number of customers, but are not caused by each customer, are not recovered in the customer charge.[3]

In 1985 the Company and Division proposed, and the Commission approved in Docket No. 84-035-01, the introduction of a customer charge for electric service based on costs similar to those approved for the natural gas utility.[4] The approved customer-related costs used to calculate the customer charge are the costs of net plant for service lines and meters, i.e., depreciation expense, income tax and return, and the expenses for meter reading and billing, less associated billing revenue. These test year net costs, divided by the average annual number of customers in the test year, then divided again by 12 months, yields the fixed monthly customer charge. Since 1985, we have used these costs for calculating a cost-based customer charge.

The Commission also found a customer charge, as opposed to a minimum bill, allows these customer-related costs to be recovered reasonably and properly. However, in order to mitigate impacts on low-use customers, the customer charge was initially set at a value much less than the minimum bill, so the minimum bill was retained.

The history of the customer charge since it was first introduced in July 1985 is presented in the table below:

[3] Report and Order in Case No. 82-057-15, "In the Matter of the Application of Mountain Fuel Supply Company for a General Increase in Rates and Charges Incident to Natural Gas Service," issued December 21, 1983, pages 24-29.

[4] Report and Order in Docket No. 84-035-01, "In the Matter of the Application of Utah Power & Light Company for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," issued July 1, 1985, pages 11-12.

| Date | Rate | Filing Number | Type of Filing |
|---|---|---|---|
| July 1, 1985 | $1.00 | Docket No. 84-035-01 | General Rate Case |
| Mar. 10, 1989 | $0.98 | Docket No. 87-035-27 | UP&L/PP&L Merger |
| Sep. 15, 1989 | $0.94 | Tariff No. 37 | Interim Decrease with the UP&L/PP&L Merger |
| Feb. 15, 1990 | $1.00 | Docket No. 89-035-10 | Pre-Merger (Benchmark) Rate Case |
| Apr. 15, 1997 | $0.98 | Docket No. 97-035-01 | Interim Decrease with 1997 Price Freeze |
| Dec. 1, 2006 | $2.00 | Docket No. 06-035-21 | General Rate Case |
| June 17, 2009 | $3.00 | Docket No. 08-035-38 | General Rate Case |

Twenty-five years ago the customer charge was introduced in order to reduce the amount of certain customer-related costs of serving low-use customers from being recovered in energy rates paid by high-use customers. During the 1990's, the increase of the customer charge to the level of approved customer-related costs was halted as greater weight was given to other rate design objectives, including ensuring all customers within a schedule could share equitably in general revenue reductions. During the first 20 years after the customer charge was introduced, it has remained around $1.00.

In 2000, in Docket No. 00-035-T07, residential rate Schedule No. 3 was approved providing direct support to qualifying low-income customers.[5] With the impacts on the low-income group of low-use customers mitigated, this Commission has resumed gradually increasing the customer charge to the level of approved customer-related costs, as shown by the increase to $2.00 in Docket No. 06-035-21 and to $3.00 in Docket No. 08-035-38.

[5] Revision to PacifiCorp's Tariff P.S.C.U. No. 43, Re: Addition of Schedules 3 and 91 for the Low-Income Lifeline Program and Surcharge for Funding.

**2. Company's Proposed Costs in the Customer Charge Calculation**

The Company proposes the Commission reconsider its 25 year old policy regarding the type of costs used to calculate the customer charge. The Company quantifies its proposal using costs provided in its class cost-of-service study, a fully-distributed embedded cost study.

The Company's class cost-of-service study begins with the test year results of operations for Utah. These results are separated into five functions, consisting of generation, transmission, distribution, customer (or retail), and miscellaneous. The results for the distribution function are further separated into substations, poles and wires, transformers, service lines, and meters. The results are then allocated to customer classes and the cost-of-service for each class by function is determined.

The Company now proposes the costs used in the design of the customer charge be the residential customers' share of all distribution costs except substations, or 82 percent of distribution costs, and all customer (or retail) costs, or costs totaling $23.38 per customer per month, nearly six times the approved costs of $3.83. In an effort to move toward this amount, the Company proposes all of the residential revenue increase be collected through an increase in the customer charge to $4.45 per month.

The Company supports its proposal by arguing it promotes intra-class equity and reduces revenue volatility. According to the Company, fixed costs must be recovered through the customer charge; it is not appropriate to recover fixed costs through energy rates. If a customer charge is set to recover less than fixed costs, then the difference is recovered through energy rates. Consequently, low-use customers pay less, and high-use customers pay more, in energy rates than the fixed costs per customer recovered in energy rates. Assuming fixed costs should be recovered equally from all customers, low-use customers are subsidized by high-use customers, producing an inequitable result. Conversely, a customer charge designed to recover fixed costs promotes intra-class equity.

The Company states progress must be made in increasing the customer charge toward the fixed costs of serving residential customers. Even at $23.00, the Company's notes its proposal does not include the fixed costs of generation, transmission, or substations, which are recovered through energy rates.

We find the equity argument does not directly apply to the Company's proposed customer charge, since the Company's proposal is based on fully-distributed embedded costs, not just fixed costs. All capital and expense accounts, including labor and overheads, are apportioned to the functions and are included in the Company's proposed costs. Moreover, the local distribution facilities are generally designed and built to meet local peak demands. Recovering these fixed costs equally from all customers ignores differences in peak use.

The Company also argues the calculation of the customer charge must change in order to address revenue volatility. The Company states a large portion of its fixed costs are recovered through energy rates, and therefore the recovery of this portion is dependent on weather and other changes in usage. Since usage varies much more than does the number of customers when comparing actual results with the test year, energy rates produce much more volatile actual revenues than do customer charges. So it is more likely the fixed costs recovered through energy rates will be either under- or over-recovered in a given time period. The Company testifies it under-recovered residential revenues by over $9 million in the summer period of 2009. In prior years, it asserts it has under-recovered residential revenues in the summer period by as much as $23 million and over-recovered by nearly $28 million.

The Commission is interested in exploring the benefits of reduced revenue volatility to customers and the Company. However, we find the record unclear as to how volatility should be defined and measured, the period over which it is measured, and what constitutes a reasonable or normal amount of volatility. Currently, the expected variation in revenues, and resulting volatility in earnings, is a recognized business risk and is included in the determination of the allowed rate of return. This currently provides an equitable treatment of shareholders' interests.

For the reasons stated above, the Commission declines to use the Company's proposal to change the costs from those currently approved for use in the design of a customer charge in this case.

### 3. Customer Charge and Minimum Bill

The Division calculates the customer charge, based on the current Commission-approved customer-related costs, to be $3.83 per month. We accept the Office's proposal of $3.75 per month, as it reasonably approximates this value. The Office's proposal is supported by SLCAP, and we note it is the Company's preferred alternative position.

SLCAP supports use of minimum bills rather than higher customer charges to promote equity and conservation and proposes to increase the minimum bill for single-phase service, from \$3.78 to \$6.00 per month. However, it proposes no change in the minimum bills for three-phase or seasonal service. Further, the billing units SLCAP uses to formulate the revenues for the residential class assuming \$6.00 per month are the same as for the \$3.78 minimum bill. This is unlikely to be the case and therefore we do not have the necessary information to fully evaluate this proposal. The Company, Division and Office propose eliminating the minimum bill for single-phase service should the Commission accept a \$3.75 customer charge. Further, the Division proposes to reduce the seasonal minimum bill from \$47.36 to \$39.00. However, insufficient evidence is provided to support changing minimum bills, so we decline to do so.

The record is deficient with respect to parties' positions for altering or eliminating the minimum bills. In order to address this issue in the next general rate case, we direct the Company and Division to provide an examination of changes to the minimum bill including: the costs used to calculate the minimum bill for single-phase service; the basis for, and revenue impacts of, increasing the minimum bill; use of the minimum bill instead of a customer charge to recover customer and/or distribution fixed costs; the relationship of the three-phase and seasonal service to single-phase service; and whether elimination of the minimum bill for single-phase service also requires the elimination of the minimum bill for three-phase and seasonal service.

**4. Energy Charges**

As proposed by both the Office and SLCAP, in order to mitigate the rate impact for lower usage customers resulting from the large increase in the customer charge (i.e., \$3.00 to \$3.75 or 25 percent), we make no change to the first block summer energy rate and the winter energy rate of Schedule No. 1. As suggested by the Office, we find this approach balances the objectives of cost causation, fairness, and rate stability.

We decline to approve the Division's or SWEEP's proposal to substantially increase the third or "tail block" energy rate, SWEEP's proposal to add a fourth block and relatively high energy rate, or WRA's proposal to impose a high use surcharge. We agree with the Office these proposals lack both cost support and analysis demonstrating how the high tail block energy rates or surcharges are expected to affect residential demand.

Rather, for the remainder of the increase required to achieve the appropriate revenue for this class, and similar to SLCAP's proposal, we raise the second and third block summer energy rates of Schedule No. 1 by an equal 3.73 percent. Absent evidence regarding marginal cost and the proper relationship between the blocks, we find this method preserves the current relationship between the second and third summer blocks which was established by parties in the Stipulation in Cost of Service, Rate Spread and Rate Design – Phase II in Docket No. 08-035-38[6] and thereby treats both blocks equally. This approach also balances the regulatory objectives of cost causation, fairness, rate stability, revenue adequacy and energy conservation.

Other than the customer charge, no party proposes changes to Schedule No. 2. We agree and make no further changes to this schedule as the increase in customer charge and existing energy rates approximately achieve the appropriate revenue for this schedule.

---

[6]This Stipulation was approved by the Commission in the June 17, 2009, Report and Order on Rate Design in Docket No. 08-035-38.

Regarding Schedule No. 25, absent testimony on the basis for which the customer charge for this class is determined and the small number of customers (eleven) currently being served under this schedule, we decline to increase this customer charge as proposed by the Company and the Office as doing so will provide minimal contribution to the required revenue increase for this schedule ($132 per year). Further, this decision is compatible with the Stipulation condition to move existing Schedule No. 25 customers to other applicable general service rate schedules.

No testimony has been provided discussing how the Company's and Office's proposed Schedule No. 25 rate designs, which increase the energy and power charges by similar amounts, will facilitate the potential movement of Schedule No. 25 to other applicable schedules. For simplicity and customer understanding, we decline to make these changes and find increasing the energy charge by 2.69 percent will provide the appropriate revenue increase for Schedule No. 25 and will not further complicate the migration of customers from Schedule No. 25.

Our rate design decisions for Schedule Nos. 1, 2, and 25 are shown in Appendix 3.

**5. Further Study**

Parties provide testimony on the benefits, necessity, and concerns regarding an updated Utah marginal cost study which the Company has agreed to conduct. In order to ensure the study addresses the concerns of the parties and identifies limitations, we will sponsor a technical conference to be led by the Division and the Company, to discuss issues associated with the schedule, objectives, and design for such marginal cost study. We also direct the Company to file with the Commission and circulate to interested parties at least two weeks prior to the technical conference the most recent Utah and Oregon marginal cost studies so parties have an opportunity to review these documents and provide comments on the study during the technical conference.

As requested by the Office, we direct the Company to file the Utah marginal cost study either in its next application for a general rate increase in Utah or April 15, 2011, whichever is earlier.

## V. ORDER

Wherefore, pursuant to our discussion, findings and conclusions made herein, we order:

1. The Stipulation on Non-Residential Rate Design - Phase II is approved.
2. PacifiCorp shall file appropriate tariff revisions consistent with the decisions made herein.
3. The tariff revisions shall reflect the determinations and the decisions contained in this Order. The Division shall review the tariff revisions for compliance with the terms of this Order.

This Report and Order constitutes final agency action on the Company's June 23, 2009, Application. Pursuant to Sections 63G-4-301 and 54-7-15 of the Utah Code, an aggrieved party may request agency review or rehearing of this Order by filing a written request with the Commission within 30 days after the issuance of this Order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the Commission does not grant a request for review or rehearing within 20 days after the filing of the request, it is deemed denied. Judicial review of the Commission's final agency action may be obtained by filing a petition for review with the Utah Supreme Court within 30 days after final agency action. Any petition for review must comply with the requirements of Sections 63G-4-401 and 63G-4-403 of the Utah Code and with the Utah Rules of Appellate Procedure.

DATED at Salt Lake City, Utah, this 2nd day of June, 2010.

/s/ Ted Boyer, Chairman

/s/ Ric Campbell, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#66935

**APPENDIX 1: STIPULATION ON NON-RESIDENTIAL RATE DESIGN**

**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 | DOCKET NO. 09-035-23<br><br>**STIPULATION ON NON-RESIDENTIAL RATE DESIGN-PHASE II** |

1. This Stipulation in the Rate Design Phase of Docket 09-035-23 ("Stipulation") is entered into by and among the parties whose signatures appear on the signature pages hereof (collectively referred to herein as the "Parties").

**I. <u>INTRODUCTION</u>**

2. The terms and conditions of this Stipulation are set forth herein. The Parties represent that this Stipulation is in the public interest and recommend that the Public Service Commission of Utah (the "Commission") approve the Stipulation and all of its terms and conditions.

## II. BACKGROUND

3. On June 23, 2009, Rocky Mountain Power ("Rocky Mountain Power" or "Company") filed an application, together with revenue requirement, cost of service, rate spread and rate design testimony, requesting approval of an increase in its retail electric utility service rates in Utah in the amount of $66.9 million, with a return on equity of 11.0 percent.

4. On July 8, 2009, the Utah Industrial Energy Consumers ("UIEC") filed a Motion to Bifurcate this proceeding into a revenue requirement phase and a cost-of-service, rate spread and rate design phase. On July 23, 2009, Rocky Mountain Power filed a response to UIEC's Motion to Bifurcate and, on July 27, 2009, the Utah Association of Energy Users ("UAE") filed a Joinder in UIEC's Motion to Bifurcate.

5. On August 4, 2009, the Commission issued a Scheduling Order establishing the procedural schedule for this case, and an Order on UIEC's Motion to Bifurcate. In its Scheduling Order, the Commission indicated that it would address rate of return, revenue requirement and cost of service in Phase I, and rate design in Phase II. On August 20, 2009, Rocky Mountain Power filed a Request to Establish a Schedule for Rate Design Testimony and Hearing. On September 21, 2009, the Commission issued an Amended Schedule Order Changing Phase II Testimony Filing and Hearing Dates.

6. On February 18, 2010, the Commission issued its order ("Order") in the case authorizing an increase in rates in the amount of approximately $32.4 million, a non-uniform percentage increase be applied to certain customers' bills as a line item for service prior to the Commission's determination of rate design in Phase II of this docket, and a return on equity of 10.6 percent.

7. On February 22, 2010, intervenors filed direct testimony in the rate design phase of the case.

8. On March 11, 2010, Rocky Mountain Power filed updated direct testimony to update the Company's previously proposed rate design proposals to reflect the revenue requirement and rate spread ordered by the Commission in this docket.

9. On March 23, 2010, all parties filed rebuttal testimony in the rate design phase of the case.

10. On March 25, 2010, certain parties met for settlement discussions on all non-residential rate design. As a result of the settlement negotiations, the Parties to this Stipulation have agreed to the rate design of all non-residential schedules. The Parties have not, however, agreed on the residential rate design or decoupling issues in this case.

## III. TERMS OF STIPULATION.

Subject to Commission approval and for purposes of this Stipulation only, unless otherwise noted, the Parties agree as follows:

11. Rate Design of All Non Residential Schedules. The Parties agree that the implementation of the rate increase granted to the Company shall be collected from all non-residential schedules as set forth in the stipulated rates attached hereto in Exhibit 1, Column B and Exhibit 2, Column G. These rates collect revenues equal to the rates approved for the non-residential schedules in Schedule 98, Tariff Rider Rate, effective February 18, 2010.

12. Schedule 25. The Parties agree to address the issue of moving customers from Schedule 25 to appropriate general service rate schedules in the next general rate case. The Company agrees to show the impacts of moving affected customers from Schedule 25 to any proposed general service schedules in its filing.

13. Residential Rate Design Not Part of Stipulation. The Parties agree that this Stipulation does not address any issues related to residential rate design or decoupling in this or any other proceeding. The parties further agree that the general terms and conditions in this non-residential rate design stipulation do not apply to any issues or evidence related to residential rate design or decoupling in this or any other proceeding.

14. Schedule in Phase II to Continue. The Parties agree to continue to follow the schedule currently in place in Phase II of this docket, but agree that any filings made pursuant to the schedule will address only residential rate design issues. The Parties further agree to request that the hearing for approval of this Stipulation be held on the same day that is already scheduled for the rate design phase of the case, or April 12 and 13, 2010. Finally, the Parties agree that, pending Commission approval of the Stipulation, non-residential rate design elements of this case shall be deemed concluded.

## IV. GENERAL TERMS AND CONDITIONS

15. All negotiations related to this Stipulation are privileged and confidential and no Party shall be bound by any position asserted in negotiations. Neither the execution of this Stipulation nor the order adopting this Stipulation shall be deemed to constitute an admission or acknowledgment by any Party of any liability, the validity or invalidity of any claim or defense, the validity or invalidity of any principle or practice, or the basis of an estoppel or waiver by any Party other than with respect to issues resolved by this Stipulation; nor shall they be introduced or used as evidence for any other purpose in a future proceeding by any Party except a proceeding to enforce the approval or terms of this Stipulation.

16. The Parties respectfully request of the Commission that the prefiled testimony on non-residential rate design issues in Phase II of this Docket be admitted into the record without witnesses being called or sworn at the proceeding. The Company, the Division and the OCS each agree to make one or more witnesses available to explain and support this Stipulation to the Commission. Such witnesses will be available for examination. So that the record in this Docket is complete, the Parties may move for admission of evidence, comments, position statements or exhibits that have been filed on the issues resolved by this Stipulation; however, notwithstanding the admission of such documents, the Parties shall support the Commission's approval of the Stipulation and the Commission order approving the Stipulation. As applied to the Division and the OCS, the explanation and support shall be consistent with their statutory authority and responsibility.

17. The Parties agree that if any person challenges the approval of this Stipulation or requests rehearing or reconsideration of any order of the Commission approving this Stipulation, each Party will use its best efforts to support the terms and conditions of the Stipulation. As applied to the Division and OCS, the phrase "use its best efforts" means that they shall do so in a manner consistent with their statutory authority and responsibility. In the event any person seeks

judicial review of a Commission order approving this Stipulation, no Party shall take a position in that judicial review opposed to the Stipulation.

18. Except with regard to the obligations of the Parties under the two immediately preceding paragraphs of this Stipulation, this Stipulation shall not be final and binding on the Parties until it has been approved without material change or condition by the Commission. This Stipulation is an integrated whole, and any Party may withdraw from it if it is not approved without material change or condition by the Commission or if the Commission's approval is rejected or materially conditioned by a reviewing court. If the Commission rejects any part of this Stipulation or imposes any material change or condition on approval of this Stipulation or if the Commission's approval of this Stipulation is rejected or materially conditioned by a reviewing court, the Parties agree to meet and discuss the applicable Commission or court order within five business days of its issuance and to attempt in good faith to determine if they are willing to modify the Stipulation consistent with the order. No Party shall withdraw from the Stipulation prior to complying with the foregoing sentence. If any Party withdraws from the Stipulation, any Party retains the right to seek additional procedures before the Commission, including cross-examination of witnesses, with respect to issues addressed by the Stipulation and no Party shall be bound or prejudiced by the terms and conditions of the Stipulation.

19. The Parties may execute this Stipulation in counterparts each of which is deemed an original and all of which only constitute one original.

BASED ON THE FOREGOING, the Parties request that the Commission issue an order approving this Stipulation and adopting the terms and conditions of this Stipulation.

Respectfully submitted this [1st] day of April, 2010.

ROCKY MOUNTAIN POWER

______________________________
Mark C. Moench
Senior Vice President & General Counsel

UTAH DIVISION OF PUBLIC UTILITIES

______________________________
Michael Ginsberg
Patricia Schmid
Assistant Attorney General

UTAH OFFICE OF CONSUMER SERVICES

______________________________
Paul H. Proctor
Assistant Attorney General

UTAH INDUSTRIAL ENERGY CONSUMERS

___________________________________
F. Robert Reeder
Vicki M. Baldwin
Parsons Behle & Latimer

UAE INTERVENTION GROUP

___________________________________
Gary Dodge
Hatch, James & Dodge

KROGER CO.

___________________________________
Kurt Boehm, Esq.
Boehm, Kurtz & Lowry

WAL-MART STORES, INC. AND SAM'S WEST, INC.

___________________________________
Holly Rachel Smith
Holly Rachel Smith, PLLC

# APPENDIX 2: NON-RESIDENTIAL RATES

**EXHIBIT 1**
**ROCKY MOUNTAIN POWER - STATE OF UTAH**
**RATE DESIGN STIPULATION**
**DOCKET NO. 09-035-23**

| | A<br>T47<br>Present<br>Price | | B<br>T47<br>Stipulated<br>Price | |
|---|---|---|---|---|
| **Schedule No. 6** | | | | |
| Customer Charge | $27.00 | | $45.00 | |
| All kW (May - Sept) | $14.94 | | $15.16 | |
| All kW (Oct - Apr) | $11.99 | | $12.17 | |
| Voltage Discount | ($0.77) | | ($0.78) | |
| All kWh | | | | |
| KWh (May - Sept) | 3.1446 | ¢ | 3.1907 | ¢ |
| KWh (Oct - Apr) | 2.9006 | ¢ | 2.9416 | ¢ |
| Seasonal Service | $324.00 | | $540.00 | |
| | | | | |
| **Schedule No. 6A - Energy Time-of-Day Option** | | | | |
| Customer Charge | $27.00 | | $45.00 | |
| Facilities kW (May - Sept) | $5.36 | | $5.37 | |
| Facilities kW (Oct - Apr) | $4.49 | | $4.50 | |
| Voltage Discount | ($0.50) | | ($0.50) | |
| On-Peak kWh (May - Sept) | 9.7915 | ¢ | 9.8184 | ¢ |
| Off-Peak kWh (May - Sept) | 2.9479 | ¢ | 2.9560 | ¢ |
| On-Peak kWh (Oct - Apr) | 8.1846 | ¢ | 8.2071 | ¢ |
| Off-Peak kWh (Oct - Apr) | 2.4632 | ¢ | 2.4782 | ¢ |
| | | | | |
| **Schedule No. 6B - Demand Time-of-Day** | | | | |
| Customer Charge | $27.00 | | $45.00 | |
| All On-peak kW (May - Sept) | $14.94 | | $15.16 | |
| All On-peak kW (Oct - Apr) | $11.99 | | $12.17 | |
| Voltage Discount | ($0.77) | | ($0.78) | |
| All kWh | | | | |
| kWh (May - Sept) | 3.1446 | ¢ | 3.1907 | ¢ |
| KWh (Oct - Apr) | 2.9006 | ¢ | 2.9416 | ¢ |
| Seasonal Service | $324.00 | | $540.00 | |

**EXHIBIT 1**
**ROCKY MOUNTAIN POWER - STATE OF UTAH**
**RATE DESIGN STIPULATION**
**DOCKET NO. 09-035-23**

| | A | | B | |
|---|---|---|---|---|
| | T47 | | T47 | |
| | Present | | Stipulated | |
| | Price | | Price | |
| **Schedule No. 8 - Composite** | | | | |
| Customer Charge | $27.00 | | $55.00 | |
| Facilities kW | $3.69 | | $3.77 | |
| On-Peak kW (May - Sept) | $12.07 | | $12.33 | |
| On-Peak kW (Oct - Apr) | $8.70 | | $8.88 | |
| Voltage Discount | ($0.88) | | ($0.90) | |
| On-Peak kWh (May - Sept) | 3.9189 | ¢ | 4.0021 | ¢ |
| On-Peak kWh (Oct - Apr) | 3.0677 | ¢ | 3.1328 | ¢ |
| Off-Peak kWh | 2.6426 | ¢ | 2.6987 | ¢ |
| | | | | |
| **Schedule No. 9 - Composite** | | | | |
| Customer Charge | $183.00 | | $200.00 | |
| Facilities kW | $1.65 | | $1.71 | |
| On-Peak kW (May -Sept) | $10.40 | | $10.76 | |
| On-Peak kW (Oct - Apr) | $7.05 | | $7.30 | |
| On-Peak kWh (May - Sept) | 3.4643 | ¢ | 3.5858 | ¢ |
| On-Peak kWh (Oct - Apr) | 2.6049 | ¢ | 2.6963 | ¢ |
| Off-Peak kWh | 2.1760 | ¢ | 2.2518 | ¢ |
| | | | | |
| **Schedule No. 9A - Energy TOD** | | | | |
| Customer Charge | $183.00 | | $200.00 | |
| Facilities Charge per kW | $1.65 | | $1.71 | |
| On-Peak kWh | 6.4024 | ¢ | 6.6247 | ¢ |
| Off-Peak kWh | 2.7554 | ¢ | 2.8479 | ¢ |
| | | | | |
| **Schedule No. 10 - Irrigation** | | | | |
| Annual Cust. Serv. Chg. Primary | $94.00 | | $98.00 | |
| Annual Cust. Serv. Chg. - Secondary | $29.00 | | $30.00 | |
| Monthly Cust. Serv. Chg. | $11.00 | | $12.00 | |
| All On-Season kW | $5.56 | | $5.75 | |
| Voltage Discount | ($1.56) | | ($1.61) | |
| First 30,000 kWh | 5.5359 | ¢ | 5.7252 | ¢ |
| All add'l kWh | 4.0918 | ¢ | 4.2318 | ¢ |
| Post Season | | | | |
| Customers | $11.00 | | $12.00 | |
| KWh | 3.7919 | ¢ | 3.9216 | ¢ |

**EXHIBIT 1**
**ROCKY MOUNTAIN POWER - STATE OF UTAH**
**RATE DESIGN STIPULATION**
**DOCKET NO. 09-035-23**

| | A<br>T47<br>Present<br>Price | | B<br>T47<br>Stipulated<br>Price | |
|---|---|---|---|---|
| **Schedule No. 10-TOD** | | | | |
| Annual Cust. Serv. Chg. - Primary | $94.00 | | $98.00 | |
| Annual Cust. Serv. Chg. - Secondary | $29.00 | | $30.00 | |
| Monthly Cust. Serv. Chg. | $11.00 | | $12.00 | |
| All On-Season kW | $5.56 | | $5.75 | |
| Voltage Discount kW | ($1.56) | | ($1.61) | |
| On-Peak kWh | 10.9369 | ¢ | $11.3110 | ¢ |
| Off-Peak kWh | 3.1547 | ¢ | $3.2631 | ¢ |
| Post Season | | | | |
| Customers | $11.00 | | $12.00 | |
| kWh | 3.7919 | ¢ | 3.9216 | ¢ |
| | | | | |
| **Schedule No. 15.2 - Traffic Signal Systems** | | | | |
| Customer Charge | $4.15 | | $4.50 | |
| All kWh | 6.8576 | ¢ | 6.9957 | ¢ |
| | | | | |
| **Schedule No. 21 - Electric Furnace Operations - Limited Service** | | | | |
| *Primary Voltage* | | | | |
| Customer Charge | $93.35 | | $97.00 | |
| Charge per kW (Facilities) | $3.22 | | $3.29 | |
| First 100,000 kWh | 5.1311 | ¢ | $5.2440 | ¢ |
| All add'l kWh | 4.3084 | ¢ | $4.4032 | ¢ |
| *44KV or Higher* | | | | |
| Customer Charge | $93.35 | | $97.00 | |
| Charge per kW (Facilties) | $3.22 | | $3.29 | |
| First 100,000 kWh | 4.0369 | ¢ | 4.1257 | ¢ |
| All add'l kWh | 3.5864 | ¢ | 3.6547 | ¢ |

**EXHIBIT 1**
**ROCKY MOUNTAIN POWER - STATE OF UTAH**
**RATE DESIGN STIPULATION**
**DOCKET NO. 09-035-23**

| | A<br>T47<br>Present<br>Price | | B<br>T47<br>Stipulated<br>Price | |
|---|---|---|---|---|
| **Schedule No. 23 - Distribution Voltage - Small Customer** | | | | |
| Customer Charge | $6.00 | | $8.00 | |
| kW over 15 (May - Sept) | $7.22 | | $7.25 | |
| kW over 15 (Oct - Apr) | $7.27 | | $7.30 | |
| Voltage Discount | ($0.41) | | ($0.41) | |
| First 1,500 kWh (May - Sept) | 9.7770 | ¢ | 9.8214 | ¢ |
| All Add'l kWh (May - Sept) | 5.4814 | ¢ | 5.5063 | ¢ |
| First 1,500 kWh (Oct - Apr) | 8.9991 | ¢ | 9.0400 | ¢ |
| All Add'l kWh (Oct - Apr) | 5.0452 | ¢ | 5.0688 | ¢ |
| Seasonal Service | $72.00 | | $96.00 | |
| | | | | |
| **Schedule No. 31 - Back-Up, Maintenance, and Supplementary Power** | | | | |
| *Secondary Voltage* | | | | |
| Customer Charge per month | $102.00 | | $104.00 | |
| Facilities Charge, per kW month | $3.72 | | $3.81 | |
| Back-up Power Charge | | | | |
| Regular, per On-Peak kW day | $0.5120 | | $0.5244 | |
| Maintenance, per On-Peak kW day | $0.2560 | | $0.2622 | |
| Excess Power, per kW month | $48.23 | | $49.40 | |
| *Primary Voltage* | | | | |
| Customer Charge per month | $460.00 | | $471.00 | |
| Facilities Charge, per kW month | $2.92 | | $2.99 | |
| Back-up Power Charge | | | | |
| Regular, per On-Peak kW day | $0.4981 | | $0.5102 | |
| Maintenance, per On-Peak kW day | $0.2491 | | $0.2551 | |
| Excess Power, per kW month | $34.76 | | $35.60 | |
| *Transmission Voltage* | | | | |
| Customer Charge per month | $515.00 | | $527.00 | |
| Facilities Charge, per kW month | $1.66 | | $1.70 | |
| Back-up Power Charge | | | | |
| Regular, per On-Peak kW day | $0.3913 | | $0.4008 | |
| Maintenance, per On-Peak kW day | $0.1957 | | $0.2004 | |
| Excess Power, per kW month | $33.47 | | $34.28 | |

# APPENDIX 3: RESIDENTIAL RATES

| | A<br>T47<br>Present<br>Price | | B<br>T47<br>New<br>Price | |
|---|---|---|---|---|
| **Schedule No. 1** - Residential | | | | |
| Customer Charge | $3.00 | | $3.75 | |
| First 400 kWh (May - Sept) | 7.5292 | ¢ | 7.5292 | ¢ |
| Next 600 kWh (May - Sept) | 8.9416 | ¢ | 9.2749 | ¢ |
| All Add'l kWh (May - Sept) | 11.1216 | ¢ | 11.5361 | ¢ |
| All kWh (Oct - Apr) | 7.8009 | ¢ | 7.8009 | ¢ |
| Phase I Minimum Bill | $3.78 | | $3.78 | |
| Phase III Minimum Bill | $11.34 | | $11.34 | |
| Seasonal Minimum Bill | $47.36 | | $47.36 | |
| **Schedule No. 2 - Residential Optional Time-of-Day** | | | | |
| Customer Charge | $3.00 | | $3.75 | |
| On-Peak kWh (May - Sept) | 4.3762 | ¢ | 4.3762 | ¢ |
| Off-Peak kWh (May - Sept) | (1.4014) | ¢ | (1.4014) | ¢ |
| First 400 kWh (May - Sept) | 7.5292 | ¢ | 7.5292 | ¢ |
| Next 600 kWh (May - Sept) | 8.9416 | ¢ | 9.2749 | ¢ |
| All Add'l kWh (May - Sept) | 11.1216 | ¢ | 11.5631 | ¢ |
| All kWh (Oct - Apr) | 7.8009 | ¢ | 7.8009 | ¢ |
| Phase I Minimum Bill | $3.78 | | $3.78 | |
| Phase III Minimum Bill | $11.34 | | $11.34 | |
| Seasonal Minimum Bill | $47.36 | | $47.36 | |
| **Schedule No. 3 - Residential Low-Income** | | | | |
| Customer Charge | $3.00 | | $3.75 | |
| First 400 kWh (May - Sept) | 7.5292 | ¢ | 7.5292 | ¢ |
| Next 600 kWh (May - Sept) | 8.9416 | ¢ | 9.2749 | ¢ |
| All Add'l kWh (May - Sept) | 11.1216 | ¢ | 11.5361 | ¢ |
| All kWh (Oct - Apr) | 7.8009 | ¢ | 7.8009 | ¢ |
| Phase I Minimum Bill | $3.78 | | $3.78 | |
| Phase III Minimum Bill | $11.34 | | $11.34 | |
| Seasonal Minimum Bill | $47.36 | | $47.36 | |
| **Schedule No. 25 - Mobile Home and House Trailer** | | | | |
| Customer Charge | $20.00 | | $20.00 | |
| kW Demand | $5.60 | | $5.60 | |
| Voltage Discount per kW | ($0.50) | | ($0.50) | |
| All kWh | 5.7975 | ¢ | 5.9533 | ¢ |
| Minimum per Home | $5.00 | | $5.00 | |