ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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IDAHO PUBLIC UTILITIES COMMISSION

201 South Main, Suite 2300
Salt Lake City, Utah 84111

February 25, 2010

VIA OVERNIGHT DELIVERY

Idaho Public Utilities Commission
472 West Washington
Boise, ID 83702-5983

Attention: Jean D. Jewell
Commission Secretary

Re: **Case No. PAC-E-10-03**
In the Matter of the Application of Rocky Mountain Power for an Increase to the Customer Efficiency Services Rate.

Rocky Mountain Power, a division of PacifiCorp, hereby submits for filing an original and seven (7) copies of its Application in the above referenced matter.

Service of pleadings, exhibits, orders and other documents relating to this proceeding should be served on the following:

Ted Weston
Idaho Regulatory Affairs Manager
201 South Main, Suite 2300
Salt Lake City, UT 84111
Telephone: (801) 220-2963
Facsimile: (801) 220-2798
E-mail: Brian.Dickman@PacifiCorp.com

Daniel Solander
Senior Counsel
201 South Main, Suite 2300
Salt Lake City, UT 84111
Telephone: (801) 220-4014
Facsimile: (801) 220-3299
E-mail: Daniel.Solander@PacifiCorp.com

It is respectfully requested that all formal correspondence and Staff requests regarding this material be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon 97232

Any informal inquiries may also be directed to Ted Weston at 801-220-2963.

Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

Enclosures

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-10-03**
MOUNTAIN POWER FOR AN	)	
INCREASE TO THE CUSTOMER	)	**APPLICATION OF**
EFFICIENCY SERVICE RATE	)	**ROCKY MOUNTAIN POWER**
	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-10-03

Application and Attachments

February 25, 2010

Mark C. Moench
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Attorneys for Rocky Mountain Power

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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AN INCREACE TO THE CUSTOMER EFFICIENCY SERVICES RATE	)))))))	**CASE NO. PAC-E-10-03** **APPLICATION**

COMES NOW, Rocky Mountain Power, a division of PacifiCorp (the "Company"), and in accordance with RP 052 and RP 201, *et. seq*., hereby applies to the Idaho Public Utilities Commission (the "Commission") for approval to adjust the Customer Efficiency Services Rate (Schedule No. 191). The adjustment is needed to facilitate the funding of ongoing demand-side management ("DSM") program expenditures and reduce the back balance or yet to be recovered DSM expenses in the DSM balancing account from $3.5 million, the April 2010 forecasted balance to $2.25 million by April 30, 2011, a reduction of approximately $1.25 million. The Company expects to review funding needs again in early 2011 to determine whether this proposed adjustment is sufficient to fund ongoing program expenses beyond April 2011 and recover the remaining balance owed the Company in the DSM balancing account at that time. In this Application, the Company seeks to increase the Schedule No. 191 rate from 3.72 percent to 5.85 percent. The Company respectfully requests that this Schedule No. 191 adjustment become effective May 1, 2010.

In support of its Application, Rocky Mountain Power states:

1. Rocky Mountain Power does business as a public utility in the State of Idaho and is subject to the jurisdiction of the Commission with regard to its public utility operations.

2. This Application is filed pursuant to *Idaho Code* §§ 61-301, 61-307, 61-622, and 61-623. In particular, *Idaho Code* § 61-623 empowers the Commission to determine the propriety of proposed rate schedules, §§ 61-307 and 61-622 require Commission approval prior to any increase in rates, and § 61-301 requires Idaho retail electric rates to be just and reasonable.

3. This Application is filed in compliance with Customer Information Rule 102 (IDAPA 31.21.02.102). Notices of the proposed rate change will be included as a bill insert starting February 25, 2010 and will continue until all Idaho customers have received a bill with a notice. The Company estimates this will take approximately 30 days from date of this filing. See Attachment 1 for a copy of the customer notice and the press release.

BACKGROUND

4. As far back as the 1970s the Company has offered a variety of DSM programs to its customers. As with all the Company's DSM programs, those offered by Rocky Mountain Power in Idaho have been designed to be cost-effective. On March 2,

2006, the Commission approved an enhanced set of DSM programs and cost recovery through Schedule No. 191, Customer Efficiency Services Rate, which was applied to customers' bills beginning on May 1, 2006. The collection rate was set at 1.5 percent, which was below the rate needed by the Company to fully fund all reasonably available cost-effective resources identified at that time. The enhanced set of programs was designed to measure Idaho customers' willingness to participate in programs and the Company's ability to deliver them cost-effectively.

To manage collection and program expenses during the initial period, the Company did not introduce the Energy FinAnswer program for business customers and tied participation to funding availability for business energy efficiency programs.

On February 14, 2008, the Company filed an application with the Idaho Public Utilities Commission requesting authorization to increase the Customer Efficiency Services Rate, Schedule No. 191, from 1.5 percent to 3.72 percent. In Order No. 30543 the Idaho Public Service Commission approved this increase effective on May 1, 2008.

The increase to the Customer Efficiency Services Rate provided additional funding for operating programs, including:

Schedule No. 117 – Refrigerator Recycling;

Schedule No. 21 - Low Income Weatherization Services; and,

Schedule Nos. 72 and 72A – Irrigation Load Control Credit Rider.

Additionally it allowed the Company to enhance some of its other programs such as:

Schedule No. 115 - FinAnswer Express;

Schedule No. 155 - Irrigation Energy Services; and,

Schedule No. 118 - Home Energy Savings.

The Company also offered one new program - Schedule No. 125 – Energy FinAnswer.

5. Program performance, including expenditures, savings and assessments of cost-effectiveness, as well as the balancing account activity associated with Schedule No. 191 for the period from January 1, 2006, through December 31, 2007, was provided in the *Annual Report of Idaho Demand Side Management Activities* filed with the Commission March 14, 2008, and prudency determination in Case No. PAC-E-08-07 Order No. 30783. Program performance, including expenditures, savings and assessment of cost effectiveness for the period from January 1, 2008, through December 31, 2008, was provided in the Annual Report of Idaho Demand Side Management Activities filed with the Commission on March 18, 2009.

The energy efficiency programs in place in 2009 are cost-effective based on a preliminary assessment using actual expenditures and achieved savings for 2009. The results from this preliminary assessment are included in Attachment 2. The *Annual Report of Idaho Demand Side Management Activities* for 2009 will be filed with the Commission on or before March 15, 2010, and will contain complete information on the 2009 program performance.

6. The load control service credits available for Irrigation Load Control Credit Rider participants (Schedules No. 72 and 72A) has not been included in or collected through the Customer Efficiency Services rate. However, these credits are

included in the program's cost-effectiveness assessments, including the preliminary assessment of the 2009 program results found in Attachment 2 of this filing. The load control service credit paid to customers for the 2009 program year was $7.3 million.

DESCRIPTION OF CHANGES AND COST DRIVERS

7. ***Schedule No. 191 – "Customer Efficiency Services"***

The Company proposes to adjust the collection rate for Schedule No. 191 from 3.72 percent to 5.85 percent of retail revenue, excluding the tariff contract customers, which is a 2.13 percent net increase to customers subject to that schedule. This collection rate is designed to fund ongoing demand-side management ("DSM") program expenditures and reduce the back balance or yet to be recovered DSM expenses in the DSM balancing account from $3.5 million, the April 2010 forecasted balance, to $2.25 million by April 30, 2011, a reduction of approximately $1.25 million. The Company will continue to review funding needs on an annual basis to determine whether this proposed adjustment is sufficient to fund ongoing program expenses and continue to recover the remaining balance owed the Company in the DSM balancing account at that time. At 5.85 percent of retail revenues, Schedule 191 will provide approximately $8.325 million per year, assuming 2008 energy usage levels. As noted, Schedule No. 191 collections does not fund an estimated $7.3 million in Schedules No. 72 or 72A irrigation load control service credits currently recovered in the Company's base rates.

Administration of the balancing account, including carrying charges, prudence review, and separating these costs from the revenue requirement in general rate cases would continue as outlined in Order No. 29976.

8. Residential Programs

While the funding by program varies, the projected residential program funding of \$.980 million (excluding funding for the Northwest Energy Efficiency Alliance) for May 1, 2010, through April 30, 2011, is consistent with the 2009 level forecasted in Case No. PAC-E-08-01.

- **Refrigerator Recycling Program**

Participation and estimated savings associated with the refrigerator recycling program in 2009 were consistent with 2008 levels. When compared to the estimates provided in Case No. PAC-E-08-01, 2008 and 2009 energy savings are 45 percent of the forecast and expenditures are 41 percent of forecast. The changes are attributed to general economic conditions prevailing for most of the period, which may have resulted in a reluctance to recycle working appliances. In the last half of 2009, all markets for Rocky Mountain Power were re-assessed. Current forecasts show an increase in refrigerator and freezer recycling in 2010 and 2011 demand in all markets including Idaho. As a result, the projected 2010 annual expenses and energy savings for the program are expected to increase by about 60 percent when compared to 2009.

- **Home Energy Efficiency Incentive program**

Energy savings associated with the Home Energy Efficiency Program more than doubled when compared to 2008, while the expenditures increased by approximately 20 percent when compared to 2008. As noted in the 2008 annual report referenced above, one of the major factors that impeded customer participation in the program in 2008 was the lighting program alignment, which was overcome in 2009. This improved alignment in 2009 resulted in a four-fold increase in lighting savings when compared with 2008.

The availability of federal tax credits and media coverage surrounding federal stimulus funding began increasing the overall awareness and interest in providing energy efficiency opportunities in homes. Contractors and retailers in turn have developed marketing messages and sales materials that feature the availability of the federal tax credit and increased customer contact. Use of the tax credit as a sales tool has been especially prominent in the window replacement market. The addition of incentives for heat pumps in 2008 increased overall activity in the HVAC market that has carried over into 2009 program results.

Weatherization activity has increased as a result of the slow-down in the new construction markets, increasing competition among contractors now focusing on the retrofit market. The impact has been threefold: 1) reduction in installed costs of weatherization services; 2) near "free" deals for customers; and 3) an increase of insulation projects. This trend has been further accelerated as the result of the availability of the federal tax credit. To better align program incentives with current market conditions, the Company utilized the notice provisions of Schedule 118 on February 3, 2010, to inform customers who visit the Company's website and contractors who have participated in the program that insulation incentives will change effective March 20, 2010.

The program expenditure forecast for 2010 is based on a December 2009 forecast and approximates 2009 expenditures. After factoring for increased activity in some areas and the proposed changes to insulation incentives, 2010 expenditures are forecasted to be about the same as 2009's actual expenditures. The program administrator has performed additional market sensitivity analysis work which indicates additional opportunity and potential program expenditures in 2010 beyond that included in the current Application. However, a relatively wide range of uncertainty associated with the overall impact of adjusted weatherization incentive levels led the Company to not further increase program funding requirements, taking a more reserved position in our forecast for the purposes of this Application. Furthermore, it should also be noted that the program funding estimates used in this Application do not include some of the key measures in the Northwest Power and Conservation Council's DRAFT 6th Power Plan such as heat pump water heaters and ductless heat pumps, measures that may be applicable to the Rocky Mountain Power's Idaho customers and impact program expenditures in the near future.

9. ***Commercial and Industrial Programs***

The projected funding for Energy FinAnswer Express and Energy FinAnswer for the period May 1, 2010, through April 30, 2011, is $800,000. This is consistent with the 2009 level forecasted in Case No. PAC-E-08-01.

The FinAnswer Express program has been available in Idaho since early 2006 and was the sole program for business customers (other than those served on Schedule 10) until May 2008 when the Energy FinAnswer program became available. Since then the Energy FinAnswer and FinAnswer Express programs have operated as originally intended, providing a full range of services and incentives for virtually all energy efficiency projects in business customer facilities. The performance of the combined program for 2008 and 2009 when compared to the forecast in the prior application indicates 83 percent of the savings were achieved for 67 percent of the forecasted expenditures. The program's 2009 savings achievement is approximately 40 percent higher than 2008 savings.

Several factors contribute to steadily increasing participation. Increased energy efficiency messaging and awareness from the residential sector affects business customers. Selected investments in energy efficiency can improve operating margins in businesses and may present attractive investments when compared to increased production capacity projects considered in the recent past.

Idaho schools have increased their focus on energy efficiency, partially as the result of the Idaho Office of Energy's K-12 assessment program which started in 2009. While the analysis work is being performed by Idaho Office of Energy funded contractors, school districts served by Rocky Mountain Power have asked the Company for some additional analysis services as they prepare to prioritize their projects. The school analysis phase will likely be completed during 2010 and the Company expects some customers will utilize available utility incentives to assist with the funding of their most promising projects.

Completed Energy FinAnswer projects increased from 2008 to 2009 and the pipeline of forecasted projects has also increased. In two other markets, the Company has increased the availability of prescriptive incentives and improved the Energy FinAnswer incentive offer to better address emerging technologies and align with code changes, changing market conditions and other utility program offerings. The changes are expected to improve program participation generating greater savings opportunities through the program. These changes, which would require tariff changes, would also be applicable to the Idaho market but are not explicitly factored into these forecasted program expenditures at this time. Taking into consideration this combination of factors, 2010 program expenditures for these programs are forecasted, for the purpose of this Application, to be approximately 30 percent higher than the programs 2009 actual expenditures.

10. ***Agricultural Programs***

The projected funding for agriculture energy efficiency and load control programs for the period May 1, 2010, through April 30, 2011, is $4.9 million, an increase of $2.6 million when compared to the 2009 estimate in Case No. PAC-E-08-01.

The Irrigation Energy Services program has been available since early 2006. As described in the 2008 annual report, the program administrator was changed in early 2009 through a competitive selection process. The 2009 savings and expenses were 215 percent and 300 percent respectively of the 2008 program savings and expenditures. Energy savings for the 2008 through 2009 period were 111 percent of the 2008 application forecast and expenditures 85 percent of the 2008 and 2009 forecasts. Irrigation Energy Services program expenditures were $807,000 in 2009, the 2010 forecast includes $600,000 of program expenses. The 2010 forecast reflects a steady state operation with costs and savings below 2009 levels, but higher than the costs incurred in 2008.

The 2009 Irrigation Energy Services program is cost effective from a utility cost standpoint; however, it did not pass the total resource cost tests. Two primary factors contributed to this result: 1) the contribution of non-recurring transition costs associated with changing program administrators; and 2) customer specific costs associated with equipment investments that delivered operational efficiencies in addition to energy efficiency benefits. The simple pre-incentive pay-back for all 2009 projects completed through the program was 5.7 years; however, seven of these projects had simple paybacks of between 15 and 20 years. The additional customer costs from these seven projects had a negative impact on the total resource costs test results from a strictly electric energy savings perspective. The projects accounted for about 50 percent of the total customer costs reported by the program and were offset by utility incentives equal to about 12 percent heavily influencing overall program results. The Company acknowledges that most customers don't make uneconomic investments; therefore, there must be additional benefits beyond just electrical savings that compelled this set of customers to proceed with these projects. For any long payback projects such as those described above that are eligible for incentives, the current program administrator will take extra steps to align energy and non-energy benefits with project costs prior to project close-out and reporting project costs. As a result, this impact on the total resource cost test is not expected to recur and the program is forecasted to be cost effective under both the total resource cost and utility cost perspectives in 2010.

Several factors contribute to higher overall forecasted program expenses when compared with prior program delivery, not the least of which is moving beyond nozzle exchanges to more complex project work. In addition, and in response to grower needs, the program administrator is providing improved service to irrigation dealers and growers including faster turnaround and increased technical rigor for site work.

The program administrator has analyzed further changes to this program to increase prescriptive incentives and better align with other programs, including those of Idaho Power and the Bonneville Power Administration. Initial estimates of savings and costs for an improved program are generally comparable with the forecasted estimates provided for 2010.

The Irrigation Load Control Credit Rider program has grown significantly since its inception in 2003 with the greatest growth occurring between 2007 and 2008. The growth has been fueled by the loss of the regional residential and farm exchange credits and in addition, beginning in 2008, of the dispatchable control option. Actual participation in 2008 of 211 megawatts and in 2009 of 258 megawatts outpaced the Company's April 2008 forecast, provided in Case No. PAC-E-08-01, of 150 megawatts and 200 megawatts respectively. The rapid growth has driven increased complexity in delivery and costs, some of which were not envisioned and until now not fully reflected in prior company forecasts. With the increased complexity and costs additional resource flexibility has been gained, grower satisfaction improved, and the program remains one of the most cost-effective programs in the Company's DSM program portfolio.

In 2008, the full transition from static timer control equipment to two-way dispatchable technology provided for a more robust and responsive control platform. While the transition has increased program costs, the resource costs have remained least cost to alternative supply side capacity resource options. The two-way technology provides the necessary platform to manage a program the size of the Idaho program, enhances the network's operational integrity, and reduces grower crop risk. In addition, it allows for a more coordinated and deliberate dispatch event, allowing the Company to stagger off and on loads preceding and following the need for the resources, minimizing distribution system disruptions, improving overall system operations, and reliability. As previously noted, the initial expectations of the impact of the transition to the two-way control technology on program size have been exceeded with 2009 participation reaching 258 megawatts, 29 percent more load under management than forecasted during the Company's February 2008 tariff rider filing that established the current collection rate of 3.72 percent. Despite the growth in network size and commensurate delivery expenses the program remains very cost-effective with total cost and utility cost benefit ratios of 5.87 and 1.89 respectively. This filing forecasts additional program growth in 2010 to be a modest 2-5 megawatts, however, program costs are forecasted to increase from $3.8 million in 2009 to $4.3 million in 2010. The increasing costs are the result of several factors with the most noteworthy being the program costs starting to catch up with the resource requirements needed to deliver the program. The rapid growth has led to greater reliance on internal Company resources each year, a situation that, due to staffing considerations, is not sustainable longer term. Beginning in 2010, a greater reliance on external resources for the delivery of the program is forecasted. This is necessary to ensure sustainability in program delivery necessary to rely on the resource in our integrated resource planning process. In addition to having to outsource more of the program delivery, several other cost pressures are impacting the 2010 program costs: 1) market transitions in the digital communications industry have resulted in the lack of market support for less expensive forms of data transfers employed in the delivery of the program in 2008; 2) the recent acquisition of Alltel, the 2009 communications provider, by Verizon and possibility of communication conductivity issues resulting from the change in providers; and 3) greater network operations software expenses associated with the development of staggered dispatch routines and equipment. For purposes of this filing, only the forecasted 2010 program costs were used in the adjustment analysis, for both 2010 and 2011. Given the uncertainty around outsourcing more of the program in 2011 than that planned for 2010, the Company felt it prudent to wait on the results of a competitive bid process scheduled in 2010 for program delivery beginning in 2011 before attempting to assess the likely impact on future program costs and recovery requirements. As currently forecasted, the 2010 Irrigation Load Control Credit Rider program is expected to remain highly cost-effective with total cost and utility cost benefit ratios of 4.67 and 1.65 respectively.

11. ***Northwest Energy Efficiency Alliance (NEEA)***

The NEEA program funding included in this Application is approximately $467,000 compared to $287,000 for 2009.

The forecasted funding and estimated savings for Idaho's share of regional market transformation efforts is based on the NEEA Strategic Plan and 2010-2014 Business Plan. The plans were developed collaboratively with stakeholders in the region and were heavily informed by early findings in the Northwest Power and Conservation Council's work on the DRAFT 6th Power Plan suggesting that significant opportunity exists in the region for greater contributions to market transformation efforts. The result is a near doubling of annual funding requested by NEEA for the 2010-2014 funding cycle, compared to the prior two five-year funding cycles. In addition to the region and NEEA seeking to increase market transformation related work activity, cost per unit of savings from NEEA's efforts have increased as the complexity of the work has increased and the contribution from lighting savings have decreased. As a result, Rocky Mountain Power's Idaho share of NEEA expenses for 2010 are forecasted at approximately $180,000 higher than 2009 and over the entire 2010-2014 funding cycle to increase from roughly $1,584,000 (prior funding cycle of 2005-2009) to $2,903,514, or approximately $264,000 annually. Rocky Mountain Power joined other NEEA stakeholders in developing NEEA's plans and supports this increased activity and funding level.

PROPOSAL OF PROGRAM OPTIONS

12. Rocky Mountain Power is committed to continue to acquire cost-effective DSM resources. As noted in this Application all of the DSM programs offered by the Company are cost effective and benefit customers. However, the Company is also sensitive to the magnitude and impact of increasing the Customer Efficiency Service rate from 3.72 percent to 5.85 percent has on customers. Therefore, if the Commission determined that increasing Schedule No. 191 to 5.85 percent was not in the public interest at this time the Company is proposing the potential elimination of one or both of the following options for Commission consideration:

1) as highlighted in section 11 of this Application the current five-year NEEA contract expired at the end of 2009, the 2010-2014 funding cycle proposes to increase the average annual funding from $317,000 to $581,000 a 83 percent increase; and,

2) section 10 of the Application summarizes the agricultural programs offered by the Company representing over 68 percent of all DSM program expenditures that are collected through Schedule No. 191. The Irrigation Energy Services program has projected expenditure of $600,000 during 2010.

The funding for each of these programs represents approximately 0.4 percent of retail revenues subject to Schedule No. 191. If the Commission determined to discontinue both of these programs it would reduce the requested increase from 5.85 percent to 5.02 percent, reducing the annual revenues collected from $8.325 million to $7.144 million.

TARIFFS AND SUPPORTING DOCUMENTATION

13. Attachment 1 to this Application contains Customer Rule 102 implementation information, including the customer notice and the press release. Attachment 2 contains a preliminary cost effectiveness assessment of 2009 program performance, a final assessment will be provided to the Commission no later than March 15, 2010. Attachment 3 contains Rocky Mountain Power's 2010 projected program expenditures and savings, and Attachment 4 contains a summary of the cost-effective forecasts for 2010, supporting the proposed Schedule No. 191 collections. Attachment 5 contains Rocky Mountain Power's Table A, which shows the effect across rate schedules of the proposed Schedule No. 191 rate change and a clean and legislative copy of the tariff.

MODIFIED PROCEDURE

14. Rocky Mountain Power believes that consideration of the proposals contained in this Application does not require an evidentiary proceeding, and accordingly the Company requests that this Application be processed under RP 201 allowing for consideration of issues under modified procedure, i.e., by written submissions rather than by an evidentiary hearing.

SERVICE OF PLEADINGS

15. Communications regarding this Application should be addressed to:

Ted Weston
Rocky Mountain Power
Manager, Idaho Regulatory Affairs
201 South Main Street, Suite 2300
Salt Lake City UT 84111
Telephone: (801) 220-2963
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Telephone: (801) 220-4014
Facsimile: (801) 220-3299
E-mail: daniel.solander@pacificorp.com

In addition, Rocky Mountain Power respectfully requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail:
PacifiCorp
Data Request Response Center
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquires also may be directed to Ted Weston at (801) 220-2963.

CONCLUSION

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission issue an Order under Modified Procedure authorizing the Company to increase Tariff Schedule No. 191, Customer Efficiency Services Rate, to 5.85 percent as described herein effective May 1, 2010.

DATED this 25th day of February, 2010.

Respectfully submitted,

Mark C. Moench
Daniel E. Solander
Attorneys for PacifiCorp

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Rocky Mountain Power
Case No. PAC-E-10-03

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ATTACHMENT 2

Preliminary 2009 DSM Program Cost Effectiveness Assessment

February 25, 2010

2009 Demand Side Management Portfolio Cost Effectiveness Results

2009 Program Portfolio Including Irrigation Load Control

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder		$7,167,160	$26,743,767	$19,576,607	3.731
Total Resource Cost Test (TRC) No Adder		$7,167,160	$24,312,516	$17,145,355	3.392
Utility Cost Test (UCT)		$13,275,355	$24,312,516	$11,037,160	1.831
Rate Impact Test (RIM)		$16,537,350	$24,312,516	$7,775,166	1.47
Participant Cost Test (PCT)		$1,190,336	$11,587,079	$10,396,743	9.734
Lifecycle Revenue Impacts ($/kWh)					

2009 Energy Efficiency Program Portfolio

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0681	$3,350,743	$4,579,445	$1,228,702	1.367
Total Resource Cost Test (TRC) No Adder	0.0681	$3,350,743	$4,163,131	$812,389	1.242
Utility Cost Test (UCT)	0.0439	$2,160,407	$4,163,131	$2,002,724	1.927
Rate Impact Test (RIM)		$5,422,401	$4,163,131	($1,259,270)	0.768
Participant Cost Test (PCT)		$1,190,336	$4,288,548	$3,098,212	3.603
Lifecycle Revenue Impacts ($/kWh)				$0.000030233	

2009 Residential Program Portfolio

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0675	$988,283	$1,511,639	$523,356	1.53
Total Resource Cost Test (TRC) No Adder	0.0675	$988,283	$1,374,217	$385,935	1.391
Utility Cost Test (UCT)	0.0572	$837,532	$1,374,217	$536,685	1.641
Rate Impact Test (RIM)		$1,980,974	$1,374,217	($606,757)	0.694
Participant Cost Test (PCT)		$150,751	$1,618,585	$1,467,835	10.737
Lifecycle Revenue Impacts ($/kWh)				$0.000007928	

2009 Non-residential Program Portfolio

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0717	$2,362,460	$3,067,806	$705,345	1.299
Total Resource Cost Test (TRC) No Adder	0.0717	$2,362,460	$2,788,914	$426,454	1.181
Utility Cost Test (UCT)	0.0402	$1,322,875	$2,788,914	$1,466,039	2.108
Rate Impact Test (RIM)		$3,441,428	$2,788,914	($652,513)	0.81
Participant Cost Test (PCT)		$1,039,585	$2,669,962	$1,630,377	2.568
Lifecycle Revenue Impacts ($/kWh)				$0.000021233	

2009 Irrigation Load Control

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder		$3,816,417	$22,164,322	$18,347,905	5.808
Total Resource Cost Test (TRC) No Adder		$3,816,417	$20,149,384	$16,332,967	5.280
Utility Cost Test (UCT)		$11,114,948	$20,149,384	$9,034,436	1.813
Rate Impact Test (RIM)		$11,114,948	$20,149,384	$9,034,436	1.813
Participant Cost Test (PCT)		$0	$7,298,531	$7,298,531	n/a
Lifecycle Revenue Impacts ($/kWh)					

2009 Home Energy Savings Program

All Measures				AC: IRP 46% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0616	$723,668	$1,052,066	$328,398	1.454
Total Resource Cost Test (TRC) No Adder	0.0616	$723,668	$956,424	$232,755	1.322
Utility Cost Test (UCT)	0.0470	$552,666	$956,424	$403,757	1.731
Rate Impact Test (RIM)		$1,325,391	$956,424	($368,968)	0.722
Participant Cost Test (PCT)		$171,002	$1,103,461	$932,459	6.453
Lifecycle Revenue Impacts ($/kWh)				$0.0000045779	

2009 Refrigerator Recycling Program(See Ya Later Refigerator)

All Measures			AC: IRP 46% LF Decrement		
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0317	$80,425	$180,651	$100,226	2.246
Total Resource Cost Test (TRC) No Adder	0.0317	$80,425	$164,228	$83,803	2.042
Utility Cost Test (UCT)	0.0397	$100,676	$164,228	$63,552	1.631
Rate Impact Test (RIM)		$290,904	$164,228	($126,676)	0.565
Participant Cost Test (PCT)		($20,251)	$237,626	$257,878	n/a
Lifecycle Revenue Impacts ($/kWh)				$0.0000046624	

2009 Low Income Weatherization

All Measures			AC: IRP 46% LF Decrement		
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0479	$184,190	$278,922	$94,732	1.514
Total Resource Cost Test (TRC) No Adder	0.0479	$184,190	$253,566	$69,376	1.377
Utility Cost Test (UCT)	0.0479	$184,190	$253,566	$69,376	1.377
Rate Impact Test (RIM)		$364,678	$253,566	($111,112)	0.695
Participant Cost Test (PCT)		$0	$277,498	$277,498	n/a
Lifecycle Revenue Impacts ($/kWh)				$0.0000010946	

2009 Energy FinAnswer Program

All Measures			AC: IRP 65% LF Decrement		
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0378	$502,893	$1,058,318	$555,425	2.104
Total Resource Cost Test (TRC) No Adder	0.0378	$502,893	$962,107	$459,214	1.913
Utility Cost Test (UCT)	0.0251	$333,730	$962,107	$628,377	2.883
Rate Impact Test (RIM)		$974,479	$962,107	($12,372)	0.987
Participant Cost Test (PCT)		$169,163	$847,899	$678,736	5.012
Lifecycle Revenue Impacts ($/kWh)				$0.0000002336	

2009 FinAnswer Express Program

All Measures				AC: IRP 65% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0577	$379,621	$607,387	$227,766	1.600
Total Resource Cost Test (TRC) No Adder	0.0577	$379,621	$552,170	$172,549	1.455
Utility Cost Test (UCT)	0.0361	$237,527	$552,170	$314,643	2.325
Rate Impact Test (RIM)		$744,677	$552,170	($192,506)	0.741
Participant Cost Test (PCT)		$142,095	$595,611	$453,517	4.192
Lifecycle Revenue Impacts ($/kWh)				$0.0000042419	

2009 Irrigation Energy Savings Program

All Measures				AC: IRP 16% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0979	$1,479,946	$1,402,101	($77,845)	0.947
Total Resource Cost Test (TRC) No Adder	0.0979	$1,479,946	$1,274,637	($205,309)	0.861
Utility Cost Test (UCT)	0.0497	$751,618	$1,274,637	$523,019	1.696
Rate Impact Test (RIM)		$1,722,272	$1,274,637	($447,635)	0.74
Participant Cost Test (PCT)		$728,328	$1,226,452	$498,124	1.684
Lifecycle Revenue Impacts ($/kWh)				$0.000009864	

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Rocky Mountain Power
Case No. PAC-E-10-03

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ATTACHMENT 3

2010 - DSM Program Budget and Savings Forecast

February 25, 2010

Idaho 2010 Demand Side Management Program Budget and Savings Forecasts

Programs	2010 - MWH	2010 - MW	2010 - $
Low Income Weatherization	249		$ 225,000
Refrigerator Recycling	1,279		$ 186,500
Home Energy Savings	2,235		$ 564,000
Alliance	3,146		$ 298,880
Annual totals - Residential	**6,908**		**$ 1,274,380**
Energy FinAnswer	1,600		$ 480,000
FinAnswer Express	1,150		$ 324,000
Irrigation Efficiency	2,369		$ 600,000
Irrigation Interruptible		261	$ 4,300,000
Alliance	1,770		$ 168,120
Annual totals - business	**6,889**	**261**	**$ 5,872,120**
Annual totals - all	**13,796**	**261**	**$ 7,146,500**

all savings figures are gross and at site

Rocky Mountain Power Program Budget by Major Cost Category

Program	Incentives	Program delivery	Estimated Utility labor	Total
Low Income Weatherization	$ 33,750	$ 181,450	$ 9,800	$ 225,000
Refrigerator Recycling	$ 29,250	$ 146,000	$ 11,250	$ 186,500
Home Energy Savings	$ 395,198	$ 151,173	$ 17,750	$ 564,121
Energy FinAnswer	$ 139,200	$ 321,600	$ 19,200	$ 480,000
FinAnswer Express	$ 92,000	$ 212,250	$ 19,750	$ 324,000
Irrigation Efficiency	$ 292,252	$ 291,748	$ 16,000	$ 600,000
Irrigation Interruptible (a)	$ -	$ 4,233,200	$ 66,800	$ 4,300,000
Annual totals	**$ 981,650**	**$ 5,537,421**	**$ 160,550**	**$ 6,679,621**

(a) estimated incentives of $7,380,000 are recovered through base rates for this program

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ATTACHMENT 4

2010 DSM Portfolio Cost Effectiveness Forecast

February 25, 2010

2010 Forecast Demand Side Management Portfolio Cost Effectiveness

2010 Forecast Program Portfolio Including Irrigation Load Control

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder		$7,648,838	$25,638,760	$17,989,922	3.352
Total Resource Cost Test (TRC) No Adder		$7,648,838	$25,131,645	$17,482,806	3.286
Utility Cost Test (UCT)		$14,345,662	$25,131,645	$10,785,982	1.752
Rate Impact Test (RIM)		$17,979,090	$25,131,645	$7,152,554	1.398
Participant Cost Test (PCT)		$1,133,176	$12,606,359	$11,473,183	11.125
Lifecycle Revenue Impacts ($/kWh)					

2010 Forecast Energy Efficiency Program Portfolio

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0603	$3,348,838	$5,578,274	$2,229,435	1.666
Total Resource Cost Test (TRC) No Adder	0.0603	$3,348,838	$5,071,158	$1,722,320	1.514
Utility Cost Test (UCT)	0.0399	$2,215,662	$5,071,158	$2,855,495	2.289
Rate Impact Test (RIM)		$5,849,090	$5,071,158	($777,933)	0.867
Participant Cost Test (PCT)		$1,133,176	$4,776,359	$3,643,183	4.215
Lifecycle Revenue Impacts ($/kWh)				$0.0000204876	

2010 Forecast Residential Program Portfolio

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0467	$1,155,055	$2,284,038	$1,128,983	1.977
Total Resource Cost Test (TRC) No Adder	0.0467	$1,155,055	$2,076,398	$921,343	1.798
Utility Cost Test (UCT)	0.0367	$908,400	$2,076,398	$1,167,998	2.286
Rate Impact Test (RIM)		$2,523,159	$2,076,398	($446,761)	0.823
Participant Cost Test (PCT)		$246,655	$2,227,117	$1,980,462	9.029
Lifecycle Revenue Impacts ($/kWh)				$0.0000107261	

2010 Forecast Non-residential Program Portfolio

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.072	$2,193,783	$3,294,236	$1,100,453	1.502
Total Resource Cost Test (TRC) No Adder	0.072	$2,193,783	$2,994,760	$800,977	1.365
Utility Cost Test (UCT)	0.0429	$1,307,263	$2,994,760	$1,687,497	2.291
Rate Impact Test (RIM)		$3,325,931	$2,994,760	($331,171)	0.9
Participant Cost Test (PCT)		$886,520	$2,549,242	$1,662,721	2.876
Lifecycle Revenue Impacts ($/kWh)				$0.0000087217	

2010 Forecast Irrigation Load Control

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder		$4,300,000	$20,060,487	$15,760,487	4.665
Total Resource Cost Test (TRC) No Adder		$4,300,000	$20,060,487	$15,760,487	4.665
Utility Cost Test (UCT)		$12,130,000	$20,060,487	$7,930,487	1.654
Rate Impact Test (RIM)		$12,130,000	$20,060,487	$7,930,487	1.654
Participant Cost Test (PCT)		$0	$7,830,000	$7,830,000	n/a
Lifecycle Revenue Impacts ($/kWh)					

2010 Forecast Home Energy Savings Program

All Measures				AC: IRP 46% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0544	$799,142	$1,629,238	$830,096	2.039
Total Resource Cost Test (TRC) No Adder	0.0544	$799,142	$1,481,126	$681,983	1.853
Utility Cost Test (UCT)	0.0357	$525,253	$1,481,126	$955,873	2.820
Rate Impact Test (RIM)		$1,659,739	$1,481,126	($178,613)	0.892
Participant Cost Test (PCT)		$273,890	$1,559,397	$1,285,508	5.694
Lifecycle Revenue Impacts ($/kWh)				$0.0000022161	

2010 Forecast Refrigerator Recycling Program(See Ya Later Refigerator)

All Measures			AC: IRP 46% LF Decrement		
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0438	$146,415	$274,977	$128,562	1.878
Total Resource Cost Test (TRC) No Adder	0.0438	$146,415	$249,979	$103,564	1.707
Utility Cost Test (UCT)	0.0520	$173,650	$249,979	$76,329	1.440
Rate Impact Test (RIM)		$421,580	$249,979	($171,601)	0.593
Participant Cost Test (PCT)		($27,235)	$313,229	$340,464	n/a
Lifecycle Revenue Impacts ($/kWh)				$0.0000063159	

2010 Forecast Low Income Weatherization

All Measures			AC: IRP 46% LF Decrement		
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0426	$209,497	$379,823	$170,325	1.813
Total Resource Cost Test (TRC) No Adder	0.0426	$209,497	$345,293	$135,796	1.648
Utility Cost Test (UCT)	0.0426	$209,497	$345,293	$135,796	1.648
Rate Impact Test (RIM)		$441,840	$345,293	($96,547)	0.781
Participant Cost Test (PCT)		$0	$354,491	$354,491	n/a
Lifecycle Revenue Impacts ($/kWh)				$0.0000009511	

2010 Forecast Energy FinAnswer Program

All Measures			AC: IRP 65% LF Decrement		
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0537	$764,246	$1,242,323	$478,077	1.626
Total Resource Cost Test (TRC) No Adder	0.0537	$764,246	$1,129,385	$365,139	1.478
Utility Cost Test (UCT)	0.0314	$446,927	$1,129,385	$682,457	2.527
Rate Impact Test (RIM)		$1,126,710	$1,129,385	$2,675	1.002
Participant Cost Test (PCT)		$317,318	$907,726	$590,407	2.861
Lifecycle Revenue Impacts ($/kWh)				($0.0000000505)	

2010 Forecast FinAnswer Express Program

All Measures			AC: IRP 65% LF Decrement		
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0775	$698,696	$922,038	$223,342	1.320
Total Resource Cost Test (TRC) No Adder	0.0775	$698,696	$838,216	$139,520	1.200
Utility Cost Test (UCT)	0.0334	$301,676	$838,216	$536,540	2.779
Rate Impact Test (RIM)		$998,980	$838,216	($160,764)	0.839
Participant Cost Test (PCT)		$397,020	$816,981	$419,961	2.058
Lifecycle Revenue Impacts ($/kWh)				$0.0000035424	

2010 Forecast Irrigation Energy Savings Program

All Measures			AC: IRP 16% LF Decrement		
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0704	$730,841	$1,129,875	$399,034	1.546
Total Resource Cost Test (TRC) No Adder	0.0704	$730,841	$1,027,159	$296,318	1.405
Utility Cost Test (UCT)	0.0538	$558,659	$1,027,159	$468,500	1.839
Rate Impact Test (RIM)		$1,200,241	$1,027,159	($173,083)	0.856
Participant Cost Test (PCT)		$172,182	$824,535	$652,353	4.789
Lifecycle Revenue Impacts ($/kWh)				$0.0000038139	

Rocky Mountain Power
Case No. PAC-E-10-03

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ATTACHMENT 5

Table A – Rate Impact by Schedule and Revised Schedule No. 191

February 25, 2010

TABLE A BY SCHEDULE
ROCKY MOUNTAIN POWER
REVISION TO CUSTOMER EFFICIENCY SERVICES RATE ADJUSTMENT
FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN IDAHO
12 MONTHS ENDING DECEMBER 2008

Line No.	Description	Present Sch.	Average No. of Customers	MWH	Present Revenue ($000)	Schedule 191 Present ($000)	Schedule 191 Proposed ($000)	Schedule 191 %	Net Change ($000)	Net Change %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) (7)/(5)	(9)	(10) (9)/(5)
	Residential Sales									
1	Residential Service	1	40,193	398,783	$36,406	$1,354	$2,130	5.85%	$775	2.13%
2	Residential Optional TOD	36	16,601	310,340	$22,920	$853	$1,341	5.85%	$488	2.13%
3	Net Metering	135	0	0	$0	$0	$0	0.00%	$0	2.13%
4	Unbilled	--	--	0	$0					
5	**Total Residential**		56,794	709,122	$59,325	$2,207	$3,471	5.85%	$1,264	2.13%
6	**Commercial & Industrial**									
7	General Service - Large Power	6	1,056	297,534	$18,957	$705	$1,109	5.85%	$404	2.13%
8	General Svc. - Lg. Power (R&F)	6A	250	35,158	$2,433	$91	$142	5.85%	$52	2.13%
9	Subtotal-Schedule 6		1,306	332,692	$21,390	$796	$1,251	5.85%	$456	2.13%
10	General Service - Med. Voltage	8	0	0	$0	$0	$0	0.00%	$0	2.13%
11	General Service - High Voltage	9	12	105,183	$5,331	$198	$312	5.85%	$114	2.13%
12	Irrigation	10	5,294	618,674	$43,253	$1,609	$2,530	5.85%	$921	2.13%
13	Comm. & Ind. Space Heating	19	186	7,610	$528	$20	$31	5.85%	$11	2.13%
14	General Service	23	6,314	126,659	$10,190	$379	$596	5.85%	$217	2.13%
15	General Service (R&F)	23A	1,401	17,981	$1,517	$56	$89	5.85%	$32	2.13%
16	Traffic Signals	23S	3	7	$1	$0	$0	5.85%	$249	2.13%
17	Subtotal-Schedule 23		7,717	144,648	11,707	$436	$685			
18	General Service Optional TOD	35	3	2,115	$143	$5	$8	5.85%	$3	2.13%
19	Special Contract 2		1	1,384,364	$56,806	$0	$0	0.00%	$0	0.00%
20	Special Contract 1		1	105,214	$4,255	$0	$0	0.00%	$0	0.00%
21	Unbilled	--	--	0	$0	$0	$0	0.00%	$0	
22	**Total Commercial & Industrial**		14,520	2,700,500	$143,414	$3,064	$4,818	3.36%	$1,754	1.22%
23	**Total Commercial & Industrial (Excluding Special Contracts)**		14,518	1,210,922	$82,354	$3,064	$4,818	5.85%	$1,754	2.13%
24	**Public Street Lighting**									
25	Security Area Lighting	7	221	275	$101	$4	$6	5.85%	$2	2.13%
26	Security Area Lighting (R&F)	7A	186	131	$52	$2	$3	5.85%	$1	2.13%
27	Street Lighting - Company	11	32	131	$56	$2	$3	5.85%	$1	2.13%
28	Street Lighting - Customer	12	297	2,166	$401	$15	$23	5.85%	$9	2.13%
29	Traffic Signal Systems	12	25	165	$16	$1	$1	5.85%	$0	2.13%
30	Unbilled	--	--	0	$0					
31	**Total Public Street Lighting**		761	2,867	$626	$23	$37	5.85%	$13	2.08%
32	**AGA (Revenue Credit)**				$540					
33	**Total Sales to Ultimate Customers**		72,075	3,412,490	$203,906	$5,294	$8,325	4.08%	$3,031	1.49%
34	**Total Sales to Ultimate Customers (Excluding Special Contracts & AGA)**		72,073	1,922,912	$142,306	$5,294	$8,325	5.85%	$3,031	2.13%

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 191

STATE OF IDAHO

Customer Efficiency Services Rate Adjustment

PURPOSE: The Customer Efficiency Services Rate Adjustment is designed to recover the costs incurred by the Company associated with Commission-approved demand-side management expenditures.

APPLICATION: This Schedule shall be applicable to all retail tariff Customers taking service under the Company's electric service schedules.

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have the following percentage increases applied prior to the application of electric service Schedule 34.

Schedule 1	5.85~~3.72~~ %
Schedule 6	5.85 ~~3.72~~ %
Schedule 6A	5.85 ~~3.72~~ %
Schedule 7	5.85 ~~3.72~~ %
Schedule 7A	5.85 ~~3.72~~ %
Schedule 8	5.85 ~~3.72~~ %
Schedule 9	5.85 ~~3.72~~ %
Schedule 10	5.85 ~~3.72~~ %
Schedule 11	5.85 ~~3.72~~ %
Schedule 12 – Street Lighting	5.85 ~~3.72~~ %
Schedule 12 – Traffic Signal	5.85 ~~3.72~~ %
Schedule 19	5.85 ~~3.72~~ %
Schedule 23	5.85 ~~3.72~~ %
Schedule 23A	5.85 ~~3.72~~ %
Schedule 24	5.85 ~~3.72~~ %
Schedule 35	5.85 ~~3.72~~ %
Schedule 35A	5.85 ~~3.72~~ %
Schedule 36	5.85 ~~3.72~~ %

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 191

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Schedule 1	5.85 %
Schedule 6	5.85 %
Schedule 6A	5.85 %
Schedule 7	5.85 %
Schedule 7A	5.85 %
Schedule 8	5.85 %
Schedule 9	5.85 %
Schedule 10	5.85 %
Schedule 11	5.85 %
Schedule 12 – Street Lighting	5.85 %
Schedule 12 – Traffic Signal	5.85 %
Schedule 19	5.85 %
Schedule 23	5.85 %
Schedule 23A	5.85 %
Schedule 24	5.85 %
Schedule 35	5.85 %
Schedule 35A	5.85 %
Schedule 36	5.85 %