ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

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IDAHO PUBLIC
UTILITIES COMMISSION

November 2, 2011

VIA OVERNIGHT DELIVERY

Jean D. Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702

Attention: Jean D. Jewell
Commission Secretary

RE: Case No. PAC-E-11-12 – In the Matter of the Application of PacifiCorp dba Rocky Mountain Power for Approval of Changes to its Electric Service Schedules and Price Increase of $32.7 Million, or Approximately 15.0 Percent

Enclosed please find the original and seven (7) copies of the testimony and exhibits of J. Ted Weston in support of the Stipulation entered into by and among Rocky Mountain Power, a division of PacifiCorp, and the following parties of record in the above captioned matter: Staff for the Idaho Public Utilities Commission; the Idaho Irrigation Pumper Association Inc.; Monsanto Company; and PacifiCorp Idaho Industrial Customers. Community Action Partnership Association of Idaho participated in the settlement negotiations however they have chosen not to be a party to the Stipulation. The Idaho Conservation League also participated in settlement negotiations but have since formally withdrawn from this proceeding.

Please contact J. Ted Weston at (801) 220-2963 if you have any further questions.

Very Truly Yours,

Jeffrey K Larsen

Jeffrey K. Larsen
Vice President of Regulation
Rocky Mountain Power

Enclosures

CERTIFICATE OF SERVICE

I hereby certify that on this 2nd of November, 2011, I caused to be served, via e-mail and/or US mail, a true and correct copy of the foregoing document in PAC-E-11-12 to the following:

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Coordinator, Regulatory Operations

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UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES AND A PRICE INCREASE OF $32.7 MILLION, OR APPROXIMATELY 15.0 PERCENT	))))))))	**CASE NO. PAC-E-11-12** **Stipulation Testimony of J. Ted Weston**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-11-12

November 2011

Q. Please state your name, business address and present position with Rocky Mountain Power (the "Company"), a division of PacifiCorp.

A. My name is J. Ted Weston and my business address is 201 South Main, Suite 2300, Salt Lake City, Utah, 84111. I am currently employed as the Manager of Idaho Regulatory Affairs for the Company.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science Degree in Accounting from Utah State University in 1983. I joined the Company in June of 1983 and I have held various accounting and regulatory positions prior to my current position. In addition to formal education, I have attended various educational, professional and electric industry related seminars during my career with the Company.

Q. What are your responsibilities as Manager of Regulatory Affairs?

A. My primary responsibilities include the coordination and management of Idaho regulatory filings, communications with the Commission and staff, and oversight of reporting requirements for the Company with the Idaho Public Utilities Commission.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified before this Commission, the Washington Transportation and Utilities Commission and the Wyoming Public Service Commission.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present and support the Stipulation reached in the Company's 2011 general rate case entered into by and among Rocky Mountain Power, a division of PacifiCorp ("Rocky Mountain Power" or the "Company"); Staff for the Idaho Public Utilities Commission ("Staff"); the Idaho Irrigation Pumpers Association, Inc. ("IIPA"); Monsanto Company ("Monsanto"); and the PacifiCorp Idaho Industrial Customers ("PIIC") collectively referred to in my testimony as the Parties. Community Action Partnership Association of Idaho ("CAPAI") participated in the settlement negotiations; however, they have chosen not to be a party to the Stipulation. The Idaho Conservation League also intervened in the case and participated in the settlement negotiations but later formally withdrew as a party in this proceeding.

More specifically, my testimony provides an overview of the Company's 2011 Idaho general rate case and an explanation of the terms and conditions of this Stipulation. I also demonstrate that this Stipulation represents a fair, just and reasonable compromise of the issues in this proceeding and that this Stipulation is in the public interest. My testimony supports the Parties' recommendation that the Idaho Public Utilities Commission ("Commission") approve the Stipulation and all of its terms and conditions.

Background

Q. What price increase did the Company request in its Application for this case?

A. On May 27, 2011, Rocky Mountain Power filed an Application with the Commission supported by the testimony of 13 witnesses with several hundreds of pages of testimony and forty-nine exhibits seeking authority to increase the

Company's base rates for electric service by $32.7 million annually, representing an average increase of approximately 15.0 percent. In the Application Rocky Mountain Power sought new rates effective date of June 27, 2011.

On June 8, 2011 the Commission suspended the rates that were the subject of the Application for a period of thirty (30) days plus five (5) months making the rate effective date December 27, 2011. Parties to the Stipulation are respectfully requesting that the Commission approve this Stipulation with January 1, 2012, as the rate-effective date.

Q. **Has the Company's Application been thoroughly audited and reviewed by the intervening parties in this case?**

A. Yes. As part of Staff's audit of this Application several meetings were held with Company representatives during the weeks of August 8 in Portland, Oregon and August 15 in Salt Lake City, Utah. In addition, the intervening parties have asked hundreds of discovery requests which the Company has responded to.

Representatives of the intervening parties met August 23 and September 22, 2011 with the Company at the Commission's office, pursuant to IDAPA 31.01.01.271 and 272, to engage in settlement discussions with a view toward resolving the issues raised in Rocky Mountain Power's Application in this proceeding. Based upon the discussions between the Parties, and as a compromise of the positions in this proceeding a settlement was reached.

Q. **What Test Period did the Company use to determine revenue requirement in this case?**

A. The Test Period for this Application was based on the historical 12-month period ending December 31, 2010, adjusted for known and measurable changes through December 31, 2011. The Test Period was prepared consistent with past Commission practice and the Company's general rate cases filed previously in Idaho.[1] The Company filed rate base on an end-of-period basis, which includes the actual rate base at December 31, 2010 plus major capital additions that will go into service by December 31, 2011.

Stipulation

Q. What is the foundation for the rate increase that the Parties agreed to in this Stipulation?

A. The Parties agreed that the starting point of the Stipulation was to accept all Commission ordered adjustments from Case No. PAC-E-10-07, Order No. 32196. Beyond that as a starting point and unless explicitly specified within the Stipulation, the Parties agreed that this was a "black box" settlement, with no agreement or acceptance by the Parties of any specific revenue requirement, cost allocation or cost of service methodology. All Parties agree that this Stipulation represents a fair, just and reasonable compromise of the issues in this proceeding and that this Stipulation is in the public interest.

Q. Please describe the terms of the Stipulation entered into by the Parties.

A. The Parties agree to support a two-year rate plan with annual rate increases of $17.0 million per year, which results in overall average annual revenue increases of approximately 7.8 percent in 2012 and 7.2 percent in 2013. The first increase to base rates will occur January 1, 2012, and will be comprised of $6.0 million of non-net power cost components (capital, operations and maintenance, and other)

[1] Refer to pages 9 and 10 of the direct testimony of Mr. Steven R. McDougal in Case No. PAC-E-11-12.

and $11.0 million of net power costs. The second increase to base rates will occur January 1, 2013, and will be comprised of $6.0 million of non-net power cost components and $11.0 million of net power costs.

Q. Why did the Parties identify the revenue requirement components between net power cost and non-net power cost?

A. Simply identifying the annual revenue requirement increase would not provide clarity to the amount of net power costs included in customers base rates. The Parties recognized that the function of the Energy Cost Adjustment Mechanism ("ECAM") is to track the difference between actual net power costs incurred to serve customers and the level of net power costs included in customers rates. Therefore, it was necessary for the Stipulation to specify that $11.0 million of increase in 2012 and in 2013 were due to increases in net power costs. Because the ECAM is based on monthly total Company dollars per megawatt-hour, Paragraph 4 of the Stipulation clarifies that the $11.0 million annual increase to net power costs on an Idaho basis represents an increase to Commission approved total Company net power costs in base rates of $1.025 billion to $1.205 billion in 2012 and from $1.205 billion to $1.385 billion in 2013. These amounts will become the total Company base net power costs for future tracking in the Company's ECAM.

Q. Does the Stipulation specify other ECAM related items?

A. Yes. The Stipulation specifies that the level of renewable energy certificate ("REC") revenue included in rates in 2012 and 2013 will be $78.8 million, on a total Company basis or $6,526,622 allocated to Idaho. This Idaho allocated amount will become the base for purposes of tracking at 100 percent in the Company's ECAM mechanism.

The Stipulation also specifies that the Idaho base load in the 2012 ECAM load change adjustment revenue ("LCAR") calculation would be the 2010 load included in Case No. PAC-E-11-12 for the 2012 ECAM deferral calculation and the 2011 load reported in the Annual Results of Operations Report for the 2013 ECAM deferral calculation.

The Stipulation also specifies that the LCAR unit value would be frozen over the rate plan period at the current rate of $5.47 per MWh (Case No. PAC-E-10-07).

Finally, the Stipulation specifies that, due to the uncertainty of the jurisdictional treatment of the dispatchable irrigation load control program currently being discussed by the MSP Standing Committee, Idaho's share of the customer load control service credit will be tracked in the ECAM. The Stipulation identifies that $1,045,423 is Idaho's current base amount that would be tracked in the ECAM for 2012 and 2013. There are two items that could change Idaho's actual expense amount: first, if other states don't support system allocation of the irrigation program; second, the agreement for the current load control service credit expires after the 2012 program season.

Q. **What was the single largest factor that the parties took into consideration during settlement discussions?**

A. The key issue dealt with by the Stipulation was to address customer rate impact from both general rate case changes and the potential changes from ECAM surcharges. Since net power costs were the single largest cost driver in this case and with the Company expecting the 2011 ECAM deferral to be in the range of $15 to $18 million, it was critical the Stipulation holistically address net power costs. Approximately 51 percent of the $32.7 million increase requested by the Company in this application, or $16.8 million, was due to increases in net power costs. On a total-Company basis, net power costs included in the Application and supported in the testimony of Company witness of Mr. Gregory N. Duvall were $1.311 billion during the test year, an increase of more than $287 million above the $1.025 billion approved by the Commission in Case No. PAC-E-10-07 and currently included in customer's rates. The Company expects actual net power costs for 2011 will be closer to $1.35 billion, increasing to over $1.5 billion during calendar year 2012.

One additional factor compounding the rate impact for Monsanto and Agrium is that April 1, 2012, will be the first time their tariff contract based load would be subject to the ECAM.[2] The Parties recognized that whatever decision they reached regarding net power costs in the rate case had a direct impact on the Company's ECAM.

Q. How does the Stipulation address the rate impact of increasing net power costs?

A. The Stipulation mitigates the rate impact in three ways. First, the rate plan spreads the increase over two years for most of the Company's customers who are already paying the ECAM rider. Second, for Agrium and Monsanto, because 2011 is the first year that their tariff contract loads are subject to the ECAM, the Stipulation

[2] All other retail tariff customers were subject to Schedule 94, Energy Cost Adjustment rates, April 1, 2010.

includes an innovative tiered approach of amortizing the deferred net power cost in the ECAM for this usage. This tiered approach allows Monsanto and Agrium to defer paying some of the ECAM increases to future years to smooth out the impact the ECAM increases would have along with the general rate increases, while at the same time continuing to allow the Company certainty of cost recovery for these costs. Third, the Stipulation specifies that the Company won't file another general rate case before May 31, 2013, with new rates not effective prior to January 1, 2014. Absent this Stipulation, the Company would probably have filed a general rate case in 2012 with rates effective in 2013 that would have included net power costs in excess of $1.5 billion. The Stipulation only increases net power costs to $1.385 billion in 2013, significantly less than what the Company projects it would be absent the Stipulation. Ultimately, 90 percent of the difference between actual net power costs and in-rates net power costs will be deferred and collected in the ECAM, customers get the benefit of the delay in paying the higher level until the costs become "actual" and also benefit from 10 percent of the incremental difference not being included in the ECAM deferral.

Q. Would you explain how the amortization you referred to will work?

A. The Stipulation specifies that the Company will amortize and collect Agrium and Monsanto's tariff contract share of Commission approved ECAM balances, which includes deferred net power costs, REC revenues, LCAR, the incremental irrigation load control credit and any other ECAM components, such as $S0^2$ sales, over the following periods:

(1) The Commission-determined 2012 ECAM balance, based on the 2011

deferrals, will be amortized beginning April 1, 2012 over a three-year period ending March 31, 2015. Any over or under collection of the 2012 ECAM balance would be added to the 2015 ECAM balance.

(2) The Commission-determined 2013 ECAM balance, based on the 2012 deferrals, will also be amortized over a three-year period beginning April 1, 2013 through March 31, 2016, with any over or under collection of that balance added to the 2016 ECAM balance.

(3) The Commission-determined 2014 ECAM balance, based on the 2013 deferrals, will also be amortized, but over a two-year period beginning April 1, 2014 through March 31, 2016, with any over-collection or under-collection of that balance added to the 2016 ECAM balance.

(4) Beginning with the Commission-determined 2015 ECAM balance, based on the 2014 deferrals, Monsanto and Agrium will pay new ECAM costs based on a 12-month collection period.

(5) Any over-collection or under-collection at the end of the amortization periods above will be trued up for each contract customer and refunded or collected as part of a subsequent ECAM collection period from these contract customers and not from other retail customers.

Q. Does the amortization apply to the small portion of Agrium's load that is served on Schedule 6 and 9?

A. No. The portion of Agrium's load served on Schedule 6 and 9 have been subject to and paying the ECAM, Schedule 94 rate, since its initial rate implementation effective April 1, 2010. The amortization schedule only applies to Agrium and

Monsanto's tariff contract load for which 2011 was the first year impacted by the ECAM.

Q. How will the Company assure that Agrium, Monsanto and the other retail customers pay only their portion of the ECAM balance?

A. Currently the Company provides Staff quarterly reports detailing the monthly ECAM deferral balances. The report has a section listing actual Idaho retail load, adjusted for line losses. This section will be expanded to provide detail of Agrium, Monsanto, and all other Idaho retail customers' load. The megawatt hours for each of these customer groups will be multiplied by the monthly net power cost differential, between base net power costs and actual net power costs to determine the net power cost deferral for each group. Then the remaining ECAM components would be spread using the same megawatt hour ratio for the month. The Company will track and report the monthly balances for these three groups through the amortization period.

Q. Does this amortization impact any other customers?

A. No. All other customers will continue to pay ECAM charges on a 12-month collection period for only their portion of the deferral as they currently do. Because the other retail customers are already paying the current Schedule 94, Energy Cost Adjustment rate on their monthly bill, the Company expects that they will experience very minor rate changes associated with the ECAM over the rate plan. The rate changes are estimated to be in the range of one to two percent increase in 2012 and by 2013 and 2014 they possibly could experience no change or a small reduction to their ECAM collection rate.

Other Terms of the Stipulation

Q. Does the Stipulation settle the value of Monsanto's curtailment products?

A. Yes. Paragraph 14 of the Stipulation specifies that the value of Monsanto's curtailment products will be increased for 2012 and 2013 from the amount approved by the Commission in Case No. PAC-E-10-07. If this Stipulation is approved by the Commission Monsanto and the Company will execute a new Electric Service Agreement for 2012 and 2013 in order to reflect the terms of the Stipulation.

Q. Does the Stipulation address the irrigation load control program?

A. Yes. The Stipulation does not change or alter the irrigation load control service credit in 2012 or prior agreements governing the irrigation load control program that require the irrigation load control service credit to be renegotiated for the 2013 season and beyond. However, the Stipulation specifies that $1,045,423 will be Idaho's base amount associated with the system allocation of the Type 1 DSM program costs included in customer's rates and that any incremental changes due to allocations or revisions to the irrigation load control program costs would be tracked in the ECAM.

Q. Does the Stipulation address the treatment of the Populus to Terminal transmission line?

A. Yes. The Parties to the Stipulation agree that the portion of the Populus to Terminal transmission line determined in Case No. PAC-E-10-07 to be plant held for future use ("PHFU") is now used and useful. The Parties further agreed that the Commission should make a specific finding that the entire Populus to

Terminal transmission line is now used and useful. The Parties respectfully request that the Commission make that finding in its order approving the Stipulation.

Although the Parties agree that the Populus to Terminal transmission line is used and useful, they further agree that the portion of the transmission line deemed PHFU in Case No. PAC-E-10-07 shall not be included in customer's rates until the rate-effective date from the Company's next general rate on or after January 1, 2014. The Parties to the Stipulation agree that the Company will continue to defer the depreciation expense associated with the Populus to Terminal transmission line, pursuant to Order No. 32224, until it is included in rates on or after January 1, 2014, and that this accumulated deferred balance will be amortized over three years from the date the costs are included in rates.

Finally, Staff, Monsanto, and the Company agree to file a Motion to Suspend the Appeal on the Populus to Terminal transmission line decision now pending in the Idaho Supreme Court, docketed as Case No. 38930-2011. A motion to suspend the procedural schedule was filed October 28, 2011 with the Idaho Supreme Court. If the Commission makes the findings requested in the Stipulation on this issue, the Company and Parties agrees that within 10 days thereof they will file a stipulation with the Idaho Supreme Court for Dismissal of the appeal.

The effect of these agreements on the Populus to Terminal transmission line is a reasonable compromise of the issues pending on Appeal and avoidance of the costs of further litigation of those issues. Although the Parties agree that the entire transmission line is currently used and useful and that the Commission should make a finding to that effect, they also agree to delay recovery of the portion of the costs disallowed for current recovery in rates in Case No. PAC-E-10-07 until on or after January 1, 2014.

Hedging

Q. How does the Stipulation address future hedging costs?

A. The Stipulation specifies that the Company will work with the Parties to establish hedging limits consistent with workgroup processes established in Utah and Oregon for new costs beginning January 1, 2013, and forward. These new costs would be related to new hedging contracts entered into on or after that date.

Rate Design

Q. How does the Stipulation address rate design?

A. The Stipulation specifies that the design of rates by rate schedule (rate design) will be consistent with the Company's proposals filed in its Application, adjusted for the $17.0 million annual revenue requirement with one modification. The Company's proposal increases the residential customer service charge for Schedule 1 and 36 was not adopted. The customer service charge for Schedule 1 and 36 will remain at $5.00 per month and $14.00 per month, respectively, during the two-year rate plan. A summary of the Stipulation rate design by rate schedule is provided in the following table.

Stipulation Rate Design Summary

Schedule	Average Increase	Customer Charge	Demand Charge	Energy Charge
1	5.88%	no change		collect the total revenue
36	7.96%	no change		collect the total revenue
6, 35	6.70%	average	3% higher than average	collect the rest of the revenue
9	7.02%	average	4% higher than average	collect the rest of the revenue
10	8.91%	average	5% higher than average	collect the rest of the revenue
7,11,12	1.07%	uniformly percentage increase to all billing elements		
19	6.40%	uniformly percentage increase to all billing elements		
23	6.88%	uniformly percentage increase to all billing elements		
SPC 1	8.91%	uniformly percentage increase to all billing elements		
SPC 2	8.91%	uniformly percentage increase to all billing elements		

Rate Spread

Q. Does the Stipulation specify how the $17.0 million revenue requirement increase will be spread between customer classes?

A. Yes. The Stipulation specifies how to calculate the rate spread, details of the rate spread are included as Exhibit 49 of my testimony. A summary of the rate spread is presented in the following table:

Rate Spread Comparison

Customer Class	Proposed	Settled
Residential – Schedule 1	7.92%	5.88%
Residential – Schedule 36	15.9%	7.96%
General Service		
Schedule 23/23A	11.8%	6.88%
Schedule 6/6A/8/35	10.8%	6.70%
Schedule 9	11.2%	7.02%
Schedule 19	9.70%	6.40%
Irrigation		
Schedule 10	19.9%	8.91%
Public Street Lighting		
Schedules 7/7A, 11, 12	0%	1.07%
Schedule 400	18.7%	8.91%
Schedule 401	19.9%	8.91%

Q. How will the Stipulation impact residential customers?

A. Idaho's average residential customer on Schedule 1 uses 837 kWh a month. At that usage level residential customers would experience a $4.84 increase per month to their bills.

Q. Has the Company updated its tariff schedules based on the Stipulation?

A. Yes. Exhibit 50 contains the clean and legislative copies of the Company's Idaho tariff schedules based on the terms of the Stipulation. The Parties to the Stipulation respectfully request that the Commission approve the Stipulation and these tariffs as filed.

Conclusion

Q. Does the Company believe the Stipulation represents a fair, just and reasonable compromise of the issues and is in the public interest?

A. Yes. All Parties to the Stipulation negotiated in good faith to reach a reasonable outcome. The Company believes that its initial request of $32.7 million was justified to meet the cost of serving its customers in Idaho. However, in an effort to reach an agreement with Parties, the Company was willing to reduce that request and stipulate to $17.0 million price increases on January 1, 2012, and January 1, 2013. In recognition of the two-year rate plan covered by this Stipulation, Rocky Mountain Power will not file another general rate case before May 31, 2013, with new rates not effective prior to January 1, 2014. Rocky Mountain Power will continue to file annual Results of Operations Reports with the Commission to enable the Commission to ensure that rates during the two-year rate plan continue to be just and reasonable. The Company has been prudent in securing resources for the benefit of its Idaho customers and should be granted cost recovery of these expenditures. The Company will continue to work to control its costs while implementing mechanisms and pricing proposals to help customers use electricity more efficiently. For these reasons the Company supports the Stipulation entered into and respectfully requests that the Commission approve it as filed.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-11-12
Exhibit No. 49
Witness: J. Ted Weston

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Stipulation Testimony of J. Ted Weston

Rate Spread

November 2011

ROCKY MOUNTAIN POWER
CASE NO. PAC-E-11-12
STIPULATED RATE SPREAD FOR THE TWO-YEAR RATE PLAN

Description	Sch. No.	Base Revenue	First Year Increase	First Year Total	First Year Percent	Second Year Increase	Second Year Total	Second Year Percent	Two Year Increase	Two Year Total	Two Year Percent
Residential	01	$41,480,591	$2,439,725	$43,920,316	5.88%	$2,385,257	$46,305,573	5.43%	$4,824,982	$46,305,573	11.63%
Residential - TOD	36	$22,532,610	$1,794,697	$24,327,307	7.96%	$1,796,941	$26,124,248	7.39%	$3,591,638	$26,124,248	15.94%
General Service - Large	06, 35	$21,103,808	$1,413,559	$22,517,367	6.70%	$1,397,532	$23,914,899	6.21%	$2,811,091	$23,914,899	13.32%
General Service - High Voltage	09	$5,889,323	$413,459	$6,302,782	7.02%	$410,273	$6,713,055	6.51%	$823,732	$6,713,055	13.99%
Irrigation	10	$41,151,802	$3,664,898	$44,816,700	8.91%	$3,695,252	$48,511,952	8.25%	$7,360,150	$48,511,952	17.89%
Street & Area Lighting	07,11,12	$597,888	$6,405	$604,293	1.07%	$3,670	$607,963	0.61%	$10,075	$607,963	1.69%
Space Heating	19	$454,158	$29,088	$483,246	6.40%	$28,653	$511,899	5.93%	$57,741	$511,899	12.71%
General Service - Small	23	$13,014,299	$895,307	$13,909,606	6.88%	$887,023	$14,796,629	6.38%	$1,782,330	$14,796,629	13.70%
Contract 1	400	$66,330,739	$5,907,284	$72,238,023	8.91%	$5,956,211	$78,194,234	8.25%	$11,863,495	$78,194,234	17.89%
Contract 2	401	$4,890,954	$435,579	$5,326,533	8.91%	$439,186	$5,765,719	8.25%	$874,765	$5,765,719	17.89%
State of Idaho	Total	$217,446,172	$17,000,000	$234,446,172	7.82%	$17,000,000	$251,446,172	7.25%	$34,000,000	$251,446,172	15.64%
AGA Revenue		*$751,615*		*$751,615*			*$751,615*			*$751,615*	
State of Idaho + AGA	Total	$218,197,787		$235,197,787	7.79%		$252,197,787	7.23%		$252,197,787	15.58%

ROCKY MOUNTAIN POWER - STATE OF IDAHO
CASE NO. PAC-E-11-12
DETAILED RATE SPREAD

		STIPULATION	
	Present	Year 1 1/1/2012	Year 2 1/1/2013
SCHEDULE NO. 1 - Residential Service			
Customer Charge	$5.00	$5.00	$5.00
All kWh (May - Oct)			
<= 700 kWh	9.6018 ¢	10.2013 ¢	10.7874 ¢
> 700 kWh	12.9624 ¢	13.7717 ¢	14.5630 ¢
All kWh (Nov - Apr)			
<= 1,000 kWh	7.3496 ¢	7.8085 ¢	8.2571 ¢
> 1,000 kWh	9.9220 ¢	10.5415 ¢	11.1472 ¢
Seasonal Service Charge	$60.00	$60.00	$60.00
SCHEDULE NO. 36 - Residential Service Optional TOD			
Customer Charge	$14.00	$14.00	$14.00
On-Peak kWh (May - Oct)	12.2191 ¢	13.3102 ¢	14.4027 ¢
Off-Peak kWh (May - Oct)	4.1697 ¢	4.5420 ¢	4.9148 ¢
On-Peak kWh (Nov - Apr)	10.4377 ¢	11.3697 ¢	12.3029 ¢
Off-Peak kWh (Nov - Apr)	3.8162 ¢	4.1570 ¢	4.4982 ¢
Seasonal Service Charge	$168.00	$168.00	$168.00
SCHEDULE NO. 6/6A - General Service - Large Power			
Customer Charge (Secondary Voltage)	$33.00	$35.00	$37.00
Customer Charge (Primary Voltage)	$99.00	$105.00	$111.00
All kW (May - Oct)	$12.22	$13.28	$14.36
All kW (Nov - Apr)	$10.05	$10.92	$11.81
All kWh	3.3805 ¢	3.5305 ¢	3.6696 ¢
Seasonal Service Charge (Secondary)	$396.00	$420.00	$444.00
Seasonal Service Charge (Primary)	$1,188.00	$1,260.00	$1,332.00
Voltage Discount	($0.57)	($0.61)	($0.65)
SCHEDULE NO. 7 - Customer Owned Light			
Residential			
Charges Per Lamp			
16,000 Lumens, HPSV	$14.67	$14.82	$14.91
SCHEDULE NO. 7/7A - Security Area Lighting			
Charges Per Lamp			
7000 Lumens, MV	$26.40	$26.67	$26.83
20,000 Lumens, MV	$47.09	$47.58	$47.86
5,600 Lumens, HPSV, Co Owned Pole	$16.77	$16.94	$17.04
5,600 Lumens, HPSV, No Co Owned Pole	$13.34	$13.48	$13.56
9,500 Lumens, HPSV, Co Owned Pole	$19.20	$19.40	$19.51
9,500 Lumens, HPSV, No Co Owned Pole	$15.77	$15.93	$16.02
16,000 Lumens, HPSV, Co Owned Pole	$25.29	$25.55	$25.70
16,000 Lumens, HPSV, No Co Owned Pole	$22.52	$22.75	$22.88
27,500 Lumens, HPSV, Co Owned Pole	$36.37	$36.75	$36.97