ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

November 21, 2012

VIA OVERNIGHT DELIVERY

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

Re: CASE No. PAC-E-12-12
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO CANCEL SCHEDULE NO. 17 AND IMPLEMENT A NEW PARTIAL REQUIREMENTS TARIFF

Dear Ms. Jewell:

Please find enclosed for filing seven copies of Rocky Mountain Power's reply comments in the above referenced matter, along with an exhibit and workpapers.

Informal inquiries may be directed to Ted Weston, Idaho Regulatory Manager at (801) 220-2963.

Very truly yours,

Jeffrey K Larsen

Jeffrey K. Larsen
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

I hereby certify that on this November 21, 2012, I caused to be served, via e-mail, a true and correct copy of the foregoing document in PAC-E-12-12 to the following:

James R. Smith (E-mail Only)
Monsanto Company
P.O. Box 816
Soda Springs, Idaho 83276
E-Mail: jim.r.smith@monsanto.com

Randall C. Budge
Racine, Olson, Nye, Budge & Bailey, Chartered
201 E. Center
P.O. Box 1391
Pocatello, ID 83204-1391
E-Mail: rcb@racinelaw.net

Brubaker & Associates
16690 Swingley Ridge Rd., #140
Chesterfield, MO 63017
E-Mail: bcollins@consultbai.com

Ronald L. Williams
William Bradbury, P.C.
1015 W. Hays Street
Boise, ID 83702
Email: ron@williamsbradbury.com

Tim Buller
PacifiCorp Idaho Industrial Customers
Agrium Us Inc.,/Nu-West Industries
3010 Conda Road
Soda Springs, ID 83276-5301
Email: TBuller@agrium.com

Amy Eissler
Coordinator, Regulatory Operations

Mark C. Moench
Idaho Bar No. 8946
Daniel E. Solander
Idaho Bar No. 8931
201 South Main, Suite 2300
Salt Lake City UT 84111
Telephone: (801) 220-4014
FAX: (801) 220-3299
Email: mark.moench@pacificorp.com
daniel.solander@pacificorp.com

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UTILITIES COMMISSION

Attorneys for Rocky Mountain Power

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO CANCEL SCHEDULE NO. 17 AND IMPLEMENT A NEW PARTIAL REQUIREMENTS TARIFF	)))))))	**CASE NO. PAC-E-12-12** **REPLY COMMENTS OF ROCKY MOUNTAIN POWER**

COMES NOW, Rocky Mountain Power, a division of PacifiCorp (the "Company"), submits the following reply to the Comments and Recommendations of Monsanto Company (Monsanto) submitted to the Idaho Public Utilities Commission (the "Commission") on November 13, 2012, and to the Comments of the PacifiCorp Idaho Industrial Customers (PIIC) and Commission Staff (Staff) submitted to the Commission on November 14, 2012, regarding the Company's application for authority to cancel electric service Schedule No. 17, Standby Service, and replace it with a new electric service Schedule No. 31, Partial Requirements Service. In addition to the Company's reply to parties, attached as Exhibit No. 2 are proposed revisions to Schedule 31 from the Company's initial filing that reflects changes addressed in these reply comments.

Reply to Monsanto's Comments and Recommendations

The Company does not agree with Monsanto's comment that Schedule 31 could be used for the first 15,000 kilowatts of their load. As stated in the Application this tariff is only applicable to customers with load less than 15,000 kilowatts. Since Monsanto's load exceeds 15,000 kilowatts, Schedule 31 would require a special contract for all of Monsanto's partial requirements service not just that over 15,000 kilowatts.

In items No. 1 and No. 5 of its comments and recommendations, Monsanto recommended incorporating terms that allow customers to specify seasonal variation and make changes to the Total Contract Demand, Supplementary Contract Demand and Back-up Contract Demand in the proposed Schedule 31. The Company agrees that the recommendation is reasonable and has added a provision modeled on the Wyoming tariff[1] to the revised electric service Schedule 31, Sheet No. 31.6, provided in Exhibit No. 2, with these reply comments. The provision would allow customers to make a change to the Total Contract Demand, Supplementary Contract Demand and Back-up Contract Demand. Any such changes in contract amounts would still be subject to other provisions of the tariff.

In response to Monsanto's recommendation No. 2, the Company believes that the full transmission demand cost should be included in the development of the proposed Back-up Facilities Rate to reflect the actual cost of the back-up facilities. There isn't a

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[1] Wyoming Electric Service Schedule No. 33.

planning reserve margin for transmission delivery as there is for generation. Monsanto's recommendation ignores this perspective and should be rejected. Additionally, simply comparing the percentage of the proposed Back-up Facilities Rate to the corresponding Supplementary Power Rate and the Company's partial requirement service schedules in Wyoming and Utah is inappropriate because it fails to recognize that the rates in each state are determined by the commission in that state. Rates are developed consistent with the cost of service and rate design policies adopted by the respective state commissions over time and implemented through rate cases based on many factors. The rates proposed for Schedule 31 in this case reflect the actual cost of service based on Idaho's currently approved corresponding full requirements electric service Schedule 9 rates.

Monsanto's recommendation No. 3 is to eliminate the Company's proposed ratio of average daily demand to monthly demand. This recommendation should be rejected. The 80 percent ratio is based on actual historical data for Schedule 9 customers and reflects the average relationship between the daily demand and monthly demand. The use of the 80 percent ratio in developing the Back-up Power Rate will result in a customer under the proposed Schedule 31 who chooses not to self-generate during an entire month to pay the same amount as an average Schedule 9 customer. The proposed approach in developing the Back-up Power Rate in this case is reasonable and results in no penalty or harm to either Schedule 9 customers or the proposed Schedule 31 customers. As noted by Staff, the Company can revisit this rate design in the future if and when the Company has load profile data from partial requirements customers in Idaho under Schedule 31.

In response to Monsanto's recommendation No. 4 for the Commission to explore adding a time of day criteria to the Back-up Power Rate, the Company does not currently have the necessary and basic information (such as on-peak demand, etc.) to develop a time of day rate. The Company agrees with Staff's comments that the rate design can be revisited in a future rate case after having actual experience with Schedule 31 in Idaho.

Reply to PIIC's Comments and Recommendations

PIIC's comments and recommendations argue that several aspects of the Company's proposed Schedule 31 rates are inconsistent with PURPA and are not cost-based. The Company disagrees; the proposed Schedule 31 tariff has no conflict with PURPA, in fact, similar tariffs have been adopted in other states[2]. PURPA guidelines apply to qualifying facilities the proposed Schedule 31 rates are retail rates subject to the Commission's approval. Moreover, the proposed rates are based on costs from the most recent cost of service study used to establish the Company's retail rates in Idaho and are designed to be consistent and make a customer indifferent between Schedule 9 for full requirements service and Schedule 31. This is consistent with PURPA, which states:

> Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics. 18 C.F.R. § 292.305(a)(2)

Absent actual Company experience in Idaho for partial requirements service, there is no other cost-based data available.

PIIC also recommends eliminating the Excess Service component from the proposed tariff, including all rates; terms and conditions; making the Back-up Power Rate

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[2] Utah Electric Service Schedule No. 31 and Wyoming Schedule No. 33.

applicable during the on-peak period only; and setting the Maintenance Service Rate at $0.00. None of these recommendations are cost based and should be rejected.

The Excess Service in tariff Schedule 31, including all rates, terms and conditions are reasonable and necessary to ensure customers establish accurate and appropriate contract levels in order to protect other customers and the Company from higher potential costs as a result of serving load in excess of the contract demand. It also prevents a customer from paying no Back-up Facilities Rate by intentionally nominating an unreasonably small amount or even zero back-up contract demand. Moreover, with the addition of the proposed language that will allow a customer to change its Total Contract Power, Supplementary Contract Power and Back-up Contract Power, the customer will not be harmed but will continue to have an incentive to accurately set contract amounts as a result of the Excess Service provisions.

PIIC recommends that the Back-up Power Rate should be applicable only during the on-peak period. As previously noted, the Company does not currently have the necessary information at this time to develop time-based rates for Schedule 31. This issue can be revisited in a future case after having actual experience with customers taking service on Schedule 31.

PIIC's argument that Maintenance Service should be set at $0.00 because the level of coordination in the tariff is unfounded. The tariff allows for a thirty-day advanced written notice for a scheduled Maintenance Service period, which can be for either a continuous thirty-day period or two continuous fifteen-day periods. While the Company reserves the right to modify the requested schedule, the customer's Maintenance Service will still occur during continuous periods that will encompass both daily on-peak and off-peak periods. Providing Maintenance Service at half of the Back-up Power Rate is fair and reasonable.

With respect to PIIC's proposed changes to the Back-up Facilities Rate and the Back-up Power Rate, the Company agrees in part. Instead of using the non-coincident peak demand data from Schedule 9 from the last rate case to develop the Back-up Facilities Rate and the Back-up Power Rate, the Company has revised the proposed rates based on the historical billing demand units from Schedule 9 from the last rate case to develop the rates. Exhibit No. 2 contains the revised Sheet No. 31.2 and work papers reflecting this change. Using the units of historical billing demand for Schedule 9 from the last rate case is more reasonable, dependable and consistent with how rates are typically developed than using estimated units recommended by PIIC. This modification reduces the Back-up Facilities Rate from \$5.97 to \$5.70 per kilowatt May through October and from \$4.51 to \$4.30 per kilowatt November through April. The Back-up Power Rate increases from \$0.18 to \$0.19 all kilowatt day May through October and from \$0.13 to \$0.14 all kilowatt day November through April.

Finally, PIIC proposed that tariff Schedule 31 be approved on an interim basis until such time when the Company completes additional studies on the costs incurred to provide partial requirements service to customers in Idaho and that this docket remain open for this duration and process. This requirement is unnecessary and the recommendation should be rejected. Since the Company does not currently have any customers taking this service in Idaho, nor is there any certainty about when a customer may take service under Schedule 31, there is no certainty or timeline for when this proposed requirement could be completed. If and when the Company has actual experience with partial requirements service in Idaho, parties can re-evaluate the rate design in a general rate case, as is the case with any other rate schedule. A prolonged separate process for Schedule 31 with no known timeframe for completion is administratively unnecessary.

Reply to Staff's Comments

The Company appreciates and supports Staff's comments and recommendations. The Company agrees that the rate design for Schedule 31 can be revisited in a future rate case after developing load profiles from actual customers taking service under Schedule 31. The Company also agrees to consider the development of a tariff for customers with self-generation less than 1,000 kW as the need arises.

DATED this 21st day of November, 2012.

Respectfully submitted,

Mark C. Moench /ÆS

Mark C. Moench
Daniel E. Solander
Attorneys for PacifiCorp

Exhibit 2

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 31 - Continued

MONTHLY BILL:

Rate:

	Billing Months May through October, Inclusive		Billing Months November through April, Inclusive	
Customer Service Charge:	$370.00	per Customer	$370.00	per Customer
Back-up Facilities Rate:	$5.70~~97~~	per kW for all kW	$4.30~~51~~	per kW for all kW
	The Facilities Rate applies to the kW of Back-up Contract Power			
Back-up Power Rate:	$0.19~~8~~	all kW Day	$0.14~~3~~	All kW Day
	Back-up Power is billed on a per day basis and is based on the fifteen (15) minute period of the Customer's greatest use of Back-up Power during the day. Scheduled Maintenance Power rate is one half (1/2) of the Back-up Power Rate.			
Excess Power Rate:	$20.52	per kW for all kW	$15.48	per kW for all kW
Supplementary Power Rate:	$10.26	per kW for all kW	$7.74	per kW for all kW
Supplementary and Back-up Energy Rate:	3.8835¢	per kWh	3.8835¢	per kWh

POWER FACTOR: This rate is based on the Customer maintaining at all times a power factor of 85% lagging, or higher, as determined by measurement. If the average power factor is found to be less than 85% lagging, the Power as recorded by the Company's meter will be increased by ¾ of 1% for every 1% that the power factor is less than 85%.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 31 - Continued

MONTHLY BILL:

Rate:

	Billing Months May through October, Inclusive		Billing Months November through April, Inclusive	
Customer Service Charge:	$370.00	per Customer	$370.00	per Customer
Back-up Facilities Rate:	$5.70	per kW for all kW	$4.30	per kW for all kW

The Facilities Rate applies to the kW of Back-up Contract Power

Back-up Power Rate:	$0.19	all kW Day	$0.14	All kW Day

Back-up Power is billed on a per day basis and is based on the fifteen (15) minute period of the Customer's greatest use of Back-up Power during the day.

Scheduled Maintenance Power rate is one half (1/2) of the Back-up Power Rate.

Excess Power Rate:	$20.52	per kW for all kW	$15.48	per kW for all kW
Supplementary Power Rate:	$10.26	per kW for all kW	$7.74	per kW for all kW
Supplementary and Back-up Energy Rate:	3.8835¢	per kWh	3.8835¢	per kWh

POWER FACTOR: This rate is based on the Customer maintaining at all times a power factor of 85% lagging, or higher, as determined by measurement. If the average power factor is found to be less than 85% lagging, the Power as recorded by the Company's meter will be increased by ¾ of 1% for every 1% that the power factor is less than 85%.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 31 – Continued

SCHEDULED MAINTENANCE (continued):

2. The Customer may request an adjustment in a scheduled maintenance outage up to 14 days in advance of the expected maintenance. Company approval, or disapproval with reason, for such adjustment shall be given within seven days of such request.

3. The Company may with reason cancel a scheduled maintenance outage at any time with seven days notice prior to the beginning of a scheduled maintenance outage. Subject to the mutual agreement of the Customer and the Company, that scheduled maintenance outage(s) canceled by the Company may be rescheduled.

Total Contract Demand, Supplementary Contract Demand, and Back-up Contract Demand

The Customer shall contract for Total Contract Demand. This is the sum of the Supplementary Contract Demand and the Back-up Contract Demand. The Customer may elect to increase Total Contract Demand by increasing Supplementary Contract Demand and/or Back-up Contract Demand prospectively at any time, provided there are facilities of adequate capacity, by providing notice to the Company. The Customer may elect to increase Total Contract Demand by increasing Supplementary Contract Demand and/or Back-up Contract Demand retroactively to the most recently completed Billing Period, provided there are facilities of adequate capacity, by providing notice to the Company by the statement due date of the Billing Period. The Supplementary Contract Demand may be reduced for a continuous period of each year provided that at least 12 month's written notice has been provided to the Company or as specified in contract. Only one request to reduce Supplementary Contract Demand may be outstanding for each account. Customer may reduce Back-up Contract Demand by providing written notice to PacifiCorp no less than six months in advance of the effective date of the desired reduction, provided, only one such request may be made in any 12-month period. Within 15 days of receipt of a timely written request by Customer, PacifiCorp shall advise Customer of the terms upon which PacifiCorp would accept a reduction in contract demand. A period of reduction shall commence at the beginning of a billing cycle and terminate at the end of a billing cycle.

FORCE MAJEURE: The Company shall not be subject to any liability or damages for inability to provide service, and the Customer shall not be subject to any liability or damage for such inability to receive service, to the extent that such inability shall be due to causes beyond the control of the party as specified in Electric Service Regulation No. 4, Supply and Use of Service, Section 3. Should any of the foregoing occur, the facilities charge shall be applied to only such Back-up Contract Demand as the Company is able to supply and the Customer is able to receive and the minimum Billing Demand applicable to Supplemental Power under this Schedule shall be waived. The Customer will have no liability for full service until such time as the Customer is able to resume such service, except for any term minimum guarantees designed to cover special facilities extension costs, if any. The party claiming Force Majeure under this provision shall make every reasonable attempt to remedy the cause thereof as diligently and expeditiously as possible.

CONTRACT PERIOD: One year or longer.

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Idaho Public Utilities Commission, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

ELECTRIC SERVICE SCHEDULE NO. 31 – Continued

SCHEDULED MAINTENANCE (continued):

2. The Customer may request an adjustment in a scheduled maintenance outage up to 14 days in advance of the expected maintenance. Company approval, or disapproval with reason, for such adjustment shall be given within seven days of such request.

3. The Company may with reason cancel a scheduled maintenance outage at any time with seven days notice prior to the beginning of a scheduled maintenance outage. Subject to the mutual agreement of the Customer and the Company, that scheduled maintenance outage(s) canceled by the Company may be rescheduled.

Total Contract Demand, Supplementary Contract Demand, and Back-up Contract Demand

The Customer shall contract for Total Contract Demand. This is the sum of the Supplementary Contract Demand and the Back-up Contract Demand. The Customer may elect to increase Total Contract Demand by increasing Supplementary Contract Demand and/or Back-up Contract Demand prospectively at any time, provided there are facilities of adequate capacity, by providing notice to the Company. The Customer may elect to increase Total Contract Demand by increasing Supplementary Contract Demand and/or Back-up Contract Demand retroactively to the most recently completed Billing Period, provided there are facilities of adequate capacity, by providing notice to the Company by the statement due date of the Billing Period. The Supplementary Contract Demand may be reduced for a continuous period of each year provided that at least 12 month's written notice has been provided to the Company or as specified in contract. Only one request to reduce Supplementary Contract Demand may be outstanding for each account. Customer may reduce Back-up Contract Demand by providing written notice to PacifiCorp no less than six months in advance of the effective date of the desired reduction, provided, only one such request may be made in any 12-month period. Within 15 days of receipt of a timely written request by Customer, PacifiCorp shall advise Customer of the terms upon which PacifiCorp would accept a reduction in contract demand. A period of reduction shall commence at the beginning of a billing cycle and terminate at the end of a billing cycle.

FORCE MAJEURE: The Company shall not be subject to any liability or damages for inability to provide service, and the Customer shall not be subject to any liability or damage for such inability to receive service, to the extent that such inability shall be due to causes beyond the control of the party as specified in Electric Service Regulation No. 4, Supply and Use of Service, Section 3. Should any of the foregoing occur, the facilities charge shall be applied to only such Back-up Contract Demand as the Company is able to supply and the Customer is able to receive and the minimum Billing Demand applicable to Supplemental Power under this Schedule shall be waived. The Customer will have no liability for full service until such time as the Customer is able to resume such service, except for any term minimum guarantees designed to cover special facilities extension costs, if any. The party claiming Force Majeure under this provision shall make every reasonable attempt to remedy the cause thereof as diligently and expeditiously as possible.

CONTRACT PERIOD: One year or longer.

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Idaho Public Utilities Commission, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

Workpapers

Rocky Mountain Power
State of Idaho
Partial Requirements Service Proposal
Transmission Voltage

Charges	Sch 31
Customer Service Charge	$370.00
Back-up Facilities Rate, All kW	
Summer (Total COS Tran + 13% Gen)	$5.70
Winter	$4.30
Back-up Power Rate - All kW Day	
Summer	$0.19
Winter	$0.14
Excess Power Rate, All kW	
Summer	$20.52
Winter	$15.48
Supplementary Power Rate, All kW	
Summer	$10.26
Winter	$7.74
Supplementary and Back-up Energy Rate	
Cents/kWh	3.8835

Power Factor:

This rate is based on the Customer maintaining at all times a power factor of 85% lagging or higher, as determined by measurement. If the average power factor is found to be less than 85% lagging, the Power as recorded by the Company's meter will be increased by 3/4 of 1% for every 1% that the power factor is less than 85%.

The proposed rates are developed from the last Cost of Service study for Idaho Schedule 9
(1) Backup Facilities Rate is based on COS Trans-demand + 13% Gen-demand
(2) Backup Power Rate is Sch 9 Power Rate minus Back-up Facilities divided by average days in a month and adjusted by assuming the average daily Backup Power is 80% of the monthly Power.
(3) Excess Power Rate is two times of Sch 9 Power Rate.

Rocky Mountain Power - State of Idaho
Rate Analysis for Partial Requirements Service
Transmission Voltage

	Idaho	
	Sch 9	Sch 31
Customer Service Charge	$370.00	$370.00
Back-up Facilities Rate		
Summer		$5.70
Winter		$4.30
Back-up Power Rate		
Summer		$0.19
Winter		$0.14
Excess Power Rate		
Summer		$20.52
Winter		$15.48
Supplementary Power Rate		
Summer	$10.26	$10.26
Winter	$7.74	$7.74
Supplementary and Back-up Energy Rate		
Summer	3.8835	3.8835
Winter	3.8835	3.8835

ID PAC-E-11-12 Cost of Service
(Tab 4, Page 6 - Unit Costs)

	Sch 9
Trans-Demand	$3.95
Gen-Demand (13%)	$1.05
Target Back-up Facilities	$5.00
Summer	$5.70
Winter	$4.30
Ratio of Average Daily to Monthly kW	
Summer	80%
Winter	80%
Ration of Excess Power to Sup Power	
Summer	2
Winter	2
Left for Daily Backup Power	
Summer	$4.56
Winter	$3.44
Checking	**Monthly Avg**
Summer	$5.70
Winter	$4.30
Adjusted	
Summer	$4.56
Winter	$3.44

Unit Costs
Rocky Mountain Power
Cost Of Service By Rate Schedule
State of Idaho
2010 Protocol
12 Months Ending December 2010

UNIT COSTS calculated with: Target Return On Rate Base	Idaho Jurisdiction Normalized	Residential Schedule 1	Residential Schedule 36	General Srv Large Power Schedules 6, 35	General Srv High Voltage Schedule 9	Irrigation Schedule 10	St. & Area Lgt Schedules 7, 11, 12	Space Heating Schedule 19	General Srv Small Power Schedule 23	Contract 1	Contract 2
UNITS											
NCP KW	11,732,230	3,406,233	2,088,458	969,706	225,153	1,736,516	7,747	20,498	878,142	2,233,800	165,976
Annual KWH	3,328,056,545	424,152,984	285,515,654	305,133,611	112,052,378	555,303,563	2,832,873	6,224,597	153,729,785	1,378,699,100	104,412,000
Average Customers	72,348	42,207	14,902	1,292	12	4,845	694	127	8,267	1	1
Load Factor	39%	17%	19%	43%	68%	44%	50%	42%	24%	85%	86%
GTD TOTAL	100.00%	17.71%	10.40%	9.31%	2.61%	19.96%	0.19%	0.20%	5.79%	31.48%	2.35%
Revenue Requirement	250,116,331	44,283,358	26,006,422	23,297,055	6,523,208	49,921,530	475,266	496,187	14,487,595	78,746,886	5,878,823
Per Billing KW	21.32	13.00	12.45	24.02	28.97	28.75	61.35	24.21	16.50	35.25	35.42
Per KWH	0.075	0.104	0.091	0.076	0.058	0.090	0.168	0.080	0.094	0.057	0.056
Per Customer	3,457.11	1,049.20	1,745.15	18,029.94	522,065.50	10,303.72	684.99	3,915.39	1,752.39	78,746,885.76	5,878,823.40
GENERATION-TOTAL	100.00%	14.12%	8.91%	9.73%	3.21%	17.27%	0.07%	0.20%	4.98%	38.64%	2.88%
Revenue Requirement	160,498,275	22,659,175	14,293,680	15,624,413	5,147,868	27,721,137	114,029	315,209	7,990,002	62,017,204	4,615,558
Per Billing KW	13.68	6.65	6.84	16.11	22.86	15.96	14.72	15.38	9.10	27.76	27.81
Per KWH	0.048	0.053	0.050	0.051	0.046	0.050	0.040	0.051	0.052	0.045	0.044
Per Customer	2,218.41	536.86	959.17	12,091.97	411,994.23	5,721.60	164.35	2,487.30	966.45	62,017,203.60	4,615,558.42
GENERATION-DEMAND	100.00%	15.67%	9.02%	10.26%	3.12%	17.41%	0.05%	0.20%	5.32%	36.33%	2.62%
Revenue Requirement	60,892,009	9,539,937	5,491,465	6,247,807	1,901,853	10,599,382	27,684	123,155	3,242,201	22,121,691	1,596,833
Per Billing KW	5.19	2.80	2.63	6.44	8.45	6.10	3.57	6.01	3.69	9.90	9.62
Per KWH	0.018	0.022	0.019	0.020	0.017	0.019	0.010	0.020	0.021	0.016	0.015
Per Customer	841.65	226.03	368.50	4,835.27	152,209.10	2,187.69	39.90	971.81	392.17	22,121,691.11	1,596,832.52
GENERATION-ENERGY	100.00%	13.17%	8.84%	9.41%	3.26%	17.19%	0.09%	0.19%	4.77%	40.05%	3.03%
Revenue Requirement	99,606,267	13,119,238	8,802,215	9,376,605	3,246,015	17,121,755	86,344	192,054	4,747,801	39,895,512	3,018,726
Per Billing KW	8.49	3.85	4.21	9.67	14.42	9.86	11.14	9.37	5.41	17.86	18.19
Per KWH	0.030	0.031	0.031	0.031	0.029	0.031	0.030	0.031	0.031	0.029	0.029
Per Customer	1,376.76	310.83	590.67	7,256.69	259,785.13	3,533.90	124.45	1,515.49	574.28	39,895,512.49	3,018,725.90
TRANSMISSION-TOTAL	100.00%	15.07%	8.97%	9.89%	3.05%	17.34%	0.06%	0.20%	5.16%	37.54%	2.72%
Revenue Requirement	43,268,322	6,521,369	3,880,954	4,281,358	1,319,218	7,502,467	24,006	86,357	2,233,164	16,244,379	1,175,051
Per Billing KW	3.69	1.91	1.86	4.42	5.86	4.32	3.10	4.21	2.54	7.27	7.08
Per KWH	0.013	0.015	0.014	0.014	0.012	0.014	0.008	0.014	0.015	0.012	0.011
Per Customer	598.06	154.51	260.43	3,313.41	105,579.67	1,548.50	34.60	681.44	270.12	16,244,378.77	1,175,050.55
TRANSMISSION-DEMAND	100.00%	15.58%	9.01%	10.06%	3.02%	17.38%	0.05%	0.20%	5.27%	36.80%	2.63%
Revenue Requirement	30,877,070	4,810,814	2,781,506	3,105,541	931,409	5,367,672	14,600	62,215	1,628,251	11,361,856	813,205
Per Billing KW	2.63	1.41	1.33	3.20	4.14	3.09	1.88	3.04	1.85	5.09	4.90
Per KWH	0.009	0.011	0.010	0.010	0.008	0.010	0.005	0.010	0.011	0.008	0.008
Per Customer	426.78	113.98	186.65	2,403.42	74,542.56	1,107.88	21.04	490.94	196.95	11,361,855.73	813,204.97
TRANSMISSION-ENERGY	100.00%	13.80%	8.87%	9.49%	3.13%	17.23%	0.08%	0.19%	4.88%	39.40%	2.92%
Revenue Requirement	12,391,252	1,710,555	1,099,448	1,175,817	387,809	2,134,795	9,406	24,142	604,912	4,882,523	361,846
Per Billing KW	1.06	0.50	0.53	1.21	1.72	1.23	1.21	1.18	0.69	2.19	2.18
Per KWH	0.004	0.004	0.004	0.004	0.003	0.004	0.003	0.004	0.004	0.004	0.003
Per Customer	171.27	40.53	73.78	909.98	31,037.10	440.62	13.56	190.50	73.17	4,882,523.04	361,845.57
DISTRIBUTION-TOTAL	100.00%	28.70%	16.00%	8.13%	0.02%	36.99%	0.76%	0.21%	8.90%	0.15%	0.15%
Revenue Requirement	37,907,016	10,878,901	6,064,150	3,082,556	7,175	14,022,782	287,190	80,411	3,372,221	55,820	55,811
Per Billing KW	3.23	3.19	2.90	3.18	0.03	8.08	37.07	3.92	3.84	0.02	0.34
Per KWH	0.011	0.026	0.021	0.010	0.000	0.025	0.101	0.013	0.022	0.000	0.001
Per Customer	523.95	257.75	406.93	2,385.64	574.22	2,894.28	413.92	634.52	407.90	55,820.18	55,810.73
DISTRIBUTION-SUBSTATION	100.00%	19.13%	10.89%	11.42%	-0.09%	50.95%	0.19%	0.20%	7.25%	0.03%	0.03%
Revenue Requirement	5,029,544	961,994	547,652	574,222	(4,400)	2,562,499	9,650	10,307	364,723	1,449	1,448
Per Billing KW	0.43	0.28	0.26	0.59	(0.02)	1.48	1.25	0.50	0.42	0.00	0.01
Per KWH	0.002	0.002	0.002	0.002	(0.000)	0.005	0.003	0.002	0.002	0.000	0.000
Per Customer	69.52	22.79	36.75	444.40	(352.16)	528.90	13.91	81.33	44.12	1,448.82	1,447.83
DISTRIBUTION- P & C	100.00%	27.83%	15.94%	8.46%	-0.08%	37.13%	1.15%	0.24%	9.28%	0.02%	0.02%
Revenue Requirement	20,730,976	5,768,869	3,305,376	1,752,879	(17,263)	7,697,829	238,996	49,888	1,924,522	4,943	4,938
Per Billing KW	1.77	1.69	1.58	1.81	(0.08)	4.43	30.85	2.43	2.19	0.00	0.03
Per KWH	0.006	0.014	0.012	0.006	(0.000)	0.014	0.084	0.008	0.013	0.000	0.000
Per Customer	286.54	136.68	221.81	1,356.58	(1,381.59)	1,588.82	344.46	393.66	232.79	4,942.65	4,938.06
DISTRIBUTION-TRANSFORMER	100.00%	26.51%	16.16%	6.93%	-0.15%	42.74%	0.23%	0.17%	7.34%	0.03%	0.03%

ID Case No. PAC-E-11-12 Cost of Service (Tab 4, Page 6 - Unit Costs)

UNIT COSTS calculated with: Target Return On Rate Base	Idaho Jurisdiction Normalized	Residential Schedule 1	Residential Schedule 36	General Srv Large Power Schedules 6, 35	General Srv High Voltage Schedule 9	Irrigation Schedule 10	St. & Area Lgt Schedules 7, 11, 12	Space Heating Schedule 19	General Srv Small Power Schedule 23	Contract 1	Contract 2
Revenue Requirement	6,994,903	1,854,538	1,130,662	485,006	(10,808)	2,989,319	15,900	12,183	513,491	2,307	2,304
Per Billing KW	0.60	0.54	0.54	0.50	(0.05)	1.72	2.05	0.59	0.58	0.00	0.01
Per KWH	0.002	0.004	0.004	0.002	(0.000)	0.005	0.006	0.002	0.003	0.000	0.000
Per Customer	96.68	43.94	75.87	375.35	(864.98)	616.99	22.92	96.14	62.11	2,306.57	2,304.20
DISTRIBUTION-METER	100.00%	31.86%	21.36%	5.86%	1.86%	25.74%	0.80%	0.12%	8.51%	1.95%	1.95%
Revenue Requirement	2,375,824	756,823	507,457	139,140	44,235	611,528	18,949	2,876	202,299	46,258	46,258
Per Billing KW	0.20	0.22	0.24	0.14	0.20	0.35	2.45	0.14	0.23	0.02	0.28
Per KWH	0.001	0.002	0.002	0.000	0.000	0.001	0.007	0.000	0.001	0.000	0.000
Per Customer	32.84	17.93	34.05	107.68	3,540.25	126.22	27.31	22.70	24.47	46,258.35	46,257.86
DISTRIBUTION-SERVICE	100.00%	55.36%	20.64%	4.73%	-0.17%	5.82%	0.13%	0.19%	13.23%	0.03%	0.03%
Revenue Requirement	2,775,769	1,536,676	573,002	131,309	(4,590)	161,607	3,694	5,157	367,185	864	863
Per Billing KW	0.24	0.45	0.27	0.14	(0.02)	0.09	0.48	0.25	0.42	0.00	0.01
Per KWH	0.001	0.004	0.002	0.000	(0.000)	0.000	0.001	0.001	0.002	0.000	0.000
Per Customer	38.37	36.41	38.45	101.62	(367.31)	33.36	5.32	40.70	44.41	863.79	862.77
RETAIL-TOTAL	100.00%	56.09%	23.39%	2.49%	0.17%	5.59%	0.62%	0.16%	11.49%	0.00%	0.01%
Revenue Requirement	6,255,555	3,508,972	1,462,974	155,693	10,531	349,539	38,975	9,864	718,583	(270)	694
Per Billing KW	0.53	1.03	0.70	0.16	0.05	0.20	5.03	0.48	0.82	(0.00)	0.00
Per KWH	0.002	0.008	0.005	0.001	0.000	0.001	0.014	0.002	0.005	(0.000)	0.000
Per Customer	86.46	83.14	98.17	120.49	842.84	72.14	56.17	77.83	86.92	(270.31)	694.39
MISC - Total	100.00%	32.69%	13.93%	7.00%	1.76%	14.89%	0.51%	0.20%	7.94%	19.65%	1.45%
Revenue Requirement	2,187,163	714,942	304,663	153,036	38,416	325,604	11,067	4,347	173,625	429,754	31,709
Per Billing KW	0.19	0.21	0.15	0.16	0.17	0.19	1.43	0.21	0.20	0.19	0.19
Per KWH	0.001	0.002	0.001	0.001	0.000	0.001	0.004	0.001	0.001	0.000	0.000
Per Customer	30.23	16.94	20.44	118.44	3,074.55	67.20	15.95	34.30	21.00	429,753.53	31,709.31
Classified Rev Req											
Generation - Demand	60,892,009	9,539,937	5,491,465	6,247,807	1,901,853	10,599,382	27,684	123,155	3,242,201	22,121,691	1,596,833
Transmission - Demand	30,877,070	4,810,814	2,781,506	3,105,541	931,409	5,367,672	14,600	62,215	1,628,251	11,361,856	813,205
Distribution - Substation	5,029,544	961,994	547,652	574,222	(4,400)	2,562,499	9,650	10,307	364,723	1,449	1,448
Distribution - P&C	20,730,976	5,768,869	3,305,376	1,752,879	(17,263)	7,697,829	238,996	49,888	1,924,522	4,943	4,938
Distribution - Transformer	6,994,903	1,854,538	1,130,662	485,006	(10,808)	2,989,319	15,900	12,183	513,491	2,307	2,304
Demand - TOTAL Rev Req	124,524,502	22,936,153	13,256,662	12,165,455	2,800,791	29,216,701	306,831	257,747	7,673,189	33,492,245	2,418,728
Generation - Energy	99,606,267	13,119,238	8,802,215	9,376,605	3,246,015	17,121,755	86,344	192,054	4,747,801	39,895,512	3,018,726
Transmission - Energy	12,391,252	1,710,555	1,099,448	1,175,817	387,809	2,134,795	9,406	24,142	604,912	4,882,523	361,846
Misc - Total	2,187,163	714,942	304,663	153,036	38,416	325,604	11,067	4,347	173,625	429,754	31,709
Energy - TOTAL Rev Req	114,184,681	15,544,735	10,206,326	10,705,458	3,672,240	19,582,155	106,817	220,542	5,526,338	45,207,789	3,412,281
Distribution - Meter	2,375,824	756,823	507,457	139,140	44,235	611,528	18,949	2,876	202,299	46,258	46,258
Distribution - Service	2,775,769	1,536,676	573,002	131,309	(4,590)	161,607	3,694	5,157	367,185	864	863
Retail Total	6,255,555	3,508,972	1,462,974	155,693	10,531	349,539	38,975	9,864	718,583	(270)	694
Customer - TOTAL Rev Req	11,407,148	5,802,471	2,543,434	426,142	50,177	1,122,674	61,618	17,897	1,288,067	46,852	47,815
Total Classification Rev Req	250,116,331	44,283,358	26,006,422	23,297,055	6,523,208	49,921,530	475,266	496,187	14,487,595	78,746,886	5,878,823
GTDRM Rev Req	250,116,331	44,283,358	26,006,422	23,297,055	6,523,208	49,921,530	475,266	496,187	14,487,595	78,746,886	5,878,823

ROCKY MOUNTAIN POWER
STATE OF IDAHO
NORMALIZED BILLING DETERMINANTS
HISTORIC 12 MONTHS ENDED DECEMBER 2010

	Units	Present Price	Present Revenue Dollars	Proposed Price	Proposed Revenue Dollars
SCHEDULE NO. 9 - General Service - High Voltage					
Composite					
Customer Charge	150	$347.00	$52,029	$370.00	$55,478
All kW (May - Oct)	124,003	$9.35	$1,159,423	$10.26	$1,272,266
All kW (Nov - Apr)	111,867	$7.06	$789,780	$7.74	$865,849
Minimum kW Summer	0	$9.35	$0	$10.26	$0
Minimum kW Winter	0	$7.06	$0	$7.74	$0
All kWh	116,839,282	3.6970 ¢	$4,319,548	3.8835 ¢	$4,537,454
Base Subtotal	116,839,282		$6,320,780		$6,731,047
Unbilled	(4,786,904)		($17,940)		($17,940)
Base Total	112,052,378		$6,302,840		$6,713,107

	20,725	
	12	
	248700	248695
	1.05	
	261135	261129.8