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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-10-07**
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	**Rebuttal Testimony of C. Craig Paice**
ELECTRIC SERVICE SCHEDULES	)	
AND A PRICE INCREASE OF $27.7	)	
MILLION, OR APPROXIMATELY	)	
13.7 PERCENT	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-10-07

November 2010

1 **Q. Are you the same C. Craig Paice that previously filed direct testimony in this**
2 **docket?**
3 A. Yes.
4 **Purpose and Summary**
5 **Q. What is the purpose of your rebuttal testimony?**
6 A. My rebuttal testimony includes revised exhibits to reflect changes in the Idaho
7 Results of Operations contained in the rebuttal testimony of Company witness Mr.
8 Steven R. McDougal. Additionally, I respond to the testimony of Idaho Public
9 Utilities Commission Staff witness Mr. Bryan Lanspery, PacifiCorp Idaho
10 Industrial Customers ("PIIC") witness Mr. Donald Schoenbeck, and Community
11 Action Partnership Association of Idaho ("CAPAI") witness Ms. Teri Ottens.
12 **Updated Exhibits**
13 **Q. Have you prepared any updates to the exhibits filed with your rebuttal**
14 **testimony?**
15 A. Yes. Exhibit No. 81 and Exhibit No. 82 are updates to Exhibit No. 47 and Exhibit
16 No. 48. The revised exhibits reflect changes in the Idaho Results of Operations as
17 presented in Company witness Mr. McDougal's rebuttal testimony.
18 **Rebuttal to Direct Testimony of Mr. Bryan Lanspery**
19 <u>Cost of Service Support for Residential Customer Increase</u>
20 **Q. Why does Mr. Lanspery propose giving residential Schedule 1 and 36**
21 **customers an equal percentage increase?**
22 A. Mr. Lanspery's proposal is based on the belief that the Company's cost of service
23 study does not provide adequate justification for the increase to residential

1 Schedule 36 customers.

2 **Q. Do you agree with his assertion regarding the Company's cost of service**
3 **results?**

4 A. No. I disagree for several reasons. First, Mr. Lanspery's assertion is based on his
5 review of two data request responses provided by the Company. He does not
6 provide any detailed analysis to illustrate why the Company's cost of service
7 results are inadequate.

8 Next, he fails to acknowledge that Staff witness Mr. Keith Hessing
9 supports the Company's cost of service study. Mr. Hessing's reasons for
10 supporting the cost study are: 1) it employs the same basic methodology used in
11 the Revised Protocol jurisdictional allocation process; and 2) it is the same
12 methodology accepted by the Commission in prior general rate case decisions.
13 Also, Mr. Hessing's cost of service results contained in Staff Exhibit No. 129 are
14 calculated using the same model and methodology proposed by the Company.

15 Finally, the Company's cost of service results presented in this case are
16 consistent with results in the prior general rate case. In case PAC-E-07-05, cost
17 of service results showed that Schedule 36 customers needed an increase slightly
18 more than 1.8 times the increase required for Schedule 1 customers. Similarly,
19 cost of service results in this case show Schedule 36 customers needing an
20 increase of about 1.9 times the increase needed for Schedule 1 customers. This
21 demonstrates that the Company's cost of service methodology produces a high
22 level of consistency between cases. For these reasons, I suggest the Commission
23 disregard Mr. Lanspery's opinion regarding the Company's cost of service results.

Rebuttal to Direct Testimony of Mr. Donald Schoenbeck

Generation and Transmission Cost Allocations

Q. Do you agree with Mr. Schoenbeck's proposal to allocate demand-related generation and transmission costs using one winter and one summer monthly system coincident peak (2 CP W/S)?

A. No. Mr. Schoenbeck's proposed use of a 2 CP method:

1) fails to recognize how the Company plans and operates its generation and transmission systems;
2) is inconsistent with inter-jurisdictional allocations;
3) has the potential to shift customer costs creating rate volatility; and
4) violates the principle of gradualism which is generally viewed as an important consideration in determining class cost causation.

In addition, Mr. Schoenbeck provides no significant analysis to support his recommendation.

Q. Why does the Company support use of a twelve system coincident peaks (12 CP) method for allocating demand-related generation and transmission costs?

A. The 12 CP method is preferable for several reasons. First, the Company has historically allocated generation and transmission demand-related costs using the 12 CP methodology to reflect the fact that the six-state system is planned and dispatched as an integrated system. This methodology has been used by the Company since the Utah Power – Pacific Power merger in 1989 and continues to be used because it reflects actual integrated system operations. During the Multi-

State Process ("MSP") case PAC-E-02-3 the Company revisited the stress factor analysis that was employed at the time of the merger to determine if a 12 CP allocation method is still the most appropriate method for the Company to use. The results indicated that all months contribute to the system peak in some way and should be included in cost allocation. This allocation issue was raised in the Company's 2001 case PAC-E-01-16 involving Monsanto's contract rate. Staff witness Mr. David Schunke endorsed the Company's 12 CP approach stating the following on page 16 of his direct testimony:

> "A 12 CP generation and transmission allocator better represents the actual system operation. It recognizes that each of the monthly peaks is of importance."

The 12 CP methodology recognizes that each of the monthly peaks is important because the Company must plan for and dispatch its resources during each of the 12 months of the year. Additionally, staff witness Mr. Keith Hessing, stated in his direct testimony in this case:

> "The cost of service methodology presented by the Company is the same methodology accepted by the Commission in recent general rate case decisions."

Second, it is appropriate for allocation methods to be consistent between interjurisdictional and class costs of service. Again, in Case PAC-E-01-16, staff witness Mr. Schunke stated the following in his direct testimony on pages 18-19:

> "I also believe that the jurisdictional allocation and the class cost-of-service allocation should employ similar methodologies. Costs come to Idaho through the jurisdictional allocation. It makes sense to be consistent in the allocation methodology and assign costs to the customer classes in the same way they are assigned to the jurisdiction."

1 The 12 CP methodology is employed in both the class cost of service study and
2 the Jurisdictional Allocation Model ("JAM"), and has been used since its approval
3 in the MSP Case. Finally, Mr. Schoenbeck fails to mention how his
4 recommended methodology would impact customer class revenue requirements.
5 For example, if the Company's cost of service by rate schedule (Exhibit No. 47,
6 Page 2) had been prepared using a 2 CP method instead of the 12 CP method, the
7 residential time-of-day class would need an additional increase of approximately
8 $1 million and the irrigation class would need an additional increase of almost $3
9 million.

10 Distribution Cost Allocations

11 **Q. Is Mr. Schoenbeck correct in his understanding of which peak load values**
12 **are used to develop distribution cost allocation factors?**

13 A. No. Mr. Schoenbeck states the following on pages 8 and 9 of his testimony:

14 "For the generation and transmission demand allocation
15 factor, it is simply the sum of all twelve monthly coincident
16 peak values ("12 CP"). For the main distribution demand
17 allocation factor, the Company starts with the same twelve
18 monthly coincident class values as used for the generation and
19 transmission allocation factor." (emphasis added)

20 While it is true that the Company uses 12 monthly system coincident peaks to
21 allocate generation and transmission demand costs, they are not used to allocate
22 distribution demand-related costs. The Company's cost of service procedures that
23 accompanied my direct testimony (see Exhibit No. 49, Tab 1, Pages 7-9) clearly
24 describe the differences between 12 system coincident peaks, 12 distribution
25 coincident peaks, and non-coincident peak loads and explains how they are used
26 to allocate demand related costs in the cost of service study. Specifically, the

Company develops and employs the following types of peak load values for use in the cost of service study:

- The 12 system coincident peaks or "12 CP" (each class' contribution to the 12 monthly peaks coincident with the Company's six-state system peak) are used to allocate class generation and transmission demand costs.
- The 12 distribution system coincident peaks or "12 DCP" (simultaneous combined demand of all distribution voltage customers at the hour of the Idaho distribution system peak weighted by the percent of substations achieving their annual peak in each month of the year) are used to allocate substation and primary line costs.
- The maximum non-coincident peaks or "NCP" (maximum monthly class non-coincident peak) are used to allocate line transformers and secondary lines.

Q. Mr. Schoenbeck proposes the use of the class single non-coincident peak (1 NCP) method to allocate distribution demand-related costs for substations and primary poles and conductors. Is this method appropriate?

A. No. Mr. Schoenbeck's recommended 1 NCP allocation method is not appropriate because it ignores the cost causing basis for these facilities, i.e. customers' load diversity. Load diversity (see cost of service procedures, pages 8-9) recognizes that individual customer peak demands occur at different times. The Company's distribution engineers recognize load diversity when they design substations and primary lines because they size these facilities to meet the simultaneous distribution peak load of the connected customers, not the 1 NCP for each

customer class as Mr. Schoenbeck recommends. As such, the Company's use of a 12 DCP method to allocate substations and primary lines is based on cost causation because it recognizes the load diversity that customers bring to the distribution system.

Q. Do you agree with Mr. Schoenbeck's assertion that the NARUC Electric Utility Cost Allocation Manual (NARUC Manual) acknowledges a 1 NCP method to be "a reasonable - and most often used - alternative" to allocate substation and primary line costs?

A. No. On page 97 of the NARUC Manual, the discussion references the selection of allocators for <u>all</u> demand-related distribution costs. Specifically, the manual states:

> "Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities." (p. 97)

As previously stated, the Company selected weighted monthly distribution peaks for allocating distribution substations and primary lines because load diversity is recognized when these facilities are designed. In addition, when discussing major costing methodologies, the NARUC Manual does not imply that a "one-size-fits-all" approach is indicative of industry practices as evidenced by the following:

> "This manual only discusses the major costing methodologies. It recognizes that no single costing methodology will be superior to any other, and the choice of methodology will depend on the unique circumstances of each utility." (p. 22)

Mr. Schoenbeck's reference to the NARUC manual appears to be taken out of context.

Q. What are the implications of Mr. Schoenbeck's proposal?

A. The test period in this case identifies the sum of the 12 DCP's at input being 3,565,097 KW and the sum of the 12 monthly NCP's for all customers at input being 12,547,715 KW. Considering that the sum of non-coincident peaks is more than three and one-half times greater than customer demand at the time of the distribution system peak, the cost to build substations would be significantly higher if they were designed to serve the undiversified load, or NCPs, of all customers. As explained earlier, substations are built to meet the simultaneous peak load of connected customers. In reference to the Company's methodology, Mr. Schoenbeck asserts on page 14 of his direct testimony that "the distribution demand allocation factor ignores the localized diversity that exists on the Company's distribution system." In fact, it is Mr. Schoenbeck's proposed 1 NCP methodology that ignores the localized diversity that exists on the Company's distribution system.

Q. Does the Company employ a 12 DCP method to allocate distribution demand-related costs in jurisdictions other than Idaho?

A. Yes. This methodology is used by the Company to allocate substations and primary lines in cost of service studies filed in California, Oregon, Utah, and Wyoming.

1 **Q. What are your conclusions regarding Mr. Schoenbeck's allocation**
2 **proposals?**
3 A. I recommend the Commission reject Mr. Schoenbeck's proposals to 1) allocate
4 demand related Generation and Transmission costs using 2 CP W/S and 2) to
5 allocate distribution substations and primary lines using a 1 NCP for reasons cited
6 above.
7 Irrigation Class Loads
8 **Q. What does Mr. Schoenbeck propose regarding irrigation class demands used**
9 **in the cost of service study?**
10 A. Mr. Schoenbeck asserts that irrigation class demands used by the Company in the
11 cost of service study are inappropriate. He proposes using one of two methods to
12 more appropriately determine the level of curtailment associated with irrigation
13 customers.
14 **Q. Do you agree with Mr. Schoenbeck's proposal?**
15 A. No. The Company indicated in response to IIPA Data Request 16, provided as
16 Exhibit No. 83, that the level of curtailment for the irrigation load control
17 program was reflected in the historic five year average (2005-2009) actual load
18 research sample data for the irrigation class. Using either one of Mr.
19 Schoenbeck's methods to calculate a load adjustment value does not necessarily
20 provide a more appropriate level of curtailment, his estimation methods are only
21 different.

1 **Response to Direct Testimony of Ms. Teri Ottens**

2 Customer-Related Costs

3 **Q. In her testimony, Ms. Ottens states that she cannot understand how anyone**
4 **analyzing utility costs can specify which of those costs are "customer**
5 **related." Please explain how the Company determines which costs are**
6 **"customer related" and why they are important.**

7 A. The cost of service study procedures filed in my direct testimony, Exhibit No. 83,
8 Tab 1, explains that customer-related costs are directly related to the number of
9 customers served. These costs include meters, meter reading, meter maintenance,
10 service drops, billing and customer service. Whether a customer turns on their
11 lights or not, the Company must provide customers with access to electricity,
12 accurately measure electric consumption, provide a bill, and answer a customer's
13 phone calls. Assigning these costs based upon the number of customers promotes
14 fairness and sends the correct price signal.

15 **Q. Does this conclude your rebuttal testimony?**

16 A. Yes, it does.

Case No. PAC-E-10-07
Exhibit No. 81
Witness: C. Craig Paice

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of C. Craig Paice

Rebuttal COS – Summary by Rate Schedule

November 2010

Summary

Rocky Mountain Power
Cost Of Service By Rate Schedule
State of Idaho
12 Months Ending December 2010
MSP Protocol
5.97% = Earned Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	01	Residential	39,005,158	7.47%	1.25	37,177,246	19,277,448	3,165,363	10,449,589	4,176,158	108,688	(1,827,912)	-4.69%
2	36	Residential - TOD	20,624,289	5.40%	0.90	21,020,592	12,527,694	2,019,744	4,887,170	1,529,673	56,312	396,303	1.92%
3	06, 35	General Service - Large	20,075,670	5.91%	0.99	20,118,275	14,450,764	2,401,473	3,069,326	143,291	53,421	42,605	0.21%
5	09	General Service - High Voltage	5,062,482	5.76%	0.96	5,097,301	4,389,406	668,407	15,713	10,466	13,310	34,819	0.69%
6	10	Irrigation	39,845,737	7.37%	1.24	38,074,064	22,816,184	3,567,868	11,411,583	172,267	106,162	(1,771,673)	-4.45%
7	07,11,12	Street & Area Lighting	600,521	42.59%	7.13	416,099	94,249	8,624	267,652	43,879	1,696	(184,422)	-30.71%
8	19	Space Heating	534,219	6.60%	1.10	522,808	359,905	60,807	89,349	11,303	1,443	(11,411)	-2.14%
9	23	General Service - Small	12,309,609	6.88%	1.15	11,938,143	7,115,305	1,210,058	2,780,566	798,224	33,991	(371,466)	-3.02%
10	SPC	Contract 1	59,524,497	4.11%	0.69	63,080,198	54,565,742	8,265,022	95,633	(1,740)	155,541	3,555,701	5.97%
11	SPC	Contract 2	4,466,432	4.96%	0.83	4,603,889	3,928,041	567,122	96,553	485	11,688	137,457	3.08%
12	Total	State of Idaho	202,048,614	5.97%	1.00	202,048,614	139,524,738	21,934,488	33,163,134	6,884,005	542,249	0	0.00%

Footnotes :

Column C : Annual revenues based on 12 months ending December 2010.
Column D : Calculated Return on Ratebase per December 2010 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Idaho Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column K : Calculated Misc.Distribution Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

Rocky Mountain Power
Cost Of Service By Rate Schedule
State of Idaho
12 Months Ending December 2010
MSP Protocol
8.34% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	01	Residential	39,005,158	7.47%	1.25	41,826,450	21,215,063	4,055,324	12,164,111	4,201,930	190,022	2,821,292	7.23%
2	36	Residential - TOD	20,624,289	5.40%	0.90	23,662,521	13,768,298	2,586,633	5,682,961	1,538,884	85,745	3,038,232	14.73%
3	06, 35	General Service - Large	20,075,670	5.91%	0.99	22,758,892	15,932,560	3,073,300	3,551,363	144,121	57,548	2,683,222	13.37%
5	09	General Service - High Voltage	5,062,482	5.76%	0.96	5,713,338	4,815,495	855,802	17,846	10,476	13,719	650,856	12.86%
6	10	Irrigation	39,845,737	7.37%	1.24	42,899,237	24,952,870	4,567,883	13,084,894	175,312	118,278	3,053,500	7.66%
7	07,11,12	Street & Area Lighting	600,521	42.59%	7.13	435,354	100,240	11,132	276,719	44,241	3,022	(165,167)	-27.50%
8	19	Space Heating	534,219	6.60%	1.10	592,593	396,898	77,821	104,755	11,382	1,736	58,374	10.93%
9	23	General Service - Small	12,309,609	6.88%	1.15	13,507,722	7,853,511	1,549,168	3,251,898	803,048	50,096	1,198,113	9.73%
10	SPC	Contract 1	59,524,497	4.11%	0.69	70,397,953	59,565,349	10,570,036	104,860	(2,293)	160,001	10,873,456	18.27%
11	SPC	Contract 2	4,466,432	4.96%	0.83	5,124,533	4,279,396	726,368	106,304	454	12,010	658,101	14.73%
12	Total	State of Idaho	202,048,614	5.97%	1.00	226,918,594	152,879,682	28,073,468	38,345,712	6,927,556	692,177	24,869,980	12.31%

Footnotes :

Column C : Annual revenues based on 12 months ending December 2010.
Column D : Calculated Return on Ratebase per December 2010 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Idaho Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
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Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column K : Calculated Misc.Distribution Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

Case No. PAC-E-10-07
Exhibit No. 82
Witness: C. Craig Paice

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of C. Craig Paice

Rebuttal COS – Summary by Function

November 2010

Class Summary

Rocky Mountain Power
Cost Of Service By Rate Schedule - All Functions
State of Idaho
MSP Protocol
12 Months Ending December 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M
	DESCRIPTION		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
14	Operating Revenues		263,688,053	48,060,324	26,299,793	27,067,730	7,005,504	50,175,484	630,297	711,194	15,942,522	81,771,366	6,023,839
15													
16	Operating Expenses												
17	Operation & Maintenance Expenses		183,779,349	30,998,293	18,131,204	18,613,957	5,135,170	32,247,356	353,053	475,363	10,464,270	62,811,289	4,549,394
18	Depreciation Expense		27,431,473	5,232,861	2,934,430	2,958,689	647,542	5,808,245	50,815	77,024	1,761,330	7,420,326	540,211
19	Amortization Expense		2,100,494	445,117	234,140	210,745	52,897	358,992	3,453	5,690	136,531	609,718	43,221
20	Taxes Other Than Income		5,735,434	1,174,372	642,821	599,566	125,427	1,199,746	5,137	16,199	381,411	1,483,880	106,874
21	Income Taxes - Federal		(30,337,634)	(4,636,374)	(2,888,659)	(3,334,816)	(945,057)	(4,915,130)	(16,987)	(83,890)	(1,714,184)	(11,025,106)	(777,429)
22	Income Taxes - State		(3,898,423)	(595,666)	(353,194)	(406,081)	(114,873)	(600,104)	(2,121)	(10,225)	(209,528)	(1,339,146)	(94,469)
23	Income Taxes Deferred		40,613,922	6,448,801	3,944,542	4,430,017	1,200,142	5,904,296	22,843	112,805	2,345,095	14,206,117	999,263
24	Investment Tax Credit Adj		(201,494)	(39,740)	(22,129)	(21,282)	(4,692)	(41,569)	(162)	(870)	(13,158)	(64,391)	(3,904)
25	Misc Revenues & Expense		(580,936)	(84,096)	(53,642)	(64,990)	(18,548)	(94,739)	(233)	(1,614)	(32,336)	(215,648)	(15,090)
26													
27	Total Operating Expenses		224,842,185	38,970,548	22,569,514	22,985,804	6,078,098	40,867,091	415,798	590,782	13,119,440	73,897,039	5,348,072
28													
29	Operating Revenue For Return		38,845,868	9,089,776	3,730,280	4,081,927	927,407	9,308,393	214,499	120,412	2,823,082	7,874,327	675,768
30													
32	Rate Base :												
33	Electric Plant In Service		1,166,794,057	224,585,472	125,722,133	124,712,160	27,904,323	238,049,714	1,414,522	3,274,540	75,122,440	322,787,494	23,271,239
34	Plant Held For Future Use		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
35	Electric Plant Acquisition Adj		3,352,852	485,360	309,593	375,067	107,051	546,784	1,346	9,314	185,621	1,244,606	87,090
36	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-
37	Prepayments		2,570,364	668,789	319,296	232,409	55,362	420,918	5,624	6,723	181,942	633,214	45,088
38	Fuel Stock		12,146,087	1,616,693	1,061,738	1,183,506	377,336	2,017,993	10,587	29,427	577,962	4,910,981	359,843
39	Materials & Supplies		9,955,856	1,783,077	1,034,108	1,085,395	280,941	1,911,249	9,575	28,088	619,230	3,009,013	215,189
40	Misc Deferred Debits		4,174,122	623,618	393,110	465,430	130,248	686,326	1,980	11,563	235,907	1,519,663	106,187
41	Cash Working Capital		2,927,613	562,386	310,323	298,597	68,338	606,498	11,542	7,750	183,302	818,207	60,570
42	Weatherization Loans		3,503,640	2,048,025	725,127	82,926	878	231,772	34,209	6,489	394,416	48	48
43	Miscellaneous Rate Base		123,279	17,341	11,156	13,189	3,898	20,341	69	327	6,523	47,885	3,349
44													
45	Total Rate Base Additions		1,206,547,861	232,370,761	129,886,576	128,428,723	28,906,076	244,491,594	1,490,553	3,374,310	77,508,345	334,940,312	24,148,601
46													
47	Rate Base Deductions :												
48	Accum Provision For Depreciation		(371,828,719)	(73,793,983)	(40,547,991)	(39,757,999)	(9,245,838)	(81,763,895)	(614,549)	(1,038,980)	(24,378,621)	(94,287,718)	(6,999,144)
49	Accum Provision For Amortization		(21,806,207)	(5,483,029)	(2,662,284)	(2,009,513)	(446,593)	(3,855,925)	(52,411)	(57,419)	(1,531,119)	(5,109,989)	(367,924)
50	Accum Deferred Income Taxes		(155,894,797)	(30,554,070)	(17,067,736)	(16,543,967)	(3,651,191)	(31,691,927)	(115,294)	(440,097)	(10,160,906)	(42,336,497)	(3,033,109)
51	Unamortized ITC		(226,270)	(44,559)	(24,829)	(24,094)	(5,258)	(46,583)	(171)	(641)	(14,806)	(60,960)	(4,370)
52	Customer Advance For Construction		(947,697)	(19,581)	(10,343)	(514,634)	(304,747)	-	-	(951)	(97,461)	-	-
53	Customer Service Deposits		-	-	-	-	-	-	-	-	-	-	-
54	Misc Rate Base Deductions		(4,891,303)	(760,557)	(465,187)	(504,647)	(139,986)	(885,222)	(4,439)	(12,770)	(268,018)	(1,725,560)	(124,918)
55													
56	Total Rate Base Deductions		(554,992,992)	(110,755,759)	(60,778,370)	(59,354,954)	(12,793,613)	(118,273,552)	(986,864)	(1,548,858)	(36,450,933)	(143,520,724)	(10,529,466)
57													
58	Total Rate Base		650,554,859	121,615,002	69,108,206	69,073,869	16,114,463	126,218,041	503,690	1,825,452	41,057,412	191,419,587	13,619,136
59													
60	Calculated Return On Rate Base		5.97%	7.47%	5.40%	5.91%	5.76%	7.37%	42.59%	6.60%	6.88%	4.11%	4.96%
61													
62	Return On Rate Base @ Jurisdictional Ave.	5.97%	38,845,868	7,261,963	4,126,582	4,124,532	962,225	7,536,719	30,076	109,001	2,451,616	11,430,028	813,224
63	Total Operating Expenses		224,842,185	38,970,548	22,569,514	22,985,804	6,078,098	40,867,091	415,798	590,782	13,119,440	73,897,039	5,348,072
64	Revenue Credits		(51,639,439)	(9,055,166)	(5,675,504)	(6,992,060)	(1,943,022)	(10,329,747)	(29,776)	(179,975)	(3,632,913)	(22,246,889)	(1,557,407)
65													
66	Total Revenue Requirements		202,048,614	37,177,246	21,020,592	20,118,275	5,097,301	38,074,064	416,099	522,808	11,938,143	63,080,198	4,603,889
67	Class Revenue		202,048,614	39,005,158	20,624,289	20,075,870	5,062,482	39,845,737	600,521	534,219	12,309,609	59,524,497	4,466,432
68													
69	Increase / (Decrease) Required to												
70	Earn Equal Rates of Return		-	(1,827,912)	396,303	42,605	34,819	(1,771,673)	(184,422)	(11,411)	(371,466)	3,555,701	137,457
71													
72	Percent %		0.00%	-4.69%	1.92%	0.21%	0.69%	-4.45%	-30.71%	-2.14%	-3.02%	5.97%	3.08%
73													
74													
75	Return On Rate Base @ Target ROR	8.34%	54,241,574	10,139,943	5,762,083	5,759,200	1,343,582	10,523,732	41,996	152,201	3,423,260	15,960,068	1,135,628
76	Total Operating Expenses Adjusted for Taxes		234,316,460	40,741,673	23,575,952	23,991,752	6,312,779	42,705,251	423,134	617,367	13,717,375	76,584,754	5,546,412
77	Revenue Credits		(51,639,439)	(9,055,166)	(5,675,504)	(6,992,060)	(1,943,022)	(10,329,747)	(29,776)	(179,975)	(3,632,913)	(22,246,889)	(1,557,407)
78													
79	Total Target Revenue Requirements		226,918,594	41,826,450	23,662,521	22,758,892	5,713,338	42,699,237	436,364	592,593	13,507,722	70,397,953	5,124,533
80	Class Revenue		202,048,614	39,005,158	20,624,289	20,075,870	5,062,482	39,845,737	600,521	534,219	12,309,609	59,524,497	4,466,432
81													
82	Increase / (Decrease) Required to												
83	Earn Target Rate of Return		24,869,980	2,821,292	3,038,232	2,683,222	650,856	3,053,500	(165,157)	58,374	1,198,113	10,873,456	658,101
84													
85	Percent %		12.31%	7.23%	14.73%	13.37%	12.86%	7.66%	-27.50%	10.93%	9.73%	18.27%	14.73%

Rocky Mountain Power
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Case No. PAC-E-10-07
Witness: C. Craig Paice

Generation Summary

Rocky Mountain Power
Cost Of Service By Rate Schedule - Generation Function
State of Idaho
MSP Protocol
12 Months Ending December 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M
	DESCRIPTION		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
14	Operating Expenses												
15	Operation & Maintenance Expenses		148,763,397	20,631,101	13,369,956	15,489,981	4,662,098	24,399,993	97,607	385,405	7,637,965	57,909,187	4,159,904
16	Depreciation Expense		14,726,494	2,140,364	1,368,153	1,649,786	470,848	2,369,577	5,960	41,103	821,432	5,475,970	383,301
17	Amortization Expense		1,452,104	220,849	137,846	161,115	45,427	234,552	787	4,046	82,406	528,081	37,013
18	Taxes Other Than Income		2,905,296	421,516	269,887	322,357	92,694	464,825	1,303	8,048	160,593	1,087,637	76,435
19	Income Taxes - Federal		(32,916,521)	(4,775,770)	(3,057,799)	(3,652,261)	(1,060,212)	(5,286,434)	(14,766)	(91,179)	(1,819,507)	(12,322,885)	(866,009)
20	Income Taxes - State		(4,050,981)	(587,741)	(376,315)	(449,476)	(129,247)	(648,125)	(1,817)	(11,221)	(223,922)	(1,516,540)	(106,577)
21	Income Taxes Deferred		30,116,710	4,369,513	2,797,683	3,341,595	960,874	4,816,436	13,510	83,423	1,664,729	11,274,605	792,341
22	Investment Tax Credit Adj		(105,548)	(15,313)	(9,805)	(11,711)	(3,368)	(16,887)	(47)	(292)	(5,834)	(39,513)	(2,777)
23	Misc Revenues & Expense		(569,491)	(82,440)	(52,585)	(63,710)	(18,183)	(92,873)	(229)	(1,582)	(31,698)	(211,400)	(14,792)
24													
25	Total Operating Expenses		160,321,161	22,322,082	14,447,020	16,787,657	5,050,932	26,283,066	102,487	417,752	8,286,163	62,185,162	4,458,839
26													
27													
28	Rate Base :												
29	Electric Plant In Service		803,731,038	87,565,196	56,112,352	67,241,464	19,289,745	96,544,876	260,142	1,678,119	33,466,437	225,728,217	15,844,491
30	Plant Held For Future Use		491,540	71,155	45,387	54,989	15,694	80,160	197	1,365	27,359	182,464	12,768
31	Electric Plant Acquisition Adj		3,352,852	485,360	309,593	375,087	107,051	546,784	1,346	9,314	186,621	1,244,606	87,090
32	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-
33	Prepayments		1,536,515	341,751	173,906	147,217	40,948	220,570	2,926	4,051	99,443	472,589	33,113
34	Fuel Stock		12,146,067	1,616,693	1,061,738	1,183,508	377,336	2,017,993	10,587	29,427	577,962	4,910,981	359,843
35	Materials & Supplies		8,012,962	1,167,529	747,357	898,629	256,436	1,277,623	3,260	22,435	447,644	2,983,186	208,863
36	Misc Deferred Debits		2,664,710	388,262	248,534	298,639	85,278	424,674	1,084	7,461	148,864	992,058	69,457
37	Cash Working Capital		1,594,991	221,075	143,267	165,985	50,172	261,461	1,048	4,130	81,848	620,532	44,576
38	Weatherization Loans		-	-	-	-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		123,279	17,341	11,156	13,189	3,898	20,341	69	327	6,523	47,085	3,349
40													
41	Total Rate Base Additions		633,653,054	91,874,363	58,853,291	70,378,907	20,226,557	101,394,681	280,660	1,756,628	35,042,700	237,181,718	16,663,549
42													
43	Rate Base Deductions :												
44	Accum Provision For Depreciation		(162,325,198)	(26,420,001)	(16,933,510)	(20,284,622)	(5,823,993)	(29,176,865)	(79,205)	(506,158)	(10,093,616)	(68,216,954)	(4,790,275)
45	Accum Provision For Amortization		(10,370,856)	(1,507,313)	(965,459)	(1,158,869)	(331,604)	(1,656,044)	(4,357)	(28,922)	(576,902)	(3,870,232)	(271,353)
46	Accum Deferred Income Taxes		(87,483,741)	(12,692,991)	(8,133,207)	(9,747,252)	(2,795,428)	(13,985,755)	(37,595)	(243,275)	(4,851,655)	(32,701,491)	(2,295,095)
47	Unamortized ITC		(118,526)	(17,197)	(11,019)	(13,208)	(3,787)	(18,949)	(51)	(330)	(6,573)	(44,304)	(3,109)
48	Customer Advance For Construction		-	-	-	-	-	-	-	-	-	-	-
49	Customer Service Deposits		-	-	-	-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		(4,012,922)	(582,253)	(358,089)	(413,988)	(125,987)	(665,116)	(2,740)	(10,272)	(203,767)	(1,567,827)	(112,883)
51													
52	Total Rate Base Deductions		(284,311,243)	(41,189,755)	(26,401,284)	(31,617,736)	(9,080,798)	(45,502,728)	(123,948)	(788,956)	(15,732,514)	(106,400,809)	(7,472,716)
53													
54	Total Rate Base		349,341,810	50,684,607	32,452,006	38,761,171	11,145,759	55,891,953	156,712	967,672	19,310,186	130,780,909	9,190,834
55													
56													
57	Return On Rate Base	5.97%	20,859,864	3,026,474	1,937,771	2,314,503	665,534	3,337,415	9,358	57,782	1,153,048	7,809,177	548,802
58	Total Operating Expenses		160,321,161	22,322,082	14,447,020	16,787,657	5,050,932	26,283,066	102,487	417,752	8,286,163	62,185,162	4,458,839
59	Revenue Credits		(41,656,267)	(6,071,108)	(3,857,098)	(4,651,396)	(1,327,061)	(6,784,297)	(17,596)	(115,628)	(2,323,906)	(15,428,597)	(1,079,600)
60													
61	Total Revenue Requirements		139,524,738	19,277,448	12,527,694	14,450,764	4,389,406	22,816,184	94,249	359,905	7,115,305	54,565,742	3,928,041
62													
63													
64	Return On Rate Base @ Target ROR	8.3377%	29,127,212	4,225,951	2,705,754	3,231,806	929,304	4,660,126	13,066	80,682	1,610,033	10,904,172	766,308
65	Total Operating Expenses Adjusted for Taxes		165,408,757	23,060,221	14,919,631	17,352,150	5,213,252	27,077,042	104,770	431,845	8,567,384	64,089,774	4,592,589
66	Revenue Credits		(41,656,267)	(6,071,108)	(3,857,098)	(4,651,396)	(1,327,061)	(6,784,297)	(17,596)	(115,628)	(2,323,906)	(15,428,597)	(1,079,600)
67													
68	Total Target Revenue Requirements		152,879,682	21,215,063	13,768,295	15,932,566	4,815,495	24,952,870	100,240	396,895	7,853,511	59,565,349	4,279,396

Generation Demand Summary

Rocky Mountain Power
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Case No. PAC-E-10-07
Witness: C. Craig Paice

Transmission Summary

Rocky Mountain Power
Cost Of Service By Rate Schedule - Transmission Function
State of Idaho
MSP Protocol
12 Months Ending December 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M
	DESCRIPTION		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
14	Operating Expenses												
15	Operation & Maintenance Expenses		12,599,956	1,621,792	1,161,672	1,403,773	400,975	2,053,744	5,286	34,868	699,060	4,692,368	327,019
16	Depreciation Expense		5,131,153	739,333	471,618	571,327	163,058	832,557	2,051	14,188	284,264	1,920,103	132,656
17	Amortization Expense		216,524	31,200	19,903	24,109	6,881	35,126	87	599	11,996	81,026	5,598
18	Taxes Other Than Income		1,048,565	152,009	96,827	114,751	32,008	170,807	428	2,906	57,922	393,707	27,200
19	Income Taxes - Federal		3,471,159	503,210	320,536	379,871	105,959	565,438	1,418	9,620	191,743	1,303,323	90,042
20	Income Taxes - State		474,483	68,785	43,815	51,926	14,484	77,291	194	1,315	26,210	178,155	12,308
21	Income Taxes Deferred		7,803,172	1,131,217	720,565	853,950	238,195	1,271,105	3,188	21,626	431,039	2,929,872	202,415
22	Investment Tax Credit Adj		(39,357)	(5,706)	(3,634)	(4,307)	(1,201)	(6,411)	(16)	(109)	(2,174)	(14,777)	(1,021)
23	Misc Revenues & Expense		(11,639)	(1,685)	(1,075)	(1,302)	(372)	(1,898)	(5)	(32)	(648)	(4,320)	(302)
24													
25	Total Operating Expenses		30,694,018	4,440,157	2,829,627	3,394,097	959,986	4,997,760	12,631	84,980	1,699,411	11,479,455	795,914
26													
27													
28	Rate Base :												
29	Electric Plant In Service		257,208,210	37,077,430	23,644,088	28,634,365	8,172,169	41,734,889	103,150	711,102	14,251,010	96,231,591	6,648,396
30	Plant Held For Future Use		(491,540)	(71,155)	(45,367)	(54,989)	(15,694)	(80,160)	(197)	(1,365)	(27,359)	(182,464)	(12,768)
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-
33	Prepayments		402,917	101,430	48,381	35,737	9,810	58,162	1,005	1,025	27,355	114,118	7,893
34	Fuel Stock		-	-	-	-	-	-	-	-	-	-	-
35	Materials & Supplies		55,984	8,066	5,145	6,233	1,779	9,087	22	155	3,101	20,949	1,447
36	Misc Deferred Debits		1,246,603	179,602	114,562	138,797	39,613	202,332	498	3,446	69,057	466,468	32,227
37	Cash Working Capital		521,210	75,360	48,029	58,068	16,587	84,955	219	1,442	28,917	194,105	13,527
38	Weatherization Loans		-	-	-	-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-	-	-	-
40													
41	Total Rate Base Additions		258,943,384	37,370,733	23,814,818	28,818,232	8,224,264	42,007,264	104,697	715,805	14,352,081	96,844,787	6,699,723
42													
43	Rate Base Deductions :												
44	Accum Provision For Depreciation		(68,498,882)	(9,869,992)	(6,296,096)	(7,627,057)	(2,176,777)	(11,113,586)	(27,377)	(189,402)	(3,794,852)	(25,632,819)	(1,770,924)
45	Accum Provision For Amortization		(3,279,391)	(472,610)	(301,419)	(365,107)	(104,201)	(532,188)	(1,313)	(9,066)	(181,684)	(1,227,030)	(84,772)
46	Accum Deferred Income Taxes		(25,525,147)	(3,680,162)	(2,346,529)	(2,841,480)	(810,945)	(4,141,679)	(10,250)	(70,566)	(1,414,322)	(9,549,281)	(659,733)
47	Unamortized ITC		(44,196)	(6,372)	(4,063)	(4,929)	(1,404)	(7,172)	(18)	(122)	(2,449)	(16,534)	(1,142)
48	Customer Advance For Construction		(679,431)	(14,024)	(7,415)	(368,956)	(216,482)	-	-	(682)	(69,873)	-	-
49	Customer Service Deposits		-	-	-	-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		(331,441)	(47,760)	(30,464)	(36,909)	(10,534)	(53,804)	(132)	(916)	(18,364)	(123,966)	(8,570)
51													
52	Total Rate Base Deductions		(98,358,487)	(14,090,920)	(8,985,987)	(11,244,428)	(3,322,343)	(15,848,630)	(39,090)	(270,755)	(5,481,543)	(36,549,650)	(2,525,141)
53													
54	Total Rate Base		160,584,897	23,279,813	14,828,831	17,573,804	4,901,921	26,158,634	65,607	445,050	8,870,538	60,295,116	4,165,582
55													
56													
57	Return On Rate Base	5.97%	9,586,830	1,390,982	885,458	1,049,365	292,703	1,561,982	3,917	26,575	529,677	3,600,336	248,735
58	Total Operating Expenses		30,694,018	4,440,157	2,829,627	3,394,097	959,986	4,997,760	12,631	84,980	1,699,411	11,479,455	795,914
59	Revenue Credits		(18,348,360)	(2,664,875)	(1,695,341)	(2,041,989)	(584,282)	(2,991,873)	(7,924)	(50,748)	(1,019,030)	(6,814,770)	(477,527)
60													
61	Total Revenue Requirements		21,934,488	3,165,363	2,019,744	2,401,473	668,407	3,567,868	8,624	60,807	1,210,058	8,265,022	567,122
62													
63													
64	Return On Rate Base @ Target ROR	8.34%	13,389,151	1,941,010	1,236,389	1,465,258	408,709	2,181,039	5,470	37,107	739,602	5,027,250	347,315
65	Total Operating Expenses Adjusted for Taxes		33,032,676	4,779,169	3,045,585	3,650,031	1,031,375	5,376,718	13,586	91,462	1,828,596	12,357,558	856,579
66	Revenue Credits		(18,348,360)	(2,664,875)	(1,695,341)	(2,041,989)	(584,282)	(2,991,873)	(7,924)	(50,748)	(1,019,030)	(6,814,770)	(477,527)
67													
68	Total Target Revenue Requirements		28,073,466	4,055,324	2,586,633	3,073,300	855,802	4,567,863	11,132	77,821	1,549,168	10,570,036	726,368

Transmission Demand Summary

Rocky Mountain Power
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Case No. PAC-E-10-07
Witness: C. Craig Paice

Distribution Summary

Rocky Mountain Power
Cost Of Service By Rate Schedule - Distribution Function
State of Idaho
MSP Protocol
12 Months Ending December 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M
	DESCRIPTION		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
14	Operating Expenses												
15	Operation & Maintenance Expenses		14,892,259	4,325,304	2,037,041	1,616,884	27,914	5,366,729	205,158	42,167	1,271,019	50,128	49,926
16	Depreciation Expense		7,505,489	2,313,060	1,080,460	736,331	13,552	2,601,460	42,186	21,806	646,338	24,247	24,247
17	Amortization Expense		227,908	73,374	34,012	21,806	329	75,434	760	664	20,350	589	589
18	Taxes Other Than Income		1,737,666	574,862	266,820	161,622	715	561,044	3,040	5,166	158,033	3,094	3,269
19	Income Taxes - Federal		(591,538)	(195,695)	(90,831)	(55,019)	(244)	(190,991)	(1,035)	(1,758)	(53,798)	(1,053)	(1,113)
20	Income Taxes - State		(80,869)	(26,760)	(12,416)	(7,521)	(33)	(26,107)	(141)	(240)	(7,354)	(144)	(152)
21	Income Taxes Deferred		2,476,303	819,221	380,239	230,323	1,019	799,529	4,333	7,361	225,208	4,409	4,659
22	Investment Tax Credit Adj		(56,590)	(18,721)	(8,689)	(5,263)	(23)	(18,271)	(99)	(168)	(5,147)	(101)	(106)
23	Misc Revenues & Expense		195	28	18	22	6	32	0	1	11	72	5
24													
25	Total Operating Expenses		26,110,831	7,864,683	3,686,654	2,699,183	43,236	9,168,859	254,203	74,787	2,256,561	81,241	81,324
26													
27													
28	Rate Base :												
29	Electric Plant In Service		300,196,545	96,653,759	44,801,849	28,719,190	434,605	99,343,383	1,001,276	874,617	26,804,772	786,402	776,888
30	Plant Held For Future Use		-	-	-	-	-	-	-	-	-	-	-
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-
33	Prepayments		462,813	192,011	78,574	31,704	633	110,495	2,466	1,177	44,166	793	793
34	Fuel Stock		-	-	-	-	-	-	-	-	-	-	-
35	Materials & Supplies		1,886,910	607,482	281,597	180,534	2,727	624,539	6,293	5,498	168,484	4,878	4,878
36	Misc Deferred Debits		43,862	14,121	6,546	4,197	63	14,518	146	128	3,917	113	113
37	Cash Working Capital		706,565	205,215	96,648	71,989	1,324	254,625	9,734	2,000	60,304	2,378	2,369
38	Weatherization Loans		-	-	-	-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-	-	-	-
40													
41	Total Rate Base Additions		303,296,696	97,672,589	45,265,215	29,007,593	439,352	100,347,560	1,019,917	883,426	27,081,642	794,566	784,841
42													
43	Rate Base Deductions :												
44	Accum Provision For Depreciation		(120,545,281)	(37,352,958)	(17,264,911)	(11,841,633)	(244,754)	(41,455,931)	(705,845)	(340,942)	(10,462,671)	(437,918)	(437,918)
45	Accum Provision For Amortization		(4,383,532)	(1,411,294)	(654,193)	(419,389)	(6,338)	(1,450,794)	(14,619)	(12,772)	(391,410)	(11,366)	(11,336)
46	Accum Deferred Income Taxes		(41,948,833)	(13,876,264)	(6,442,802)	(3,934,957)	(43,508)	(13,487,579)	(68,804)	(124,745)	(3,820,584)	(79,964)	(77,625)
47	Unamortized ITC		(63,548)	(20,989)	(9,747)	(5,967)	(67)	(20,463)	(102)	(189)	(5,783)	(122)	(119)
48	Customer Advance For Construction		(268,266)	(5,537)	(2,928)	(145,678)	(86,265)	-	-	(269)	(27,888)	-	-
49	Customer Service Deposits		-	-	-	-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		(520,126)	(156,662)	(74,157)	(50,750)	(2,608)	(161,929)	(1,556)	(1,507)	(44,394)	(23,793)	(2,769)
51													
52	Total Rate Base Deductions		(167,729,585)	(52,823,704)	(24,448,738)	(16,398,376)	(383,540)	(56,576,695)	(782,727)	(480,424)	(14,752,431)	(553,184)	(529,767)
53													
54	Total Rate Base		135,567,110	44,848,885	20,816,477	12,609,218	55,812	43,770,865	237,191	402,996	12,329,211	241,382	255,074
55													
56													
57	Return On Rate Base	5.97%	8,094,970	2,678,012	1,242,991	752,920	3,333	2,613,642	14,163	24,064	736,201	14,413	15,231
58	Total Operating Expenses		26,110,831	7,864,683	3,686,654	2,699,183	43,236	9,168,859	254,203	74,787	2,256,561	81,241	81,324
59	Revenue Credits		(1,042,668)	(93,106)	(42,475)	(282,777)	(30,856)	(370,918)	(715)	(9,502)	(212,295)	(22)	(2)
60													
61	Total Revenue Requirements		33,163,134	10,449,589	4,887,170	3,069,326	15,713	11,411,583	267,652	89,349	2,780,566	95,633	96,553
62													
63													
64	Return On Rate Base @ Target ROR	8.34%	11,303,233	3,739,384	1,735,624	1,051,324	4,653	3,649,501	19,776	33,601	1,027,976	20,126	21,267
65	Total Operating Expenses Adjusted for Taxes		28,085,146	8,517,834	3,989,812	2,782,816	44,049	9,806,310	257,657	80,656	2,436,216	84,758	85,039
66	Revenue Credits		(1,042,668)	(93,106)	(42,475)	(282,777)	(30,856)	(370,918)	(715)	(9,502)	(212,295)	(22)	(2)
67													
68	Total Target Revenue Requirements		38,345,712	12,164,111	5,682,961	3,551,363	17,846	13,084,894	276,719	104,755	3,251,898	104,860	106,304
	Distribution Substations												

Retail Summary

Rocky Mountain Power
Cost Of Service By Rate Schedule - Retail Services Function
State of Idaho
MSP Protocol
12 Months Ending December 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M
	DESCRIPTION		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
14	Operating Expenses												
15	Operation & Maintenance Expenses		6,983,389	4,116,128	1,508,162	149,169	10,608	320,118	43,202	11,486	822,919	955	641
16	Depreciation Expense		68,336	40,104	14,199	1,245	84	4,650	616	127	7,297	7	7
17	Amortization Expense		203,957	119,694	42,379	3,715	249	13,880	1,840	379	21,780	21	21
18	Taxes Other Than Income		43,908	25,983	9,287	837	11	3,070	386	80	4,864	(558)	(31)
19	Income Taxes - Federal		(104,244)	(61,688)	(22,049)	(1,986)	(26)	(7,288)	(868)	(189)	(11,548)	1,326	73
20	Income Taxes - State		(14,249)	(8,432)	(3,014)	(272)	(3)	(996)	(119)	(26)	(1,578)	181	10
21	Income Taxes Deferred		217,737	128,850	46,055	4,149	53	15,223	1,813	395	24,120	(2,769)	(152)
22	Investment Tax Credit Adj		-	-	-	-	-	-	-	-	-	-	-
23	Misc Revenues & Expense		-	-	-	-	-	-	-	-	-	-	-
24													
25	Total Operating Expenses		7,398,834	4,360,638	1,595,019	156,856	10,976	348,657	46,849	12,252	867,855	(837)	569
26													
27													
28	Rate Base :												
29	Electric Plant In Service		5,658,265	3,269,087	1,163,843	117,140	7,804	426,568	49,952	10,703	600,221	11,284	1,664
30	Plant Held For Future Use		-	-	-	-	-	-	-	-	-	-	-
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-
33	Prepayments		4,103	2,408	852	75	5	279	37	8	438	0	0
34	Fuel Stock		-	-	-	-	-	-	-	-	-	-	-
35	Materials & Supplies		-	-	-	-	-	-	-	-	-	-	-
36	Misc Deferred Debits		(31,228)	(5,938)	(3,347)	(3,366)	(755)	(6,362)	(36)	(88)	(2,007)	(8,704)	(626)
37	Cash Working Capital		101,734	59,964	21,971	2,173	155	4,663	629	167	11,988	14	9
38	Weatherization Loans		-	-	-	-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-	-	-	-
40													
41	Total Rate Base Additions		5,732,872	3,325,520	1,183,319	116,022	7,208	425,147	50,582	10,790	610,641	2,595	1,048
42													
43	Rate Base Deductions :												
44	Accum Provision For Depreciation		(257,358)	(151,033)	(53,475)	(4,687)	(315)	(17,514)	(2,321)	(478)	(27,482)	(26)	(26)
45	Accum Provision For Amortization		(3,572,428)	(2,091,811)	(741,213)	(66,348)	(4,450)	(246,899)	(32,122)	(6,659)	(381,123)	(1,341)	(463)
46	Accum Deferred Income Taxes		(737,075)	(404,654)	(145,198)	(20,279)	(1,312)	(76,714)	(6,645)	(1,511)	(74,347)	(5,761)	(655)
47	Unamortized ITC		-	-	-	-	-	-	-	-	-	-	-
48	Customer Advance For Construction		-	-	-	-	-	-	-	-	-	-	-
49	Customer Service Deposits		-	-	-	-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		(26,814)	(3,882)	(2,476)	(3,000)	(856)	(4,373)	(11)	(74)	(1,493)	(9,954)	(697)
51													
52	Total Rate Base Deductions		(4,593,676)	(2,651,380)	(942,361)	(94,314)	(6,932)	(345,500)	(41,099)	(8,722)	(484,445)	(17,081)	(1,841)
53													
54	Total Rate Base		1,139,196	674,140	240,958	21,708	276	79,648	9,483	2,067	126,196	(14,487)	(794)
55													
56													
57	Return On Rate Base	5.97%	68,024	40,254	14,386	1,296	16	4,756	566	123	7,535	(865)	(47)
58	Total Operating Expenses		7,398,834	4,360,638	1,595,019	156,856	10,976	348,657	46,849	12,252	867,855	(837)	569
59	Revenue Credits		(582,852)	(224,734)	(79,734)	(14,861)	(527)	(181,146)	(3,537)	(1,072)	(77,166)	(37)	(37)
60													
61	Total Revenue Requirements		6,884,005	4,176,158	1,529,673	143,291	10,466	172,267	43,879	11,303	798,224	(1,740)	485
62													
63													
64	Return On Rate Base @ Target ROR	8.34%	94,983	56,208	20,090	1,810	23	6,641	791	172	10,522	(1,208)	(66)
65	Total Operating Expenses Adjusted for Taxes		7,415,424	4,370,456	1,598,528	157,172	10,980	349,817	46,958	12,282	869,692	(1,048)	558
66	Revenue Credits		(582,852)	(224,734)	(79,734)	(14,861)	(527)	(181,146)	(3,537)	(1,072)	(77,166)	(37)	(37)
67													
68	Total Target Revenue Requirements		6,927,566	4,201,930	1,538,884	144,121	10,476	175,312	44,241	11,382	803,048	(2,293)	454

Rocky Mountain Power
Exhibit No. 82 Page 5 of 6
Case No. PAC-E-10-07
Witness: C. Craig Paice

MISC Summary

Rocky Mountain Power
Cost Of Service By Rate Schedule - Miscellaneous Function
State of Idaho
MSP Protocol
12 Months Ending December 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M
	DESCRIPTION		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
14	Operating Expenses												
15	Operation & Maintenance Expenses		540,349	103,968	54,974	54,150	13,575	106,771	1,601	1,447	33,306	158,652	11,904
16	Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-
17	Amortization Expense		-	-	-	-	-	-	-	-	-	-	-
18	Taxes Other Than Income		-	-	-	-	-	-	-	-	-	-	-
19	Income Taxes - Federal		(196,190)	(106,431)	(38,516)	(5,401)	(535)	(15,855)	(1,736)	(384)	(21,074)	(5,836)	(422)
20	Income Taxes - State		(26,818)	(14,548)	(5,265)	(738)	(73)	(2,167)	(237)	(52)	(2,881)	(798)	(58)
21	Income Taxes Deferred		-	-	-	-	-	-	-	-	-	-	-
22	Investment Tax Credit Adj		-	-	-	-	-	-	-	-	-	-	-
23	Misc Revenues & Expense		-	-	-	-	-	-	-	-	-	-	-
24													
25	Total Operating Expenses		317,341	(17,011)	11,193	48,011	12,967	88,749	(372)	1,011	9,351	152,018	11,425
26													
27													
28	Rate Base :												
29	Electric Plant In Service		-	-	-	-	-	-	-	-	-	-	-
30	Plant Held For Future Use		-	-	-	-	-	-	-	-	-	-	-
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-
33	Prepayments		164,017	31,188	17,581	17,677	3,966	33,412	189	463	10,539	45,714	3,288
34	Fuel Stock		-	-	-	-	-	-	-	-	-	-	-
35	Materials & Supplies		-	-	-	-	-	-	-	-	-	-	-
36	Misc Deferred Debits		250,175	47,571	26,816	26,963	6,049	50,964	288	706	16,076	69,727	5,015
37	Cash Working Capital		4,013	772	408	402	101	793	12	11	247	1,176	88
38	Weatherization Loans		3,503,640	2,048,025	726,127	62,926	578	231,772	34,209	6,489	394,415	48	48
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-	-	-	-
40													
41	Total Rate Base Additions		3,921,845	2,127,556	769,933	107,968	10,695	316,941	34,697	7,668	421,281	116,667	8,440
42													
43	Rate Base Deductions :												
44	Accum Provision For Depreciation		-	-	-	-	-	-	-	-	-	-	-
45	Accum Provision For Amortization		-	-	-	-	-	-	-	-	-	-	-
46	Accum Deferred Income Taxes		-	-	-	-	-	-	-	-	-	-	-
47	Unamortized ITC		-	-	-	-	-	-	-	-	-	-	-
48	Customer Advance For Construction		-	-	-	-	-	-	-	-	-	-	-
49	Customer Service Deposits		-	-	-	-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		-	-	-	-	-	-	-	-	-	-	-
51													
52	Total Rate Base Deductions		-	-	-	-	-	-	-	-	-	-	-
53													
54	Total Rate Base		3,921,845	2,127,556	769,933	107,968	10,695	316,941	34,697	7,668	421,281	116,667	8,440
55													
56													
57	Return On Rate Base	5.97%	234,181	127,040	45,974	6,447	639	18,925	2,072	458	25,155	6,966	504
58	Total Operating Expenses		317,341	(17,011)	11,193	48,011	12,967	88,749	(372)	1,011	9,351	152,018	11,425
59	Revenue Credits		(9,273)	(1,342)	(856)	(1,037)	(296)	(1,512)	(4)	(26)	(516)	(3,443)	(241)
60													
61	Total Revenue Requirements		542,249	108,688	56,312	53,421	13,310	106,162	1,696	1,443	33,991	155,541	11,688
62													
63													
64	Return On Rate Base @ Target ROR	8.34%	326,993	177,390	64,195	9,002	892	26,426	2,893	639	35,125	9,727	704
65	Total Operating Expenses Adjusted for Taxes		374,457	13,974	22,406	49,583	13,123	93,365	133	1,122	15,486	153,717	11,547
66	Revenue Credits		(9,273)	(1,342)	(856)	(1,037)	(296)	(1,512)	(4)	(26)	(516)	(3,443)	(241)
67													
68	Total Target Revenue Requirements		692,177	190,022	85,745	57,548	13,719	118,278	3,022	1,736	50,096	160,001	12,010

Case No. PAC-E-10-07
Exhibit No. 83
Witness: C. Craig Paice

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of C. Craig Paice

IIPA Data Request 16

November 2010

IIPA Data Request 16

With respect to Exhibit 49, Tab 5, page 7, please answer the following:

A. Are all of these values actual? If not, please provide and explanation of how they were normalized and the workpapers that support the normalization.

B. What level of curtailment of Schedule 10 load is reflected on line 23? Is this level of curtailment the same as occurred in 2008 and 2009 or is expected to be incurred in 2010?

C. What is the level of curtailment that is reflected in each month on line 26 for the Irrigation load?

Response to IIPA Data Request 16

A. The values presented reflect estimates of forecast class demand levels at the time of the merged Company system peak. Base year load measurements (census) and estimates (sample data) are adjusted to match test year energy levels.

B. The level of curtailment of Schedule 10 load reflected on line 23 is derived from the historic five year average (2005-2009) of actual load research sample data adjusted to test period energy. Because the load curtailment program operated during most of this five year period, the load curtailment program impact is reflected in the five year average data. The level of curtailment is based on this five year average and does not represent any individual year or any specific curtailment amount.

C. No class load data is shown on line 26. Please refer to the Company's response to part B. above.

Recordholder: C. Craig Paice / Scott D. Thornton
Sponsor: C. Craig Paice