BEFORE THE

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IDAHO PUBLIC
UTILITIES COMMISSION

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES	)	CASE NO. PAC-E-07-5

DIRECT TESTIMONY OF PATRICIA HARMS

IDAHO PUBLIC UTILITIES COMMISSION

SEPTEMBER 28, 2007

Q. Please state your name and address for the record.

A. My name is Patricia Harms. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission (Commission) as a Senior Auditor.

Q. Give a brief description of your educational background and experience.

A. I graduated from Boise State University, Boise, Idaho in 1981 with a B.A. degree in Business Administration, emphasis in Accounting. I am a Certified Public Accountant licensed by the State of Idaho. Prior to joining the Commission Staff in 2000, I was employed by the State of Alaska as an In Charge Auditor and performed both financial and performance audits of governmental agencies. I have attended many seminars and classes involving auditing and accounting. While at the Commission I have audited a number of utilities including water, electric, gas and telephone utilities and provided comments and testimony in a number of cases that dealt with general rates, hook-up fees, accounting issues, and other regulatory issues. I have also completed the National Association of Regulatory Utility Commissioners' (NARUC) annual regulatory studies program at Michigan

State University. I also attend meetings of NARUC's Staff Subcommittee on Accounting and Finance.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the summary exhibits that reflect all the adjustments of Staff witnesses for Rocky Mountain Power (Company) in this general rate case. I quantify the Idaho revenue requirement and revenue increase proposed for Idaho retail customers in this case.

My testimony also describes the proposed calculation of test year rate base and annualizing/pro forma plant adjustments and explains the rationale supporting Staff's position. My testimony further describes the adjustments proposed by Staff as a result of this position.

Additionally, my testimony describes Staff's proposed adjustment related to the Company's treatment of costs related to abandoned projects. Finally, my testimony describes Staff's adjustment regarding tax credits related to the Blundell Bottoming Cycle project.

Q. What exhibits are you sponsoring?

A. I am sponsoring Staff Exhibit Nos. 108-113. Staff Exhibit No. 108 calculates Staff's proposed revenue requirement under the rate mitigation cap stipulated and approved by the Commission in Case No. PAC-E-02-3. Staff

Exhibit No. 109 reflects Rocky Mountain Power's Normalized Results of Operations under the Revised Protocol cost methodology as Adjusted by Staff. Staff Exhibit No. 110 calculates the Revised Protocol revenue requirement price increase for Rocky Mountain Power. Staff Exhibit No. 111 reflects Rocky Mountain Power's Normalized Results of Operations under the Rolled-In cost methodology as Adjusted by Staff. Staff Exhibit No. 112 lists the adjustments proposed by Staff and the related change to the Idaho revenue requirement under the Revised Protocol cost methodology. Staff Exhibit No. 113 lists the system-wide amounts for capital projects Staff annualized or pro formed into Staff's proposed rate base.

Q. What is the purpose of Staff Exhibit No. 108?

A. This exhibit shows the Idaho revenue requirement proposed by Staff and reflects the rate mitigation cap as stipulated and approved by the Commission in Case No. PAC-E-02-3.

Q. What revenue requirement does Staff propose in this case?

A. The revenue requirement proposed is $190,229,447 as shown on Staff Exhibit No. 108, line 3. This results in an overall net increase of $11.2 million or 6.28%. The Company proposed in its Application a net increase of $18.5 million or 10.32% in prices for the

Company's Idaho retail customers.

Q. How is revenue requirement calculated in this case?

A. The $193,808,268 (Staff Exhibit No. 108, line 6) revenue requirement calculated under the Revised Protocol methodology is reduced to the rate mitigation cap of $190,229,447 (Staff Exhibit No. 108, line 3) as stipulated and approved by the Commission in Case No. PAC-E-02-3. This stipulation states:

> For all Idaho general rate proceedings initiated after the effective date of this Stipulation and Revised Protocol, and until March 31, 2009, the Company's Idaho revenue requirement to be used for purposes of setting rates for Idaho customers will be the lesser of: (i) the Company's Idaho revenue requirement calculated under the Rolled-In Allocation method multiplied by 101.67 percent, or (ii) the Company's Idaho revenue requirement resulting from use of the Revised Protocol.

The test period for this case is based on the historical twelve-month period ending December 31, 2006 that has been adjusted for known and measurable adjustments through December 31, 2007 for operating revenues and expenses. Rate base levels are based on a thirteen-month average using the balances from January 2006 through January 2007 with annualizing and pro forma adjustments for known and measurable plant additions placed in service through December 31, 2007. Staff's adjusted rate base is $487,197,283.

Q. How is the revenue requirement price increase on Staff Exhibit No. 110 calculated?

A. Staff calculated the revenue requirement price increase using a Rate Base of $487,197,283 and an 8.267% overall rate of return described in Staff witness Carlock's testimony. Staff's recommended Idaho revenue requirement price change of $14,815,425 is shown on Staff Exhibit No. 110. This revenue requirement price increase is also shown on Staff Exhibit No. 109.

Rate of Return

Q. How does Staff's proposed overall return compare to that requested by the Company?

A. The 8.267% overall rate of return Staff witness Carlock proposes is based upon a return on equity of 10.25%. This return on equity is 0.5% lower than that proposed by Rocky Mountain Power in its Application.

Based upon the case filed by the Company, this overall rate of return would result in an Idaho revenue requirement reduction of approximately $2 million.

Rate Base

Q. How have you provided for recovery of the Company's investments in rate base?

A. Staff proposes to establish the revenue requirement for the Company using rate base levels based on a thirteen-month average using the balances from

January 2006 through January 2007 with annualizing and pro forma adjustments for known and measurable plant additions through December 31, 2007.

Q. How does Staff propose recovery of the Company's investment in plant made during the 2006 test year?

A. Staff proposes several ways for the Company to recover plant investments it made in 2006. First, Staff proposes a thirteen-month average rate base for all plant in service investment incurred during 2006. Each plant in service project, regardless of size, is included in Staff's thirteen-month average rate base. In addition, projects in service during 2006 costing over $100 million system-wide or that are generation facilities reflected in power supply and/or transmission costs related to projects over $2 million system-wide were annualized.

Q. How did Staff determine the dollar threshold for annualizing projects during 2006?

A. The Company's Unadjusted Electric Plant in Service for 2006 on a beginning and ending average is $14,745,911,135 (Exhibit No. 11, page 2.2, line 36) system-wide. Compared to that investment level, Staff considered the Company's $2 million system-wide threshold for annualizing major projects in 2006 as too low ($2,000,000 per project divided by $14,745,911,135 total electric plant in service is .00014 or 0.014%). The $100 million threshold represents a single project as 0.7% of the Company's average Plant in Service during 2006 ($100,000,000 divided by $14,745,911,135). Based upon a review of the Company's plant additions on Exhibit No. 11, pages 8.82 through 8.85 there is a definite difference in the number and magnitude of projects. There are a few large projects and many smaller projects. Those six (three in 2006 and three in 2007) large projects range from $118 million to $331 million. Further, the Company has identified that Board of Directors' approval of individual capital expenditure projects has been replaced with the requirement of PacifiCorp CEO approval for projects greater than $25 million.

Q. If Staff used the Company's $25 million threshold for capital expenditure projects requiring PacifiCorp CEO approval, what additional projects would be annualized in 2006?

A. None. There are no projects in service during 2006 costing more than $25 million but less than $100 million system-wide according to Company Exhibit No. 11, pages 8.8.2 and 8.8.3. So, effectively, Staff's $100 million threshold for including plant within rate base and the Company's $25 million threshold for capital expenditures requiring CEO approval has the same impact.

Q. What 2006 projects were annualized in rate base as a result of meeting the $100 million system-wide threshold?

A. Three projects met this threshold. The projects are Currant Creek Phase II ($177 million system-wide), the Leaning Juniper 1 Wind Plant ($175 million system-wide), and the Huntington Unit II Scrubber ($118 million system-wide).

Q. Did Staff consider whether a generation project greater than $2 million system-wide is included in the power supply model and cost calculation for the Company as one of its criteria for annualizing projects in 2006?

A. Yes. Staff also used generation projects included in the power supply model as one of its criteria for annualizing projects in 2006. However, according to the Company, no projects greater than $2 million but less than $100 million system-wide produced power supply cost savings.

Q. How did Staff propose recovery for transmission projects in 2006?

A. In addition to inclusion within Staff's proposed thirteen-month average, Staff annualized the 2006 transmission projects listed in Company Exhibit No. 11, page 8.8.2. These projects totaled $75 million system-wide.

Q. How does Staff's proposal for 2006 plant additions compare to the Company's case?

A. As identified by Staff Exhibit No. 113, Staff annualized 18 projects with a system-wide total of $546,599,918. This is approximately 85% of the projects listed on Exhibit No. 11, pages 8.8.2 and 8.8.3 when distribution projects that would be allocated situs to other states are removed from the list. This annualizing adjustment incorporates those projects into rate base as if they had been in place for the entire year. Additionally, the associated depreciation and tax effects of this adjustment were calculated and included in Staff's proposed revenue requirement.

This methodology was developed under the supervision of Staff witness Carlock, Deputy Administrator of the Utilities Division, to ensure annualizing or adding major plant additions such as this as if it were in service for the entire test year is consistent with the policy used for major plant additions in Idaho Power and Avista rate cases (Case Nos. IPC-E-03-13 and AVU-E-04-1).

Q. How does Staff propose recovery of the Company's investment in plant made in 2007 (post test year)?

A. Staff has made pro forma adjustments for projects placed in service through December 31, 2007 costing over $100 million system-wide. Staff also adjusted for projects that are reflected in the power supply model and costs and/or transmission projects over $2 million system-wide. These projects were also pro formed into rate base.

Q. What 2007 projects were pro formed into rate base as a result of meeting the $100 million system-wide threshold?

A. Three projects met this threshold. The projects are Lake Side Capital Build ($331 million system-wide), the Marengo Wind Project ($259 million system-wide), and the Goodnoe Hills Wind Project ($197 million system-wide). These generation resource investments were weighted by the in service date to align the rate base investment with its inclusion in the calculation of net power supply costs.

Q. Did Staff pro form into rate base any 2007 projects greater that $2 million but less than $100 million system-wide that were included in the power supply model and cost calculation?

A. Yes. The Blundell Bottoming Cycle project ($28 million system-wide) was also weighted by the in service date to align the rate base investment with its inclusion of the plant, costs and availability in the calculation of net power supply costs.

Q. Were there any other adjustments associated with the Blundell Bottoming Cycle project?

A. Yes. The Company did not include the Federal Renewable Energy Tax Credit and the Utah State Renewable Energy Credit associated with this plant. The Federal Renewable Energy credit would equal $312,412 system-wide and $20,562 would be allocated to Idaho. The Utah State Renewable Energy credit would be $54,672 system-wide of which $1,822 would be allocated to Idaho. This adjustment reduces Idaho revenue requirement by approximately $40,000.

Q. How did Staff propose recovery for transmission projects in 2007?

A. Staff weighted the Company's investment in 2007 transmission projects by the updated in service dates provided for the projects listed in Company Exhibit No. 11, page 8.8.4. One third (five of the fifteen) of projects listed in Company Exhibit No. 11, page 8.8.4 will not be placed in service during 2007 as originally planned by the Company. One project has been delayed a year. As a result, Staff has excluded these projects from its proposed rate base in this case.

Q. Are there any projects included in Staff's rate base that are planned to go into service after the hearing in this case?

A. Yes. The in service dates for the Blundell Bottoming Cycle project, Goodnoe Hills Wind Project, and two transmission projects are December 2007. Although Goodnoe Hills is a $197 million project system-wide, due to net power cost savings its Idaho revenue requirement is approximately $60,000.

Q. What would be Staff's recommendation if these projects did not go in service before December 31, 2007?

A. Staff would recommend removing these projects from rate base if they are not placed in service before December 31, 2007. This would be consistent with other post test year adjustments and assure the projects are used and useful when rates become effective.

Q. How does Staff's proposal for 2007 plant additions compare to the Company's case?

A. As identified by Staff Exhibit No. 113, Staff included in its case 14 projects with a system-wide total of $946,738,633. This is over 80% of the projects listed on Exhibit No. 11, pages 8.8.4 and 8.8.5. (Notably this percentage is approximately 90% when the projects now with in service dates in 2008 and distribution projects that would not be allocated to Idaho are removed from the denominator). These pro forma Staff adjustments incorporate those projects weighted by the number of months the plant would be in service during 2007. Additionally, the associated depreciation and tax effects of this adjustment were calculated and included in Staff's proposed revenue requirement.

Q. What is the change in Staff's proposed Idaho revenue requirement based upon the proposed treatment of 2006 and 2007 rate base/plant additions and associated costs compared to the Company's filing?

A. Staff's proposal results in a reduction in Idaho revenue requirement of approximately $1 million. This still provides a reduction in regulatory lag by including projects to be completed after Staff's prefile but before the effective date of customer rates.

Q. You have described Staff's proposal regarding rate base. What historic test year does Rocky Mountain Power use in this case and what adjustments does it propose?

A. The Company's case is based on historical data for the twelve-months ended December 31, 2006. The Company then made various normalizing, annualizing and known and measurable adjustments to test year revenues, expenses and rate base. Rate base presented by the Company was initially an average of beginning and ending account balances. The Company proposed annualizing over

60 projects listed on Exhibit No. 11, pages 8.8.2 and 8.8.3 as if they were in place for the entire year. Because of the Company's beginning and ending average rate base, these projects were already in the Company's filing as if they had been in place for six months of the year even if an individual project's in service date was December 2006.

The Company listed almost 60 post-test year projects on Exhibit No. 11, pages 8.8.4 and 8.8.5 to include in rate base for the number of months they would be in service during 2007.

Q. How does Rocky Mountain Power's post-test year adjustments compare to those proposed by other companies' when the revenue requirement was not part of a stipulated agreement?

A. Idaho Power in Case No. IPC-E-03-13 filed a 2003 test year with 6 months of actual expenses, revenues and investments and 6 months estimated. Various normalizing, annualizing and known and measurable adjustments were made to test year revenues and expenses. In addition, a thirteen-month average rate base was used to recognize that some plant was in service for only part of the test year. Finally, less than ten major plant additions were added beyond the end of the test year. These major projects were included in the rate base calculation as if they were in service for the entire test year.

In Case No. AVU-E-04-1, Avista used a historic test year from January 1, 2002 to December 31, 2002. The Company then included various normalizing, annualizing and known and measurable adjustments to test year revenues and expenses. It used an average of the monthly averages to establish rate base levels. Avista included only five major plant additions beyond the test year; two generation projects and three transmission projects. These five major projects were included in the rate base calculation as if they were in service for the entire test year.

Q. What rate base treatment did the Commission allow in these cases?

A. The Commission required rate base be set using a thirteen-month average or the average of the thirteen-monthly averages for the test year. The Commission also allowed these companies to include limited major plant additions completed after the test year as if they had been in service for the entire year provided an adjustment was made to reflect revenue producing or expense reducing benefits from these projects in the revenue requirement.

Q. Did the Commission approve the test year with post-test year plant additions as proposed by the companies in these two cases?

A. Yes. However, in both cases the Commission expressed specific concern regarding annualizing plant additions added late in the year or after the Company's test year as if it were in place for a full year. In Order No. 29505, in Case No. IPC-E-03-13, the Commission stated:

> We generally believe that including investment in the calculation of average-year rate base as if it were in service the entire year when it was not… creates a mismatch between test year revenue and expenses.

Q. How does Staff's proposed rate base treatment address this issue?

A. Using a thirteen-month average rate base reduces the expense/revenue mismatch identified by the Commission that occurs when the costs of plant adjustments are added as if they were in place for a whole year without adding any benefits.

Over 85% of the plant additions annualized by Staff in the 2006 test year were generation resources. These projects are included in the Company's power supply model and reflected in the net power supply costs, producing benefits to customers. The Company has also included additional maintenance, depreciation and property taxes for these projects and where applicable, renewable energy tax credits. The remaining projects annualized are transmission related. The availability of these transmission projects is also reflected in the power supply model to improve reliability and to make cost effective purchases or sales that reduce customer costs. Although it may not result in cost savings that have been directly quantified, Staff is familiar with the calculations to assure customer benefits are received from these projects. Therefore, they are included in Staff's proposed rate base.

Neither the Company nor Staff proposes to include post test year plant additions in rate base as if they were in place for the whole year. Instead, Staff proposes to include those projects as previously described based upon their in service dates. Again, over 85% of these 2007 projects were generation resources that are reflected in the Company's power supply cost model and reflect net power cost savings. The remaining projects are transmission.

Q. Please identify other Staff adjustments to rate base that are summarized in your exhibits.

A. Staff witness Leckie proposes two adjustments to rate base. He has removed the cost of a coal lease from rate base reducing the Idaho revenue requirement by approximately $26,000. He has also removed the cost of a

Jim Bridger dragline from rate base reducing the Idaho revenue requirement by approximately $15,000.

Expenses

Q. Has Staff made any adjustments to expenses?

A. Yes. Staff has adjusted depreciation expense due to Staff's proposed plant adjustments, reduced expenses for abandoned projects, adjusted power supply costs, removed some costs associated with incentive and severance pay, reduced net lease expenses, removed certain administrative and general expenses, and reduced other expenses.

Q. How was depreciation expense calculated for Staff's proposed plant adjustments?

A. First depreciation expense changed due to the thirteen-month average Staff proposed compared to the beginning/ending average filed in the Company's case. Second, Staff annualized depreciation expense for major plant additions added during the test year. Third, depreciation expense for pro forma plant additions added to rate base is based on the number of months the plant is included in the test period rate base.

Q. How are abandoned projects included in the Company's case?

A. The Company expensed approximately $1.6 million system-wide of costs associated with abandoned projects.

According to the Company, many of these costs are associated with projects contemplated by customers but not completed. These costs do not represent assets that are used and useful. Staff proposes removal of these costs as they do not provide service to customers and should not be included in customer rates. On an Idaho-allocated basis, this reduces revenue requirement by approximately $80,000.

Q. Please identify other Staff adjustments to expenses that are summarized in your exhibits.

A. Staff witness Lanspery proposes three power supply cost adjustments. The first relates to an error by the Company in extracting data associated with gas purchases. This reduces Idaho revenue requirement by approximately $2.5 million. Second, he proposes adjusting power supply costs associated with the Monsanto credit. This increases Idaho revenue requirement by approximately $110,000. Third, Staff witness Lanspery proposes an adjustment associated with the Idaho Irrigators Load Control Program. This reduces Idaho revenue requirement by approximately $940,000. Staff witness Lanspery's testimony discusses these adjustments in detail.

Staff witness Leckie proposes several adjustments. 1) He proposes reducing incentive pay, reducing Idaho revenue requirement by approximately $160,000. 2) He also proposes reducing net lease expense. This adjustment reduces Idaho revenue requirement by approximately $7,000. 3) He proposes to remove from the Company's case the costs associated with changing the Company's fiscal year to a calendar year end. This adjustment reduces Idaho revenue requirement by approximately $25,000. 4) He adjusts for severance costs, reducing Idaho revenue requirement by approximately $160,000. Staff witness Leckie provides further detail regarding these adjustments in his testimony.

Staff witness Nobbs proposes to remove expenses that are nonrecurring or should not be paid by Idaho utility customers. His adjustments reduce Idaho revenue requirement by approximately $93,000. His testimony discusses these adjustments in detail.

Revenues

Q. Has Staff made any adjustments to revenues?

A. Yes. Staff witness Carlock has imputed revenue associated with the Company's Green Tags. These adjustments reduce Idaho revenue requirement by approximately $270,000. Her testimony discusses these adjustments in detail.

Taxes

Q. How did Staff's adjustments change taxes in the case?

A. Staff's adjustments to revenues and expenses change federal and state income taxes as taxable income changes. In addition, federal and state income taxes are changed because interest expense must be "trued up" for changes in rate base such as the adjustments to plant proposed by Staff.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

ROCKY MOUNTAIN POWER
STATE OF IDAHO
Normalized Results of Operations
12 Months Ended December 2006 with Known and Measurables

Line No.		(A) Original Filing	(B) Case Proposed by Staff
(1)	December 2006 Rolled-In Revenue Requirement	194,215,986	187,104,796
(2)	Rate Mitigation Cap	101.67%	101.67%
(3)	Capped Revised Protocol Revenue Requirement	197,459,393	190,229,447
(4)	Normalized December 2006 General Business Revenues	178,992,843	178,992,843
(5)	**Capped Revised Protocol Price Change**	**18,466,550**	**11,236,604**
	Revised Protocol		
(6)	Filed Revised Protocol Revenue Requirement	201,020,661	193,808,268
(7)	Normalized December 2006 General Business Revenues	178,992,843	178,992,843
(8)	Revised Protocol Price Change	22,027,818	14,815,425
(9)	**Capped Revised Protocol Price Change**	**18,466,550**	11,236,604
(10)	Reduction to Revised Protocol Revenue Requirement	**(3,561,268)**	**(3,578,821)**
	Capped Revenue Requirement Increase as a Percentage of Line 7	10.32%	6.28%

Exhibit No. 108
Case No. PAC-E-07-5
P. Harms, Staff
9/28/07

Rocky Mountain Power
IDAHO
Normalized Results of Operations - REVISED PROTOCOL
12 Months Ended DECEMBER 2006

	(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1 Operating Revenues:			
2 General Business Revenues	178,992,843	14,815,425	193,808,268
3 Interdepartmental	-		
4 Special Sales	122,881,936		
5 Other Operating Revenues	6,601,123		
6 Total Operating Revenues	308,475,902		
7			
8 Operating Expenses:			
9 Steam Production	51,759,768		
10 Nuclear Production	-		
11 Hydro Production	2,324,572		
12 Other Power Supply	149,261,969		
13 Transmission	9,009,675		
14 Distribution	10,088,461		
15 Customer Accounting	4,586,151	21,784	4,607,935
16 Customer Service & Info	1,661,078		
17 Sales	-		
18 Administrative & General	11,114,389		
19			
20 Total O&M Expenses	239,806,062		
21			
22 Depreciation	24,215,016		
23 Amortization	3,268,986		
24 Taxes Other Than Income	4,932,527	-	4,932,527
25 Income Taxes - Federal	4,754,556	4,942,703	9,697,259
26 Income Taxes - State	771,172	671,631	1,442,804
27 Income Taxes - Def Net	557,970		
28 Investment Tax Credit Adj.	(757,790)		
29 Misc Revenue & Expense	(168,477)		
30			
31 Total Operating Expenses:	277,380,021	5,636,118	283,016,140
32			
33 Operating Rev For Return:	31,095,880	9,179,306	40,275,187
34			
35 Rate Base:			
36 Electric Plant In Service	917,578,857		
37 Plant Held for Future Use	(3,408)		
38 Misc Deferred Debits	3,493,591		
39 Elec Plant Acq Adj	5,019,178		
40 Nuclear Fuel	-		
41 Prepayments	2,922,256		
42 Fuel Stock	6,281,196		
43 Material & Supplies	7,453,023		
44 Working Capital	4,276,120		
45 Weatherization Loans	5,790,713		
46 Misc Rate Base	577,049		
47			
48 Total Electric Plant:	953,388,575	-	953,388,575
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(358,147,663)		
52 Accum Prov For Amort	(20,236,770)		
53 Accum Def Income Tax	(76,841,792)		
54 Unamortized ITC	(2,125,265)		
55 Customer Adv For Const	(465,858)		
56 Customer Service Deposits	-		
57 Misc Rate Base Deductions	(8,373,943)		
58			
59 Total Rate Base Deductions	(466,191,291)	-	(466,191,291)
60			
61 Total Rate Base:	487,197,283	-	487,197,283
62			
63 Return on Rate Base	6.383%		8.267%
64			
65 Return on Equity	6.512%		10.250%
66			
67 TAX CALCULATION:			
68 Operating Revenue	36,421,788	14,793,641	51,215,429
69 Other Deductions			
70 Interest (AFUDC)			
71 Interest	14,974,788	-	14,974,788
72 Schedule "M" Additions	12,357,745	-	12,357,745
73 Schedule "M" Deductions	17,141,075	-	17,141,075
74 Income Before Tax	16,663,669	14,793,641	31,457,310
75			
76 State Income Taxes	771,172	671,631	1,442,804
77 Taxable Income	15,892,497	14,122,010	30,014,507
78			
79 Federal Income Taxes + Other	4,754,556	4,942,703	9,697,259

Ref. Page 2.2

Exhibit No. 109
Case No. PAC-E-07-5
P. Harms, Staff
9/28/07

Rocky Mountain Power
IDAHO
Normalized Results of Operations - REVISED PROTOCOL
12 Months Ended DECEMBER 2006

Net Rate Base	$	487,197,283	Ref. Page 1.1
Return on Rate Base Requested		8.267%	Ref. Page 2.1
Revenues Required to Earn Requested Return		40,275,187	
Less Current Operating Revenues		(31,095,880)	
Increase to Current Revenues		9,179,306	
Net to Gross Bump-up		161.40%	
Price Change Required for Requested Return	$	14,815,425	
Requested Price Change	$	14,815,425	
Uncollectible Percent		0.147%	Ref. Page 1.3
Increased Uncollectible Expense	$	21,784	
Requested Price Change	$	14,815,425	
Franchise Tax		0.000%	Ref. Page 1.3
Revenue Tax		0.000%	Ref. Page 1.3
Resource Supplier Tax		0.000%	Ref. Page 1.3
Gross Receipts		0.000%	Ref. Page 1.3
Increase Taxes Other Than Income	$	-	
Requested Price Change	$	14,815,425	
Uncollectible Expense		(21,784)	
Taxes Other Than Income		-	
Income Before Taxes	$	14,793,641	
State Effective Tax Rate		4.54%	Ref. Page 2.1
State Income Taxes	$	671,631	
Taxable Income	$	14,122,010	
Federal Income Tax Rate		35.00%	Ref. Page 2.1
Federal Income Taxes	$	4,942,703	
Operating Income		100.000%	
Net Operating Income		61.958%	Ref. Page 1.3
Net to Gross Bump-Up		161.40%	

Rocky Mountain Power
IDAHO
Normalized Results of Operations - REVISED PROTOCOL
12 Months Ended DECEMBER 2006

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.147%	(1)
Taxes Other - Franchise Tax	0.000%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier Tax	0.000%	
Taxes Other - Gross Receipts	0.000%	
Sub-Total	99.853%	
State Income Tax @ 4.54%	4.533%	
Sub-Total	95.320%	
Federal Income Tax @ 35.00%	33.362%	
Net Operating Income	61.958%	

(1) Computation equals:
Idaho situs uncollectible accounts (FERC904) divided by Idaho general business revenues (page 2.12, column "Idaho", line 714) divided by (page 2.2, column "adj total", line 1)

Rocky Mountain Power
IDAHO
Normalized Results of Operations - ROLLED-IN
12 Months Ended DECEMBER 2006

	(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1 Operating Revenues:			
2 General Business Revenues	178,992,843	8,111,953	187,104,796
3 Interdepartmental	-		
4 Special Sales	122,881,936		
5 Other Operating Revenues	6,601,135		
6 Total Operating Revenues	308,475,914		
7			
8 Operating Expenses:			
9 Steam Production	52,078,916		
10 Nuclear Production	-		
11 Hydro Production	2,324,572		
12 Other Power Supply	142,191,189		
13 Transmission	9,009,675		
14 Distribution	10,088,461		
15 Customer Accounting	4,586,151	11,927	4,598,078
16 Customer Service & Info	1,661,078		
17 Sales	-		
18 Administrative & General	11,123,414		
19			
20 Total O&M Expenses	233,063,455		
21			
22 Depreciation	24,215,735		
23 Amortization	3,267,350		
24 Taxes Other Than Income	4,936,717	-	4,936,717
25 Income Taxes - Federal	6,994,229	2,706,300	9,700,529
26 Income Taxes - State	1,127,217	367,741	1,494,958
27 Income Taxes - Def Net	552,155		
28 Investment Tax Credit Adj.	(757,790)		
29 Misc Revenue & Expense	(168,468)		
30			
31 Total Operating Expenses:	273,230,599	3,085,968	276,316,568
32			
33 Operating Rev For Return:	35,245,314	5,025,985	40,271,300
34			
35 Rate Base:			
36 Electric Plant In Service	918,320,604		
37 Plant Held for Future Use	(3,408)		
38 Misc Deferred Debits	3,555,375		
39 Elec Plant Acq Adj	5,019,178		
40 Nuclear Fuel	-		
41 Prepayments	2,924,321		
42 Fuel Stock	6,311,959		
43 Material & Supplies	7,473,953		
44 Working Capital	4,219,413		
45 Weatherization Loans	5,790,713		
46 Misc Rate Base	577,049		
47			
48 Total Electric Plant:	954,189,157	-	954,189,157
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(358,986,583)		
52 Accum Prov For Amort	(20,245,273)		
53 Accum Def Income Tax	(76,837,855)		
54 Unamortized ITC	(2,125,265)		
55 Customer Adv For Const	(465,858)		
56 Customer Service Deposits	-		
57 Misc Rate Base Deductions	(8,378,058)		
58			
59 Total Rate Base Deductions	(467,038,893)	-	(467,038,893)
60			
61 Total Rate Base:	487,150,264	-	487,150,264
62			
63 Return on Rate Base	7.235%		8.267%
64			
65 Return on Equity	8.203%		10.250%
66			
67 TAX CALCULATION:			
68 Operating Revenue	43,161,125	8,100,026	51,261,151
69 Other Deductions			
70 Interest (AFUDC)			
71 Interest	14,973,343	-	14,973,343
72 Schedule "M" Additions	12,377,016	-	12,377,016
73 Schedule "M" Deductions	17,146,019	-	17,146,019
74 Income Before Tax	23,418,779	8,100,026	31,518,806
75			
76 State Income Taxes	1,127,217	367,741	1,494,958
77 Taxable Income	22,291,563	7,732,285	30,023,847
78			
79 Federal Income Taxes + Other	6,994,229	2,706,300	9,700,529

Ref. Page 2.2

Exhibit No. 111
Case No. PAC-E-07-5
P. Harms, Staff
9/28/07

ROCKY MOUNTAIN POWER
STATE OF IDAHO
Revenue Requirement Impact of Staff's Proposed Adjustments
12 Months Ended December 2006 with Known and Measurables

Line No.	Description of Staff Proposal	Staff Witness	Impact to Company's Revenue Requirement Increase (Decrease)
1	Allow return on equity of 10.25% compared to 10.75% requested by Company.	Carlock	($2,000,000)
2	Allow recovery of Company's investment in plant on a 13-month average, annualizing certain projects in 2006 and adding certain projects in 2007.	Harms	($1,000,000)
3	Remove coal lease cost not known and measurable at prefle date.	Leckie	($26,000)
4	Remove not used and useful mining equipment from rate base.	Leckie	($15,000)
5	Include renewable energy tax credits associated with steam production project.	Harms	($40,000)
6	Remove cost of abandoned projects from operating expenses.	Harms	($80,000)
7	Remove power supply cost error in data extract associated gas purchases.	Lanspery	($2,500,000)
8	Adjust power supply cost associated with the Monsanto credit.	Lanspery	$110,000
9	Allocate Idaho irrigation load control program system-wide.	Lanspery	($940,000)
10	Reduce incentive pay costs.	Leckie	($160,000)
11	Reduce net lease expense due to economic incentives.	Leckie	($7,000)
12	Remove costs associated with changing fiscal year to calendar year.	Leckie	($25,000)
13	Reduce severance pay costs.	Leckie	($160,000)
14	Remove expenses that are norecurring or not Idaho utility related.	Nobbs	($93,000)
15	Impute revenue associated with the Company's Green Tags.	Carlock	(270,000)

Exhibit No. 112
Case No. PAC-E-07-5
P. Harms, Staff
9/28/07

Idaho General Rate Case
IPUC Modified Capital Additions

Function	Project	Factor	Treatment	In Service Date	Months	Amount	Adjustment	Adjustment by Type of Project
2006 Annualized Plant Adds								
Other Production	Currant Creek Power Project	SG	Annualize through Jan 2007	Mar-2006	2	176,643,838	27,175,975	
Other Production	Leaning Juniper 1 Wind Plant	SG	Annualize through Jan 2007	Sep-2006	8	175,434,259	107,959,544	
	Subtotal Other Production							135,135,519
Transmission	Currant Creek Power Project	SG	Annualize through Jan 2007	Mar-2006	2	1,558,157	239,716	
Transmission	Summit-Vineyard (Lake Side) Interconnect	SG	Annualize through Jan 2007	Oct-2006	9	13,680,809	9,471,329	
Transmission	Summit-Vineyard Transmission Project	SG	Annualize through Jan 2007	Sep-2006	8	1,728,888	1,063,931	
Transmission	809 PDIT EMS SCADA Phase 2 (EPIC)	SG	Annualize through Jan 2007	Nov-2006	10	178,027	136,944	
Transmission	Beall Ln Sub Construct New 115-12kV Sub	SG	Annualize through Jan 2007	Sep-2006	8	230,374	141,768	
Transmission	Gordon Ave (Layton): New 138-12.5k Sub	SG	Annualize through Jan 2007	Dec-2006	11	663,741	561,627	
Transmission	Bitter Creek Provide 230kV Svc Anadarko	SG	Annualize through Jan 2007	Mar-2006	2	2,376,579	365,628	
Transmission	90th South-Oquirrh Reconductor 138kV Ln	SG	Annualize through Jan 2007	Nov-2006	10	2,790,814	2,146,780	
Transmission	Claim Jumper Provide 230 Svc Anadarko	SG	Annualize through Jan 2007	Sep-2006	8	3,445,752	2,120,463	
Transmission	Quarry-DimpleDell Loop-Phase 2	SG	Annualize through Jan 2007	Mar-2006	2	4,000,120	615,403	
Transmission	Crow Reservation Renew Right-of-Way	SG	Annualize through Jan 2007	Nov-2006	10	4,660,594	3,585,073	
Transmission	Syracuse Add 345-138kV Transfmr (394MVA)	SG	Annualize through Jan 2007	May-2006	4	5,498,258	1,691,772	
Transmission	519 PDIT RQAS Ranger QAS Sys SCADA PT015	SG	Annualize through Jan 2007	Aug-2006	7	5,915,145	3,185,078	
Transmission	90th So & Terminal Subs: Loop- in CW Lns	SG	Annualize through Jan 2007	Jun-2006	5	7,100,721	2,731,047	
Transmission	SW Utah Load Growth Project	SG	Annualize through Jan 2007	May-2006	4	22,856,683	7,032,825	
	Subtotal Transmission							35,089,384
Steam Production	GEN RESOURCE DEV. CAI PROJECT	SG	Annualize through Jan 2007	Dec-2006	11	117,837,160	99,708,366	99,708,366
						546,599,918	269,933,269	269,933,269
2007 Pro Forma Plant Adds								
Other Production	Lake Side Capital Build	SG	Number of Months in Test Period	Jun-2007	7	330,841,583	192,990,924	
Other Production	Marengo Wind Project	SG	Number of Months in Test Period	Aug-2007	5	258,541,351	107,725,563	
Other Production	Goodnoe Hills (Formely East & West) Wind Project	SG	Number of Months in Test Period	Nov-2007	2	196,572,406	32,762,068	
	Subtotal Other Production							333,478,554
Steam Production	Blundell Bottoming Cycle	SG	Number of Months in Test Period	Nov-2007	2	27,700,643	4,616,774	4,616,774
Transmission	Summit Vineyard Lake Side Transmission	SG	Number of Months in Test Period	Sep-2007	4	44,549,831	14,849,944	
Transmission	Camp Williams-Mona 345kV #4 Line Project	SG	Number of Months in Test Period	Jun-2007	7	24,253,547	14,147,902	
Transmission	Summit Vineyard (Lake Side) Trns Interconnect	SG	Number of Months in Test Period	May-2007	8	9,861,575	6,574,383	
Transmission	Marengo Wind Project	SG	Number of Months in Test Period	Apr-2007	9	7,866,514	5,899,886	
Transmission	Emery Moore 69kV Add	SG	Number of Months in Test Period	Jul-2007	6	2,418,912	1,209,456	
Transmission	Oakley-Kamas line	SG	Number of Months in Test Period	Dec-2007	1	3,469,191	289,099	
Transmission	Shute Creek To Mona System Upgrade Study	SG	Number of Months in Test Period	Dec-2007	1	3,945,882	328,824	
Transmission	Craven Crk Provide 230kV Svc to Enterprise Prod-Pioneer	SG	Number of Months in Test Period	Jul-2007	6	5,108,986	2,554,493	
Transmission	Cache Valley Add. Bridgerland Sw St Ph 1	SG	Number of Months in Test Period	Jul-2007	6	15,505,664	7,752,832	
Transmission	Chappel Creek - provide 230kV service to Jonah Field	SG	Number of Months in Test Period	Dec-2007	1	16,102,548	1,341,879	
	Subtotal Transmission							54,948,698
						946,738,633	393,044,025	393,044,025
				Total Plant Add Adjustment			**662,977,295**	**662,977,295**

Exhibit No. 113
Case No. PAC-E-07-5
P. Harms, Staff
9/28/07

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 28[TH] DAY OF SEPTEMBER 2007, SERVED THE FOREGOING **DIRECT TESTIMONY OF PATRICIA HARMS,** IN CASE NO. PAC-E-07-05, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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