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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-07-05**
MOUNTAIN POWER FOR APPROVAL	)	
OF CHANGES TO ITS ELECTRIC	)	**Rebuttal Testimony**
SERVICE SCHEDULES	)	**of Steven R. McDougal**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-07-05

October 2007

Q. Please state your name, business address and present position with the Company (also referred to as Rocky Mountain Power).

A. My name is Steven R. McDougal and my business address is 201 South Main, Suite 2300, Salt Lake City, Utah, 84111. I am currently employed as the Director of Revenue Requirements for Rocky Mountain Power.

Q. Are you the same Steven R. McDougal that previously submitted testimony in this proceeding?

A. Yes.

Purpose of Testimony

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

A. My rebuttal testimony explains and supports the Company's revised overall revenue increase request of $15.4 million, reduced from the $18.5 million request originally filed by the Company. In addition, my testimony provides the following:

- A detailed calculation of the $15.4 million requested revenue increase, including a summary of the differences between the original filed request and the current amount. The revised request includes the impact of adjustments proposed by other parties that the Company is willing to accept and other miscellaneous adjustments to the original filing.
- The Company's response to other revenue requirement issues raised in the direct testimony of intervening parties in this case.
- Revisions to the estimated revenue requirement of the additional resources included in this case and previously provided as Exhibit No. 13 to my direct

testimony.

Required Revenue Increase

Q. What price increase is required to achieve the requested return on equity in this case?

A. As shown in Exhibit No. 47, an overall price increase of $18.6 million is required to produce the 10.75 percent return on equity requested by the Company in this proceeding.

Q. Is the Company requesting the full $18.6 million required to earn a 10.75 percent return on equity?

A. No. The Company has reflected the Rate Mitigation Cap as approved by the Commission and described in my direct testimony. The Rate Mitigation Cap decreases the revenue increase requested in my rebuttal testimony to $15.4 million.

Q. Please describe the calculation of the revised overall revenue increase.

A. The Company's revised revenue increase of $15.4 million was calculated using the same allocation methodology and factors included in the original case, and it incorporates adjustments proposed by other parties and miscellaneous items identified by the Company that required adjustments from the Company's original request. In support of the revised calculation, I am providing the following exhibits:

- Exhibit No. 47 shows the total Idaho revenue requirement and the capped revised protocol price change of $15.4 million. This replaces Exhibit No. 11 page 1.0 from my direct testimony.

- Exhibit No. 48 contains revised results of operations summary, Exhibit No. 11 Tab 2 from my direct testimony.
- Exhibit No. 49 contains backup pages for the revised and new adjustments made to my direct testimony. These adjustments are summarized below and are all included as adjustments in Exhibit Nos. 47 and 48.

Revenue Requirement Revisions

Q. Please identify and briefly describe the revenue requirement adjustments proposed by intervening parties that the Company agrees to accept.

A. The following adjustments were proposed by intervening parties and have been accepted in whole or in part by the Company:

Impute Additional Renewable Energy Credit (Green Tag) Revenues (Exhibit No. 49, page 3.8) – Increases revenues for the variance between calendar year 2006 actual revenues included in the case and the expected calendar year 2007 levels through December 2007. This adjustment replaces the adjustments proposed by staff witness Ms. Terri Carlock. Support for this revised adjustment and reasons for the modification to Ms. Carlock's adjustments are provided by Company witness Mr. Mark R. Tallman.

Abandoned Projects (Exhibit No. 49, page 3.9) – Remove test year write-off expense associated with abandoned projects as proposed by Staff witness Ms. Patricia Harms.

Non-Recurring expenses (Exhibit No. 49, page 3.10) – Removes items that are not considered recurring and/or related to Idaho utility operations from the test year as proposed by Staff witness Mr. John Nobbs. The Company is willing to partially accept Mr. Nobbs' proposed adjustment, with the exception of certain general rate case expenses. The Company also requests an accounting clarification as it relates to a settlement between the Company and the IRS. These two items are addressed in more detail later in my testimony.

Net Lease Expense (Exhibit No. 49, page 3.11) – Reduces net lease expense (lease expense less sublease revenues) for certain floors in the One Utah Center as proposed by Staff witness Mr. Joe Leckie.

Fiscal Year Conversion (Exhibit No. 49, page 3.12) – Removes the costs originally included in the case for the Company to change its fiscal year to a calendar year reporting period as proposed by Staff witness Mr. Leckie.

Change-in-Control Severance (Exhibit No. 49, page 3.13) – Removes a portion of the change-in-control severance expense as proposed by Staff witness Mr. Leckie. This is discussed in more detail below and in the rebuttal testimony of Company witness Mr. Erich D. Wilson wherein he discusses the details supporting the Company's severance plan and the prudent nature of its use.

Blundell Tax Credits (Exhibit No. 49, page 7.9) – Adds into results the Federal Renewable Energy Tax Credit and Utah State Renewable Energy Tax Credit associated with the Blundell bottoming cycle facility that were inadvertently excluded from the original filing as identified by Staff witness Ms. Harms.

Cottonwood Coal Lease (Exhibit No. 49, page 8.13) – Removes the Company's estimate of payments to the Utah Trust Lands Administration regarding the Company's bid in an auction to lease the Cottonwood coal reserves as proposed by Staff witness Mr. Leckie.

Bridger Dragline (Exhibit No. 49, page 8.14) – Removes the book value of a dragline included in the Jim Bridger Mine rate base that has now been sold. This adjustment was proposed by Staff witness Mr. Leckie.

Q. **Please identify and briefly describe any other revenue requirement adjustments that the Company is making that are different from those contained in your original filing.**

A. The following are additional adjustments proposed by the Company and that are reflected in the Company's rebuttal revenue requirement:

Wage and Benefit Adjustment (Exhibit No. 49, pages 4.20 through 4.23) – Senior Executive Retirement Program costs were inadvertently removed from the filing in both the original wage adjustment and the MEHC transition adjustment. Some mining benefit expenses were also included in both the wage adjustment and in the cost of fuel. Both of these items that were double counted are corrected. This adjusts Exhibit No. 11, pages 4.2 through 4.5 in my direct testimony, which are the wage annualization adjustment and the pro forma wage adjustment.

Incremental O&M (Exhibit No. 49, page 4.24) – Removes the incremental O&M expense associated with the Goodnoe Hills wind plant. The Company expects some of the individual wind turbines to be in service before the end of 2007, but the entire project will not be completed. Since the project will not be completely in service, we are removing the incremental O&M associated with the plant in this adjustment, the rate base in the following adjustment, the Renewable Energy Tax Credit in the adjustment to page 7.11 below, and the projected energy from net power costs. This adjustment corrects Exhibit No. 11, page 4.10 in the original filing.

Net Power Costs (Exhibit No. 49, page 5.7) – Reflects the change in the net power cost study to reflect the removal of the Goodnoe Hills wind plant, and corrects errors related to gas swap mark-to-market values, allocation codes identified with actual net power costs, and the double counting of certain demand side management costs. These adjustments are discussed in more detail by Company witness Mr. Mark T. Widmer. This adjustment corrects Exhibit No. 11, page 5.1 in the original filing.

Major Plant Additions (Exhibit No. 49, page 8.15) – Removes certain major plant additions (5 transmission, 1 hydro) from rate base because their projected in-service dates have been extended beyond the test period. This adjustment also removes the rate base associated with the Goodnoe Hills wind plant, consistent with other adjustments in this filing. This adjusts Exhibit No. 11, page 8.8 in the original filing. This adjustment is discussed in more detail below.

Depreciation Expense (Exhibit No. 49, page 6.3) – Removes depreciation expense and reserve related to the removal of certain major plant additions (5 transmission and 1 hydro) described above. This adjustment also reflects the removal of the Goodnoe Hills wind plant. This corrects Exhibit No. 11, pages 6.1 and 6.2 in the original filing.

Oregon Tax Credit (Exhibit No. 49, page 7.10) – Adds into results an Oregon Business Energy Tax Credit ("BETC") resulting from the Leaning Juniper wind plant. This tax credit was inadvertently left out of the Company's original filing.

Renewable Energy Tax Credit (Exhibit No. 49, page 7.11) – Removes the

Renewable Energy Tax Credit associated with the Goodnoe Hills wind plant. This adjusts Exhibit No. 11, page 7.3 in the original filing.

SO2 Emission Allowance Sales

Q. Why does the Company support a 15-year amortization of revenue from the sale of SO2 emission allowances?

A. Revenue from the sale of SO2 emission allowances is amortized over 15 years to match the benefits and costs of the allowances. The SO2 emissions allowances are partially a result of new clean air investments such as the Huntington 2 scrubber. These investments, along with the cost of the power plants, are spread over a longer period of time. As such, it is appropriate that the revenue from the sale of SO2 emission allowances also be spread over a longer period of time to better align the cost and benefits associated with these investments, and the Company believes that 15 years is an appropriate time period.

Q. Are there any other reasons for spreading the SO2 allowances over a longer period?

A. Another reason for spreading the sales revenue over 15 years is the variability in both the volume of sales and the sales price. Since both of these are difficult to predict, a 15 year amortization ensures Idaho customers receive the benefits of any sales, even if they do not occur in a test period. Under Mr. Michael Gorman's proposal to reflect sales as they occurred, the only sales that will be reflected in rates will be those that materialize during the test period of a filed rate case.

Severance Expense

Q. Please describe the adjustments the Company has agreed to make with respect to change-in-control severance.

A. As noted above, the Company agrees to accept Staff's adjustment to change-in-control severance as proposed by Mr. Leckie. While the Company believes the costs were prudently incurred and should be fully recovered, for ratemaking purposes in this case, the Company is willing to accept Mr. Leckie's position based on his cost benefit calculations as the Company believes Staff's position represents a reasonable compromise in this case.

Q. What about Mr. Timothy Shurtz's proposed adjustment to change-in-control severance?

A. Mr. Shurtz filed a response to a data request from the Company indicating that he agrees with Commission Staff's proposed adjustment, which the Company has also accepted. Accordingly, the Company does not believe there is a need to respond to Mr. Shurtz's direct testimony on this issue.

Q. What about Monsanto's proposed adjustment to change-in-control severance?

A. The Company disagrees with Mr. Gorman's adjustment.

Q. Why does the Company disagree with Mr. Gorman's proposed severance adjustment?

A. Mr. Gorman asserts that the Company should not be able to defer severance of any employees displaced prior to October 2006 when the deferral order was approved. This does not match the enabling costs associated with a manpower reduction with the benefit customers are receiving through reduced salaries. In support of this position, Mr. Gorman impliedly relies upon a state of Washington rule. Such a position arbitrarily denies recovery of a substantial portion of the severance costs based on a rule that has no bearing in the state of Idaho. The Idaho Commission has allowed the recovery of prudent costs incurred prior to filing for deferred accounting authorization in prior proceedings. Two examples of proceedings where recovery was granted for costs incurred prior to the filing of the deferral application are case PAC-E-03-5 for tax audit payments and PAC-E-02-1 for excess net power costs related to the spike in power prices during late 2000 to mid-2001.

Mr. Gorman also proposes to allocate the costs to Idaho based on the proportion of merger savings ultimately allocated to Idaho. Proposing ad hoc allocation methods sets a bad precedent and is not consistent with the allocation method used in this case and approved by the Commission. Severance costs should be allocated in accordance with cost causation and the Revised Protocol methodology, similar to all other costs in the case.

Plant Additions

Q. What is the Company's position on the proposed adjustments to major plant additions?

A. The Company acknowledges that as a result of the test year conventions being applied in this case, plant that will not be in service prior to January 1, 2008, should not be included in revenue requirement. However, the Company once again reiterates that it is spending a significant amount of capital to meet the needs of its customers for which it is not earning a return due to regulatory lag and test year conventions. With that said, as part of our rebuttal case we have removed those plant additions identified by Staff (5 transmission and 1 hydro identified below) that will not be completed prior to January 1, 2008. In addition, we are removing the Goodnoe Hills wind plant because the plant will not be completely in service by the end of the year. The Company does not agree with the additional adjustments made to major plant additions.

Q. **Please identify the 5 transmission and 1 hydro project which are being removed from the major plant additions.**

A. Below is a list of the 5 transmission and 1 hydro project being removed from this filing due to a change in the projected in-service date for each project:

- McClelland Emigration Tap 1.4Mi OH Line (transmission)
- Transmission Relay Repl Zone 3 Setting (transmission)
- Copco transformer 250 MVA (transmission)
- Line 1 Conversion Project, Convert Line 1 to 115 kV (transmission)
- Upper Green River Valley project (transmission)
- Copco 2 Electrical Overhaul (hydro)

Q. **Do you believe the electric plant in service amounts included in this case are at a reasonable level given the test year conventions that are being applied?**

A. Yes. There was considerable discussion in testimony as to whether the major plant additions included in the case are known and measurable. The best measure of electric plant in service is to look at actual results. Actual electric plant in service allocated to Idaho as of September 30, 2007 is $955 million. This is $29 million above the $926 million of electric plant in service included in the original filing and $32 million above the electric plant in service included in this rebuttal filing of $923 million.

Q. Please respond to Monsanto's argument that you have not included increases in accumulated depreciation in your rate base forecast.

A. The Company has followed a traditional procedure for using an historic test period with known and measurable adjustments for plant additions. While Monsanto mentions the exclusion of the increases in depreciation reserve, they fails to mention customers benefited because this was more than offset by also excluding from rate base plant additions less than $2 million. In 2006, the Company spent $477 million on projects costing less than $2 million, and only had depreciation and amortization expense of $454 million. In 2007, we expect to spend over $477 million on projects costing less than $2 million, none of which are included in this case. The Company's filing does adjust the accumulated depreciation reserve for the depreciation associated with the plant additions included in the filing.

It is the Company's desire to move to a fully forecasted test year to set rates based on a forecast of all changes in rate base, expenses, and revenue, it has not done so in this case. Monsanto's proposal is simply attempting to "cherry pick" certain additional items in contravention to the Commission established test period convention in Idaho simply to reduce the revenue requirement in this proceeding. To follow Monsanto's logic would be to prepare a full forecast test period case, including all plant additions, even those less than $2 million, and include increases in accumulated depreciation of approximately $25 million per year.

Q. What is the Company's position on the $100 million threshold proposed by Staff for major plant additions?

A. The $100 million threshold for major plant additions proposed by Staff is unreasonably high. As pointed out by Staff, only a small percentage of the Company's plant additions meet this limit. Staff's proposed adjustment only allows partial recovery of prudently incurred investment in projects costing less than $100 million unless the investments were made prior to January 31, 2007.

Staff tries to justify the exclusion of plant under $100 million as being immaterial. Although the individual projects may be immaterial, when added together they become material. In 2006, the Company spent $125 million on projects which individually cost between $2 million and $100 million, but for which the Company will not be allowed full recovery using the $100 million threshold proposed by staff. During 2007, the Company will invest a total of $172 million on projects individually costing between $2 million and $100 million. In aggregate, these projects are material to the Company and the Company believes it is entitled to a return on this investment.

New Depreciation Rates

Q. Please respond to Monsanto's suggestion that the new depreciation rates filed with this Commission would result in $1 million reduction in the revenue requirement.

A. The new depreciation rates are not included in this case and should not be.

Although the depreciation study has been filed, it is not yet approved, is still subject to change, and will not become effective until January 1, 2008 at the earliest.

Q. If the new depreciation rates are used, what else should be updated in the case?

A. If new depreciation rates not effective until 2008 are included in this case, the Commission should look at the use of a forecast test period to correctly forecast all components of the Company's revenue requirement to a 2008 level. To be consistent, the Company should forecast loads, revenues, net power costs, O&M costs, and rate base to their projected 2008 levels.

Non-Recurring Expenses

Q. Why is the Company removing the adjustment proposed by Staff witness Mr. Nobbs pertaining to general rate case costs from other states?

A. The Company objects to Mr. Nobbs' proposal for two reasons: 1) the Company believes that these costs should be allocated to all states; and 2) his adjustment incorrectly changes the allocation of rate case costs for all states other than Idaho to situs allocation, while leaving Idaho rate case costs system allocated so that only a small percentage is being paid by Idaho customers.

Q. Why should the costs of general rate cases in all states served by the Company be system allocated?

A. The Company is filing rate cases in several of its states each year. Due to the volume of rate cases and structure of the Company's staff, work done on rate cases in one state often reduces the work required for rate cases in other states.

The only alternative available to allocate costs fairly would be to keep track of all rate case costs, including employee labor, and whether the costs were specific to one state or multiple states. The Company does not currently have such a system in place.

Q. What is your position on Staff witness Mr. Nobbs' adjustment to amortize the IRS settlement related to tax exempt bonds?

A. The Company has included Mr. Nobbs' adjustment to amortize costs for a one-time settlement with the IRS in our rebuttal case; the Company is willing to accept Mr. Nobbs' adjustment on the condition that the Commission authorize deferred accounting treatment of the unamortized balance, allowing the Company to set up a regulatory asset for the remaining balance.

Revenue Growth

Q. Please respond to Dr. Dennis Peseau's proposal to adjust revenues to account for load growth included as Agrium Exhibit No. 405.

A. Agrium Exhibit No. 405 has the following errors:

- Agrium's exhibit compares the incremental revenues to the average net power cost ("NPC") level rather than the incremental NPC amount. The average NPC of $15.35 is significantly below the incremental NPC required to serve new load. If the incremental NPC is estimated at $50/MWh, multiplied by the 33,562 MWh used by Dr. Peseau, then his calculated revenue requirement reduction is overstated by over $1,160,000.
- Agrium's Exhibit No. 405 only adds incremental load for Idaho. To be correct, load should be increased in all states since NPC are system

allocated. On the other had, if Idaho is the only state with increased load, there must also be a corresponding increase in Idaho jurisdictional allocation factors. Adjusting the Idaho energy factor by including an additional 33,562 MWh and the Idaho capacity by adding 3.8 MW per month (33,562/8760 hours per year), would increase Idaho revenue requirement by approximately $1 million. This $1 million should be included as a deduction in Dr. Peseau's computation.

- The Company has not included revenue in this case related to load growth, nor has it included the corresponding additional capital cost for meters, lines, or infrastructure. These costs would be incremental to all of the capital additions already included in the case.

If Dr. Peseau's adjustment were corrected to reflect the errors noted above, it would have minimal if any impact on the Company's Idaho revenue requirement.

Property Taxes

Q. Has the Idaho property tax reduction mentioned by Mr. Shurtz been included in this case?

A. Yes. The affect of House Bill No. 1 has been reflected by the use of a 9.3 mill, or .93 percent composite Idaho property tax rate applied to an estimate of assessed value. This rate is approximately 22 percent lower than the 12.0 mill, or 1.2 percent composite Idaho property tax rate for 2005. Thus, the amount of Idaho property tax expense included in the company's current rate case is lower due to the passage of House Bill No. 1. It is important to note, however, that for purposes of setting the Company's rates, property tax expense is allocated on a system wide basis. Thus, customers in Idaho and the other five states served by PacifiCorp share in the benefit of reduced Idaho taxes in the same way that Idaho customers would from favorable tax legislation passed by other states.

Mailing

Q. Have you reviewed the issue raised by Mr. Shurtz regarding the cost difference between mailing bills and having bills sent electronically to customers?

A. The Company continually explores options to reduce customer costs, and currently offers customers the option of receiving bills electronically and of paying online. Despite these alternative options, the number of customer mailings increased by 400,000 between 2005 and 2006. As a result of these increases, the postage adjustment proposed by the Company is appropriate.

Q. Does this conclude your testimony?

A. Yes.

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Case No. PAC-E-07-05
Exhibit No. 47
Witness: Steven R. McDougal

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Steven R. McDougal

Revised Price Change

October 2007

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

(1)	December 2006 Rolled-In Revenue Requirement	191,196,377
(2)	Rate Mitigation Cap	101.67%
(3)	Capped Revised Protocol Revenue Requirement	194,389,357
(4)	Normalized December 2006 General Business Revenues	178,992,843
(5)	**Capped Revised Protocol Price Change**	**15,396,514**
Revised Protocol		
(6)	Filed Revised Protocol Revenue Requirement	197,613,774
(7)	Normalized December 2006 General Business Revenues	178,992,843
(8)	Revised Protocol Price Change	18,620,931
(9)	**Capped Revised Protocol Price Change**	**15,396,514**
(10)	Reduction to Revised Protocol Revenue Requirement	**(3,224,417)**

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Case No. PAC-E-07-05
Exhibit No. 48
Witness: Steven R. McDougal

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Steven R. McDougal

Revised Results of Operations

October 2007

Rocky Mountain Power
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	IDAHO
PERIOD:	DECEMBER 2006
FILE:	JAM-Idaho GRC-Dec2006DRebuttal101707
PREPARED BY:	Revenue Requirement Department
DATE:	10/24/2007
TIME:	3:37:05 PM
TYPE OF RATE BASE:	Beginning/Ending
ALLOCATION METHOD:	REVISED PROTOCOL
FERC JURISDICTION:	Separate Jurisdiction
8 OR 12 CP:	12 Coincidental Peaks
DEMAND %	75% Demand
ENERGY %	25% Energy

TAX INFORMATION

TAX RATE ASSUMPTIONS:	TAX RATE
FEDERAL RATE	35.00%
STATE EFFECTIVE RATE	4.54%
TAX GROSS UP FACTOR	1.614
FEDERAL/STATE COMBINED RATE	37.95%

CAPITAL STRUCTURE INFORMATION

	CAPITAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
DEBT	49.10%	6.26%	3.074%
PREFERRED	0.50%	5.41%	0.027%
COMMON	50.40%	10.75%	5.418%
	100.00%		8.519%

OTHER INFORMATION

REVISED PROTOCOL
Beginning/Ending

RESULTS OF OPERATIONS SUMMARY

Description of Account Summary:	Ref	UNADJUSTED RESULTS TOTAL	OTHER	IDAHO	IDAHO ADJUSTMENTS	ADJ TOTAL
Operating Revenues						
General Business Revenues	2.3	2,847,007,473	2,707,459,234	139,548,239	39,444,604	178,992,843
Interdepartmental	2.3	(7)	(7)	0	0	0
Special Sales	2.3	750,904,692	704,076,767	46,827,925	76,032,200	122,860,125
Other Operating Revenues	2.4	147,397,762	142,055,496	5,342,266	1,132,789	6,475,056
Total Operating Revenues	2.4	3,745,309,919	3,553,591,489	191,718,430	116,609,593	308,328,023
Operating Expenses:						
Steam Production	2.5	740,727,406	692,965,418	47,761,989	3,993,722	51,755,711
Nuclear Production	2.6	0	0	0	0	0
Hydro Production	2.7	36,497,550	34,195,851	2,301,699	22,960	2,324,659
Other Power Supply	2.9	925,911,510	885,451,266	40,460,243	109,339,949	149,800,192
Transmission	2.10	136,930,481	128,278,726	8,651,756	357,936	9,009,692
Distribution	2.12	218,820,422	207,464,521	11,355,901	(1,278,420)	10,077,481
Customer Accounting	2.12	107,864,332	103,228,728	4,635,604	(49,249)	4,586,354
Customer Service & Infor	2.13	52,739,370	49,601,990	3,137,380	(1,476,275)	1,661,105
Sales	2.13	0	0	0	0	0
Administrative & General	2.14	238,975,926	225,798,106	13,177,820	(1,874,813)	11,303,007
Total O & M Expenses	2.14	2,458,466,997	2,326,984,605	131,482,392	109,035,809	240,518,200
Depreciation	2.16	391,176,792	368,273,332	22,903,460	1,589,645	24,493,105
Amortization	2.17	62,931,521	59,727,356	3,204,165	140,673	3,344,838
Taxes Other Than Income	2.17	101,034,471	96,321,414	4,713,057	217,460	4,930,517
Income Taxes - Federal	2.20	140,680,908	137,500,624	3,180,285	(403,792)	2,776,492
Income Taxes - State	2.20	17,190,112	16,801,131	388,981	25,013	413,994
Income Taxes - Def Net	2.19	27,178,051	25,500,976	1,677,075	758,784	2,435,858
Investment Tax Credit Adj.	2.17	(5,854,860)	(5,097,070)	(757,790)	0	(757,790)
Misc Revenue & Expense	2.4	(15,439,233)	(14,415,629)	(1,023,605)	855,123	(168,481)
Total Operating Expenses	2.20	3,177,364,759	3,011,596,740	165,768,019	112,218,715	277,986,734
Operating Revenue for Return		567,945,160	541,994,749	25,950,411	4,390,879	30,341,289
Rate Base:						
Electric Plant in Service	2.30	14,745,911,135	13,879,811,503	866,099,632	57,182,299	923,281,931
Plant Held for Future Use	2.31	3,283,901	3,218,437	65,464	(65,464)	0
Misc Deferred Debits	2.33	112,065,538	108,895,143	3,170,395	515,239	3,685,634
Elec Plant Acq Adj	2.31	80,044,642	74,996,668	5,047,975	0	5,047,975
Nuclear Fuel	2.31	0	0	0	0	0
Prepayments	2.32	29,605,268	27,831,068	1,774,200	0	1,774,200
Fuel Stock	2.32	67,885,637	63,430,222	4,455,414	1,285,407	5,740,822
Material & Supplies	2.32	123,572,819	116,086,160	7,486,659	0	7,486,659
Working Capital	2.33	66,893,859	63,843,094	3,050,764	1,095,675	4,146,439
Weatherization Loans	2.31	18,187,445	12,359,012	5,828,433	0	5,828,433
Miscellaneous Rate Base	2.34	7,676,454	7,088,719	587,735	0	587,735
Total Electric Plant		15,255,126,697	14,357,560,027	897,566,670	60,013,156	957,579,826
Rate Base Deductions:						
Accum Prov For Depr	2.38	(5,801,309,811)	(5,445,638,690)	(355,671,121)	(518,643)	(356,189,764)
Accum Prov For Amort	2.39	(372,108,846)	(351,419,894)	(20,688,952)	(38,318)	(20,727,270)
Accum Def Income Taxes	2.35	(1,194,262,511)	(1,115,991,726)	(78,270,785)	311,620	(77,959,165)
Unamortized ITC	2.35	(12,979,804)	(12,921,554)	(58,250)	(2,067,067)	(2,125,317)
Customer Adv for Const	2.34	(8,446,845)	(8,686,619)	239,773	(499,058)	(259,285)
Customer Service Deposits	2.34	0	0	0	0	0
Misc. Rate Base Deductions	2.34	(92,950,646)	(87,656,742)	(5,293,904)	(3,420,148)	(8,714,052)
Total Rate Base Deductions		(7,482,058,464)	(7,022,315,226)	(459,743,239)	(6,231,614)	(465,974,852)
Total Rate Base		7,773,068,233	7,335,244,801	437,823,432	53,781,542	491,604,974
Return on Rate Base		7.307%		5.927%		6.172%
Return on Equity		8.345%		5.608%		6.094%
Net Power Costs		773,021,586		51,152,344		57,755,258
100 Basis Points in Equity:						
Revenue Requirement Impact		63,136,606		3,556,213		3,993,052
Rate Base Decrease		(501,579,685)		(34,311,644)		(37,114,022)

REVISED PROTOCOL
Beginning/Ending

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	UNADJUSTED RESULTS TOTAL	OTHER	IDAHO	IDAHO ADJUSTMENT	ADJ TOTAL
Sales to Ultimate Customers									
440	Residential Sales								
		0	S		1,065,628,795	1,032,652,803	32,975,992	18,074,470	51,050,462
				B1	1,065,628,795	1,032,652,803	32,975,992	18,074,470	51,050,462
442	Commercial & Industrial Sales								
		0	S		1,746,291,229	1,639,970,519	106,320,710	21,370,359	127,691,069
		P	SE		-	-	-	-	-
		PT	SG		-	-	-	-	-
				B1	1,746,291,229	1,639,970,519	106,320,710	21,370,359	127,691,069
444	Public Street & Highway Lighting								
		0	S		18,427,832	18,176,295	251,537	(225)	251,312
		0	SO		-	-	-	-	-
				B1	18,427,832	18,176,295	251,537	(225)	251,312
445	Other Sales to Public Authority								
		0	S		16,659,617	16,659,617	-	-	-
				B1	16,659,617	16,659,617	-	-	-
448	Interdepartmental								
		DPW	S		(7)	(7)	-	-	-
		GP	SO		-	-	-	-	-
				B1	(7)	(7)	-	-	-
Total Sales to Ultimate Customers				B1	**2,847,007,465**	**2,707,459,226**	**139,548,239**	**39,444,604**	**178,992,843**
447	Sales for Resale								
		WSF	S		7,738,888	7,738,888	-	-	-
		WSF	SG		757,499,306	709,727,999	47,771,307	75,088,817	122,860,125
		WSF	SE		(14,333,503)	(13,390,120)	(943,383)	943,383	-
		WSF	SG		-	-	-	-	-
				B1	750,904,692	704,076,767	46,827,925	76,032,200	122,860,125
449	Provision for Rate Refund								
		WSF	S		0	0	-	-	-
		WSF	SG		-	-	-	-	-
				B1	0	0	-	-	-
Total Sales from Electricity				B1	**3,597,912,157**	**3,411,535,993**	**186,376,164**	**115,476,804**	**301,852,968**
450	Forfeited Discounts & Interest								
		CUST	S		5,910,738	5,673,838	236,900	-	236,900
		CUST	SO		-	-	-	-	-
				B1	5,910,738	5,673,838	236,900	-	236,900
451	Misc Electric Revenue								
		CUST	S		6,263,802	6,148,114	115,688	-	115,688
		GP	SG		-	-	-	-	-
		GP	SO		25,024	23,555	1,470	-	1,470
				B1	6,288,827	6,171,669	117,158	-	117,158
453	Water Sales								
		P	SG		15,228	14,267	960	-	960
				B1	15,228	14,267	960	-	960
454	Rent of Electric Property								
		DPW	S		14,268,511	13,913,665	354,846	-	354,846
		T	SG		4,906,539	4,597,111	309,428	-	309,428
		GP	SO		217,826	205,032	12,794	-	12,794
				B1	19,392,877	18,715,808	677,069	-	677,069

REVISED PROTOCOL
Beginning/Ending

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	UNADJUSTED RESULTS TOTAL	OTHER	IDAHO	IDAHO ADJUSTMENT	ADJ TOTAL
140										
141	456	Other Electric Revenue								
142			DMSC	S		47,969,612	47,969,388	224	-	224
143			CUST	CN		-	-	-	-	-
144			OTHSE	SE		11,951,743	11,165,120	786,623	-	786,623
145			OTHSO	SO		241	227	14	-	14
146			OTHSGR	SG		55,868,497	52,345,179	3,523,318	1,132,789	4,656,108
147										
148										
149					B1	115,790,092	111,479,913	4,310,179	1,132,789	5,442,969
150										
151		**Total Other Electric Revenues**			B1	**147,397,762**	**142,055,495**	**5,342,266**	**1,132,789**	**6,475,056**
152										
153		**Total Electric Operating Revenues**			B1	**3,745,309,919**	**3,553,591,489**	**191,718,430**	**116,609,593**	**308,328,023**
154										
155		Summary of Revenues by Factor								
156		S				2,929,159,018	2,788,903,121	140,255,897	39,444,604	179,700,501
157		CN				-	-	-	-	-
158		SE				(2,381,760)	(2,225,001)	(156,759)	943,383	786,623
159		SO				243,091	228,813	14,278	-	14,278
160		SG				818,289,570	766,684,556	51,605,014	76,221,607	127,826,621
161		DGP				-	-	-	-	-
162										
163		Total Electric Operating Revenues				3,745,309,919	3,553,591,489	191,718,430	116,609,593	308,328,023
164		Miscellaneous Revenues								
165	41160	Gain on Sale of Utility Plant - CR								
166			DPW	S		-	-	-	-	-
167			T	SG		-	-	-	-	-
168			G	SO		-	-	-	-	-
169			T	SG		-	-	-	-	-
170			P	SG		-	-	-	-	-
171					B1	-	-	-	-	-
172										
173	41170	Loss on Sale of Utility Plant								
174			DPW	S		-	-	-	-	-
175			T	SG		-	-	-	-	-
176					B1	-	-	-	-	-
177										
178	4118	Gain from Emission Allowances								
179			P	S		-	-	-	-	-
180			P	SE		(15,619,250)	(14,591,244)	(1,028,006)	855,123	(172,883)
181					B1	(15,619,250)	(14,591,244)	(1,028,006)	855,123	(172,883)
182										
183	41181	Gain from Disposition of NOX Credits								
184			P	SE		-	-	-	-	-
185					B1	-	-	-	-	-
186										
187	4194	Impact Housing Interest Income								
188			P	SG		-	-	-	-	-
189					B1	-	-	-	-	-
190										
191	421	(Gain) / Loss on Sale of Utility Plant								
192			DPW	S		72,809	72,841	(32)	-	(32)
193			T	SG		253	237	16	-	16
194			T	SG		-	-	-	-	-
195			PTD	CN		67,583	64,856	2,727	-	2,727
196			PTD	SO		182,879	172,137	10,741	-	10,741
197			P	SG		(143,507)	(134,457)	(9,050)	-	(9,050)
198					B1	180,017	175,615	4,401	-	4,401
199										
200		**Total Miscellaneous Revenues**				**(15,439,233)**	**(14,415,629)**	**(1,023,605)**	**855,123**	**(168,481)**
201		Miscellaneous Expenses								
202	4311	Interest on Customer Deposits								
203			CUST	S		-	-	-	-	-
204					B1	-	-	-	-	-
205		**Total Miscellaneous Expenses**				-	-	-	-	-
206										
207		**Net Misc Revenue and Expense**			B1	**(15,439,233)**	**(14,415,629)**	**(1,023,605)**	**855,123**	**(168,481)**
208										

REVISED PROTOCOL
Beginning/Ending

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	UNADJUSTED RESULTS TOTAL	OTHER	IDAHO	IDAHO ADJUSTMENT	ADJ TOTAL
500	Operation Supervision & Engineering								
		P	SG		21,159,284	19,824,885	1,334,399	257,983	1,592,382
		P	SSGCH		1,526,906	1,437,837	89,070	(146)	88,924
				B2	22,686,191	21,262,722	1,423,469	257,837	1,681,306
501	Fuel Related								
		P	SE		439,612,173	410,678,392	28,933,781	3,250,496	32,184,277
		P	SE		-	-	-	-	-
		P	SE		-	-	-	-	-
		P	SSECT		-	-	-	-	-
		P	SSECH		45,467,404	42,691,684	2,775,720	308,592	3,084,313
				B2	485,079,578	453,370,076	31,709,502	3,559,088	35,268,590
502	Steam Expenses								
		P	SG		29,831,632	27,950,315	1,881,317	-	1,881,317
		P	SSGCH		2,488,756	2,343,578	145,178	-	145,178
				B2	32,320,388	30,293,893	2,026,494	-	2,026,494
503	Steam From Other Sources								
		P	SE		3,110,724	2,905,987	204,737	12,903	217,640
				B2	3,110,724	2,905,987	204,737	12,903	217,640
505	Electric Expenses								
		P	SG		2,862,058	2,681,564	180,494	-	180,494
		P	SSGCH		1,353,346	1,274,401	78,945	-	78,945
				B2	4,215,405	3,955,965	259,440	-	259,440
506	Misc. Steam Expense								
		P	SG		28,907,136	27,084,123	1,823,014	-	1,823,014
		P	SE		-	-	-	-	-
		P	SSGCH		1,783,535	1,679,496	104,040	-	104,040
				B2	30,690,672	28,763,618	1,927,053	-	1,927,053
507	Rents								
		P	SG		1,050,584	984,329	66,255	-	66,255
		P	SSGCH		122,887	115,719	7,168	-	7,168
				B2	1,173,471	1,100,048	73,423	-	73,423
510	Maint Supervision & Engineering								
		P	SG		5,171,457	4,845,321	326,135	-	326,135
		P	SSGCH		2,432,903	2,290,983	141,919	-	141,919
				B2	7,604,360	7,136,305	468,055	-	468,055
511	Maintenance of Structures								
		P	SG		18,800,652	17,614,998	1,185,654	-	1,185,654
		P	SSGCH		675,302	635,909	39,393	-	39,393
				B2	19,475,953	18,250,907	1,225,046	-	1,225,046
512	Maintenance of Boiler Plant								
		P	SG		87,213,304	81,713,241	5,500,063	-	5,500,063
		P	SSGCH		3,033,533	2,856,577	176,956	-	176,956
				B2	90,246,837	84,569,818	5,677,019	-	5,677,019
513	Maintenance of Electric Plant								
		P	SG		31,859,935	29,850,704	2,009,231	-	2,009,231
		P	SSGCH		646,757	609,029	37,728	-	37,728
				B2	32,506,692	30,459,734	2,046,958	-	2,046,958
514	Maintenance of Misc. Steam Plant								
		P	SG		9,115,402	8,540,543	574,858	163,894	738,752
		P	SSGCH		2,501,736	2,355,801	145,935	-	145,935
				B2	11,617,137	10,896,344	720,793	163,894	884,687
Total Steam Power Generation				B2	**740,727,406**	**692,965,418**	**47,761,989**	**3,993,722**	**51,755,711**

REVISED PROTOCOL
Beginning/Ending

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	UNADJUSTED RESULTS TOTAL	OTHER	IDAHO	IDAHO ADJUSTMENT	ADJ TOTAL
517	Operation Super & Engineering								
		P	SG		-	-	-	-	-
				B2	-	-	-	-	-
518	Nuclear Fuel Expense								
		P	SE		-	-	-	-	-
				B2	-	-	-	-	-
519	Coolants and Water								
		P	SG		-	-	-	-	-
				B2	-	-	-	-	-
520	Steam Expenses								
		P	SG		-	-	-	-	-
				B2	-	-	-	-	-
523	Electric Expenses								
		P	SG		-	-	-	-	-
				B2	-	-	-	-	-
524	Misc. Nuclear Expenses								
		P	SG		-	-	-	-	-
				B2	-	-	-	-	-
528	Maintenance Super & Engineering								
		P	SG		-	-	-	-	-
				B2	-	-	-	-	-
529	Maintenance of Structures								
		P	SG		-	-	-	-	-
				B2	-	-	-	-	-
530	Maintenance of Reactor Plant								
		P	SG		-	-	-	-	-
				B2	-	-	-	-	-
531	Maintenance of Electric Plant								
		P	SG		-	-	-	-	-
				B2	-	-	-	-	-
532	Maintenance of Misc Nuclear								
		P	SG		-	-	-	-	-
				B2	-	-	-	-	-
Total Nuclear Power Generation				B2	-	-	-	-	-
535	Operation Super & Engineering								
		P	SG		-	-	-	-	-
		P	SG		4,867,553	4,560,583	306,970	20,334	327,303
		P	SG		2,581,405	2,418,610	162,795	20,864	183,659
				B2	7,448,958	6,979,193	469,765	41,197	510,962
536	Water For Power								
		P	SG		-	-	-	-	-
		P	SG		157,569	147,632	9,937	-	9,937
		P	SG		83,976	78,680	5,296	-	5,296
				B2	241,545	226,312	15,233	-	15,233