Before the

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-07-05**

Direct Testimony and Exhibits of

Michael Gorman

Volume 1 – Revenue Requirement

On behalf of

Monsanto Company

Project 8819
September 28, 2007

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

PUBLIC

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Table of Contents to the Direct Testimony of Michael Gorman

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Direct Testimony of Michael Gorman

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A My name is Michael Gorman and my business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, MO 63141-2000.

Q **WHAT IS YOUR OCCUPATION?**

A I am an energy advisor and a consultant in the field of public utility regulation and a managing principal in the firm of Brubaker & Associates, Inc. (BAI).

Q **PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A These are set forth in Appendix A.

Q **ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am appearing on behalf of Monsanto Company.

Q **PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.**

A In this Volume 1 testimony, I propose adjustments to Rocky Mountain Power's (RMP or Company) claimed revenue requirement in this proceeding. In my Volume 2 testimony, I will recommend a fair return on common equity and overall rate of return for RMP. I also identify flaws in RMP's proposed rate of return and explain why it is inflated, unjust and unreasonable.

Q PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENTS TO THE COMPANY'S REVENUE REQUIREMENT IN THIS PROCEEDING.

A My proposed revenue requirement adjustments are listed in Table 1 below. As set forth in Table 1, I conclude that the Company's revenue requirement is overstated by at least $9.97 million.

TABLE 1

Idaho Revenue Adjustment Summary

Description	Amount ($000)
SO_2 Revenue Credit	682
Severance Cost	542
Pension Expense	1,000
Major Plant Additions	4,721
Return on Equity	3,020
Total Revenue Adjustment	9,965

Each of the revenue requirement adjustments listed above in Table 1 will be explained below.

Q PLEASE SUMMARIZE YOUR RECOMMENDED RETURN ON EQUITY FOR RMP IN THIS PROCEEDING.

A I recommend RMP be authorized a return on equity of 10.0%. As set forth in my Volume 2 direct testimony, my recommended return on equity is based on several financial models including the discounted cash flow (DCF) model, risk premium model, and capital asset pricing model. The financial models were applied to companies that were reasonably comparable in total investment risk to RMP. Hence, my recommended return on equity represents fair compensation based on RMP's investment risk.

I also show that my recommended return on equity will maintain RMP's financial integrity by supporting credit metrics adequate to maintain RMP's current bond rating.

As set forth on Exhibit 214 (MPG-1), reducing RMP's return on equity to 10.0% from 10.75% will reduce its Idaho retail revenue requirement by $3.0 million.

Revenue Requirement Adjustments

Q DID RMP INCLUDE A REVENUE CREDIT FOR SO_2 ALLOWANCE SALES?

A Yes, but the revenue credit is less than the test year SO_2 allowance sales revenue. RMP is proposing to defer the revenue received from the sale of SO_2 credits and amortize the revenue deferral over a 15-year period. RMP asserts that this 15-year period will match the revenue allowance amortization with the life of the asset producing the SO_2 allowances.

Q IS THE SO_2 ALLOWANCE SALES REVENUE AMORTIZATION PROPOSED BY RMP REASONABLE?

A No. There is no legitimate reason to defer and amortize the SO_2 allowance sales revenue. ***

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Q WHAT AMOUNT OF SO_2 ALLOWANCE SALES REVENUE SHOULD BE INCLUDED IN RMP'S COST OF SERVICE?

A The test year actual allowance revenue of $15.6 million total Company[1] is a reasonable, albeit conservative, estimate of RMP's annual recurring revenue from the sale of SO_2 allowance. As such, SO_2 allowance sales will be an annual recurring revenue source that should be recognized in setting RMP's rates.

Therefore, I recommend to include the actual test year SO_2 allowance sales revenue in RMP's cost of service. This will lower RMP's Idaho annual revenue requirement by $682,089, as shown on Exhibit 215 (MPG-2).

Q WHY DO YOU BELIEVE THAT THE TEST YEAR SO_2 ALLOWANCE SALES REVENUE IS REASONABLY REFLECTIVE OF THE NORMALIZED ANNUAL RECURRING REVENUE CREDIT FOR RMP?

A As shown on Exhibit 216 (MPG-3), RMP has received annual revenue credits in the range of $14.7 million to $16.2 million in the last three years. The three-year average annual SO_2 allowance sales revenue over the three-year period is $15.5 million. The test year SO_2 allowance sales revenue of $15.6 million is comparable to the three-year historical average.

Further, the test year SO_2 sales allowance revenue is conservative in relationship to RMP's projected annual SO_2 revenue through 2015. RMP's projected SO_2 allowance sales revenue is included in the confidential response to Monsanto Data Request No. 2.16, which is attached as Confidential Exhibit 217 (MPG-4).

Based on this assessment, I believe the test year SO_2 sales allowance revenue is a reasonable proxy of the annual recurring revenues received by RMP for

[1]McDougal Direct Testimony, Exhibit 11 at p. 3.4.

SO_2 allowance sales, and should be used to offset the rate increase needed from retail sales customers in this proceeding.

Q IS RMP PROPOSING TO INCLUDE THE AMORTIZATION OF DEFERRED SEVERANCE COSTS IN ITS REVENUE REQUIREMENT?

A Yes. RMP proposes to amortize $39.5 million of deferred employee severance costs associated with MidAmerican Energy Holdings Company's (MEHC) acquisition of PacifiCorp from Scottish Power. The Company proposes to amortize the deferred severance costs over a three-year period. The Company asserts that the Commission approved the deferrals of these severance costs in Docket No. E-06-11.

Q IS RMP'S SEVERANCE COST AMORTIZATION REASONABLE?

A No. I take two issues with this cost item. The first issue I take with the Company's proposed recovery of deferred severance cost expenses relates to the amount of deferred severance costs subject to recovery. RMP requested authority to defer severance costs in Idaho in October 2006. However, its proposed deferred severance cost balance includes significant severance expenses incurred prior to the filing at the Idaho Commission requesting this deferral. Including severance cost expenses in the deferral balance that were incurred prior to RMP's requesting authority to defer this cost is retroactive ratemaking and should not be permitted. Therefore, I propose to remove the severance costs from the Idaho allocated severance cost deferral balance that were incurred prior to RMP's request to the Idaho Commission for approval to defer these costs in October 2006.

As shown on Exhibit 218 (MPG-5), removing all severance costs incurred prior to October 2006 lowers the total Company deferral balance subject to recovery from Idaho customers from $39.5 million down to $13.2 million.

Q HAVE OTHER JURISDICTIONS REMOVED SEVERANCE COSTS THAT WERE INCURRED PRIOR TO THE COMMISSION'S APPROVAL FOR DEFERRAL OF THESE COSTS?

A Yes. In Washington, the Commission accepted the Staff's recommendation to limit severance costs included in the deferral balance to costs incurred after the Company requested authority from the Commission to defer these costs.[2]

Q HAS RMP DEFERRED ALL SEVERANCE COSTS ON ITS FINANCIAL STATEMENTS AS THE COSTS WERE INCURRED?

A No. In its second quarter of 2007, SCC10Q, PacifiCorp noted that it had incurred severance expenses of $3 million and $8 million during the three-month period ending June 30, 2007 and 2006, respectively, and $8 million and $20 million during the six-month period ending June 30, 2007 and 2006, respectively. However, it established a regulatory asset of only $2 million which reduced the severance expenses based on authorization from commissions to start to defer these expenses in a regulatory asset. Hence, PacifiCorp only started to defer severance expenses for financial reporting purposes after it received regulatory commission approval for the deferrals.

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[2]Washington State Utilities and Transportation Commission, Docket Nos. UE-061546 and UE-060817 at pp. 43-44, Order Date: June 21, 2007.

Q IF ALL THE SEVERANCE COSTS INCURRED BEFORE OCTOBER 2006 ARE NOT INCLUDED IN THE DEFERRAL BALANCE AND AMORTIZED IN FUTURE RATES, IS IT POSSIBLE THAT RMP WILL BE ABLE TO RECOVER THESE SEVERANCE COSTS?

A Yes. RMP's evidence indicates that severing employees will result in approximately $22 million of reduced annual employee expense. This employee expense savings is not yet built into rates and thus is not being passed on to customers. Rather, the employee expense savings is being retained by RMP until its rates are adjusted to reflect the lower employee cost.

My proposed deferral balance adjustment removes $26 million of severance costs from the deferral balance incurred before October 2006. This expense can be recovered with a little more than one year of RMP's estimated annual severed employee cost savings.

Rates in this case are not expected to go into effect until January 1, 2008,[3] which is more than 15 months after the employee severance savings were created. Hence, RMP can recover the severance costs incurred prior to October 2006 with the employee expense savings created by the severed employee savings until rates are adjusted to pass on this saving to customers.

Q WHAT IS THE SECOND ISSUE YOU TAKE WITH RMP'S SEVERANCE COST ALLOCATION FOR IDAHO?

A RMP's allocation factor for Idaho is inflated. Specifically, as shown on Page 4.17 of RMP witness Mr. Steven R. McDougal's Exhibit 11, RMP proposes to allocate 5.873% of the annual severance costs deferral amortization expense to the Idaho

[3]McDougal Direct Testimony, p. 6.

jurisdiction. However, this factor exceeds the amount of merger savings allocated to Idaho.

Specifically, on Page 4.17, using various allocation factors for specific cost savings items, Mr. McDougal estimates that the Idaho jurisdiction savings will be $1,182,581 out of total Company savings of $22,473,994. This indicates that the Idaho jurisdiction will receive 5.262% of total Company savings created by the MEHC transaction. Hence, the allocation of deferred severance costs amortization should be based on the same allocation of merger savings, or 5.262%.

Q WHAT IS THE IMPACT ON THE IDAHO REVENUE REQUIREMENT FROM YOUR PROPOSED TWO ADJUSTMENTS TO THE SEVERANCE COST AMORTIZATION?

A As shown on the attached Exhibit 218 (MPG-5), eliminating severance costs incurred prior to the deferral authority in Idaho, and reducing the Idaho jurisdictional allocation factor to 5.262% from 5.873% reduces the Idaho test year severance cost amortization expense to $231,323 from $773,709 as proposed by RMP. Hence, these adjustments reduced the Idaho revenue requirement by $542,387.

Q PLEASE DESCRIBE RMP'S PROPOSED TEST YEAR AMOUNT OF PENSION EXPENSE.

A RMP proposes to increase its total pension expense to $72.5 million from $49.5 million. This is a total increase of $23 million and an increase of $17 million in O&M expense. RMP explains that the expense adjustment includes its calendar year (CY) 2007 pension cash contribution rather than its CY 2007 pension expense. RPM explains that it believes this adjustment is consistent with the Idaho Commission's practice to include pension cash contribution rather than pension expense in a utility revenue requirement in two recent rate cases: Idaho Power Company (Case No. IPC-E-03-13, Order No. 29505) and Avista (Case No. AVU-E-04-01, Order No. 29602).

Q IS THE PENSION EXPENSE ADJUSTMENT PROPOSED BY RMP REASONABLE?

A No. RMP's pension expense adjustment should be rejected for at least two reasons. First, the two Idaho Commission Orders do not support RMP's pension expense adjustment. In both of these Orders, the Idaho Commission found that the amount of expense included in a utility's cost of service should be "fair and reasonable."[4]

In the Idaho Power case, the Commission rejected the utility's request to use the pension service cost in its cost of service. The Company argued that the service cost was more stable than both the FAS 87 expense and the pension cash contribution. The record in that case showed that including the pension service cost in cost of service would have allowed the utility to recover significantly more expense from customers than was actually being contributed to the pension trust. Because of the significant discrepancy between annual cash contributions and annual pension service cost, the Commission approved an amount to be included in cost of service based on the utility's expected cash contribution.

In the Avista case, the utility was allowed to amortize a portion of pension cash contribution in excess of the annual expense to avoid penalizing the utility for making additional pension contributions. In the Avista case, the Commission used a hybrid of expense and cash contribution to set the pension cost of service.

In both cases, the Commission carefully considered the need to balance the amount of expenses paid by customers with the amount of cash contributions made

[4]Order No. 29505, p. 21, and Order No. 29602, p. 24.

to the pension trust. In its determination, the Commission found the pension cost included in cost of service should be just and reasonable.

Q DID RMP DEMONSTRATE THAT IT IS JUST AND REASONABLE TO USE THE PENSION CASH CONTRIBUTION RATHER THAN PENSION EXPENSE IN ITS COST OF SERVICE IN THIS CASE?

A No. In this case, RMP has not supported its implicit assertion that its pension expense will be consistently lower than its pension cash contribution. Indeed, RMP's evidence in this case is contrary to this conclusion.

Specifically, RMP witness Erich D. Wilson testified that the Company regularly reviews changes to laws and regulations, which led to its decision to change its pension plan to create a more stable and predictable retirement plan cost structure.[5] Mr. Wilson also stated that the Company changed the pension benefit program to remain competitive with other energy service providers and reflect recent legislation passed under the Pension Protection Act of 2006. He asserts that this change allows businesses to see the benefit of a more predictable method of funding employee retirement benefits. While Mr. Wilson acknowledges that cash contributions can be different than the pension expense, he asserts at page 20 that, over the long run, the accrued expense will equal the total cash contributions; however, in a given year, the cash contribution may be significantly different than the accrued expense. Further, in response to Monsanto Data Request No. 9.1, RMP provided its projection of cash contributions and FAS 87 pension expense over the next five years and over the last five years. In this response, the Company's projections indicate that its cash contribution in the test year will be significantly higher than in any of the years over the next five years. As such, the test year cash contribution is not a just and

[5] Wilson Direct Testimony, p. 15.

reasonable amount to include in cost of service in this proceeding, because it would allow the Company to over-recover cash contributions to its pension plan while rates are in effect.

Mr. Wilson's testimony does not support the implicit contention that RMP's pension expense will be consistently lower than its annual pension cash contributions.

Q WHAT AMOUNT OF PENSION EXPENSE DO YOU PROPOSE BE INCLUDED IN RMP'S COST OF SERVICE IN THIS PROCEEDING?

A The Company's evidence indicates that it has taken measures to stabilize its annual pension expense. The change to its pension plan appears to be comparable to those offered to employees in other enterprises and utility companies.

RMP's effort to stabilize pension expenses suggests that the Company's proposal to increase its pension cost of service to an amount above its estimated annual pension expense is not just and reasonable. Hence, I recommend the Commission set the Company's pension expense based on the lower of the cash contribution or annual pension expense in this case. RMP should be required to demonstrate and prove that it is fair and reasonable to increase its pension cost of service to reflect its projected cash contribution rather than its expense. RMP has not made this showing.

As set forth on Exhibit 219 (MPG-6), maintaining the cost of the pension expense component of cost of service at the pension expense level rather than the pension cash contribution will reduce the Idaho jurisdictional pension expense by $1 million.

2007 Plant Additions

Q HAS RMP INCLUDED MAJOR PLANT ADDITIONS IN ITS RATE BASE IN THIS CASE?

A Yes. The Company increased its rate base for projected plant additions during CY 2006 and 2007.

Q IS RMP'S PROPOSAL TO INCREASE ITS RATE BASE AND DEPRECIATION EXPENSE FOR PROJECTED CY 2007 PLANT ADDITIONS REASONABLE?

A No. The Company is using a CY 2006 test year with known and measurable changes through 2007 as the appropriate test period used to reflect its cost of service in this proceeding.[6] The Company has inconsistently gone outside of the 2006 test year in order to reflect expected 2007 plant additions without also reflecting expected 2007 sales growth, and known CY 2007 rate base cost decreases. Therefore, RMP's 2007 plant additions to its CY 2006 rate base are inappropriate and unreasonably inflate its claimed revenue deficiency.

Q WHY DO YOU BELIEVE THE COMPANY'S REVENUES WILL GROW IN 2007 RELATIVE TO THE 2006 TEST YEAR?

A Mr. McDougal testified that the Company's fuel cost is increasing due to customer load growth.[7] Also, RMP witness Mark T. Widmer testifies that the Company's filing reflects a system-wide increase in load of 2.3 million MWh, or growth of 4.1%.[8] This load growth will also increase the Company's revenue in 2007 relative to 2006. Hence, any increase in rate base caused by 2007 plant additions will be covered in whole or in part by higher revenue at current rates due to increased sales.

[6]McDougal Direct Testimony, p. 4.
[7]McDougal Direct Testimony, p. 11.
[8]Widmer Direct Testimony, p. 3.

Q WHAT KNOWN RATE BASE 2007 COST DECREASES DID RMP EXCLUDE?

A The Company has not reflected the known rate base reduction in 2007 relative to 2006 created by the increase to accumulated depreciation. RMP is proposing to charge Idaho customers $22.9 million of Idaho jurisdictional depreciation expense in CY 2006. Also, in CY 2006, the Company proposed to charge customers $3.3 million of amortization expense. In total, RMP proposed to recover $26.2 million of its 2006 rate base through this capital expense recovery. This depreciation and amortization recovery in CY 2006 will increase its accumulated depreciation account which will decrease its CY 2007 rate base.

This known rate base decrease in 2007 will offset more than 80% of RMP's proposed plant additions in CY 2007 (depreciation and amortization of $26.2 million versus plant additions of $32.3 million). As such, RMP has included projected rate base increases for CY 2007 by reflecting projected plant additions, but has ignored the rate base decreases created by recovery of additional depreciation and deferred taxes in 2007 relative to 2006.

Q WHAT IS THE IMPACT ON RMP'S PROPOSED REVENUE DEFICIENCY IF 2007 PLANT ADDITIONS ARE EXCLUDED FROM ITS 2006 TEST YEAR?

A As shown on Exhibit 220 (MPG-7), removing these 2007 plant additions lowers RMP's resource deficiency by $4.7 million.

Q HAS RMP UPDATED ITS PROJECTED PLANT ADDITIONS IN 2007?

A Yes. The Company's update of its 2007 plant additions indicates that certain major generating assets will go into service later than originally projected, and the Company's estimates of additional transmission investments will be lower than it originally projected. RMP's updated 2007 plant additions further illustrate that these costs do not meet the known and measurable standard to increase test year rate base, and do not properly reflect known and measurable cost decreases that will in whole or in large part eliminate these 2007 cost increases in designing rates.

Q ARE THERE ANY OTHER POST-TEST YEAR FACTORS THAT COULD REDUCE RMP'S COST OF SERVICE WHEN THE RATES FROM THIS PROCEEDING ARE IN EFFECT?

A Yes. RMP has reached an agreement with various stakeholders in Wyoming concerning a change to depreciation rates. If those revised depreciation rates are implemented across its system, then RMP's cost of service for Idaho would be reduced by approximately $1 million.

Q DOES THIS CONCLUDE YOUR VOLUME 1 – REVENUE REQUIREMENT DIRECT TESTIMONY?

A Yes, it does.

<u>**Qualifications of Michael Gorman**</u>

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Michael P. Gorman. My business mailing address is P. O. Box 412000, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q **PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and a managing principal with Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q **PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A In 1983 I received a Bachelors of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission (ICC). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. In April 1995 the firm of Brubaker & Associates, Inc. (BAI) was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals (RFPs) for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements. Continuing, I have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona; Corpus Christi, Texas; and Plano, Texas.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the regulatory commissions in Arizona, California, Delaware, Georgia, Illinois, Indiana, Iowa, Louisiana, Michigan, Missouri, New Mexico, New Jersey, Oklahoma, Oregon, Tennessee, Texas, Utah, Vermont, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial ratepayers; and negotiated rate disputes for industrial ratepayers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst (CFA) from the Charter Financial Analyst Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of CFA's Financial Analyst Society.

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ROCKY MOUNTAIN POWER

Rate of Return Reduction Impact

1. Proposed Capital Structure[1]

Line	Description	Amount (1)	Weight (2)	Cost (3)	Weighted Cost (4)	Pre-Tax Weighted Cost (5)
1	Common Stock	$ 4,645,400,280	50.4%	**10.75%**	5.42%	8.75%
2	Preferred Stock	$ 41,463,300	0.5%	5.410%	0.02%	0.04%
3	Long-Term Debt	$ 4,523,205,000	49.1%	6.26%	3.07%	3.07%
4	Total	$ 9,210,068,580	100.00%		**8.52%**	**11.86%**
5	Tax Conversion Factor					1.614

2. Proposed Capital Structure with ROE Reduction

Line	Description	Amount (1)	Weight (2)	Cost (3)	Weighted Cost (4)	Pre-Tax Weighted Cost (5)
6	Common Stock	$ 4,645,400,280	50.4%	**10.00%**	5.04%	8.14%
7	Preferred Stock	$ 41,463,300	0.5%	5.410%	0.02%	0.04%
8	Long-Term Debt	$ 4,523,205,000	49.1%	6.26%	3.07%	3.07%
9	Total	$ 9,210,068,580	100.00%		**8.14%**	**11.25%**
10	Pre-Tax ROR Impact with ROE Reduction					0.61%
11	Rate Base (Idaho)					$ 494,597,902
12	**Revenue Impact with ROE Reduction**					**$ 3,019,794**

Source:
[1] Williams Direct at 3 and Attach Monsanto 1.6. b..

ROCKY MOUNTAIN POWER

SO2 Allowance Sales Revenue Adjustment

Line	Description		Idaho Allocated (1)	Reference (2)
1	SO_2 Allowance Sales Revenue	$	855,123	McDougal, Exh. 11 pg. 3.4
2	Remove Rate Base Offset	$	(1,458,728)	McDougal, Exh. 11 pg. 3.4
3	Revenue from Rate Base Change	$	(173,034)	Line 2 * 11.862%
4	Revenue Impact	$	682,089	Line 1 + Line 3

ROCKY MOUNTAIN POWER

SO2 Allowance Sales Revenue

Line	Description	Date Booked (1)	Sales to Date Dec - 07 (2)	2005 (3)	Test Year 2006 (4)	2007 (5)
1	EPA Auction	May - 05	$ 2,065,357	$ 2,065,357		
2	EPA Auction	Jun - 05	200,914	200,914		
3	JP Morgan Sale	Dec - 05	13,958,500	13,958,500		
4	JP Morgan Sale	Feb - 06	12,995,000		$ 12,995,000	
5	EPA Auction	May - 06	2,392,408		2,392,408	
6	EPA Auction	Jun - 06	232,244		232,244	
7	Sale	Mar - 07	2,322,500			$ 2,322,500
8	Sale	Apr - 07	2,250,000			2,250,000
9	EPA Auction	May - 07	1,500,000			1,500,000
10	Sale	Jun - 07	2,250,000			2,250,000
11	Sales	Sep - 07	2,250,000			2,250,000
12	Sales	Oct - 07	2,250,000			2,250,000
13	Sales	Nov - 07	1,890,000			1,890,000
14	Total		$ 46,556,923	$ 16,224,771	$ 15,619,652	$ 14,712,500
15	3-Year Average		$ 15,518,974			

Source:
Steven McDougal, Exhibit 11, pg 3.4.1

Monsanto Data Request 2.16

Referring to page 12 of the testimony of Mr. McDougal, beginning at line 17, please provide for each of the years 2000 through 2006, and as projected for each of the years 2007 through 2015, the number of SO^2 allowances sold and the revenues per allowance, and in total. In addition, please provide for each year the beginning of year balance, the number acquired, the number sold and the end of year balance.

Response to Monsanto Data Request 2.16

Please see Confidential Attachment Monsanto 2.16 for the data requested above. This information is confidential and is provided subject to the terms and conditions of the protective order in this proceeding.

[Steven R. McDougal is expected to sponsor this response at hearing.]

SO2 ALLOWANCE REVENUE SUMMARY - MONSANTO 2-16

September 27, 2007

CY	BEGINNING BALANCE	Allowances Sold	Average $/Allowance	Total Revenue	EPA ALLOCATION	SWAP DIFFERENTIAL	CONSUMED	ENDING BALANCE
2000								
2001								
2002								
2003								
2004								
2005								
2006								
2007								
2007								
2008								
2009								
2010								
2011								
2012								
2013								
2014								
2015								

ROCKY MOUNTAIN POWER

Severance Cost Adjustment

Line	Description	RMP Proposed Severance Costs (1)	Severance Costs Incurred After 10/2006 (2)
1	Non-Executive Total	$ 28,167,501	$ 12,684,222
2	Executive Total	$ 11,354,507	$ 504,070
3	Total Severance	$ 39,522,007	$ 13,188,291
4	Amortized over 3 years	$ 13,174,002	$ 4,396,097
5	Company Idaho Allocation Factor	5.873%	
6	Gorman Idaho Allocation Factor		5.262%
7	Idaho Jurisdictional Amount	$ 773,709	$ 231,323
8	Idaho Severance Cost Adjustment	$ 542,387	

Source:
Erich D. Wilson, Exhibit 24 & 25

ROCKY MOUNTAIN POWER

Non-Executive Severance Costs

Line	Month	Severance Costs (1)	Severance Costs Incurred After 10/2006 (2)
1	March-06	$ 2,823,721	$ -
2	April-06	582,822	-
3	May-06	2,167,518	-
4	June-06	3,769,040	-
5	July-06	1,012,902	-
6	August-06	2,966,908	-
7	September-06	2,632,872	-
8	October-06	8,391,698	8,391,698
9	November-06	2,636,674	2,636,674
10	December-06	844,993	844,993
11	January-07	695,851	695,851
12	February-07	511,396	511,396
13	March-07	182,211	182,211
14	Total Non-Executive	$ 29,218,606	$ 13,262,822
15	Remove Backfill	$ 1,051,105	$ 578,600
16	Net Total Non-Executive	$ 28,167,501	$ 12,684,222

Source:
Erich D. Wilson, Exhibit 24

ROCKY MOUNTAIN POWER

Executive Severance Costs

Line	Month	Total Employee Costs (1)	Severance Costs (2)	Severance Costs Cappped at 88% of Employee Costs (3)	Severance Costs Incurred After 10/2006 (4)
1	March-06	$ 2,925,013	$ 9,061,014	$ 2,580,158	
2	April-06	$ 284,054	$ 944,409	$ 250,565	
3	September-06	$ 630,962	$ 1,485,017	$ 556,573	
4	November-06	$ 1,077,232	$ 4,129,645	$ 950,228	$ 950,228
5	Grand Total	$ 4,917,261	$ 15,620,085	$ 4,337,523	$ 950,228
6	Remove Backfill		$ 4,265,579		$ 446,158
7	Net Total		$ 11,354,507		$ 504,070

Source:
Erich D. Wilson, Exhibit 25

Case No. PAC-E-07-05
Exhibit 219 (MPG-6)

ROCKY MOUNTAIN POWER

Adjustment to Pension Costs

Line	Description	Amount (1)
1	Pension Funding to Electric Expense	$ 72,549,317
2	Actuarial Pension Expense in Results	$ 49,648,020
3	Total Difference	$ 22,901,297
4	O&M Portion	74.35%
5	Adjustment to O&M - Pension	$ 17,027,114
6	Idaho Allocation Factor	5.873%
7	Idaho Allocated Adjustment to O&M - Pension	$ 1,000,002

Source:
Steven McDougal, Exhibit 11, pg 4.14 & 4.14.1

ROCKY MOUNTAIN POWER

Remove Calendar Year 2007 Plant Additions
Revenue Impact
Idaho Allocation

Line	Description	Amount (1)	Reference (2)
	Rate Base Impact		
1	Plant Additions	$ 32,302,051	McDougal, Exh. 11 pg. 8.8
2	Less: Accumulated Depreciation	$ 500,429	McDougal, Exh. 11 pg. 6.2
3	Less: Deferred Taxes	$ 435,956	McDougal, Exh. 11 pg. 8.8
4	Rate Base	$ 31,365,666	Line 1 - Line 2 - Line 3
	Operating Expense Impact		
5	Depreciation Expense	$ 1,000,858	McDougal, Exh. 11 pg. 6.1
6	Income Tax	$ 1,048,554	Rate Base * (11.862%-8.519%)
7	Total Operating Expense	$ 2,049,412	Line 5 + Line 6
8	Operating Income	$ 2,671,950	Rate Base * 8.519%
9	**Revenue Requirement**	$ 4,721,362	Line 7 + Line 8

ROCKY MOUNTAIN POWER

Rocky Mountain Power Proposed
Cost of Capital

Line	Description	Percent (1)	Cost Rate (2)	Weighted Return Component (3)	Pretax Return (4)
1	Total Debt	49.100%	6.260%	3.074%	3.074%
2	Preferred Stock	0.500%	5.410%	0.027%	0.044%
3	Common Equity	50.400%	10.750%	5.418%	8.745%
4	Rate of Return			8.519%	11.862%

Source:
Steven McDougal, Exhibit 11, pg 2.1
Tax Gross-up Factor = 1.614