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	)	**Direct Testimony of Bruce N. Williams**
ELECTRIC SERVICE SCHEDULES	)	
	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-07-05

June 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 Bruce N. Williams. My business address is 825 NE Multnomah, Suite 1900, Portland, Oregon 97232. I am the Vice President and Treasurer for the Company.

Qualifications

Q. Please briefly describe your education and business experience.

A. I received a Bachelor of Science degree in Business Administration with a concentration in Finance from Oregon State University in June 1980. I also received the Chartered Financial Analyst designation upon passing the examination in September 1986. I have been employed by the Company for 22 years. My business experience has included financing of the Company's electric operations and non-utility activities, investment management, and investor relations.

Q. Please describe your present duties.

A. I am responsible for the Company's treasury, credit risk management, pension and other investment management activities. In this proceeding, I am responsible for the preparation of the Company's embedded cost of debt and preferred equity, and the testimony related to capital structure.

Purpose of Testimony

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

A. I will first present a financing overview of the Company. Next, I will discuss the planned amounts of common equity, debt, and preferred stock to be included in the Company's capital structure. I will then analyze the embedded cost of debt and preferred stock supporting Rocky Mountain Power's electric operations in the state of Idaho as of March 2007, with anticipated changes through December 2007. This analysis includes the known and measurable changes to the debt and preferred stock portfolios and capital contributions from our parent company.

Q. What financial information is your analysis based on?

A. The historical test period used in this case is the twelve months ending December 2006, updated with known and measurable changes. To match Rocky Mountain Power's cost as closely as possible with customers' rates, the capital structure applied in this case is the Company's actual capital structure as of March 31, 2007, with known and measurable changes occurring through December 31, 2007. This time period captures significant transactions between the end of the historical test period and the beginning of the rate effective period. Rocky Mountain Power believes it is appropriate to include these transactions in this proceeding as it reflects ongoing capital costs to fund operations. As I discuss later, I propose changes to remove long-term debt and preferred stock that will mature or is subject to mandatory redemption prior to December 31, 2007.

Q. What is the overall cost of capital that Rocky Mountain Power is proposing in this proceeding?

A. Rocky Mountain Power is proposing an overall cost of capital of 8.52 percent. This cost includes the return on equity recommendation from Dr. Sam Hadaway and the following capital structure and costs:

Rocky Mountain Power

Overall Cost of Capital

Component	Percent of Total	Cost	Weighted Average
Long Term Debt	49.1%	6.26%	3.07%
Preferred Stock	0.5%	5.41%	.03%
Common Stock Equity	50.4%	10.75%	5.42%
	100.0%		8.52%

Financing Overview

Q. How does the Company finance its electric utility operations?

A. The Company finances the cash flow requirements of its regulated utility operations through a mix of debt and equity securities designed to provide a competitive cost of capital and predictable capital market access.

Q. How does the Company meet its debt and preferred equity financing requirements?

A. The Company relies on a mix of first mortgage bonds, other secured debt, tax exempt debt and preferred stock to meet its long-term debt and preferred stock financing requirements. The Company has concluded the majority of its long-term financing utilizing secured first mortgage bonds issued under the Mortgage Indenture dated January 9, 1989. Exhibit No. 7 shows that, as of December 31, 2007, the Company will have approximately $3.8 billion of first mortgage bonds outstanding, with an average cost of 6.55 percent and average remaining maturity of 16 years. Presently, all outstanding first mortgage bonds bear interest at fixed rates. Proceeds from the issuance of the first mortgage bonds (and other financing instruments) are used to finance the combined utility operations across the Company's six-state service territory.

Another important source of financing has been the tax-exempt financing associated with certain qualifying equipment at power generation plants. Under arrangements with local counties and other tax-exempt entities, the Company borrows the proceeds and guarantees the repayment of the long-term debt in order to take advantage of their tax-exempt status in financings. As of December 31, 2007, the Company's tax-exempt portfolio will be $738 million in principal amount which had an average cost of 4.74 percent at March 31, 2007 (which includes the cost of issuance and credit enhancement).

Capital Structure

Q. How does the Company determine the amount of common equity, debt, and preferred stock to be included in the planned capital structure?

A. As a regulated utility, Rocky Mountain Power has a duty and an obligation to provide adequate, efficient, just and reasonable service to customers in its Idaho service territory while balancing cost and risk. In order to fulfill this obligation, Rocky Mountain Power must make significant capital expenditures for plant and network maintenance, power generation and delivery infrastructure, clean air investments, hydro re-licensing and other activities. Through its planning process, the Company determined the amounts of new financing needed to support these activities and calculated the required equity and debt ratios required to maintain our current 'A-' credit rating for senior secured debt. These determinations are then reflected in the Company's budget.

Q. **Have the Company's recent actions and budgets reflected an expectation that the capital structure will include an increase in equity?**

A. Yes. Following the acquisition by MidAmerican Energy Holdings Company on March 21, 2006, the Company has received a total of $215 million of cash capital contributions from its direct parent company, PPW Holdings, LLC. Similarly, the Company's 2007 budget includes additional cash equity contributions of $150 million prior to June 30, 2007.

Q. **Why does the Company's budget reflect the need for additional equity in the capital structure?**

A. The budget reflects the cost increases described in this case, including fuel, net power costs, certain labor related costs, investment in major supply side resources, thermal plant maintenance, hydro re-licensing and clean air requirements. These cost increases, coupled with the increasingly more rigorous expectations of the credit rating agencies for credit metrics and balance sheet strength, mean that additional equity will be required along with improved business results and other considerations to support the Company's current 'A-' credit rating from Standard & Poor's, its 'A3' rating from Moody's Investors Service ("Moody's"), and to prevent Fitch Ratings from further downgrades, with the last downgrade occurring in January 2006.

Q. **How does this projected capital structure match up to comparable electric utilities?**

A. The projected capital structure is consistent with the comparable group that Dr.

Hadaway has selected in his estimate of return on equity. Both the Company and the group of comparable companies show an increasing percentage of common equity in their capital structures. The Value Line estimate of common equity ratio for the comparable group averages 50.0 percent.

Q. Please describe the changes to the Company's levels of debt financing.

A. Through the period ending December 31, 2007, the balance of the outstanding long-term debt will change through maturities, principal amortization and sinking fund requirements. Based upon the long-term debt series outstanding on March 31, 2007, I have calculated the reduction to the outstanding balances for maturities, principal amortization and sinking fund requirements, which are scheduled to occur during the period ending December 31, 2007. The total long-term debt maturities and principal amortized over this period is $119.9 million. The resulting $4.5 billion of long-term debt is consistent with the Company's budget and is necessary to fund our ongoing operations. At this time the Company has no plans to issue additional long-term debt prior to December 31, 2007.

Q. Please describe the changes to the Company's level of preferred equity financing.

A. For preferred stock, I started with the balance outstanding at March 31, 2007, and made a reduction of $37.5 million of preferred stock to reflect the final sinking fund requirement of the $7.48 No Par Serial Preferred stock series that will occur on June 15, 2007.

Q. Is the proposed capital structure consistent with the Company's current credit rating?

A. Yes. This planned capital structure is intended to enable the Company to deliver its budgeted capital expenditures while maintaining credit ratios that support the continuance of its current 'A-' credit rating.

Q. What is the relationship between a strong credit rating and customer benefits?

A. The credit rating assigned to a utility by the credit rating agencies directly affects the price the utility pays to attract the capital necessary to support its current and future operating needs. A strong credit rating directly benefits customers by reducing immediate and future borrowing costs related to the financing needed to support regulatory operations.

During periods of capital market disruptions, higher-rated companies are more likely to have continuous, uninterrupted access to capital. This is not always the case with lower-rated companies, which during such periods may find themselves either unable to secure capital or able to secure capital only on unfavorable terms and conditions.

In addition, higher-rated companies have greater access to the long-term markets for power and fuel purchases and sales. Such access provides these companies with more alternatives when attempting to meet the current and future load requirements of their customers. Finally, a company with strong ratings will often avoid having to meet costly collateral requirements that are typically imposed on lower-rated companies when securing power or fuel in these markets.

Q. Is the Company subject to rating agency debt imputation associated with Purchased Power Agreements?

A. Yes. Rating agencies and financial analysts consider Purchased Power Agreements to be debt-like and will impute debt and related interest when calculating financial ratios.

For example, Standard & Poor's will adjust published results and add in debt and interest resulting from purchase power agreements when assessing the Company's creditworthiness. They do so in order to obtain a more accurate assessment of a company's financial commitments and fixed payments. Exhibit No. 8 is the May 12, 2003 publication by Standard & Poor's detailing its view of the debt aspects of purchase power agreements which was refined by their March 30, 2007 publication (Exhibit No. 9).

Q. How does this impact Rocky Mountain Power?

A. During a recent ratings review, Standard & Poor's evaluated the Company's purchase power agreements and other related long-term commitments. Following this review, Standard & Poor's added approximately $537 million of additional debt and related interest expense to our leverage and coverage tests due to PacifiCorp's purchase power agreements.

Financing Cost Calculation

Q. How did you calculate the Company's embedded costs of long-term debt and preferred stock?

A. I calculated the embedded costs of debt and preferred stock using the methodology relied upon in the Company's previous rate filings in Idaho and elsewhere.

Q. Please explain the cost of debt calculation.

A. I calculated the cost of debt by issue, based on each debt series' interest rate and net proceeds at the issuance date, to produce a bond yield to maturity for each series of debt. It should be noted that in the event a bond was issued to refinance a higher cost bond, the pre-tax premium and unamortized costs, if any, associated with the refinancing were subtracted from the net proceeds of the bonds that were issued. The bond yield was then multiplied by the principal amount outstanding of each debt issue, resulting in an annualized cost of each debt issue. Aggregating the annual cost of each debt issue produces the total annualized cost of debt. Dividing the total annualized cost of debt by the total principal amount of debt outstanding produces the weighted average cost for all debt issues. This is the Company's embedded cost of long-term debt.

Q. How did you calculate the embedded cost of preferred stock?

A. The embedded cost of preferred stock was calculated by first determining the cost of money for each issue. This is the result of dividing the annual dividend rate by the per share net proceeds for each series of preferred stock. The cost associated with each series was then multiplied by the total par or stated value outstanding for each issue to yield the annualized cost for each issue. The sum of annualized costs for each issue produces the total annual cost for the entire preferred stock portfolio. I then divided the total annual cost by the total amount of preferred stock outstanding to produce the weighted average cost of all issues. This is the Company's embedded cost of preferred stock.

Embedded Cost of Long-Term Debt

Q. What is the Company's embedded cost of long-term debt?

A. Exhibit No. 7 shows the embedded cost of long-term debt at March 31, 2007, adjusted for the known and measurable changes discussed above to be 6.26 percent.

Embedded Cost of Preferred Stock

Q. What is the Company's embedded cost of preferred stock?

A. Exhibit No. 10 shows the embedded cost of preferred stock at March 31, 2007, adjusted for the known and measurable changes discussed above to be 5.41 percent.

Q. Does this conclude your testimony?

A. Yes.

Case No. PAC-E-07-05
Exhibit No. 7
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Pro Forma Cost of Long-Term Debt

June 2007

Rocky Mountain Power
Exhibit No. 7 page 1 of 3
CASE NO. PAC-E-07-05
Witness Bruce N. Williams

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Summary
December 31, 2007

LINE NO.	DESCRIPTION	AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	YTM	LINE NO.
1											1
2	**Total First Mortgage Bonds**	**$3,784,835,000**	**($34,537,272)**	**($38,145,597)**	**$3,712,152,131**	**$247,986,033**	**6.33%**	**6.55%**	**21.8**	**16.0**	2
3											3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$400,470,000	($10,560,810)	($9,550,194)	$380,358,996	$18,967,516	4.39%	4.74%	28.0	13.5	4
5	Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,294,232)	($7,621,229)	$325,984,539	$16,046,592	4.51%	4.75%	27.8	10.2	5
6	**Total Pollution Control Revenue Bonds**	**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**	**$35,014,109**	**4.45%**	**4.74%**	**27.9**	**12.0**	6
7											7
8	**Total Cost of Long Term Debt**	**$4,523,205,000**	**($49,392,314)**	**($55,317,020)**	**$4,418,495,666**	**$283,000,142**	**6.02%**	**6.26%**	**22.8**	**15.3**	8
9											9

PACIFICORP
Electric Operations
Proforma Cost of Long-Term Debt Detail
December 31, 2007

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1															1
2		**First Mortgage Bonds**													2
3	8.271%	C-U Series due thru Oct 2010	04/15/92	10/01/10	18	2	$48,972,000	$13,200,000	$0	$0	$13,200,000	$100.000	8.271%	$1,091,772	3
4	7.978%	C-U Series due thru Oct 2011	04/15/92	10/01/11	18	2	$4,422,000	$1,469,000	$0	$0	$1,469,000	$100.000	7.978%	$117,197	4
5	8.493%	C-U Series due thru Oct 2012	04/15/92	10/01/12	19	3	$19,772,000	$7,988,000	$0	$0	$7,988,000	$100.000	8.493%	$678,421	5
6	8.797%	C-U Series due thru Oct 2013	04/15/92	10/01/13	19	3	$16,203,000	$7,542,000	$0	$0	$7,542,000	$100.000	8.797%	$663,470	6
7	8.734%	C-U Series due thru Oct 2014	04/15/92	10/01/14	20	4	$28,218,000	$14,492,000	$0	$0	$14,492,000	$100.000	8.734%	$1,265,731	7
8	8.294%	C-U Series due thru Oct 2015	04/15/92	10/01/15	20	5	$46,946,000	$25,697,000	$0	$0	$25,697,000	$100.000	8.294%	$2,131,309	8
9	8.635%	C-U Series due thru Oct 2016	04/15/92	10/01/16	21	5	$18,750,000	$11,159,000	$0	$0	$11,159,000	$100.000	8.635%	$963,580	9
10	8.470%	C-U Series due thru Oct 2017	04/15/92	10/01/17	22	6	$19,609,000	$12,288,000	$0	$0	$12,288,000	$100.000	8.470%	$1,040,794	10
11	**8.475%**	**Subtotal - Amortizing FMBs**			**20**	**4**		**$93,835,000**	**$0**	**$0**	**$93,835,000**		**8.475%**	**$7,952,273**	11
12															12
13	4.300%	Series due Sep 2008	09/08/03	09/15/08	5	1	$200,000,000	$200,000,000	($1,610,660)	($5,967,819)	$192,421,521	$96.211	5.167%	$10,334,000	13
14	6.900%	Series due Nov 2011	11/21/01	11/15/11	10	4	$500,000,000	$500,000,000	($5,338,849)	$0	$494,661,151	$98.932	7.051%	$35,255,000	14
15	5.450%	Series due Sep 2013	09/08/03	09/15/13	10	6	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	$96.189	5.961%	$11,922,000	15
16	4.950%	Series due Aug 2014	08/24/04	08/15/14	10	7	$200,000,000	$200,000,000	($2,170,365)	$0	$197,829,635	$98.915	5.090%	$10,180,000	16
17	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	24	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	17
18	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	27	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	18
19	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	27	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	19
20	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	29	$350,000,000	$350,000,000	($3,935,488)	$0	$346,064,512	$98.876	6.183%	$21,640,500	20
21	5.750%	Series due Aug 2036	03/14/07	04/01/37	30	29	$600,000,000	$600,000,000	($774,000)	$0	$599,226,000	$99.871	5.759%	$34,554,000	21
22	**5.979%**	**Subtotal - Bullet FMBs**			**22**	**19**		**$2,850,000,000**	**($25,791,718)**	**($13,231,634)**	**$2,810,976,648**		**6.154%**	**$175,401,500**	22
23															23
24	9.150%	Series C due Aug 2011	08/09/91	08/09/11	20	4	$8,000,000	$8,000,000	($75,327)	$0	$7,924,673	$99.058	9.254%	$740,320	24
25	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	4	$20,000,000	$20,000,000	($132,118)	$0	$19,867,882	$99.339	9.022%	$1,804,400	25
26	8.920%	Series C due Sep 2011	08/16/91	09/01/11	20	4	$20,000,000	$20,000,000	($188,318)	$0	$19,811,682	$99.058	9.022%	$1,804,400	26
27	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	4	$25,000,000	$25,000,000	($175,398)	$0	$24,824,602	$99.298	9.026%	$2,256,500	27
28	8.290%	Series C due Dec 2011	12/31/91	12/30/11	20	4	$3,000,000	$3,000,000	($23,040)	($410,784)	$2,566,175	$85.539	9.972%	$299,160	28
29	8.260%	Series C due Jan 2012	01/09/92	01/10/12	20	4	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	$85.542	9.938%	$99,380	29
30	8.280%	Series C due Jan 2012	01/10/92	01/10/12	20	4	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	$85.642	9.947%	$198,940	30
31	8.250%	Series C due Feb 2012	01/15/92	02/01/12	20	4	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	$85.542	9.925%	$297,750	31
32	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	14	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	$85.539	10.066%	$1,509,900	32
33	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	14	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	$85.539	9.889%	$494,450	33
34	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	14	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	$85.642	9.745%	$487,250	34
35	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	14	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	$85.542	9.768%	$390,720	35
36	**8.766%**	**Subtotal - Series C MTNs**			**23**	**6**		**$111,000,000**	**($855,533)**	**($5,203,268)**	**$104,941,200**		**9.354%**	**$10,383,170**	36
37															37
38	8.130%	Series E due Jan 2013	01/20/93	01/22/13	20	5	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	$92.525	8.939%	$893,900	38
39	8.050%	Series E due Sep 2022	09/18/92	09/18/22	30	15	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	$87.820	9.258%	$1,388,700	39
40	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	15	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	$87.820	9.280%	$742,400	40
41	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	15	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	$87.820	9.325%	$1,119,000	41
42	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	15	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	$87.820	9.336%	$4,668,000	42
43	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	15	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	$87.820	9.258%	$925,800	43
44	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	15	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	$90.953	8.953%	$2,238,250	44
45	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	15	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	$87.895	9.283%	$2,413,580	45
46	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	15	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	$99.056	8.316%	$332,640	46
47	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	15	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	$92.525	8.951%	$447,550	47
48	**8.100%**	**Subtotal - Series E MTNs**			**29**	**14**		**$165,000,000**	**($1,303,552)**	**($16,835,712)**	**$146,860,736**		**9.194%**	**$15,169,820**	48
49															49
50	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	16	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	$93.730	7.804%	$858,440	50
51	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	16	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	$93.730	7.804%	$2,107,080	51
52	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	16	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	$97.294	7.457%	$1,118,550	52
53	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	16	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	$97.294	7.467%	$2,240,100	53

PACIFICORP
Electric Operations
Proforma Cost of Long-Term Debt Detail
December 31, 2007

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
54	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	16	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.810%	$136,200	54
55	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	16	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.780%	$135,600	55
56	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	16	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	$98.552	6.865%	$343,250	56
57	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	16	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	57
58	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	16	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	58
59	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	16	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	59
60	**7.044%**	**Subtotal - Series F MTNs**			**30**	**16**		**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**		**7.291%**	**$10,208,020**	60
61															61
62	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	18	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	$99.096	6.781%	$6,781,000	62
63	**6.710%**	**Subtotal - Series G MTNs**			**30**	**18**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	63
64															64
65	6.375%	Series H due May 2008	05/12/98	05/15/08	10	0	$200,000,000	$200,000,000	($2,060,179)	$0	$197,939,821	$98.970	6.517%	$13,034,000	65
66	7.000%	Series H due Jul 2009	07/15/97	07/15/09	12	2	$125,000,000	$125,000,000	($2,428,154)	$0	$122,571,846	$98.057	7.245%	$9,056,250	66
67	**6.615%**	**Subtotal - Series H MTNs**			**11**	**1**		**$325,000,000**	**($4,488,333)**	**$0**	**$320,511,667**		**6.797%**	**$22,090,250**	67
68															68
69	**6.328%**	**Total First Mortgage Bonds**			**22**	**16**		**$3,784,835,000**	**($34,537,272)**	**($38,145,597)**	**$3,712,152,131**		**6.552%**	**$247,986,033**	69
70															70
71		Pollution Control Revenue Bonds													71
72	4.117%	Moffat 94 due May 2013	11/17/94	05/01/13	18	5	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	$97.666	4.302%	$1,748,978	72
73	4.002%	Converse 88 due Jan 2014	01/14/88	01/01/14	26	6	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	$95.672	4.280%	$727,600	73
74	4.002%	Sweetwater 84 due Dec 2014	12/12/84	12/01/14	30	7	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	$98.481	4.091%	$613,650	74
75	3.643%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	8	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	$92.555	4.123%	$1,855,350	75
76	4.229%	Forsyth 86 due Dec 2016	12/29/86	12/01/16	30	9	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	$96.414	4.447%	$377,995	76
77	5.745%	Lincoln 93 due Nov 2021	11/01/93	11/01/21	28	14	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	$89.869	6.538%	$542,654	77
78	5.770%	Emery 93A due Nov 2023	11/01/93	11/01/23	30	16	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	$90.394	6.502%	$3,023,430	78
79	5.745%	Emery 93B due Nov 2023	11/01/93	11/01/23	30	16	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	$88.813	6.607%	$1,083,548	79
80	4.117%	Carbon 94 due Nov 2024	11/17/94	11/01/24	30	17	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	$97.169	4.286%	$401,384	80
81	4.087%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	17	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	$96.385	4.303%	$352,416	81
82	4.222%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	17	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	$95.736	4.483%	$5,466,570	82
83	4.190%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	17	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	$96.651	4.392%	$661,435	83
84	4.087%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	17	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	$97.183	4.255%	$904,613	84
85	4.231%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	18	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	$97.509	4.381%	$232,193	85
86	4.324%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	18	$22,000,000	$22,000,000	($404,262)	$0	$21,595,738	$98.162	4.435%	$975,700	86
87	**4.395%**	**Subtotal - Secured PCRBs**			**28**	**14**		**$400,470,000**	**($10,560,810)**	**($9,550,194)**	**$380,358,996**		**4.736%**	**$18,967,516**	87
88															88
89	4.576%	Sweetwater 88B due Jan 2014	01/14/88	01/01/14	26	6	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	$95.852	4.858%	$558,670	89
90	4.446%	Sweetwater 90A due Jul 2015	07/25/90	07/01/15	25	8	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	$97.920	4.586%	$3,210,200	90
91	4.502%	Emery 91 due Jul 2015	05/23/91	07/01/15	24	8	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	$92.353	5.055%	$2,274,750	91
92	4.425%	Sweetwater 88A due Jan 2017	01/14/88	01/01/17	29	9	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	$97.391	4.589%	$2,294,500	92
93	4.576%	Forsyth 88 due Jan 2018	01/14/88	01/01/18	30	10	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	$96.903	4.771%	$2,146,950	93
94	4.466%	Gillette 88 due Jan 2018	01/14/88	01/01/18	30	10	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	$96.704	4.671%	$1,924,452	94
95	4.121%	Converse 92 due Dec 2020	09/29/92	12/01/20	28	13	$22,485,000	$22,485,000	($242,164)	($303,303)	$21,939,533	$97.574	4.270%	$960,110	95
96	4.121%	Sweetwater 92A due Dec 2020	09/29/92	12/01/20	28	13	$9,335,000	$9,335,000	($167,524)	($134,094)	$9,033,382	$96.769	4.321%	$403,365	96
97	4.121%	Sweetwater 92B due Dec 2020	09/29/92	12/01/20	28	13	$6,305,000	$6,305,000	($151,908)	($97,735)	$6,055,357	$96.041	4.367%	$275,339	97
98	4.603%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	18	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	$97.322	4.772%	$1,164,368	98
99	6.150%	Emery 96 due Sep 2030	09/24/96	09/30/30	34	23	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	$94.201	6.579%	$833,888	99
100	**4.513%**	**Subtotal - Unsecured PCRBs**			**28**	**10**		**$337,900,000**	**($4,294,232)**	**($7,621,229)**	**$325,984,539**		**4.749%**	**$16,046,592**	100
101															101
102	**4.449%**	**Total PCRB Obligations**			**28**	**12**		**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**		**4.742%**	**$35,014,109**	102
103															103
104	**6.022%**	**Total Long-Term Debt**			**23**	**15**		**$4,523,205,000**	**($49,392,314)**	**($55,317,020)**	**$4,418,495,666**		**6.257%**	**$283,000,142**	104
105															105

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Case No. PAC-E-07-05
Exhibit No. 8
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Utilities & Perspectives
May 12, 2003 Publication

June 2007

Rocky Mountain Power
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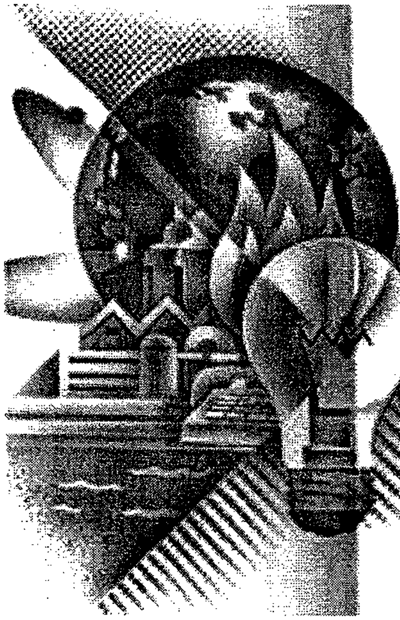

Standard & Poor's

UTILITIES & PERSPECTIVES

GLOBAL UTILITIES RATING SERVICE

STANDARD & POOR'S

"Buy Versus Build": Debt Aspects of Purchased-Power Agreements

Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery—and thus release from the payment obligation—is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. (see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002). The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity

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component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as

Table 1

ABC Utility Co. Adjustment to Capital Structure

	Original capital structure		Adjusted capital structure	
	$	%	$	%
Debt	1,400	54	1,400	48
Adjustment to debt	—	—	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

Table 2

ABC Utility Co. Adjustment to Pretax Interest Coverage

		Original pretax interest coverage		Adjusted pretax interest coverage	
Net income	120				
Income taxes	65	300		(300+33)	
Interest expense	115	115	= 2.6x	(115+33)	= 2.3x
Pretax available	300				

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