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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES AND A PRICE INCREASE OF $32.7 MILLION, OR APPROXIMATELY 15.0 PERCENT	))))))))	**CASE NO. PAC-E-11-12** **Direct Testimony of Bruce N. Williams**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-11-12

May 2011

Q. Please state your name, business address and present position with Rocky Mountain Power (the "Company"), a division of PacifiCorp.

A. My name is Bruce N. Williams. My business address is 825 NE Multnomah, Suite 1900, Portland, Oregon 97232. My present position is Vice President and Treasurer.

Qualifications

Q. Please 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 1980. I also received the Chartered Financial Analyst designation upon passing the examination during 1986. I have been employed by the Company for 25 years. My business experience has included financing of the Company's electric operations and non-utility activities, responsibility for the investment management of the Company's qualified and non-qualified retirement plan assets, 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. I am also responsible for the preparation of PacifiCorp's embedded cost of debt and preferred equity and any associated testimony related to capital structure for regulatory filings in all of PacifiCorp's state and federal jurisdictions.

Q. Please provide a summary of your testimony?

A. My testimony discusses the Company's capital structure and costs of capital. It supports the proposed common equity level of 52.3 percent and provides evidence of why that level is appropriate and demonstrates the benefits to customers, including maintaining the Company's current credit ratings which will facilitate continued access to the capital markets for the Company and over the long-term a more competitive cost of debt and overall cost of capital. This capital structure is necessary to enable the Company to continue to invest in infrastructure in order to provide safe and reliable service to our customers at reasonable costs.

Q. What is the overall cost of capital that you are proposing in this proceeding?

A. Rocky Mountain Power is proposing an overall cost of capital of 8.25 percent. This cost includes the return on equity recommendation of 10.5 percent from Dr. Samuel C. Hadaway and the following capital structure and costs:

Overall Cost of Capital

Component	Percent of Total	% Cost	Weighted Average
Long Term Debt	47.4%	5.78%	2.74%
Preferred Stock	0.3%	5.43%	0.02%
Common Stock Equity	52.3%	10.50%	5.49%
Total	100.0%	8.25%	

Financing Overview

Q. Please explain Rocky Mountain Power's need for and sources of new capital.

A. Rocky Mountain Power is in the process of adding significant new plant investments over multiple years. These investments include required pollution control equipment, generation upgrades, and transmission facilities. These investments help system reliability, improve power delivery and help to assure safe operations for the benefit of its customers.

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

A. Generally, the Company finances its regulated utility operations utilizing approximately a 50/50 percent mix of debt and common equity capital. Immediately prior to and during periods of significant capital expenditures, the Company may allow the common equity component of the capital structure to increase. This provides more flexibility regarding the type and timing of debt financing, better access to the capital markets, a more competitive cost of debt, and over the long-run, more stable credit ratings; all of which assist in financing such expenditures. In addition, all else being equal, the Company will need to have a greater common equity component to offset various adjustments that rating agencies make to the debt component of the Company's published financial statements. I will discuss these adjustments in greater detail later in this testimony.

Q. Has the Company recently begun paying dividends to MidAmerican Energy Holdings Company ("MEHC")?

A. Yes. With the passage of recent legislation enacting bonus depreciation, the Company's expected net cash flow during the next two years will increase significantly. This will reduce but not eliminate the need for new borrowings and, absent the payment of dividends, retention of earnings could cause the percentage of common equity to grow beyond the level necessary to support the current credit ratings. Consequently, dividend payments are now necessary, in combination with debt issuances, to keep the percentage of equity in the Company's capital structure in line with the level sufficient to support the Company's credit ratings. As a result, the Company has initiated the payment of dividends to MEHC to continue to manage the common equity component of the capital structure and keep the Company's overall cost of capital at a prudent level.

Q. Please explain why dividends were not paid to MEHC in the past.

A. Since the acquisition in 2006 by MEHC, the Company has managed the capital structure through the timing and amount of long-term debt issuances and capital contributions while forgoing any common dividend distributions. MEHC recognizes that the Company is in a period requiring significant capital investment which, until recently, has far exceeded the Company's ability to finance with internally generated funds. As such, MEHC allowed the Company to retain earnings totaling over $2 billion and even increased its investment in the Company by more than $1 billion in order to enable the Company to finance capital investment and help maintain the credit ratings during this period of capital spending. As I will discuss later, the maintenance of credit ratings has allowed the Company to access the capital markets when other utilities were denied access, provided a lower cost of debt and a lower overall cost of capital.

Q. Shouldn't the additional cash flow generated by the tax law changes mitigate the need for a rate increase?

A. Only to a limited extent. Bonus depreciation provides a temporary cash flow benefit to the Company in the form of accelerated tax benefits, but this cash benefit does not translate one-for-one into a reduction in revenue requirements. Income tax expense, a component of revenue requirements, generally is unchanged as a result of bonus depreciation, as the current income tax benefits received from bonus depreciation generally are fully offset by additional deferred income tax expenses. Customers receive benefits from bonus depreciation in the form of increased deferred income tax liabilities, which reduces rate base and by lower equity levels carried in the Company's capital structure than would otherwise be the case without the benefits of bonus depreciation. This capital structure with a lower equity level still produces financial results that meet the rating agency's expectations due to the improved cash flow metrics resulting from bonus depreciation.

Credit Ratings

Q. Why should this Commission be concerned about credit ratings and the views expressed by rating agencies?

A. This Commission should be concerned about credit ratings and the views of rating agencies for several reasons. First, the credit rating of a utility has a direct impact on the price that a utility pays to attract the capital necessary to support its current and future operating needs. Many institutional investors have fiduciary responsibilities to their clients, and are typically not permitted to purchase non investment grade (i.e. rated below BBB-) securities or in some cases even securities rated below a single A.

Second, credit ratings are an estimate of the probability of default by the issuer on each rated security. Lower ratings equate to higher risks and higher costs of debt. However, even investment grade rated borrowers have experienced recent problems accessing the capital markets or even been shut out entirely. The financial crisis of 2008 and 2009 provided clear and compelling evidence of the benefits of the Company's credit rating as it was able to issue new long-term debt during the midst of the financial turmoil. Other lower rated utilities were simply shut out of the market and could not obtain new capital regardless of how much they were willing to pay.

Q. Can you give the Commission examples where poor credit ratings hurt a utility's flexibility in the credit markets?

A. Yes. Arizona Public Service Company (rated at that time Baa2/BBB-) filed a letter with the Arizona Corporation Commission during October 2008 stating that the commercial paper market was completely closed to them and, they likely could not successfully issue long-term debt. See Exhibit No. 5, APS Access to Corporate Debt Markets.

Further, those issuers who could access the markets paid rates well above the levels that the Company was able to achieve. For example, Nevada Power (rated Baa3/BBB) issued new debt two days following PacifiCorp's January 2009 issuance and was required by investors to pay a coupon of 7.375% for a five year maturity. Subsequently, Puget Sound Energy (rated Baa2/A-) issued new seven year debt at a credit spread over Treasuries of 480.3 basis points resulting in a 6.75 percent coupon.

Q. How do these coupon rates compare to PacifiCorp during that period and more recently?

A. The Company completed in January 2009 an offering of $350 million of first mortgage bonds with a 10 year maturity at a coupon rate of 5.50 percent and $650 million of 30 year first mortgage bonds with a coupon of 6.00 percent. The Company was able to achieve both a longer maturity and lower cost than either of those other utilities.

More recently, the Company completed an issuance of $400 million of first mortgage bonds at a coupon rate of 3.85 percent which compares very favorably to debt issuances by similarly or higher rated utility issuers including Pacific Gas & Electric Company, The Detroit Edison Company and Southern California Edison Company. This favorable debt rate is included in the cost of debt calculation in this docket.

Further, the Company has a near constant need for short-term liquidity as well as periodic long-term debt issuances. We daily pay significant amounts to suppliers whom we count on providing necessary goods and services such as fuel and spare parts and inventory. Being unable to access funds can risk the successful completion of necessary capital infrastructure projects and would increase the chance of outages and service failures over the long-term.

The Company's creditworthiness, as reflected in its credit ratings, will strongly influence its ability to attract capital in the competitive markets and the resulting cost of that capital.

Q. Can regulatory actions or orders affect a Company's credit rating?

A. Yes, in a very significant way. Regulated utilities such as the Company are fairly unique since they unilaterally cannot set their own prices for their services. The financial integrity of a regulated utility is largely a result of how the utility is treated on cost recovery issues and the prices set by regulators. Rates are established by regulators to permit the utility to recover prudently incurred operating expenses and a reasonable opportunity to earn a fair return on the capital invested. Therefore, rate decisions by utility commissions have a direct and significant impact on the financial condition of utilities.

Rating agencies and investors have a keen understanding of the importance of regulatory outcomes. For example, Standard & Poor's writes: "(t)he assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of U.S. regulated, investor-owned utility's business risk."[1] Similarly, Moody's has stated:

> [f]or a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return.[2]

Q. How does maintenance of the Company's current credit ratings benefit customers?

A. The Company is in the midst of a period of heavy capital spending and investing in infrastructure in order to provide for the needs of customers. If the Company does not have consistent access to the capital markets at reasonable costs these borrowings and the resulting costs of building new facilities become more expensive than it otherwise would be. The inability to access financial markets can threaten the completion of these necessary projects which, in turn, will impact system reliability and customer safety. All of these resulting higher costs are ultimately borne by the customers. Maintaining the current single-A credit rating makes it more likely the Company will have access to the capital markets at

[1] Standard & Poor's Ratings Direct – Assessing U.S. Utility Regulatory Environments; March 11, 2010.
[2] Moody's Investors Service Regulated Electric and Gas Utilities; August 2009.

reasonable costs even during periods of financial turmoil. Such a rating will allow the Company continued access to the capital markets that will enable it to fulfill its capital investments for the benefit of customers.

Q. Are there other identifiable advantages to a favorable rating?

A. Yes. Higher-rated companies have greater access to the long-term markets for power purchases and sales. Such access provides these companies with more alternatives when attempting to meet the current and future load requirements of their customers. Additionally, 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 in these markets.

In my opinion, maintaining the current single-A rating provides the best balance between costs and continued access to the capital markets which is necessary to fund capital projects for the benefit of customers.

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

A. Yes. This capital structure is intended to enable the Company to deliver its required capital expenditures and achieve financial metrics which will meet rating agency expectations. S&P has stated very clearly their expectations for PacifiCorp: "we expect FFO to total debt and FFO interest coverage will be in the high teens and the 4.0x - 4.5x range, respectively. We view these cash flow levels as minimum levels to retain the rating."[3]

[3] Standard & Poor's Ratings Direct April 28, 2011.

Q. Does the Company's credit rating benefit because of MEHC and its parent Berkshire Hathaway?

A. Yes. Although ring fenced, historically, the Company's credit ratios have been weak for the ratings level and we have been able to sustain our ratings, in part through the acquisition by MEHC and its parent, Berkshire Hathaway. S&P was very clear on this point in their recent assessment of PacifiCorp in stating "....cash flows metrics remain just adequate to support the ratings." S&P further stated:

> .....the Company's funds for operations (FFO) to total debt has been consistently in the high teens, slightly below our expected credit metrics for the rating, since it was acquired by [MEHC]. Leverage has also been somewhat high for the rating at 53 percent at year-end 2009. However, we expect that credit metrics will improve in the coming years, producing FFO total debt in the area of 20 percent, FFO interest coverage ....in the range of 4.0x – 4.5x, and leverage of about 50 percent.[4]

Clearly, Rocky Mountain Power and its customers have benefited from the higher ratings the Company would otherwise not likely have been awarded on a stand-alone basis. Another important element supporting the Company's current ratings is the rating agencies' expectations that Rocky Mountain Power will receive supportive regulatory treatment including reasonable outcomes in rate proceedings, including applications to recover the full cost of large scale capital projects. Absent ownership by MEHC and constructive regulatory treatment that permits a fair opportunity for the Company to recover its reasonable and prudent expenses, including a return on its investment comparable to other similarly

[4] Standard & Poor's Rating Direct October 7, 2010.

situated utilities, PacifiCorp's senior secured and corporate credit ratings would have likely suffered at least a one rating level downgrade.

Q. Has there been any changes in the Company's credit ratings that needs clarification?

A. Yes. In March 2009, S&P upgraded PacifiCorp's senior secured debt to 'A' while it downgraded PacifiCorp's short-term debt ratings to 'A-2'. Similarly, Moody's revised PacifiCorp's senior secured debt to 'A2' from 'A3' in August 2009.

Q. Please explain these rating changes.

A. The action on PacifiCorp's senior secured debt merely reflects a change in S&P's methodology rather than a change in PacifiCorp's credit quality or financial metrics. S&P changed its approach to estimating the amount of collateral that would be available to senior secured debt holders in the event of a default by PacifiCorp on its first mortgage bonds.

S&P has been cautious about PacifiCorp credit metrics and, as noted previously, views the Company's credit metrics on a stand-alone basis as just adequate to support the ratings. Indeed, in downgrading the Company's short-term debt ratings, S&P cited a need to take a firmer view on linking PacifiCorp short-term ratings to stand-alone credit quality. S&P sustained their current 'A-' corporate credit rating based on their expectation "that management will achieve cash flow metrics more consistent with an 'A' rating over the next several years."[5]

The upgrade of the Company's senior secured debt by Moody's was part of an industry-wide action in which the majority of senior secured debt ratings of

[5] Standard & Poor's Rating Direct April 30, 2010.

investment-grade regulated utilities were upgraded by one level. The action was a result of Moody's analysis of the history of regulated utility defaults and was not specific or unique to the Company.

Q. Do S&P's recent credit reports on PacifiCorp underline S&P's expectation that PacifiCorp improve its financial metrics in order to maintain its current credit rating?

A. Yes. S&P made several references to the need for PacifiCorp to improve its stand-alone financial metrics, noting that PacifiCorp's financial risk profile reflects a large capital program and the need to shore up cash flow metrics. S&P also stated that, "[g]iven the recent turmoil in both the liquidity and capital markets, we have taken a firmer view on the need to link the PacifiCorp short-term ratings to its stand-alone quality, which supports an 'A-2' short-term rating." S&P also reiterated its credit view that, "supportive rate case outcomes remain key to maintaining and improving upon the company's financial performance." Exhibit Nos. 6, 7, 8 are the April 28, 2011, October 7, 2010, and April 30, 2010, S&P Ratings Direct publications.

Q. Do other rating agencies share S&P's view concerning the need for supportive rate case outcomes?

A. Yes. Fitch stated, "[t]he current ratings and stable outlook assume [PacifiCorp] continues to benefit from parent company support and reasonable outcomes in pending and future rate proceedings to recover anticipated, significant capital investment."[6] More recently, Fitch wrote:

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[6] Fitch Ratings – October 1, 2010.

> "Given the size of its planned capital investment, timely recovery of capital and related operating and maintenance costs is crucial for PPW's creditworthiness. Therefore, currently unanticipated adverse developments in PPW's six regulatory jurisdictions, leading to greater regulatory lag or lower recoveries, and resulting weaker coverage ratios compared with Fitch's projections could lead to future deterioration in PPW's creditworthiness and lower credit ratings."[7] Likewise Moody's lists "Reasonably supportive regulatory environment" as one of the ratings drivers. Moody's also states, "The stable outlook incorporates Moody's expectation that PacifiCorp will continue to receive reasonable regulatory treatment for the recovery of its higher capital expenditures…." Further as to what could change the rating-down; Moody's writes "…..if there were to be adverse regulatory rulings on current and future rate cases such that we would anticipate a sustained deterioration in financial metrics..."[8]

Capital Structure

Q. **How did the Company determine the capital structure proposed in this case?**

A. The test period in this proceeding is the 12 months ending December 31, 2010, with known and measurable changes through December 2011. To appropriately match the Company's costs with customer prices during the period, the capital structure is based on the actual capital structure at March 31, 2011, and forecasted capital activity, including known and measurable changes, through December 31, 2011. The Company has averaged the five quarter end capital structures measured beginning at December 31, 2010, and concluding with December 31, 2011. The capital activity includes known maturities of certain debt issues that were outstanding at December 31, 2010, subsequent issuances of long-term debt and the payment of dividends. The known and measurable changes represent actual and forecasted capital activity since March 31, 2011.

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[7] Fitch Ratings – January 6, 2011.
[8] Moody's Investor Service May 9, 2011.

Q. Why is Rocky Mountain Power using an average of five quarter ends to determine the proposed capital structure rather than simply an average of the beginning and ending points as in previous cases?

A. As the Company has grown, its capital expenditure program has increased significantly from historical levels which, in turn, have required new financings to also be much larger. These larger financings are usually more efficient due to lower transactional costs, and better received by investors who value the greater liquidity that larger financings typically offer. However, the trade-off is greater volatility in the Company's capital structure ratios, particularly at quarter-end following sizable financings. As such, the Company is proposing in this case to use a capital structure that employs an average of the five quarter ending balances spanning the test period to help smooth out this volatility. This is also the same methodology the Company used in its most recent rate case, Case No. PAC-E-10-07, and approved by the Commission.

Q. How does this capital structure compare to what in the Commission ordered the Company's most recent rate case?

A. The capital structures are compared in the table below.

Rocky Mountain Power Comparison of Capital Structures		
	Case No. PAC-E-10-07	**2011 General Rate Case**
Long-Term Debt	**47.6%**	**47.4%**
Preferred Stock	**0.3%**	**0.3%**
Common Equity	**52.1%**	**52.3%**
Totals	**100.0%**	**100.0%**

The proposed capital structure in this docket has a slightly higher common equity component than the Company's capital structure in the prior case which the

Commission accepted without adjustment.

Q. What type of debt and preferred equity securities does the Company employ in meeting its financing requirements?

A. The Company relies on a mix of first mortgage bonds, other secured debt, tax-exempt debt, and preferred stock to help meet its long-term financing requirements. These securities employ various maturities in order to provide flexibility and mitigate refinancing risks. The Company has completed the majority of its long-term financing utilizing secured first mortgage bonds issued under the Mortgage Indenture dated January 9, 1989. Exhibit No. 9 Cost of Long-Term Debt shows that, over the 12 months ended December 31, 2011, the Company is projected to have an average of approximately $5.7 billion of first mortgage bonds outstanding, with an average cost of 6.24 percent. 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 operation.

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, these entities issue securities, the Company borrows the proceeds of these issuances from the respective entities and pledges its credit quality to repay the debt in order to take advantage of the tax-exempt status of the financings. These bonds are primarily in a variable rate mode and are re-marketed, some as often as weekly. In addition to tax-exempt status, these securities take advantage of current very low short-term interest rates. On the other hand, the variable rate structure of this type of financing exposes the Company to re-marketing and interest rate risks as well as dislocations in the short-term credit markets. Hence, the Company is careful as to the total amount of this variable rate financing that it maintains in its capital structure.

During the 12 months ended December 31, 2011, PacifiCorp's tax-exempt portfolio is projected to be $738 million in principal amount with an average cost of 2.23 percent (which includes the cost of issuance and credit enhancement).

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

A. As a regulated public utility, the Company has a duty and an obligation to provide safe, adequate and reliable service to customers in its Idaho service territory while prudently balancing cost and risk. In order for Rocky Mountain Power to fulfill its service obligation, the Company is making significant capital expenditures for new plant investment, including transmission and environmental control investments on existing fossil-fired generation units. Each of these capital investments also has associated operating and maintenance costs. Through its planning process, the Company determined the amount of necessary new financing needed to support these activities and to provide financial results and credit ratings that balance the cost of capital with continued access to the financial markets.

Q. Please describe the changes to the amount of outstanding long-term debt.

A. During the 12 months ending December 31, 2011, the balance of the outstanding long-term debt will change through maturities and principal amortization totaling $586.7 million.

In addition, the Company recently completed the issuance of new long-term debt in the amount of $400 million with a coupon rate of 3.85 percent This issuance is included in the proposed capital structure and the cost is included in the cost of debt calculation.

Purchase Power Agreements

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

A. Yes. Rating agencies and financial analysts consider Purchase Power Agreements ("PPAs") to be debt-like and will impute debt and related interest when calculating financial ratios. For example, S&P will adjust the Company's published financial results and impute debt balances and interest expense resulting from PPAs when assessing creditworthiness. They do so in order to obtain a more accurate assessment of a company's financial commitments and fixed payments. Exhibit No. 10 S&P RatingsDirect May 7, 2007, is a publication by S&P detailing its view of the debt aspects of PPAs.

Q. How does this impact the Company?

A. During a recent ratings review, S&P evaluated the Company's PPAs and other related long-term commitments. Approximately $396 million of additional debt and $26 million of related interest expense were added to the Company's debt and coverage tests solely as a result of PPAs. There were also other adjustments made by S&P that resulted in a total of approximately $1 billion of debt and $78 million of interest being imputed into PacifiCorp's credit ratios.[9]

Q. How would the inclusion of this PPA related debt and these other adjustments affect the Company's capital structure as S&P reviews your credit metrics?

A. Negatively. By including the imputed debt resulting from PPAs and these other adjustments, the Company's capital structure has a lower equity component as a corollary to the higher debt component, lower coverage ratios and reduced financial flexibility than what might otherwise appear to be the case from a review of the book value capital structure. For example, if one were to add the total $1 billion amount of debt adjustments that Standard & Poor's makes to the Company's capital structure in this case, the resulting common equity percentage would decline from 52.3 percent to 48.7 percent. The 48.7 percent equity ratio falls below S&P's published expectations for PacifiCorp.

	Book Values/Ratios	Rating Agency Adjustments	Adjusted Book Values/Ratios
Long-Term Debt	$6,466 / 47.4%	$1,000	$ 7,466 / 51.0%
Preferred Stock	$41 / 0.3 %	0	$41 / 0.3 %
Common Equity	$7,129 / 52.3%	0	$ 7129 / 48.7%
Totals	$13,636 / 100.0%	$1,000	$ 14,636 / 100.0%

Financing Cost Calculations

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

[9] Standard & Poor's Rating Direct October 7, 2010.

methodology relied upon in the Company's previous rate cases in Idaho and other jurisdictions.

Q. Please explain the cost of long-term 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. Each 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. I begin by dividing the annual dividend per share by the per share net proceeds for each series of preferred stock. The resulting cost rate 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 for all issues.

The result is the Company's embedded cost of preferred stock.

Q. A portion of the securities in the Company's debt portfolio bears variable rates. What is the basis for the projected interest rates used by the Company?

A. The Company's variable rate long-term debt in this case is in the form of tax-exempt debt. Exhibit No. 11 PCRB Variable Rates shows that, on average, these securities had been trading at approximately 94 percent of the 30-day London Inter Bank Offer Rate (LIBOR) for the period January 2000 through March 2011. Therefore, the Company has applied a factor of 94 percent to the forward 30-day LIBOR rates at each future quarter-end spanning the test period and then added the respective credit enhancement and remarketing fees for each floating rate tax-exempt bond. Credit enhancement and remarketing fees are included in the interest component because these are costs which contribute directly to the interest rate on the securities and are charged to interest expense. This method is consistent with the Company's past practices when determining the cost of debt in previous Idaho general rate cases as well as the other states that regulate PacifiCorp.

Embedded Cost of Long-Term Debt

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

A. The cost of long-term debt is 5.78 percent for the period ending December 31, 2011, as shown in Exhibit No. 9, Cost of Long-Term Debt.

Embedded Cost of Preferred Stock

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

A. Exhibit No. 12, Cost of Preferred Stock, shows the embedded cost of preferred stock for the period ending December 31, 2011, to be 5.43 percent.

Q. Does this conclude your direct testimony?

A. Yes.

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Case No. PAC-E-11-12
Exhibit No. 5
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

APS Access to Commercial Paper Market

May 2011

PINNACLE WEST
CAPITAL CORPORATION

LAW DEPARTMENT

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October 17, 2008

Commissioner Kristin K. Mayes
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: Docket No. E-01345A-08-0172 (Interim Rate Motion)

Dear Commissioner Mayes:

On October 8, 2008, you filed a letter in which you requested Arizona Public Service Company ("APS" or "Company") to respond to five specific issues covering a range of subjects. Because several of these issues are germane to the Company's pending Motion for Interim Rates, the Company has chosen to submit its response in the above docket. For the convenience of the parties to this proceeding, I have attached a copy of your October 8th letter as Appendix A.

APS Access to Commercial Paper Market and *Other Credit-Related Issues*

APS first began experiencing trouble accessing the commercial paper market in August of 2007 when the sub-prime credit issues began to impact the capital markets. Access has continued to be sporadic throughout 2008, with the amount of commercial paper APS can issue often being limited even when access to the market was possible. Beginning September 17, 2008, the commercial paper market has been completely closed to APS.

As discussed during the hearing, APS had total lines of credit of $900 million. The first line of $400 million expires at the end of 2010, with a second for $500 million expiring at the end of 2011. The purpose of these lines of credit is to provide the Company with liquidity and working capital when commercial paper cannot be utilized – not fund capital expenditures.[1] Indeed, Decision No. 69947 (October 30, 2007) specifically limited the use of the $500 million line of credit to fuel/purchased power requirements and thus cannot be used to fund the Company's capital requirements. As of September 30, 2008, approximately $270 million had to be drawn down due to the problems in the commercial paper market described above. Also, $34 million of the Company's credit line was with bankrupt Lehman Brothers and thus no longer

[1] *Borrowing on bank lines of credit is normally 25 to 50 basis points more expensive than commercial paper.*

exists. Another $36 million was with Wachovia, which is in the process of being acquired by Wells Fargo. Whether the new owner of Wachovia will assume the $36 million commitment is uncertain, to say the least. Accordingly, APS's previous $900 million lines of credit are now no more than $866 million, and may be as low as $830 million. Finally, as a result of recent write-downs of bank assets, there is $2 trillion less credit capacity in the U.S. banking system than there was before this global financial crisis began. As a result, APS will likely encounter difficulty in maintaining its remaining lines of credit in the future, and there is no doubt that these lines of credit would, in any case, be insufficient to meet APS's capital expenditure needs over the next few years.

Liquidity is absolutely vital to the financial integrity of an electric utility. APS itself was contacted by each of the three rating agencies after the Lehman Brothers bankruptcy and asked about the Company's exposure to Lehman, Morgan Stanley, Merrill Lynch and Goldman Sachs, as well as its ability to count on its lines of credit given the chaos in the short-term credit markets. A recent example of the critical importance of liquidity is Constellation Energy, the parent of Baltimore Gas & Electric Company, which began 2008 with a stock price of over $100 per share. After facing a liquidity crisis driven by threatened credit rating downgrades and the resultant cash collateral calls that nearly drove Constellation to the brink of bankruptcy, it was forced to sell itself to MidAmerican Energy (the same entity that bought out PacifiCorp) for $26.50 per share.

And the damage has not been limited to the short-term debt market. Despite massive efforts by our Federal government and governments in Europe and Asia to pump liquidity into the national and international credit markets, access to the corporate debt market is extremely strained, with only the most highly-rated corporations being successful in raising long-term debt capital. At present, APS likely could not successfully issue long-term debt. Whether this financial market environment will improve by the spring of next year, when APS likely will need to issue debt, is unknown.

Geo*Smart* Solar Financing Program

On Thursday, September 25, 2008 GE Money announced that it will no longer offer unsecured installment consumer financing for its energy efficiency and renewable energy programs after October 23, 2008 because of the current turmoil in the credit markets. The action specifically affected the Electric & Gas Industries Association's ("EGIA") GEO*Smart* Financing Program offered by APS because GE Money provided the financial support for the program. Although APS had no prior warning of GE Money's actions, APS remains committed to its partnership with EGIA. EGIA, as a non-profit entity implementing similar financing programs for utilities around the country, is situated to identify other suitable financial institutions to back the Geo*Smart* program. In recent conversations, EGIA informed APS that a number of financial institutions have been identified that **may** be able to provide funding for GEO*Smart*. APS remains hopeful but cannot offer any assurance that EGIA will secure other financial backing in the future.

Transactions with Investment Banks or Similar Financial Institutions

Attached as Appendix B is a list of the banks with which APS has existing lines of credit. As noted before, Lehman Brothers and Wachovia are in that group. APS has also submitted a $1.1 million claim against Lehman Brothers in bankruptcy over a hedging transaction. APS has conducted numerous transactions with Morgan Stanley and Goldman Sachs, who together are major players in the U.S energy markets. Although it would seriously reduce the overall liquidity of these energy markets should Morgan Stanley and/or Goldman Sachs bow out of the energy market, APS itself had controls in place well before all these problems began that limited its exposure to any single trading partner, including those discussed above. However, with chaotic and unprecedented market events such as we are presently experiencing, no amount of internal controls can provide complete protection against potential losses.[2] Finally, AIG is a carrier for APS property and casualty insurance. APS believes that these insurance policies will continue to be honored.

Auction Rate Securities

APS does not have any funds invested in auction rate securities ("ARS"). APS is an issuer of ARS, with $343 million outstanding and with maturities in 2029 and 2034. The average rate of interest paid on these securities has been 3.2%, thus providing very attractive financing for APS and its customers.

Palo Verde

Palo Verde Unit 3 experienced two relatively brief unplanned outages recently. The first was from September 16 to September 20 when a failed transmitter in the control circuitry for one of the two power supplies to the reactor control rods required the unit to be shut down. That was safely accomplished, and after the electronic card that included the failed component was replaced, the unit was returned to full power without incident. The second was from September 27 to 30 when high sulfate levels were detected in the secondary steam system (the system that connects the steam generators with the steam turbine). After operators had shut down the unit, the secondary system chemistry was returned to normal, the unit again returned to service without incident and has been operating at full power since then. APS estimates that the amount of additional fuel and purchased power costs deferred for recovery through the PSA to be approximately $3 million.[3]

Neither outage involved what could be characterized as an unusual event for a nuclear power plant and is the sort of occurrence anticipated in the budgeted effective forced outage rate ("EFOR") for Palo Verde. Palo Verde, like all generators, including all APS generators, has an

[2] Although such transactions are not directly with APS, the APS decommissioning trusts and the Pinnacle West retirement funds have relatively small investments in some of the troubled entities identified in your letter, as likely do most if not all large investment funds in this country.

[3] As the Commission is aware, APS absorbs 10% of higher fuel costs, and a portion of outage costs are embedded in the base fuel cost. In addition, a small amount is allocated to wholesale customers. Thus, the total cost of the outages was $4.4 million.

anticipated EFOR based primarily on past operations. This is merely an acknowledgement that all machines, no matter how well designed, constructed, operated, and maintained, will sometimes fail. Electric generators are no exception to that rule.

To date this year, the overall Palo Verde capacity factor has been 98% (excluding refueling outages). This past summer, Palo Verde set an all-time record for generation.

Throughout both outage events, Palo Verde staff demonstrated their safety-first focus by using effective problem identification and resolution behaviors, took proper action during troubleshooting (including developing contingency plans) and work planning. They executed all needed repairs with a focus on human performance. The NRC was kept fully informed throughout these outages and monitored Palo Verde's decision-making process and the actions taken. APS does not believe these outages have had any negative impact on APS's substantial progress in resolving the NRC's Confirmatory Action Letter.

Sincerely,

Thomas L. Mumaw

Thomas L. Mumaw

Attorney for Arizona Public
Service Company

Attachments

cc: Mike Gleason, Chairman
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Jeff Hatch-Miller
Gary Pierce
Brian McNeil
Ernest Johnson
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Janet Wagner
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Appendix A

ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Commissioner

Direct Line: (602) 542-4143
Fax: (602) 542-0765
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October 8, 2008

Mr. Don Brandt
President and CEO
Arizona Public Service
400 No. Fifth Street
M.S. 9042
Phoenix, AZ 85004

Re: Impact of recent financial crisis on APS' access to commercial paper markets and ability to finance capital projects; forced cancellation of GeoSmart Solar Loan Program; transactions with investment banks; exposure to auction rate securities; status of outages at Palo Verde Nuclear Generating Station's Unit 3.

Dear Mr. Brandt:

As you know, the recent upheaval in America's financial markets has had an unsettling effect on our national and local economies. It has also had serious consequences for individuals and companies who need to access financing, as credit tightens and capital markets become less fluid.

In recognition of the current environment, I write to request that you provide the Commission with information regarding whether the unfolding events on Wall Street have had an impact on Arizona Public Service Company ("APS"), with a particular focus on several areas.

First, please tell the Commission whether APS has experienced difficulty gaining access to short or long term debt markets. In particular, have you seen a decline in the Company's ability to issue commercial paper, a practice that has become common among large utilities seeking to make payments for short term capital expenditures and operating expenses. If so, please describe the ways in which you have responded to this deficiency in order to meet the Company's capital needs. Have you experienced additional expenses associated with accessing these markets? What is the short-term and long-term impact to APS' planned capital projects?

Second, APS recently reported to my office that it was forced to scuttle its GeoSmart Solar Financing Program – the program by which APS was offering loans to customers wishing to install solar panels who could not afford to do so solely using rebates – because General Electric pulled its funding due to the credit crisis. Please detail the circumstances surrounding this program suspension and whether you believe APS will be able to re-start the program in the future. Please also inform the Commission whether any other renewable energy or other capital expenditure programs have been threatened or come under pressure as a result of the tightened credit markets, and the Company's strategy for addressing these pressures.

Third, please tell the Commission whether APS engaged in any significant financial transactions with Lehman Brothers, American International Group, Bear Stearns, or any other investment firm that has been the subject of recent bankruptcies or governmental takeovers. If so, please detail those transactions, and to what extent they have impacted the Company.

Fourth, it is my understanding that APS has had some exposure to auction rate securities. As you know, the auction rate securities market recently collapsed. Please describe the Company's auction rate securities holdings, what worth those securities now have, and what the Company intends to do with those securities in order to minimize any losses associated with them.

Finally, as you know, Palo Verde Nuclear Generating Station's ("PVNGS") Unit Three was down from September 27th to October 1st – making for a second outage in less than a month. Please tell the Commission how these Unit Three outages will impact the Company's efforts to resolve PVNGS' Category Four status with the Nuclear Regulatory Commission, as well as the estimated replacement costs that have been passed through the Company's Purchased Power and Fuel Adjustment Clause as a result of these outages.

Thank you for your attention to these questions.

Sincerely,

Kris Mayes
Commissioner

Cc: Chairman Mike Gleason
Commissioner William A. Mundell
Commissioner Jeff Hatch-Miller
Commissioner Gary Pierce
Ernest Johnson
Janice Alward
Brian McNeil
Rebecca Wilder

Appendix B

APS Revolving Lines of Credit
($K)

	Bank	Amount	% of Total
1	Bank of America	$92,857	10.3%
2	Bank of New York Mellon	80,000	8.9%
3	Citigroup	76,572	8.5%
4	JPMorgan	76,572	8.5%
5	Keybank	68,571	7.6%
6	CSFB	60,857	6.7%
7	Barclays Bank	52,857	5.9%
8	Wells Fargo	52,857	5.9%
9	UBS Warburg	52,857	5.9%
10	Union Bank	38,571	4.3%
11	Sun Trust	36,000	4.0%
12	Mizuho	28,571	3.2%
13	KBC Bank	24,000	2.7%
14	Dresdner	24,000	2.7%
15	US Bank	17,143	1.9%
16	Chang Hwa Commercial Bk	15,000	1.6%
17	BOTM	11,429	1.3%
18	Northern Trust	11,429	1.3%
19	Bank Hapoalim	10,000	1.1%
20	Subtotal	$830,143	92.3%
21	Wachovia	36,000	4.0%
22	Lehman Brothers	33,857	3.7%
23	Total	$900,000	100.0%

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UTILITIES COMMISSION

Case No. PAC-E-11-12
Exhibit No. 6
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct Rating Factors
April 28, 2011

May 2011

Rocky Mountain Power
Exhibit No. 6 Page 1 of 4
Case No. PAC-E-11-12
Witness: Bruce N. Williams

STANDARD
&POOR'S

Global Credit Portal

RatingsDirect®

April 28, 2011

Summary:

PacifiCorp

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Summary: PacifiCorp

Credit Rating: A-/Stable/A-2

Rationale

The 'A-' corporate credit ratings on PacifiCorp reflect what Standard & Poor's Ratings Services views as a "significant" financial profile and is supported by its modest use of leverage to finance a large capital program and adequate cash flow metrics. Its "excellent" business profile benefits from the geographical, market, and regulatory diversity provided by its six-state service territory. PacifiCorp is an electric utility that serves customers under the name Rocky Mountain Power in Utah, Wyoming, and Idaho, and as Pacific Power in Oregon, Washington, and California. Utah and Oregon are the most important regions for the company, providing around 42% and 24% of annual retail sales, respectively.

PacifiCorp's financial performance has held steady throughout the recession. The utility's credit metrics would have deteriorated slightly in 2010 but for the benefits of bonus depreciation, which added $700 million in deferred taxes to the company's $1.4 billion in cash flow. Beneath this benefit, authorized rate increases in Utah, Wyoming, and Idaho supported a 1% increase in gross margin, but operating revenues and operating income for the year were both down slightly, by 0.6% and 2.2%, respectively, largely due to lower wholesale volumes and margins and weaker growth in retail sales. In 2010, funds from operations (FFO) to total debt was 25%, FFO interest coverage was 5.4x, and leverage was 50%.

A key consideration in 2011 is whether resurgence in sales will occur to rekindle modest growth. Although overall 2010 retail sales revenues increased by about 1%, this growth has been led by Rocky Mountain Power (which accounted for roughly two-thirds of retail sales). Utah's population and economic growth continue to outpace the nation's. Declines have been meaningful for Pacific Power, with retail sales falling a cumulative 4.4% over 2009 and 2010 on a weather-adjusted basis. Industrial load loss has been especially significant in Oregon, but may have bottomed.

Our expectation in 2011 is that the sales growth for Rocky Mountain Power market will continue to improve. A slower, more hesitant recovery appears likely for Pacific Power sales, and we expect retail sales through 2012 there to remain below levels seen when MidAmerican Energy Holdings Co. (MEHC; BBB+/Stable) acquired PacifiCorp in March 2006. As a result, growth led by Rocky Mountain should produce financial metrics in line with past performance, with FFO to total debt in the high teens and FFO interest coverage of 4.0x-4.5x. These expectations do not reflect any additional benefits for bonus depreciation. Leverage is not forecast to change from its current level of 50% of total capitalization.

PacifiCorp is wholly owned by MEHC. In turn, MEHC is privately held and majority owned by Berkshire Hathaway (AA+/Stable/A-1+). MEHC's stated strategy when it acquired PacifiCorp was to invest significant capital to upgrade its infrastructure. Its largest project is Energy Gateway, a new, 2,000-mile high-voltage transmission line that is being constructed in segments. In the company's 2010 10-K filing, it disclosed that it expects to spend $6 billion for the project, with about $1 billion of that amount to be spent over the next three years. MEHC has demonstrated a willingness to support the utility's capital program, providing PacifiCorp with $1.1 billion equity contributions since 2006. This has allowed the company to grow without straining borrowings.

The company's consolidated earned return on equity, at 8.2%, is below authorized levels, which vary but are in the area of 10%. For the company's investment strategy to succeed, PacifiCorp's customers will be required to shoulder nearly annual increases in electric rates at a time when utility regulators around the U.S. are especially focused on holding down costs. A March ruling in Idaho, which is a small portion of PacifiCorp's franchise, reduced the company's request by $11 million to $13.8 million, noting that difficult economic conditions challenge customer ability to pay rate increases. Two large rate cases are in process in Utah and Wyoming. It has requested a $232 million increase in Utah effective September 2011 that would increase rates an average of 14% if approved as filed. Also pending is a $98 million rate case in Wyoming, representing a 17% increase, with rates also requested to go into effect in September.

Liquidity

On a stand-alone basis (i.e., unenhanced by the existing contingent equity agreement available to MEHC to support any of its regulated subsidiaries, including PacifiCorp) we view the company's liquidity as "adequate" under our corporate liquidity methodology. This methodology categorizes liquidity in five standard descriptors (exceptional, strong, adequate, less than adequate, and weak). Projected sources of liquidity, which consist of operating cash flow and available bank lines, exceed projected uses, the company's committed capital expenditures, debt maturities, and common dividends by more than 1.2x over the next 12 months. Under our criteria, we exclude as sources of liquidity any facilities expiring within one year of the liquidity assessment date. This assessment does not consider MEHC draws on its contingent equity that it could make to support PacifiCorp's projected capital requirements and debt maturities over the next two years.

As of Dec. 31, 2010, cash and cash equivalents totaled $31 million. The utility maintains unsecured credit facilities totaling nearly $1.4 billion that mature 2012-2013. (A $760 million facility decreases to $720 million in July 2011. This reduction is reflected in our liquidity calculations.) As of Dec. 31, 2010, the company had additional borrowing capacity of $1.1 billion, because of $36 million of borrowings under the facility and $304 million of liquidity reserved to support variable-rate tax-exempt bond obligations and letters of credit. There are no rating triggers on the credit lines. PacifiCorp's next substantial long-term debt maturities are $587 million due in 2011 and $261 million in 2013.

Outlook

The stable outlook on the PacifiCorp ratings incorporates our expectation that MEHC will continue to support the utility by contributing sufficient equity to manage its debt levels to 50% of total capitalization on a fully adjusted basis. We expect FFO to total debt and FFO interest coverage will be in the high teens and the 4.0x-4.5x range, respectively. We view these cash flow levels as minimum levels to maintain the rating. As in 2010, credit metrics could exceed these levels this year, depending on whether the company is able to utilize bonus depreciation benefits. We do not expect upward ratings momentum for the utility, given its heavy investment program. PacifiCorp benefits from regulatory insulation from its parent. Our criteria provide that the PacifiCorp corporate credit rating can be no more than three notches above the MEHC consolidated credit rating. The companies are a notch apart. We do not see significant risks that the utility rating will fall as a result of adverse rating changes on MEHC, which also has a stable rating outlook.

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UTILITIES COMMISSION

Case No. PAC-E-11-12
Exhibit No. 7
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct Rating Factors
October 7, 2010

May 2011

Rocky Mountain Power
Exhibit No. 7 Page 1 of 9
Case No. PAC-E-11-12
Witness: Bruce N. Williams

STANDARD & POOR'S

Global Credit Portal
RatingsDirect®

October 7, 2010

PacifiCorp

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PacifiCorp

Major Rating Factors

Corporate Credit Rating

A-/Stable/A-2

Strengths:

- Market and regulatory diversity is afforded by PacifiCorp's electric utility business, which serves portions of six western U.S. states;
- Retail electric rates compare favorably with those of other electric suppliers operating in the states PacifiCorp serves, suggesting that the company may be able to maintain its competitive advantage despite its ongoing need for rate relief to support a large capital program;
- The company has made progress in putting into place fuel and purchased power adjusters in the six states it serves (an adjuster was put into effect in Idaho in 2009, and one is pending in PacifiCorp's largest market, Utah);
- The completion of new natural gas plants, along with wind farm investment, is reducing the company's reliance on purchased power; and
- A settlement reached in February 2010 regarding the contentious Klamath hydro relicensing case has the potential to adequately address the company's financial exposure if the project is decommissioned, which will not occur before 2020.

Weaknesses:

- Despite the company's policy of filing near annual rate cases in the states PacifiCorp serves, regulatory lag continues to allow only modest improvement in the company's financial profile: Its return on equity remains under authorized levels and although leverage has improved since MidAmerican Energy Holdings Co. acquired the utility in 2006, cash flow metrics remain just adequate to support the rating;
- Regulators will need to consistently support retail rate increases to recover PacifiCorp's planned capital investments, although the recessionary environment has caused some scaling-back of capital plans; and
- Growth in the percentage of generation provided by natural gas costs mitigates some of the company's potential exposure to carbon regulation, but introduces greater potential for cost volatility.

Rationale

The 'A-' corporate credit rating on PacifiCorp (PPW) reflects its "excellent" business risk profile, evidenced by a diverse and growing service territory, and "significant" financial risk profile. PPW has made modest strides in improving regulatory outcomes which should put the company on a path to achieving cash flow coverage metrics that comfortably support the rating. The company has made progress in increasing core earnings amid a recession and a period of heavy capital spending for the company. The company has achieved this by focusing on strengthening the regulatory mechanisms that are in place in the six states it serves and working to minimize regulatory lag by filing for nearly annual rate relief in almost all states it serves.

In 2010 PPW has continued to receive revenue increases through rate case outcomes, fuel adjustments and other recovery mechanisms. Highlights of key regulatory rulings that have provided increased revenues to the company in

2010 include a Utah general rate increase beginning in February 2010 for $32 million (or a 2% increase), and a $31 million increase for the recovery of two major projects approved in June. Also in Utah, the company's largest market, the company has received approval to establish an energy cost adjustment mechanism, with the mechanism design under consideration before the Utah Public Service Commission. In January 2010, the Oregon Public Utility Commission (OPUC) approved a stipulation in the company's 2009 general rate case increasing base rates by $42 million, effective Feb. 2, 2010. In January 2010, PPW received a rate increase of $14 million, or 5%, in Washington. In March 2010, PPW filed a new general rate case in Oregon requesting an increase in the rates by $131 million, or 13% increase, and in July reached a multiparty stipulation for an increase of $85 million, or 8%. If approved by the OPUC, the rates will be effective Jan. 1, 2011.

As with many electric utilities, the company's 2008 and 2009 credit metrics have been buoyed by deferred tax increases, which boosted funds from operations metrics. But these effects notwithstanding, the company's funds from operations (FFO) to total debt has been consistently in the high teens, slightly below our expected credit metrics for the rating, since it was acquired by MidAmerican Energy Holdings Co. (MEHC; BBB+/Stable/--). Leverage has also been somewhat high for the rating at 53% at year-end 2009. However, we expect that credit metrics will improve in the coming years, producing FFO to total debt in the area of 20%, FFO interest coverage of 20% or better and in the range of 4.0x-4.5x, and leverage of about 50%. (We would note that PPW has, over the last three years, produced FFO to total debt of more than 20%, but this is due to benefits of deferred taxes.)

PPW serves 1.7 million customers in portions of six western states: Utah, Oregon, Wyoming, Washington, Idaho, and California. The company operates as Pacific Power in Oregon, Washington, and California, and as Rocky Mountain Power in Utah, Wyoming, and Idaho. The company's two largest markets, Utah and Oregon, accounted for about 67% of the company's retail electric sales in 2009, with Wyoming and Washington at 25%, and the balance being sold to customers in Idaho and California. As of Dec. 31, 2009, the utility's long-term debt was $6.4 billion.

PPW completed $2.3 billion in capital expenditures in 2009, up from $1.8 billion in 2008. The company projects that it will spend $4.6 billion in 2010-2012, excluding non-cash allowance for funds used during construction. The largest component of PPW's capital program is the construction of the Gateway transmission project, an estimated $4.6 billion, 2,000-mile transmission line connecting portions of Wyoming, Utah, Idaho, Oregon, and the southwestern U.S. The project is being completed in phases, with initial portions of new lines being placed in service as early as 2010 and a tentative completion date of 2018. About 34% of the company's total capital budget over the next three years (2010-2012) is devoted to transmission investment, of which Gateway is a component. In 2008, the Federal Energy Regulatory Commission awarded the company incentive rate treatment of 200 basis points for seven of the eight project segments.

PPW is owned by MEHC. In turn, MEHC is privately held and majority owned by Berkshire Hathaway (AA+/Stable/A-1+). MEHC has demonstrated a willingness to deploy equity to support the utility's large capital program, providing the utility with $865 million in equity contributions since it purchased the company in March 2006. Although PPW is investing heavily in its system, we expect PPW distributions to MEHC to be minimal.

MEHC's credit profile is supported by Berkshire Hathaway, which has in place through February 2011 a $3.5 billion equity commitment agreement between itself and MEHC in which MEHC can unilaterally call upon Berkshire Hathaway to support either its debt repayment or the capital needs of its regulated subsidiaries, including PPW. In March 2010, the agreement was extended through February 2014 at a lower level of $2 billion. We view this agreement between PPW's parent and a 'AA+' rated entity as reducing the likelihood of a PPW default.

Nevertheless, we expect PPW to grow into a stand-alone credit profile consistent with the 'A-' rating on the company. We take this view because the utility has no right to cause MEHC to make an equity contribution, either from MEHC or via Berkshire Hathaway through an MEHC board request. Although MEHC would typically have strong incentives to support the utility by tapping the Berkshire Hathaway contingent equity, we would note that in a catastrophic utility event, MEHC would be expected to do so only if doing so were in the parent's best economic interests. Such a scenario is remote and would require an unprecedented event such as what occurred during the western energy crisis, when regulators refused to allow utilities to recover power procurement costs.

Short-term credit factors

On a stand-alone basis (i.e., unenhanced by the existing contingent equity agreement available to MEHC to support any of its regulated subsidiaries, including PPW) we view PPW's liquidity as "strong" under our corporate liquidity methodology. This methodology categorizes liquidity in five standard descriptors (exceptional, strong, adequate, less than adequate, and weak). Projected sources of liquidity, which consist of operating cash flow and available bank lines, exceed projected uses, the company's committed capital expenditures, debt maturities, and common dividends by about 1.5x. Under our criteria, we exclude as sources of liquidity any facilities expiring within one year of the liquidity assessment date. Presuming that MEHC draws on its contingent equity to support PPW's projected capital requirements and debt maturities over the next two years, liquidity would be bolstered to more than 2x, or "exceptional."

As of June 30, 2010, PPW's cash and cash equivalents totaled $110 million. The utility maintains unsecured credit facilities totaling nearly $1.4 billion that mature 2012-2013. As of June 30, 2010, PPW had additional borrowing capacity of $1.1 billion, because $304 million of liquidity is reserved to support variable-rate tax-exempt bond obligations and letters of credit. There are no rating triggers on the credit lines. PPW's next substantial long-term debt maturities are $600 million due in 2011 and $284 million in 2013.

Outlook

The stable outlook on the PPW ratings incorporates our expectation that MEHC will continue to support the utility by contributing equity sufficient to ensure that fully adjusted debt to total capitalization is managed over the next few years to a level of closer to 50% and that FFO to total debt and FFO interest coverage will be in the area of 20% and the 4.0x-4.5x range, respectively. Given that PPW's financial risk profile is weak for the ratings, we do not expect near-term upward ratings momentum for the utility. PPW's regulatory and structural insulation shields the utility from MEHC credit deterioration, to an extent. Specifically, our criteria provide that the PPW corporate credit rating can be no more than three notches above the MEHC consolidated credit rating. The company is comfortably within this range, so we do not see significant risks that the utility rating will fall as a result of adverse rating changes on MEHC, which also has a stable rating outlook.

Table 1.

PacifiCorp -- Peer Comparison*

	PacifiCorp	Portland General Electric Co.	Pacific Gas & Electric Co.
Rating as of Sept. 22, 2010	A-/Stable/A-2	BBB/Stable/A-2	BBB+/Watch Neg/A-2

Table 1.

PacifiCorp -- Peer Comparison* (cont.)

	--Average of past three fiscal years--		
(Mil. $)			
Revenues	4,404.3	1,764.0	13,218.9
Net income from cont. oper.	479.7	109.0	1,157.7
Funds from operations (FFO)	1,342.3	326.5	3,030.0
Capital expenditures	1,850.2	511.4	3,437.7
Cash and short-term investments	134.7	38.0	175.7
Debt	6,641.7	1,875.2	12,662.8
Preferred stock	34.2	0.0	258.0
Equity	5,926.2	1,404.3	10,032.3
Debt and equity	12,567.9	3,279.5	22,695.2
Adjusted ratios			
EBIT interest coverage (x)	2.8	2.2	2.9
FFO int. cov. (x)	4.3	3.5	4.1
FFO/debt (%)	20.2	17.4	23.9
Discretionary cash flow/debt (%)	(10.5)	(14.4)	(14.1)
Net cash flow/capex (%)	72.5	51.5	71.2
Total debt/debt plus equity (%)	52.8	57.2	55.8
Return on common equity (%)	7.2	6.3	11.1
Common dividend payout ratio (unadj.) (%)	2.7	59.6	49.6

*Fully adjusted (including postretirement obligations).

Table 2.

PacifiCorp -- Financial Summary*

	--Fiscal year ended Dec. 31--				
	2009	**2008**	**2007**	**2006**	**2006**
Rating history	A-/Stable/A-2	A-/Watch Neg/A-1	A-/Stable/A-1	A-/Stable/A-1	A-/Stable/A-1
(Mil. $)					
Revenues	4,457.0	4,498.0	4,258.0	4,154.1	3,896.7
Net income from continuing operations	542.0	458.0	439.0	307.9	360.7
Funds from operations (FFO)	1,760.1	1,272.1	994.8	927.6	864.5
Capital expenditures	2,297.1	1,757.0	1,496.4	1,375.0	1,030.5
Cash and short-term investments	117.0	59.0	228.0	59.0	119.6
Debt	7,415.8	6,635.9	5,873.5	5,473.6	5,185.3
Preferred stock	20.5	41.0	41.0	41.3	41.3
Equity	6,711.5	5,987.0	5,080.0	4,426.8	3,750.7
Debt and equity	14,127.3	12,622.9	10,953.5	9,900.4	8,936.0
Adjusted ratios					
EBIT interest coverage (x)	2.7	2.8	2.8	2.5	3.0
FFO int. cov. (x)	4.9	4.2	3.5	3.8	3.8
FFO/debt (%)	23.7	19.2	16.9	16.9	16.7
Discretionary cash flow/debt (%)	(10.2)	(10.7)	(10.5)	(10.7)	(5.6)

Table 2.

PacifiCorp -- Financial Summary* (cont.)					
Net cash flow/capex (%)	76.6	72.3	66.3	66.1	66.7
Debt/debt and equity (%)	52.5	52.6	53.6	55.3	58.0
Return on common equity (%)	7.0	6.8	7.8	6.2	8.9
Common dividend payout ratio (unadj.) (%)	7.0	0.0	0.0	5.2	49.1

*Fully adjusted (including postretirement obligations).

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

--Fiscal year ended Dec. 31, 2009--

PacifiCorp reported amounts	Debt	Shareholders' equity	Operating income (before D&A)	Operating income (before D&A)	Operating income (after D&A)	Interest expense	Cash flow from operations	Cash flow from operations	Dividends paid	Capital expenditures
Reported	6,416.0	6,732.0	1,609.0	1,609.0	1,060.0	359.0	1,500.0	1,500.0	2.0	2,328.0
Standard & Poor's adjustments										
Operating leases	36.5	--	5.0	2.3	2.3	2.3	2.7	2.7	--	4.1
Intermediate hybrids reported as equity	20.5	(20.5)	--	--	--	1.0	(1.0)	(1.0)	(1.0)	--
Postretirement benefit obligations	369.9	--	20.0	20.0	20.0	5.0	33.8	33.8	--	--
Accrued interest not included in reported debt	111.0	--	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	35.0	(35.0)	(35.0)	--	(35.0)
Power purchase agreements	395.7	--	63.3	63.3	25.8	25.8	37.5	37.5	--	--
Asset retirement obligations	66.3	--	9.0	9.0	9.0	9.0	5.2	5.2	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	83.0	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	217.0	--	--
Total adjustments	999.8	(20.5)	97.3	94.6	140.2	78.2	43.1	260.1	(1.0)	(30.9)

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)* (cont.)

Standard & Poor's adjusted amounts

	Debt	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	7,415.8	6,711.5	1,706.3	1,703.6	1,200.2	437.2	1,543.1	1,760.1	1.0	2,297.1

*PacifiCorp reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of October 7, 2010)*

PacifiCorp	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB
Senior Secured (69 Issues)	A
Senior Unsecured (1 Issue)	A-
Senior Unsecured (2 Issues)	A/Developing
Corporate Credit Ratings History	
27-Mar-2009	A-/Stable/A-2
18-Sep-2008	A-/Watch Neg/A-1
22-Mar-2006	A-/Stable/A-1
06-Mar-2006	A-/Stable/A-2
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
CE Casecnan Water and Energy Co. Inc.	
Senior Secured (1 Issue)	BB+/Stable
CE Electric U.K. Funding Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+/Stable
CE Generation LLC	
Senior Secured (1 Issue)	BB+/Stable
Cordova Energy Co. LLC	
Senior Secured (1 Issue)	BB/Stable
Iowa-Illinois Gas & Electric Co.	
Senior Unsecured (5 Issues)	A-/A-2
Kern River Gas Transmission Co.	
Senior Secured (2 Issues)	A-/Stable
MidAmerican Energy Co.	
Issuer Credit Rating	A-/Stable/A-2

Ratings Detail (As Of October 7, 2010)* (cont.)	
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB+
Senior Unsecured (9 Issues)	A-
Senior Unsecured (2 Issues)	A-/A-2
MidAmerican Energy Holdings Co.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock (2 Issues)	BBB-
Senior Unsecured (8 Issues)	BBB+
MidAmerican Funding LLC	
Senior Secured (2 Issues)	BBB+
Midwest Power Systems Inc.	
Senior Unsecured (1 Issue)	A-/A-2
Northern Electric Distribution Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured (1 Issue)	A-
Northern Electric Finance PLC	
Senior Unsecured (1 Issue)	A-/Stable
Northern Electric PLC	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	A-
Northern Natural Gas Co.	
Issuer Credit Rating	A/Stable/--
Senior Unsecured (5 Issues)	A
Salton Sea Funding Corp.	
Senior Secured (2 Issues)	BBB-/Stable
Yorkshire Electricity Distribution PLC	
Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured (1 Issue)	A-
Senior Unsecured (1 Issue)	A-/Stable
Yorkshire Electricity Group PLC	
Issuer Credit Rating	BBB+/Stable/--
Yorkshire Power Group Ltd.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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UTILITIES COMMISSION

Case No. PAC-E-11-12
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 Ratings Direct Rating Factors
April 30, 2010

May 2011

STANDARD
&POOR'S

Global Credit Portal
RatingsDirect®

April 30, 2010

PacifiCorp

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PacifiCorp

Major Rating Factors

Corporate Credit Rating

A-/Stable/A-2

Strengths:

- Market and regulatory diversity afforded by PacifiCorp's electric utility business, which serves portions of six western U.S. states;
- Retail electric rates compare favorably with those of other electric suppliers operating in the states PacifiCorp serves, suggesting that the company may be able to maintain its competitive advantage despite its ongoing need for rate relief to support a large capital program;
- The company has made progress in putting into place fuel and purchased power adjusters in the six states it serves (an adjuster was put into effect in Idaho in 2009, and one is pending in PacifiCorp's largest market, Utah);
- The completion of 1,068 megawatts of new natural gas plants, along with wind farm investment, is reducing the company's reliance on purchased power; and
- A tentative resolution in the contentious Klamath hydro relicensing case has the potential to adequately address the company's financial exposure if the project is decommissioned, as is now envisioned.

Weaknesses:

- Despite recent rate relief in nearly all states PacifiCorp serves, regulatory lag continues to allow only modest improvement in the company's financial profile: Its return on equity remains under authorized levels and although leverage has improved since MidAmerican Energy Holdings Co. (MEHC) acquired it in 2006, cash flow metrics remain weak;
- Regulators will need to consistently support retail rate increases to recover PacifiCorp's planned capital investments, although the recessionary environment has caused some scaling-back of capital plans;
- Growth in the percentage of generation provided by natural gas costs mitigates some of the company's potential exposure to carbon regulation, but introduces greater potential for cost volatility.

Rationale

The 'A-' corporate credit rating (CCR) on PacifiCorp reflects its "excellent" business risk profile, evidenced by a diverse and growing service territory, and "aggressive" financial risk profile that reflects a large capital program and the need to shore up its cash flow metrics. While the ring-fenced utility's credit metrics are more consistent on a stand-alone basis with a 'BBB' category rating, Standard & Poor's Ratings Services expects that management will achieve cash flow metrics more consistent with an 'A' category rating over the next several years. PacifiCorp is owned by MidAmerican Energy Holdings Co. (MEHC; BBB+/Stable/--). In turn, MEHC is privately held and majority owned by Berkshire Hathaway (AA+/Stable/A-1+), which at year-end 2009 had an 89.5% interest in MEHC on an undiluted basis. (MEHC's remaining common equity is owned by Walter Scott [9.7%] and President and Chief Executive Officer Greg Abel [0.8%]). MEHC has demonstrated a willingness to deploy equity to support the utility's large capital program, providing the utility with $865 million in equity contributions since it purchased the company in March 2006.

MEHC's credit profile is supported by Berkshire, which has in place through February 2011 a $3.5 billion equity commitment agreement between itself and MEHC in which MEHC can unilaterally call upon Berkshire to support either its debt repayment or the capital needs of its regulated subsidiaries, including PacifiCorp. In March 2010, the agreement was amended to extend through February 2014 at a lower level of $2 billion. We view this agreement between PacifiCorp's parent and a 'AA+' rated entity as reducing the likelihood of a PacifiCorp default.

Nevertheless, we expect PacifiCorp to grow into a stand-alone credit profile consistent with the 'A-' rating on the company. We take this view because the utility has no right to cause MEHC to make an equity contribution, either from MEHC or via Berkshire through an MEHC board request. While MEHC would typically have strong incentives to support the utility by tapping the Berkshire contingent equity, we would note that in a catastrophic utility event, MEHC would be expected to do so only if doing so were in the economic best interests of the parent. Such a scenario is remote and would require an unprecedented event such as what occurred during the western energy crisis, when regulators refused to allow utilities to recover power procurement costs.

PacifiCorp serves 1.7 million customers in portions of six western states: Utah, Oregon, Wyoming, Washington, Idaho, and California. The company operates as Pacific Power in Oregon, Washington, and California, and as Rocky Mountain Power in Utah, Wyoming, and Idaho. The company's two largest markets, Utah and Oregon, accounted for about 67% of the company's retail electric sales in 2009, with Wyoming and Washington at 25%, and the balance being sold to customers in Idaho and California. As of Dec. 31, 2009, the utility's long-term debt was $6.4 billion. Consolidated long-term debt at MEHC (which includes PacifiCorp's debt) was nearly $20 billion as of the same date.

Supportive rate case outcomes remain key to maintaining and improving upon the company's financial performance. When MEHC purchased PacifiCorp in 2006 from ScottishPower, the utility had consistently been unable to earn its authorized return on equity (ROE), which varies by jurisdiction but ranges from 10% to 10.6%. Management has focused on improving its returns, with some success. In 2009, our calculations suggest that the consolidated ROE for PacifiCorp was 8.5%. Regulatory lag remains an issue for the company, although the company is permitted under state regulation to use forward test years for rate cases in Utah, Oregon, Wyoming, and California. (Idaho and Washington require historical test years.)

In 2009, several parties, interveners, and the company reached a settlement to implement fuel and purchased power adjustments, which the IPUC approved. The Utah Public Service Commission (UPSC) is considering the design of a new fuel adjuster, and the company in February 2010 filed to seek approval to defer the difference between the net power costs allowed in the company's 2009 rate case and actual costs incurred. That request is pending before the commission.

Recent general rate case activity includes the company's settlement agreement with the UPSC on Feb. 18, 2010, for a retail rate increase of $32 million, an average price increase of 2%, as compared with the original $67 million sought. In Wyoming, the company has filed a general rate case with the Wyoming Public Service Commission for an increase of as much as $71 million. Early this year, the commission in Oregon approved a stipulation agreement that includes an annual increase to $42 million, as well as three tariff riders for the collection of an additional $8 million that is associated with various cost initiatives over the course of the next three years. In Washington, the commission and PacifiCorp reached a settlement agreement for an annual increase of $14 million, or an average price increase of

5%. Pro forma rate adjustments in California were made in January 2009 to address energy cost adjustments and attrition adjustments. The company has filed a general rate case with the California Public Utilities Commission for an annual increase of $8 million that remains pending.

PacifiCorp completed $2.3 billion in capital expenditures in 2009, up from $1.8 billion in 2008. The company is projected to spend $4.6 billion in 2010-2012, excluding non-cash allowance for funds used during construction. The largest component of PacifiCorp's capital program is the construction of the Gateway transmission project, an estimated $4.6 billion, 2,000-mile transmission line connecting portions of Wyoming, Utah, Idaho, Oregon, and the southwestern U.S. The project is being completed in phases, with initial portions of new lines being placed in service as early as 2010 and a completion date scheduled for 2018. About 34% of the company's total capital budget over the next three years (2010-2012) is devoted to transmission investment, of which Gateway is a component. In 2008, the Federal Energy Regulatory Commission awarded the company incentive rate treatment of 200 basis points for seven of the eight project segments.

Lower fuel prices, decreased volume of wholesale electricity purchases, and favorable rate approvals on retail electricity sales and sales of renewable energy credits affected PacifiCorp's 2009 results. Although revenues declined slightly, by almost 1%, gross margins per megawatt-hour sold increased by almost 6%, as did the company's earnings before interest and taxes. Operating income increased about 11% due in large part to retail revenues increases provided by regulatory rate relief. For 2009, cash flows from operations rose by $508 million to $1.5 billion, but the majority of this was attributable to the deferred income taxes. In 2009, retail sales declined by 3%, while wholesale sales were approximately flat. About 30%-32% of PacifiCorp's total electric sales are to industrial customers. As a result, we had expected sales contraction to be a drag on 2009 performance, as industrial sales are more sensitive to the business cycle than is residential electric consumption. Industrial sales declined 7% in 2009.

Year-end leverage for the company was 53%, virtually unchanged year over year. Borrowing in 2009 was partially offset by $125 million of equity contribution from MEHC. These equity investments will be key to maintaining a balanced capital structure throughout the company's capital program. Debt to total capitalization reflects several adjustments we make, the largest of which include adding $395 million for power purchase obligations and $370 million for post-retirement obligations. We expect that PacifiCorp will not be in a position to make distributions to its parent while it is executing its capital program and that MEHC will manage PacifiCorp's debt leverage downward to the 50% area in the next several years.

Short-term credit factors

The company's liquidity position is strong. The PacifiCorp 'A-2' short-term rating reflects that although the contingent equity agreement between MEHC and Berkshire supports MEHC and its subsidiaries, the agreement is not a source of instantaneous liquidity. The agreement allows Berkshire up to 180 days to fund a request by MEHC. Given the recent turmoil in both the liquidity and capital markets, we have taken a firmer view on the need to link the PacifiCorp short-term ratings to its stand-alone credit quality, which supports an 'A-2' short-term rating. However, we note that although Berkshire contractually has up to six months to respond to an MEHC call for liquidity, it has strong economic incentives to do so.

PacifiCorp's cash and cash equivalents totaled $117 million as of Dec. 31, 2009. In addition, the company has $1.395 billion in unsecured revolving credit structured in two separate agreements: an $800 million line expiring July 2013 and a $700 million line extending through October 2012. The company had letters of credit in place for $258 million, leaving $1.137 billion available under its revolving facilities.

Outlook

The stable outlook on the PacifiCorp ratings incorporates our expectation that MEHC will continue to support the utility by contributing equity sufficient to ensure that our fully adjusted debt to total capitalization is managed over the next few years to an adjusted level of closer to 50% and that FFO to total debt and FFO interest coverage will be 20% or better and in the range of 4.0x-4.5x, respectively. Given that PacifiCorp's financial risk profile is weak for the current ratings, we do not expect near-term upward ratings momentum for the utility. PacifiCorp's regulatory and structural insulation shields the utility from some MEHC credit deterioration, to an extent. Specifically, our criteria provide that the PacifiCorp CCR can be no more than three notches above the MEHC consolidated credit rating. The company is comfortably within this range, so we do not see significant prospects for the utility rating to fall as a result of adverse rating changes on MEHC, which also enjoys a stable outlook.

Table 1.

PacifiCorp -- Peer Comparison*

	PacifiCorp	Portland General Electric Co.	Pacific Gas & Electric Co.
Rating as of April 28, 2010	A-/Stable/A-2	BBB/Stable/A-2	BBB+/Stable/A-2
	--Average of past three fiscal years--		
(Mil. $)			
Revenues	4,404.3	1,764.0	13,218.9
Net income from cont. oper.	479.7	109.0	1,157.7
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Debt	6,641.7	1,875.2	12,662.8
Equity	5,926.2	1,404.3	10,032.3
Adjusted ratios			
Oper. income (bef. D&A)/revenues (%)	35.8	25.9	29.3
EBIT interest coverage (x)	2.8	2.2	2.9
EBITDA interest coverage (x)	4.0	3.8	4.4
Return on capital (%)	8.0	7.6	10.2
FFO/debt (%)	20.2	17.4	23.9
Debt/EBITDA (x)	4.2	4.1	3.3

*Fully adjusted (including postretirement obligations).

Table 2.

PacifiCorp -- Financial Summary*

	--Fiscal year ended Mar. 31--				
	2009	2008	2007	2006	2006
Rating history	A-/Stable/A-2	A-/Stable/A-1	A-/Stable/A-1	A-/Stable/A-1	A-/Stable/A-1
(Mil. $)					
Revenues	4,457.0	4,498.0	4,258.0	4,154.1	3,896.7
Net income from continuing operations	542.0	458.0	439.0	307.9	360.7
Funds from operations (FFO)	1,760.1	1,272.1	994.8	927.6	864.5
Capital expenditures	2,297.1	1,757.0	1,496.4	1,375.0	1,030.5
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Equity	6,711.5	5,987.0	5,080.0	4,426.8	3,750.7
Debt and equity	14,127.3	12,622.9	10,953.5	9,900.4	8,936.0
Adjusted ratios					
EBIT interest coverage (x)	2.7	2.8	2.8	2.5	3.0
FFO int. cov. (x)	4.9	4.2	3.5	3.8	3.8
FFO/debt (%)	23.7	19.2	16.9	16.9	16.7
Discretionary cash flow/debt (%)	(10.2)	(10.7)	(10.5)	(10.7)	(5.6)
Net cash flow/capex (%)	76.6	72.3	66.3	66.1	66.7
Debt/debt and equity (%)	52.5	52.6	53.6	55.3	58.0
Return on common equity (%)	7.0	6.8	7.8	6.2	8.9
Common dividend payout ratio (unadj.) (%)	7.0	0.0	0.0	5.2	49.1

*Fully adjusted (including postretirement obligations).

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2009--									
PacifiCorp reported amounts										
	Debt	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	6,416.0	6,732.0	1,609.0	1,609.0	1,060.0	359.0	1,500.0	1,500.0	2.0	2,328.0
Standard & Poor's adjustments										
Operating leases	36.5	--	5.0	2.3	2.3	2.3	2.7	2.7	--	4.1
Intermediate hybrids reported as equity	20.5	(20.5)	--	--	--	1.0	(1.0)	(1.0)	(1.0)	--
Postretirement benefit obligations	369.9	--	20.0	20.0	20.0	5.0	33.8	33.8	--	--
Accrued interest not included in reported debt	111.0	--	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	35.0	(35.0)	(35.0)	--	(35.0)
Power purchase agreements	395.7	--	63.3	63.3	25.8	25.8	37.5	37.5	--	--
Asset retirement obligations	66.3	--	9.0	9.0	9.0	9.0	5.2	5.2	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	83.0	--	--	--	--	--

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)* (cont.)

Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	217.0	--	--
Total adjustments	999.8	(20.5)	97.3	94.6	140.2	78.2	43.1	260.1	(1.0)	(30.9)

Standard & Poor's adjusted amounts

	Debt	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	7,415.8	6,711.5	1,706.3	1,703.6	1,200.2	437.2	1,543.1	1,760.1	1.0	2,297.1

*PacifiCorp reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of April 30, 2010)*

PacifiCorp	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB
Senior Secured (70 Issues)	A
Senior Unsecured (1 Issue)	A-
Senior Unsecured (3 Issues)	A-/A-2
Senior Unsecured (2 Issues)	A/Developing
Corporate Credit Ratings History	
27-Mar-2009	A-/Stable/A-2
18-Sep-2008	A-/Watch Neg/A-1
22-Mar-2006	A-/Stable/A-1
06-Mar-2006	A-/Stable/A-2
25-May-2005	A-/Watch Neg/A-2
Business Risk Profile	Excellent
Financial Risk Profile	Aggressive
Related Entities	
CE Casecnan Water and Energy Co. Inc.	
Senior Secured (1 Issue)	BB-/Stable
CE Electric U.K. Funding Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+/Stable
CE Generation LLC	
Senior Secured (1 Issue)	BB+/Stable
Cordova Energy Co. LLC	
Senior Secured (1 Issue)	BB/Stable

Ratings Detail (As Of April 30, 2010)*(cont.)	
Iowa-Illinois Gas & Electric Co.	
Senior Unsecured (5 Issues)	A-/A-2
Kern River Gas Transmission Co.	
Senior Secured (2 Issues)	A-/Stable
MidAmerican Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB+
Senior Unsecured (9 Issues)	A-
Senior Unsecured (2 Issues)	A-/A-2
MidAmerican Energy Holdings Co.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock (2 Issues)	BBB-
Senior Unsecured (8 Issues)	BBB+
MidAmerican Funding LLC	
Senior Secured (2 Issues)	BBB+
Midwest Power Systems Inc.	
Senior Unsecured (1 Issue)	A-/A-2
Northern Electric Distribution Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured (1 Issue)	A-
Northern Electric Finance PLC	
Senior Unsecured (1 Issue)	A-/Stable
Northern Electric PLC	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	A-
Northern Natural Gas Co.	
Issuer Credit Rating	A/Stable/--
Senior Unsecured (5 Issues)	A
Salton Sea Funding Corp.	
Senior Secured (3 Issues)	BBB-/Stable
Utah Power & Light Co.	
Senior Secured (1 Issue)	AAA/Negative
Yorkshire Electricity Distribution PLC	
Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured (1 Issue)	A-
Senior Unsecured (1 Issue)	A-/Stable
Yorkshire Electricity Group PLC	
Issuer Credit Rating	BBB+/Stable/--
Yorkshire Power Group Ltd.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard

Ratings Detail (As Of April 30, 2010)* (cont.)

& Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

RECEIVED
2011 MAY 27 AM 10: 55
IDAHO PUBLIC
UTILITIES COMMISSION

Case No. PAC-E-11-12
Exhibit No. 9
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Cost of Long Term Debt

May 2011

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Summary
Fiscal Year Ending December 31, 2011

LINE NO.	DESCRIPTION	AVERAGE AMOUNT OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	LINE NO.
1										1
2	**Total First Mortgage Bonds**	**$5,727,433,800**	**($60,370,260)**	**($32,095,620)**	**$5,634,967,920**	**$357,588,500**	**6.086%**	**6.243%**	**23.2**	2
3										3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$400,470,000	($10,560,810)	($9,550,194)	$380,358,996	$11,338,285	2.541%	2.831%	28.0	4
5	Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,294,232)	($7,621,229)	$325,984,539	$5,100,115	1.346%	1.509%	27.8	5
6	**Total Pollution Control Revenue Bonds**	**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**	**$16,438,400**	**1.994%**	**2.226%**	**27.9**	6
7										7
8	**Total Cost of Long Term Debt**	**$6,465,803,800**	**($75,225,302)**	**($49,267,043)**	**$6,341,311,455**	**$374,026,900**	**5.618%**	**5.785%**	**23.8**	8
9										9
10	***average of the 5 quarter-ending balances spanning the fiscal year**									10
11										11

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail
Fiscal Year Ending December 31, 2011

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT AVERAGE 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)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1														1
2		**First Mortgage Bonds**												2
3	7.978%	C-U Series due thru Oct 2011	04/15/92	10/01/11	19	$4,422,000	$329,600	$0	$0	$329,600	$100.000	7.977%	$26,292	3
4	8.493%	C-U Series due thru Oct 2012	04/15/92	10/01/12	20	$19,772,000	$3,245,400	$0	$0	$3,245,400	$100.000	8.492%	$275,599	4
5	8.797%	C-U Series due thru Oct 2013	04/15/92	10/01/13	20	$16,203,000	$3,987,400	$0	$0	$3,987,400	$100.000	8.796%	$350,732	5
6	8.734%	C-U Series due thru Oct 2014	04/15/92	10/01/14	21	$28,218,000	$8,892,600	$0	$0	$8,892,600	$100.000	8.733%	$776,591	6
7	8.294%	C-U Series due thru Oct 2015	04/15/92	10/01/15	21	$46,946,000	$17,310,800	$0	$0	$17,310,800	$100.000	8.293%	$1,435,585	7
8	8.635%	C-U Series due thru Oct 2016	04/15/92	10/01/16	22	$18,750,000	$8,094,800	$0	$0	$8,094,800	$100.000	8.634%	$698,905	8
9	8.470%	C-U Series due thru Oct 2017	04/15/92	10/01/17	22	$19,609,000	$9,373,200	$0	$0	$9,373,200	$100.000	8.469%	$793,816	9
10	**8.506%**	**Subtotal - Amortizing FMBs**			**21**		**$51,233,800**	**$0**	**$0**	**$51,233,800**		**8.505%**	**$4,357,520**	10
11														11
12	6.900%	Series due Nov 2011	11/21/01	11/15/11	10	$500,000,000	$400,000,000	($4,271,080)	$0	$395,728,920	$98.932	7.051%	$28,204,000	12
13	5.450%	Series due Sep 2013	09/08/03	09/15/13	10	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	$96.189	5.960%	$11,920,000	13
14	4.950%	Series due Aug 2014	08/24/04	08/15/14	10	$200,000,000	$200,000,000	($2,170,365)	$0	$197,829,635	$98.915	5.090%	$10,180,000	14
15	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	15
16	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	16
17	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	17
18	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	$350,000,000	$350,000,000	($4,048,881)	$0	$345,951,119	$98.843	6.185%	$21,647,500	18
19	5.750%	Series due Apr 2037	03/14/07	04/01/37	30	$600,000,000	$600,000,000	($613,216)	$0	$599,386,784	$99.898	5.757%	$34,542,000	19
20	6.250%	Series due Oct 2037	10/03/07	10/15/37	30	$600,000,000	$600,000,000	($5,877,281)	$0	$594,122,719	$99.020	6.323%	$37,938,000	20
21	5.650%	Series due Jul 2018	07/17/08	07/15/18	10	$500,000,000	$500,000,000	($3,972,221)	$0	$496,027,779	$99.206	5.756%	$28,780,000	21
22	6.350%	Series due Jul 2038	07/17/08	07/15/38	30	$300,000,000	$300,000,000	($3,961,333)	$0	$296,038,667	$98.680	6.450%	$19,350,000	22
23	5.500%	Series due Jan 2019	01/08/09	01/15/19	10	$350,000,000	$350,000,000	($4,808,293)	$0	$345,191,707	$98.626	5.682%	$19,887,000	23
24	6.000%	Series due Jan 2039	01/08/09	01/15/39	30	$650,000,000	$650,000,000	($12,309,687)	$0	$637,690,313	$98.106	6.139%	$39,903,500	24
25	3.850%	Series due Jun 2021	05/12/11	06/15/21	10	$400,000,000	$240,000,000	($2,351,400)	$0	$237,648,600	$99.020	3.968%	$9,523,200	25
26	**5.919%**	**Subtotal - Bullet FMBs**			**23**		**$5,190,000,000**	**($56,346,111)**	**($7,263,815)**	**$5,126,390,074**		**6.038%**	**$313,391,200**	26
27														27
28	9.150%	Series C due Aug 2011	08/09/91	08/09/11	20	$8,000,000	$4,800,000	($45,196)	$0	$4,754,804	$99.058	9.254%	$444,192	28
29	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	$20,000,000	$12,000,000	($79,271)	$0	$11,920,729	$99.339	9.021%	$1,082,520	29
30	8.920%	Series C due Sep 2011	08/16/91	09/01/11	20	$20,000,000	$12,000,000	($112,991)	$0	$11,887,009	$99.058	9.022%	$1,082,640	30
31	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	$25,000,000	$15,000,000	($105,239)	$0	$14,894,761	$99.298	9.026%	$1,353,900	31
32	8.290%	Series C due Dec 2011	12/31/91	12/30/11	20	$3,000,000	$2,400,000	($18,432)	($328,627)	$2,052,940	$85.539	9.972%	$239,328	32
33	8.260%	Series C due Jan 2012	01/09/92	01/10/12	20	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	$85.542	9.938%	$99,380	33
34	8.280%	Series C due Jan 2012	01/10/92	01/10/12	20	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	$85.642	9.947%	$198,940	34
35	8.250%	Series C due Feb 2012	01/15/92	02/01/12	20	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	$85.542	9.924%	$297,720	35
36	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	$85.539	10.066%	$1,509,900	36
37	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	$85.539	9.889%	$494,450	37
38	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	$85.642	9.745%	$487,250	38
39	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	$85.542	9.768%	$390,720	39
40	**8.698%**	**Subtotal - Series C MTNs**			**24**		**$81,200,000**	**($622,460)**	**($5,121,111)**	**$75,456,429**		**9.459%**	**$7,680,940**	40
41														41
42	8.130%	Series E due Jan 2013	01/20/93	01/22/13	20	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	$92.525	8.939%	$893,900	42
43	8.050%	Series E due Sep 2022	09/18/92	09/18/22	30	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	$87.820	9.258%	$1,388,700	43
44	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	$87.820	9.280%	$742,400	44
45	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	$87.820	9.325%	$1,119,000	45
46	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	$87.820	9.336%	$4,668,000	46
47	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	$87.820	9.258%	$925,800	47
48	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	$90.953	8.953%	$2,238,250	48
49	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	$87.895	9.283%	$2,413,580	49
50	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	$99.056	8.316%	$332,640	50
51	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	$92.525	8.951%	$447,550	51
52	**8.100%**	**Subtotal - Series E MTNs**			**29**		**$165,000,000**	**($1,303,552)**	**($16,835,712)**	**$146,860,736**		**9.194%**	**$15,169,820**	52
53														53

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail
Fiscal Year Ending December 31, 2011

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT AVERAGE 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)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
54	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	$93.730	7.804%	$858,440	54
55	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	$93.730	7.804%	$2,107,080	55
56	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	$97.294	7.457%	$1,118,550	56
57	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	$97.294	7.467%	$2,240,100	57
58	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.810%	$136,200	58
59	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.780%	$135,600	59
60	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	$98.552	6.865%	$343,250	60
61	6.750%	Series F due Oct 2023	10/23/93	10/26/23	30	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	61
62	6.750%	Series F due Oct 2023	10/23/93	10/26/23	30	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	62
63	6.750%	Series F due Oct 2023	10/23/93	10/26/23	30	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	63
64	**7.044%**	**Subtotal - Series F MTNs**			**30**		**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**		**7.291%**	**$10,208,020**	64
65														65
66	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	$99.096	6.781%	$6,781,000	66
67	**6.710%**	**Subtotal - Series G MTNs**			**30**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	67
68														68
69	**6.086%**	**Total First Mortgage Bonds**			**23**		**$5,727,433,800**	**($60,370,260)**	**($32,095,620)**	**$5,634,967,920**		**6.243%**	**$357,588,500**	69
70														70
71		**Pollution Control Revenue Bonds**												71
72	1.252%	Moffat 94 due May 2013	11/17/94	05/01/13	18	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	$97.666	1.396%	$567,544	72
73	4.002%	Converse 88 due Jan 2014	01/14/88	01/01/14	26	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	$95.672	4.279%	$727,430	73
74	4.002%	Sweetwater 84 due Dec 2014	12/12/84	12/01/14	30	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	$98.481	4.091%	$613,650	74
75	1.357%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	$92.555	1.724%	$775,800	75
76	4.229%	Forsyth 86 due Dec 2016	12/29/86	12/01/16	30	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	$96.414	4.446%	$377,910	76
77	5.745%	Lincoln 93 due Nov 2021	11/01/93	11/01/21	28	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	$89.869	6.536%	$542,488	77
78	5.770%	Emery 93A due Nov 2023	11/01/93	11/01/23	30	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	$90.394	6.500%	$3,022,500	78
79	5.745%	Emery 93B due Nov 2023	11/01/93	11/01/23	30	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	$88.813	6.604%	$1,083,056	79
80	1.155%	Carbon 94 due Nov 2024	11/17/94	11/01/24	30	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	$97.169	1.268%	$118,748	80
81	1.173%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	$96.385	1.319%	$108,026	81
82	1.230%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	$95.736	1.405%	$1,713,257	82
83	1.281%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	$96.651	1.418%	$213,551	83
84	1.134%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	$97.183	1.247%	$265,112	84
85	4.231%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	$97.509	4.381%	$232,193	85
86	4.330%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	$22,000,000	$22,000,000	($404,262)	$0	$21,595,738	$98.162	4.441%	$977,020	86
87	**2.541%**	**Subtotal - Secured PCRBs**			**28**		**$400,470,000**	**($10,560,810)**	**($9,550,194)**	**$380,358,996**		**2.831%**	**$11,338,285**	87
88														88
89	1.128%	Sweetwater 88B due Jan 2014	01/14/88	01/01/14	26	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	$95.852	1.317%	$151,455	89
90	1.124%	Sweetwater 90A due Jul 2015	07/25/90	07/01/15	25	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	$97.920	1.221%	$854,700	90
91	1.142%	Emery 91 due Jul 2015	05/23/91	07/01/15	24	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	$92.353	1.522%	$684,900	91
92	1.181%	Sweetwater 88A due Jan 2017	01/14/88	01/01/17	29	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	$97.391	1.290%	$645,000	92
93	1.140%	Forsyth 88 due Jan 2018	01/14/88	01/01/18	30	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	$96.903	1.264%	$568,800	93
94	1.138%	Gillette 88 due Jan 2018	01/14/88	01/01/18	30	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	$96.704	1.270%	$523,240	94
95	1.280%	Converse 92 due Dec 2020	09/29/92	12/01/20	28	$22,485,000	$22,485,000	($242,164)	($303,303)	$21,939,533	$97.574	1.384%	$311,192	95
96	1.282%	Sweetwater 92A due Dec 2020	09/29/92	12/01/20	28	$9,335,000	$9,335,000	($167,524)	($134,094)	$9,033,382	$96.769	1.421%	$132,650	96
97	1.282%	Sweetwater 92B due Dec 2020	09/29/92	12/01/20	28	$6,305,000	$6,305,000	($151,908)	($97,735)	$6,055,357	$96.041	1.453%	$91,612	97
98	1.134%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	$97.322	1.241%	$302,804	98
99	6.150%	Emery 96 due Sep 2030	09/24/96	09/30/30	34	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	$94.201	6.578%	$833,762	99
100	**1.346%**	**Subtotal - Unsecured PCRBs**			**28**		**$337,900,000**	**($4,294,232)**	**($7,621,229)**	**$325,984,539**		**1.509%**	**$5,100,115**	100
101														101
102	**1.994%**	**Total PCRB Obligations**			**28**		**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**		**2.226%**	**$16,438,400**	102
103														103
104	**5.618%**	**Total Long-Term Debt**			**24**		**$6,465,803,800**	**($75,225,302)**	**($49,267,043)**	**$6,341,311,455**		**5.785%**	**$374,026,900**	104
105														105

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Case No. PAC-E-11-12
Exhibit No. 10
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct Rating Factors
May 7, 2007

May 2011

STANDARD & POOR'S

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May 7, 2007

Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

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Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	**Assumption**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Thereafter**
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity.

Rocky Mountain Power
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Witness: Bruce N. Williams

We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

PCRB Variable Rates

May 2011

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2011

	30 Day LIBOR Daily Ave (a)	Floating Rate PCRBs Daily Ave (b)	PCRB / LIBOR (b)/(a)
Jan-00	5.81%	3.33%	57%
Feb-00	5.89%	3.62%	62%
Mar-00	6.05%	3.68%	61%
Apr-00	6.16%	4.02%	65%
May-00	6.54%	4.89%	75%
Jun-00	6.65%	4.35%	65%
Jul-00	6.63%	3.99%	60%
Aug-00	6.62%	4.09%	62%
Sep-00	6.62%	4.50%	68%
Oct-00	6.62%	4.36%	66%
Nov-00	6.63%	4.33%	65%
Dec-00	6.68%	4.14%	62%
Jan-01	5.88%	3.10%	53%
Feb-01	5.53%	3.59%	65%
Mar-01	5.13%	3.18%	62%
Apr-01	4.82%	3.72%	77%
May-01	4.16%	3.38%	81%
Jun-01	3.92%	3.03%	77%
Jul-01	3.82%	2.65%	69%
Aug-01	3.64%	2.36%	65%
Sep-01	3.17%	2.42%	76%
Oct-01	2.48%	2.18%	88%
Nov-01	2.13%	1.79%	84%
Dec-01	1.96%	1.64%	84%
Jan-02	1.81%	1.49%	82%
Feb-02	1.85%	1.39%	75%
Mar-02	1.89%	1.46%	77%
Apr-02	1.86%	1.58%	85%
May-02	1.84%	1.67%	91%
Jun-02	1.84%	1.58%	86%
Jul-02	1.83%	1.49%	81%
Aug-02	1.80%	1.49%	83%
Sep-02	1.82%	1.69%	93%
Oct-02	1.81%	1.84%	102%
Nov-02	1.44%	1.66%	115%
Dec-02	1.42%	1.57%	110%
Jan-03	1.36%	1.40%	103%
Feb-03	1.34%	1.43%	107%
Mar-03	1.31%	1.45%	111%
Apr-03	1.31%	1.52%	115%
May-03	1.31%	1.56%	119%
Jun-03	1.16%	1.38%	119%
Jul-03	1.11%	1.12%	102%
Aug-03	1.11%	1.16%	104%
Sep-03	1.12%	1.24%	111%
Oct-03	1.12%	1.24%	111%
Nov-03	1.13%	1.36%	121%
Dec-03	1.15%	1.32%	114%
Jan-04	1.11%	1.21%	110%
Feb-04	1.10%	1.17%	107%
Mar-04	1.09%	1.20%	110%
Apr-04	1.10%	1.27%	115%
May-04	1.10%	1.29%	117%
Jun-04	1.25%	1.28%	102%
Jul-04	1.41%	1.26%	89%

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2011

	30 Day LIBOR Daily Ave (a)	Floating Rate PCRBs Daily Ave (b)	PCRB / LIBOR (b)/(a)
Aug-04	1.60%	1.40%	88%
Sep-04	1.78%	1.49%	83%
Oct-04	1.90%	1.72%	91%
Nov-04	2.19%	1.65%	75%
Dec-04	2.39%	1.67%	70%
Jan-05	2.49%	1.78%	72%
Feb-05	2.61%	1.88%	72%
Mar-05	2.81%	1.95%	69%
Apr-05	2.97%	2.50%	84%
May-05	3.09%	2.93%	95%
Jun-05	3.25%	2.39%	74%
Jul-05	3.43%	2.28%	67%
Aug-05	3.69%	2.44%	66%
Sep-05	3.78%	2.55%	68%
Oct-05	3.99%	2.66%	67%
Nov-05	4.15%	2.93%	71%
Dec-05	4.36%	3.10%	71%
Jan-06	4.48%	3.02%	67%
Feb-06	4.58%	3.13%	68%
Mar-06	4.76%	3.11%	65%
Apr-06	4.92%	3.45%	70%
May-06	5.08%	3.52%	69%
Jun-06	5.24%	3.74%	71%
Jul-06	5.37%	3.60%	67%
Aug-06	5.35%	3.53%	66%
Sep-06	5.33%	3.61%	68%
Oct-06	5.32%	3.57%	67%
Nov-06	5.32%	3.62%	68%
Dec-06	5.35%	3.70%	69%
Jan-07	5.32%	3.64%	68%
Feb-07	5.32%	3.63%	68%
Mar-07	5.32%	3.64%	68%
Apr-07	5.32%	3.79%	71%
May-07	5.32%	3.90%	73%
Jun-07	5.32%	3.76%	71%
Jul-07	5.32%	3.66%	69%
Aug-07	5.52%	3.76%	68%
Sep-07	5.48%	3.84%	70%
Oct-07	4.98%	3.56%	72%
Nov-07	4.75%	3.53%	74%
Dec-07	5.00%	3.25%	65%
Jan-08	3.95%	3.02%	76%
Feb-08	3.14%	2.86%	91%
Mar-08	2.80%	3.79%	135%
Apr-08	2.79%	2.23%	80%
May-08	2.63%	1.93%	73%
Jun-08	2.47%	2.77%	112%
Jul-08	2.46%	4.12%	168%
Aug-08	2.47%	3.03%	123%
Sep-08	2.94%	4.57%	155%
Oct-08	3.87%	4.89%	126%
Nov-08	1.68%	2.34%	139%
Dec-08	1.01%	1.02%	101%
Jan-09	0.39%	0.70%	181%
Feb-09	0.46%	0.68%	147%

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2011

	30 Day LIBOR Daily Ave (a)	Floating Rate PCRBs Daily Ave (b)	PCRB / LIBOR (b)/(a)
Mar-09	0.53%	0.66%	124%
Apr-09	0.45%	0.63%	140%
May-09	0.35%	0.53%	153%
Jun-09	0.32%	0.45%	143%
Jul-09	0.29%	0.41%	142%
Aug-09	0.27%	0.43%	158%
Sep-09	0.25%	0.40%	161%
Oct-09	0.24%	0.39%	159%
Nov-09	0.24%	0.37%	157%
Dec-09	0.23%	0.38%	165%
Jan-10	0.23%	0.32%	138%
Feb-10	0.23%	0.32%	137%
Mar-10	0.24%	0.32%	135%
Apr-10	0.26%	0.35%	134%
May-10	0.33%	0.34%	101%
Jun-10	0.35%	0.33%	93%
Jul-10	0.33%	0.30%	90%
Aug-10	0.27%	0.31%	115%
Sep-10	0.26%	0.31%	119%
Oct-10	0.26%	0.27%	106%
Nov-10	0.25%	0.27%	107%
Dec-10	0.26%	0.29%	110%
Jan-11	0.26%	0.26%	100%
Feb-11	0.26%	0.26%	98%
Mar-11	0.25%	0.24%	96%
Average			94%

	Forward 30 Day LIBOR* (1)	Historical Floating Rate PCRB / 30 Day LIBOR (2)	Forecast Floating Rate PCRB (1) * (2)
6/30/2011	0.48%	94%	0.45%
9/30/2011	0.82%	94%	0.77%
12/31/2011	1.16%	94%	1.09%

* Source: Bloomberg L.P. (3/31/11)

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ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Cost of Preferred Stock

May 2011

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PACIFICORP
Electric Operations
Cost of Preferred Stock
Fiscal Year Ending December 31, 2011

Line No.	Description of Issue (1)	Issuance Date (2)	Call Price (3)	Annual Dividend Rate (4)	Shares O/S (5)	Total Par or Stated Value O/S (6)	Net Premium & (Expense) (7)	Net Proceeds to Company (8)	% of Gross Proceeds (9)	Cost of Money (10)	Annual Cost (11)	Line No.
1	**5% Preferred Stock, $100 Par Value**	(a)	110.00%	5.000%	126,243	$12,624,300	($98,049)	$12,526,251	99.223%	5.039%	$636,156	1
2												2
3	**Serial Preferred, $100 Par Value**											3
4	4.52% Series	Oct-55	103.50%	4.520%	2,065	$206,500	($9,676)	$196,824	95.314%	4.742%	$9,793	4
5	7.00% Series	(b)	None	7.000%	18,046	$1,804,600	(c)	$1,804,600	100.000%	7.000%	$126,322	5
6	6.00% Series	(b)	None	6.000%	5,930	$593,000	(c)	$593,000	100.000%	6.000%	$35,580	6
7	5.00% Series	(b)	100.00%	5.000%	41,908	$4,190,800	(c)	$4,190,800	100.000%	5.000%	$209,540	7
8	5.40% Series	(b)	101.00%	5.400%	65,959	$6,595,900	(c)	$6,595,900	100.000%	5.400%	$356,179	8
9	4.72% Series	Aug-63	103.50%	4.720%	65,854	$6,585,400	($28,596)	$6,556,804	99.566%	4.741%	$312,186	9
10	4.56% Series	Feb-65	102.34%	4.560%	81,326	$8,132,600	($47,177)	$8,085,423	99.420%	4.587%	$373,010	10
11												11
12		May-95	(d)								$67,955	12
13		Oct-95	(e)								$84,019	13
14												14
15	**Total Cost of Preferred Stock**			5.032%	407,331	$40,733,100	($183,498)	$40,549,602		5.427%	$2,210,740	15
16												16
17												17

18 (a) Issue replaced 6% and 7% preferred stock of Pacific Power & Light Company and Northwestern Electric Company
19 and 5% preferred stock of Mountain States Power Company, most of which sold in the 1920's and 1930's.
20 (b) These issues replaced an issue of The California Oregon Power Company as a result of the merger of that Company into Pacific Power & Light Co.
21 (c) Original issue expense/premium has been fully amortized or expensed
22 (d) Column 11 is the after-tax annual amortization of expenses related to the 8.375% QUIDS due 6/30/35 which were redeemed 11/20/00.
23 (e) Column 11 is the annual amortization of expenses related to the 8.55% QUIDS due 12/31/25 which were redeemed 11/20/00.
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