Rocky Mountain Power
Docket No. 20-035-04
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Nikki L. Kobliha

May 2020

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp.

A. My name is Nikki L. Kobliha and my business address is 825 NE Multnomah Street, Suite 1900, Portland, Oregon 97232. I am currently employed as Vice President, Chief Financial Officer and Treasurer for PacifiCorp. I am testifying for PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company").

Q. Please describe your education and professional experience.

A. I received a Bachelor of Business Administration with a concentration in Accounting from the University of Portland in 1994. I became a Certified Public Accountant in 1996. I joined PacifiCorp in 1997 and have taken on roles of increasing responsibility before being appointed Chief Financial Officer in 2015. I am responsible for all aspects of PacifiCorp's finance, accounting, income tax, internal audit, Securities and Exchange Commission reporting, treasury, credit risk management, pension, and other investment management activities.

II. SUMMARY AND PURPOSE OF TESTIMONY

Q. Please summarize the purpose of your testimony.

A. My testimony covers three areas:

- First, I support PacifiCorp's overall cost of capital recommendation, including a capital structure with a common equity level of 53.67 percent, the proposed cost of long-term debt of 4.81 percent, and cost of preferred stock of 6.75 percent.
- Second, I explain how PacifiCorp is implementing the effects of the Tax Cuts and Jobs Act ("TCJA"), as outlined in the orders issued by the Public Service

Commission of Utah ("Commission").[1] Notably, I explain why the Company has updated the calculation for amortization of Excess Deferred Income Tax ("EDIT") balances using the Reverse South Georgia Method ("RSGM"), which results in an increase in benefits to be amortized in this case than presented in the TCJA proceeding.

- Lastly, I explain and support the reasonableness of the Company's projected pension costs and inclusion of the prepaid pension balance in rate base.

Q. What is the purpose of the cost of capital recommendation?

A. The Company's proposed capital structure with a common equity level of 53.67 percent is required to maintain PacifiCorp's current credit ratings, which provide for a more competitive cost of debt. The overall cost of capital facilitates continued access by the Company to the capital markets over the long term to the benefit of customers. This capital structure enables the Company's continued investment in infrastructure to provide safe and reliable service from new cost-effective energy resources at reasonable costs.

Q. What overall cost of capital do you recommend for PacifiCorp?

A. PacifiCorp proposes an overall cost of capital of 7.70 percent. This cost includes the return on equity recommendation of 10.20 percent, supported by the direct testimony of Ms. Ann E. Bulkley, and the capital structure and costs shown in Table 1.

[1] *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018,"* Docket No. 17-035-69, Order (April 27, 2018) & Order Approving Settlement Stipulation (Nov. 9, 2018).

Table 1: Overall Cost of Capital

Component	$m	% of Total	Cost %	Weighted
Long-Term Debt	$ 8,423	46.32%	4.81%	2.23%
Preferred Stock	$ 2	0.01%	6.75%	0.00%
Common Stock Equity	$ 9,759	53.67%	10.20%	5.47%
	$ 18,184	100.00%		7.70%

Q. What time period does your analysis cover?

A. The capital structure for the Company is measured over the 12-month period ending December 31, 2021, the approved test period in this proceeding, using an average of the five quarter-ending balances, based on known and measurable changes through December 31, 2021. Similarly, the costs of the long-term debt and preferred stock are an average of the costs measured for each of the five quarter-ending balances spanning the calendar 2021 test period, using the Company's actual costs adjusted for known and measurable changes through December 31, 2021.

III. FINANCING OVERVIEW

Q. Please explain PacifiCorp's need for and sources of new capital.

A. PacifiCorp requires capital to meet its customers' needs for new cost-effective transmission and renewable generation, increased reliability, improved power delivery, and safe operations. PacifiCorp also needs new capital to fund long-term debt maturities.

As described in the testimony of Mr. Gary W. Hoogeveen, through the Energy Vision 2020 project, PacifiCorp is in the process of completing the repowering of its wind generation fleet and significantly increasing its wind generation and transmission capacity. PacifiCorp expects to spend approximately $3.6 billion for investments in renewable energy projects and related transmission through calendar year 2021. This capital spending will require PacifiCorp to raise funds by issuing new long-term debt in the capital markets, retaining earnings, and if needed, obtaining new capital contributions from its parent company, Berkshire Hathaway Energy Company ("BHE").

Q. How does PacifiCorp finance its electric utility operations?

A. Generally, PacifiCorp finances its regulated utility operations using a mix of debt and common equity capital of approximately 48/52 percent, respectively. During periods of significant capital expenditures, as expected to continue now through calendar year-end 2023 for potential new investments identified in the 2019 IRP action plan,[2] the Company will need to maintain an average common equity component in excess of 52 percent to maintain its credit rating and finance the debt component of the capital structure at the lowest reasonable cost to customers. Maintaining the Company's credit rating will provide more flexibility on the type and timing of debt financing, better access to capital markets, a more competitive cost of debt, and over the long-run, more stable credit ratings. In addition, PacifiCorp needs a greater common equity component to offset various adjustments that rating agencies make to the debt component of the Company's published financial statements and to mitigate the impact the TCJA has had on the Company's credit metrics. I discuss these adjustments in greater detail later in my testimony.

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[2] *PacifiCorp's 2019 Integrated Resource Plan*, Docket No. 19-035-02, Chapter 1 – Executive Summary, p. 22 (Oct. 18, 2019).

Q. How does PacifiCorp determine the levels of common equity, debt, and preferred stock to include in its capital structure?

A. As a regulated public utility, PacifiCorp has a duty and an obligation to provide safe, adequate, and reliable service to customers in its Utah service area while prudently balancing cost and risk. Major capital expenditures are required in the near-term for new plant investment to fulfill its service obligation, including capital expenditures for repowering wind projects, new wind, and transmission. These capital investments also have associated operating and maintenance costs. As part of its annual business planning process, PacifiCorp reviews all of its estimated cash inflows and outflows to determine the amount, timing, and type of new financing required to support these activities and provide for financial results and credit ratings that balance the cost of capital with continued access to the financial markets.

Q. How does PacifiCorp manage its dividends to BHE?

A. PacifiCorp benefits from its affiliation with BHE as there is no dividend requirement. Historically, PacifiCorp has paid dividends to BHE to manage the common equity component of the capital structure and keep the Company's overall cost of capital at a prudent level. In major capital investment periods, PacifiCorp is able to retain earnings to help finance capital investments and forgo paying dividends to BHE. For example, following BHE's acquisition of PacifiCorp in 2006, PacifiCorp managed the capital structure through the timing and amount of long-term debt issuances and capital contributions from BHE, while forgoing any common dividends for nearly five years. At other times, 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. Accordingly, dividend payments can be necessary, in combination with debt issuances, to maintain the appropriate percentage of equity in PacifiCorp's capital structure. With the increased capital investment required for the Energy Vision 2020 project and other capital expenditures, however, the proposed capital structure in this case anticipates no additional common dividend payments by PacifiCorp to BHE through calendar year 2021.

Q. What type of debt does PacifiCorp use in meeting its financing requirements?

A. PacifiCorp has completed the majority of its recent long-term financing using secured first mortgage bonds issued under the Mortgage Indenture dated January 9, 1989. Exhibit RMP___(NLK-1), Pro forma Cost of Long-Term Debt, shows that, over the test period, PacifiCorp is projected to have an average of approximately $8.4 billion of first mortgage bonds outstanding, with an average cost of 4.81 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 utility operations.

Another important source of financing in the past 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, and PacifiCorp borrows the proceeds of these issuances and pledges its credit quality to repay the debt to take advantage of the tax-exempt status of the financing. During the test period, PacifiCorp's tax-exempt portfolio is projected to be approximately $218 million, with an average cost of 1.61 percent, including the cost of issuance and remarketing.

Credit Ratings

Q. What are PacifiCorp's current credit ratings?

A. PacifiCorp's current ratings are shown in Table 2.

Table 2: PacifiCorp Credit Ratings

	Moody's	Standard & Poor's
Senior Secured Debt	A1	A+
Senior Unsecured Debt	A3	A
Outlook	Stable	Stable

Q. How does the maintenance of PacifiCorp's current credit rating benefit customers?

A. 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 Baa3/BBB-) securities or in some cases even securities rated below single A. A solid credit rating directly benefits customers by reducing the immediate and future borrowing costs related to the financing needed to support regulatory obligations.

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. The Great Recession of 2008 to 2009 provides a clear and compelling example of the benefits of the Company's credit rating because PacifiCorp was able to issue new long-term debt in the midst of the financial turmoil. Other lower-rated utilities were shut out of the market and could not obtain new capital.

Third, PacifiCorp has a near-constant need for short-term liquidity as well as periodic long-term debt issuances. PacifiCorp pays significant amounts daily to suppliers whom we count on to provide necessary goods and services, such as fuel, energy, 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.

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

Q. Please provide examples where poor credit ratings hurt a utility's flexibility in the credit markets.

A. During the Great Recession in 2008, Arizona Public Service Company (rated Baa2/BBB- at that time) filed a letter with the Arizona Corporation Commission in October 2008 stating that the commercial paper market was completely closed to it and it likely could not successfully issue long-term debt.[3]

Further, those issuers who could access the markets paid rates well above the levels that PacifiCorp was able to obtain. For example, PacifiCorp issued new 10-year and 30-year long-term debt in January 2009 with 5.50 percent and 6.00 percent coupon rates, respectively. Subsequently, Puget Sound Energy (rated Baa2/A- at that time) issued new seven-year debt at a credit spread over Treasuries of 480.3 basis points resulting in a 6.75 percent coupon.

[3] *See* Exhibit RMP___(NLK-2).

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

A. Yes. Regulated utilities such as PacifiCorp are unique in that they cannot unilaterally set the price for their services. The financial integrity of a regulated utility is largely a result of the prudence of utility operations and the corresponding 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.

Rating agencies and investors have a keen understanding of the importance of regulatory outcomes. For example, Standard & Poor's ("S&P") has opined on the correlation between regulatory outcomes and credit ratings, concluding:

> Although not common, rate case outcomes can sometimes lead directly to a change in our opinion of creditworthiness. Often it's a case that takes on greater importance because of the issues being litigated. For example, in 2010, we downgraded Florida Power & Light and its affiliates following a Florida Public Service Commission rate ruling that attracted attention due to drastic changes to settled practices on rate case particulars like depreciation rates. More recently, in June 2016, we downgraded Central Hudson Electric & Gas due to our revised opinion of regulatory risk. While that reflected the company's own management of regulatory risk, it was prompted in part by other rate case decisions in New York that highlighted the overall risk in the state.[4]

Similarly, Moody's recently issued a credit opinion for PacifiCorp, concluding:

> The stable outlook incorporates our expectation that PacifiCorp will continue to receive reasonable regulatory treatment, and that funding requirements will be financed in a manner consistent with management's commitment to maintain a healthy financial profile.
>
> . . . The ratings could be downgraded if PacifiCorp's capital expenditures are funded in a manner inconsistent with its current financial profile, or if adverse regulatory rulings lower its credit

[4] S&P Ratings Direct, *Assessing U.S. Investor-Owned Utility Regulatory Environments* (Aug. 10, 2016), at 4.

metrics, as demonstrated for example, by a ratio of CFO pre-W/C/Debt sustained below 20%.[5]

As discussed in the testimony of Ms. Bulkley, Section VIII, Regulatory and Business Risk, the regulatory environment and the rate decisions by utility commissions have a direct and significant impact on the financial condition of utilities.

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

A. PacifiCorp is in the midst of a period of major capital spending and investing in cost-effective infrastructure to provide electric service that is reliable, clean, and affordable. If PacifiCorp 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 they otherwise would be. The inability to access financial markets can threaten the completion of necessary projects and can impact system reliability and customer safety. Maintaining the current single A credit rating makes it more likely PacifiCorp will have access to the capital markets at reasonable costs even during periods of financial turmoil.

Q. Can you provide an example of how the current ratings have benefited customers?

A. Yes. One example is PacifiCorp's ability to significantly reduce its cost of long-term debt primarily through obtaining new financings at very attractive interest rates. The lower cost of debt benefits customers through a lower overall rate of return and lower revenue requirement.

To determine the savings realized from maintaining a higher credit rating, in Exhibit RMP___(NLK-3) New Debt Issue Spreads, I compare the actual effective

[5] Moody's Credit Opinion, *PacifiCorp Update to Credit Analysis* (June 27, 2019), at 2.

interest rate on the Company's existing long-term debt through March 31, 2020, which was issued since its acquisition by BHE in 2006, comprising 15 series of debt, to what the effective interest rate would have been with a BBB credit rating. The spread of each issuance was changed to match what a BBB rated utility achieved at about the same point in time that PacifiCorp issued the debt. The total result for the 15 series of debt averaging $6.0 billion, would have been an effective average interest rate of approximately 5.31 percent or 55 basis points higher than the actual effective interest rate. Combined with the existing pre-acquisition debt, the resulting overall cost of long-term debt would increase to 5.20 percent if the Company had a BBB rating. PacifiCorp is currently projecting an overall cost of long-term debt of 4.81 percent, or approximately 39 basis points lower than it might have otherwise been under the scenario I described above.

Table 3 below shows the reduction in the Company's cost of long-term debt since 2009.

Table 3: PacifiCorp's Cost of Long-Term Debt

	2020 GRC Effective 2021	13-035-184 August 2014	11-035-200 Sept 2012	10-035-124 Sept 2011	09-035-23 Feb 2010	08-035-38 April 2009
Cost of Long-Term Debt	4.81%	5.2%	5.37%	5.71%	5.98%	6.02%

PacifiCorp's customers have benefited from a 121 basis points (1.21 percent) reduction in the Company's cost of long-term debt. The Company estimates that this reduction in the average cost of debt since 2009 results in a decrease of approximately $44 million in the revenue requirement in the current case. Customers have also benefited from the

Company's ability to negotiate lower underwriting fees on long-term debt issuances through BHE's global underwriting fee position.

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. This access provides these companies with more alternatives 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 PacifiCorp's current credit rating?

A. Yes. This capital structure is intended to help the Company deliver its required capital expenditures and achieve financial metrics that will meet rating agency expectations.

Q. Does PacifiCorp's credit rating benefit because of BHE and its parent Berkshire Hathaway Inc.?

A. Yes. Although ring-fenced, PacifiCorp's credit ratios have been weak for its ratings level. PacifiCorp has been able to sustain its ratings in part through the acquisition by BHE and its parent, Berkshire Hathaway Inc. S&P was very clear on this point in its March 2019 assessment of PacifiCorp:

> Under our group rating methodology, we consider PacifiCorp to be a core subsidiary of BHE with a group credit profile of 'a'. The core

> status reflects our view that PacifiCorp is highly unlikely to be sold, has strong long-term commitment from senior management, is successful at what it does, and contributes meaningfully to the group. At the same time, we consider PacifiCorp as potentially insulated, with existing insulation measures that would support a one-notch separation between PacifiCorp and parent BHE. Given its core subsidiary status and BHE's group credit profile of 'a', the issuer credit rating on PacifiCorp is 'A'.[6]

Moody's states in their June 2019 credit opinion of PacifiCorp:

> PacifiCorp benefits from its affiliation with Berkshire Hathaway Inc., which requires no regular dividends from PacifiCorp or BHE. From a credit perspective, the company's ability to retain its earnings as an entity that is privately held, particularly by a deep-pocketed sponsor like Berkshire Hathaway Inc., is an advantage over most other investor owned utilities that are typically held to a regular dividend to their shareholders. PacifiCorp currently pays dividends that are sized to manage its equity ratio (as measured by unadjusted equity to equity plus long term debt) around its allowed levels of slightly higher than 50% (regulations restrict dividends if this ratio falls below 44%). As of December 2018, PacifiCorp reports its actual equity percentage, as calculated under this test, was 54%. Furthermore, BHE has placed PacifiCorp in a ring-fencing structure that restricts dividends if PacifiCorp's ratings fall to non-investment grade.[7]

These examples are evidence of the credit rating benefit resulting from BHE's ownership of PacifiCorp.

Q. How does the TCJA impact PacifiCorp's credit rating?

A. The three main rating agencies have issued reports on the impact of tax reform on U.S. utilities and their holding companies and believe that tax reform will be unfavorable to utilities in the near term but with regulatory support for a stronger capital structure, highly rated utilities may retain positive credit ratings. For example, S&P determined:

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[6] S&P Ratings Direct, *PacifiCorp* (Mar. 15, 2019), at 9.

[7] Moody's Credit Opinion, *PacifiCorp Update to Credit Analysis* (June 27, 2019), at 6.

> The impact could be sharpened or softened by regulators depending on how much they want to lower utility rates immediately instead of using some of the lower revenue requirement from tax reform to allow the utility to retain the cash for infrastructure investment or other expenses. Regulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact.[8]

The Company has passed through partial benefits related to tax reform and is planning to pass through all of the remaining benefits in its jurisdictions; thus the negative impact to the Company's key credit metric (Moody's CFO pre-W/C/Debt) has not yet been fully realized. Absent regulatory support for a stronger capital structure, however, the Company's cash from operations will likely fall below levels where it can maintain the minimum 20 percent expectation for this credit metric, which could increase the likelihood of a downgrade. Moody's states in their January 24, 2018 Sector Comment on Tax Reform:

> Tax reform mainly affects companies that already had limited cushion in their credit profile. The tax reform usually resulted in a further 150-250 bps drop in CFO pre-W/C/debt.
>
> Moody's expects that most utilities will attempt to manage any negative financial implications of tax reform through regulatory channels. Corporate financial policies could also change. The actions taken by utilities will be incorporated into our credit analysis on a prospective basis. It is conceivable that some companies will sufficiently defend their credit profiles.
>
> In practice, we believe that most companies will actively manage their cash flow to debt ratios by issuing more equity or obtaining relief by working through regulatory channels.[9]

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[8] S&P Ratings Direct, *U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound* (Jan. 24, 2018), at 5.

[9] Moody's, *Tax Reform is Credit Negative for Sector, But Impact Varies by Company* (Jan. 24, 2018), at 3.

Q. Have other public service commissions recognized that the TCJA has had an adverse impact on utility cash flows and credit ratings?

A. Yes. In a recent decision involving Questar Gas Company dba Dominion Energy Wyoming ("Dominion"), the Wyoming Public Service Commission ("Wyoming PSC") approved a modification to the stipulation in the Questar-Dominion merger case. The original stipulation required Dominion to maintain an equity ratio in the range of 50-55 percent, and the modification partially lifted the 55 percent cap on the equity ratio. In approving the modification, the Wyoming PSC found that an "unintended consequence of the [TCJA] is that it has put pressure on Dominion's credit metrics," by reducing cash flow and negatively affecting the Funds From Operations metric. The Wyoming PSC explained that "a deterioration of the Company's credit metrics could result in a downgrade in Dominion's credit rating, which would in turn result in a higher cost of debt for the Company and its customers." The Wyoming PSC also noted that, to improve its credit metrics in response to the TCJA and avoid a downgrade, Dominion believed it was necessary to issue additional equity to replace debt potentially exceeding the 55 percent equity cap. The Wyoming PSC approved the requested modification, finding it to be in the public interest.

Similarly, in February 2019, the Public Utility Commission of Oregon ("Oregon PUC") adopted a staff memo recommending approval of an application by Avista Corp. (Avista) to issue stock.[10] Staff's memo included the following statements about the TCJA and the importance of maintaining strong credit ratings:

[10] *In the matter of Avista Corp., dba Avista Util., Application for Authorization to Issue 3,500,000 Shares of Common Stock*, Docket No. UF 4308, Order No. 19-067 (Feb. 28, 2019).

> Staff finds that the Tax Cuts and Jobs Act of 2017 created unanticipated stresses on [Avista's] credit ratings. The requested authorization signals to rating agencies that the Company is committed to the equity portion of its capital structure. However, it is Staff's finding that restoring a notch in credit ratings involves more than just remedying the cause for the downgrade. On December 21, 2018, Moody's stated, "Avista's credit profile reflects its low-risk vertically integrated electric and gas utility business, regulatory uncertainty in WA and the expected negative cash flow impact of tax reform." Authorization herein as recommended by Staff starts the process of addressing rating agency concerns and restoring a positive credit outlook.[11]

In July 2019, the Oregon PUC approved Avista's application to issue debt securities, adopting Staff's memo stating that, as a result of the TCJA, "[r]aising the Company's credit ratings back up a notch will require hard work and persistence on the part of Avista's finance group as well as a supportive regulatory environment and achieving target metrics."[12]

Rating Agency Debt Imputations

Q. Is PacifiCorp subject to rating agency debt imputation associated with power purchase agreements ("PPAs")?

A. Yes. Rating agencies and financial analysts consider PPAs to be debt-like and will impute debt and related interest when calculating financial ratios. For example, S&P will adjust PacifiCorp's published financial results and impute debt balances and interest expense resulting from PPAs when assessing creditworthiness. They do so to obtain a more accurate assessment of a Company's financial commitments and fixed payments. S&P Ratings Direct November 19, 2013, details its view of the debt aspects

[11] *Id.* at Appendix A, p.4; see also *In the matter of Portland Gen. Elec. Co., Request for Authority to Extend the Maturity of an Existing $500 Million Revolving Credit Agreement,* Docket No. UF 4272(3), Order No. 19-025 at Appendix A, p.9. (Jan. 23, 2019) (including similar observations regarding an application by Portland General Electric).

[12] *In the matter of Avista Corp., dba Avista Util., Application for Authorization to Issue and Sell $600,000,000 of Debt Securities,* Docket No. UF 4313, Order No. 19-249 (July 30, 2019).

of PPAs and other debt imputations, and is included as Confidential Exhibit RMP___(NLK-4).

Q. How does this impact PacifiCorp?

A. In its most recent evaluation of PacifiCorp, S&P added approximately $479 million of additional debt and $21 million of related interest expense to the Company's debt and coverage tests for PPAs and other liabilities of the Company that are considered to be debt-like by S&P.

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

A. Negatively. By including the imputed debt resulting from PPAs and these other adjustments, PacifiCorp'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, as shown in Table 4, if one were to apply the total $479 million amount of debt adjustments that S&P most recently made to PacifiCorp's proposed capital structure in this case, the resulting common equity percentage would decline from 53.67 percent to 52.29 percent. The corresponding higher average adjusted debt percentage of 47.70 percent over the test period reflects an adjusted capital structure that approximates the 48/52 percent baseline mix of debt and common equity capital that PacifiCorp targets.

Table 4: Rating Agency Adjusted Capital

	Proposed Cap Structure		Rating	Adjusted Cap Structure	
	Book Values	% of Total	Agency Adjmts	Book Values	% of Total
Long-Term Debt	$ 8,423	46.32%	$ 479	$ 8,902	47.70%
Preferred Stock		0.01%	(1)	1	0.01%
Common Equity	9,759	53.67%	0	9,759	52.29%
	$ 18,184	100.00%	$ 478	$ 18,662	100.00%

IV. CAPITAL STRUCTURE DETERMINATION

Q. How did the Company determine its recommended capital structure?

A. The capital structure is based on the actual capital structure at March 31, 2020, and forecasted capital activity, including known and measurable changes, through December 31, 2021. PacifiCorp averaged the five quarter-end capital structures measured beginning at December 31, 2020, and concluding with December 31, 2021, resulting in a capital structure with an equity component of 53.67 percent. The capital activity includes known maturities of certain debt issues that were outstanding at March 31, 2020, and subsequent issuances of long-term debt. The known and measurable changes represent forecasted capital activity since March 31, 2020.

Q. Why does the Company propose a capital structure calculated using a five-quarter average?

A. This approach smooths volatility in the capital structure, which will fluctuate as the Company expends capital, issues or retires debt, retains earnings, or declares dividends. This approach is consistent with the Company's previous general rate cases beginning with Docket No. 09-035-23.

Q. How does the Company's proposed capital structure compare to recent actual capital structures and to the capital structure authorized in PacifiCorp's last general rate case, Docket No. 13-035-184 ("2014 Rate Case")?

A. The capital structures are compared in Table 5 below.

Table 5: Forecast and Actual Capital Structures

PacifiCorp's Comparison of % Capital Structures						
	Dec 31, 2021 Forecast*	Dec 31, 2020 Forecast*	Dec 31, 2019 Actual*	Dec 31, 2018 Actual*	Dec 31, 2017 Actual*	13-035-184 Capital Structure
Long-Term Debt	46.32 %	48.39 %	48.36 %	47.89 %	48.49 %	48.55 %
Preferred Stock	0.01 %	0.01 %	0.02 %	0.02 %	0.02 %	0.02 %
Common Equity	53.67 %	51.60 %	51.62 %	52.09 %	51.49 %	51.43 %
Totals	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

*Five quarter-end average % Capital Structure calculated for trailing 12 month period ending

The percentage increase in the common equity component of the capital structure from the actual December 31, 2019 five-quarter average to that projected for the 2021 forecast test period is due to earnings offset by debt issuances and the forgoing of any common dividend payments in 2020 and 2021. Further, both of the Company's projected capital structures for 2020 and 2021 contain a higher common equity component than what was approved by the Commission in the 2014 Rate Case. As discussed above, PacifiCorp's increased capital investment requirements and ratings pressure caused by the TCJA require PacifiCorp to increase the equity in its capital structure to maintain its current ratings.

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

A. Consistent with my determination of the percentage capital structure discussed previously, I have similarly calculated the embedded costs of debt and preferred stock as an average of the five quarter-end cost calculations spanning the test period, beginning at December 31, 2020, and concluding with December 31, 2021.

Q. Please explain the cost of long-term debt calculation.

A. I calculated the embedded cost of debt using the methodology relied upon in the Company's previous rate cases in Utah and other jurisdictions. More specifically, 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 outstanding as of each of the five quarter-ending dates spanning the 12-month calendar 2021 test period. 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.

Q. Please describe the changes to the amount of outstanding long-term debt between December 31, 2019, and December 31, 2021.

A. Approximately $38 million and $420 million of the Company's variable and fixed rate long-term debt, respectively, will mature during this period, and I have therefore removed this debt when appropriate in the determination of the proposed average cost of debt. Also, as reflected in Exhibit RMP___(NLK-1), Pro forma Cost of Long-Term Debt, are the new first mortgage bond issuances made by the Company in April 2020, consisting of a $400 million 10-year 2.70% series and a $600 million 31-year term 3.30% series. The total issuance costs reflected for each of these two recent new debt issuances in Exhibit RMP___(NLK-1), Pro forma Cost of Long-Term Debt, are based both on actual and estimated costs. The Company currently anticipates no further long-term debt issuances will be necessary through December 31, 2021.

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

A. The Company's variable rate long-term debt in this case is in the form of tax-exempt debt. Exhibit RMP___(NLK-5), Variable Rate Pollution Control Revenue Bonds, shows that, on average, these securities have been trading at approximately 84 percent of the 30-day London Inter Bank Offer Rate ("LIBOR") for the period January 2000 through December 2019. Therefore, the Company has applied a factor of 84 percent to the forward 30-day LIBOR rate as of each of the five quarter-ending dates spanning calendar year 2021 and then added the respective credit facility and remarketing fees for each floating rate tax-exempt bond outstanding during the period. Credit facility 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 Utah general rate cases as well as in other states that regulate PacifiCorp.

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 began by dividing the annual dividend per share by the per share net proceeds for each series of preferred stock. The resulting 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 PacifiCorp's embedded cost of preferred stock.

Embedded Cost of Long-Term Debt

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

A. The cost of long-term debt is 4.81 percent, as shown in Exhibit RMP___(NLK-1), Pro forma Cost of Long-Term Debt.

Embedded Cost of Preferred Stock

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

A. Exhibit RMP___(NLK-6), Cost of Preferred Stock, shows the embedded costs of preferred stock to be 6.75 percent.

VI. IMPLEMENTATION OF TCJA TAX BENEFITS IN RATES

Q. How does PacifiCorp propose to include the benefits of the TCJA's lower tax rate in this proceeding?

A. PacifiCorp included the tax benefits by: (1) embedding the lower tax rate in base rates as discussed in the testimony of Mr. Steven R. McDougal; (2) including a rate base deduction for unamortized protected Excess Deferred Income Tax ("EDIT") and lowering income tax expense for the annual level of amortization; and (3) returning to customers the tax benefits deferred as of December 31, 2020.

These actions are consistent with the Commission's decision in Docket No. 17-035-69.[13]

Q. Please quantify the TCJA balances deferred as of December 31, 2020, that will be refunded to customers.

A. The total amount of deferred TCJA tax benefits projected to be available as of December 31, 2020, is $142.6 million. PacifiCorp's proposal to return this balance to customers is explained in the direct testimony of Mr. McDougal.

Q. How do the EDIT balances presented in this case differ from the balances in the November 9, 2018, Order Approving Settlement Stipulation in Docket No. 17-035-69?

A. As discussed in the Company's March 25, 2020 supplemental notice in Docket No. 17-035-69, the Company has made two changes.

First, while total EDIT has not changed, PacifiCorp made a correction in the classification between protected and non-protected EDIT. The misclassification was identified during the process of extracting non-protected property EDIT balances from the Company's tax fixed asset system so that they could be used in the manner as described in the Commission-approved stipulation. The correction resulted in more EDIT classified as non-protected and less classified as protected.

Second, PacifiCorp will be using the RSGM to amortize protected EDIT, retroactive to January 1, 2018, because the Company's books and underlying records do not contain the necessary vintage account data to use the Average Rate Assumption

[13] *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018,"* Docket No. 17-035-69, Order (April 27, 2018) & Order Approving Settlement Stipulation (Nov. 9, 2018).

Method ("ARAM") as originally contemplated. The amortization of PacifiCorp's protected EDIT for 2018, 2019, and 2020 is greater under the RSGM as compared to the Company's ARAM projections.

The Reverse South Georgia Method

Q. Please explain why PacifiCorp's books and underlying records do not contain the necessary vintage account data to use the ARAM.

A. For some assets and in certain circumstances, PacifiCorp records situs book depreciation on system-allocated assets. For background, PacifiCorp depreciates system-allocated assets using a base composite life; this base level of book depreciation is system-allocated. An incremental amount of book depreciation is calculated for jurisdictions that approve a composite life different from the base or otherwise approve accelerated book depreciation for system-allocated assets; this incremental amount of book depreciation is situs-allocated.

To use the ARAM, book depreciation is required at a jurisdictional level by vintage and tax class to have the necessary vintage account data. Because book depreciation is not maintained at this level for book accounting purposes, PacifiCorp relies on its tax fixed asset system to produce the necessary vintage account data for tax purposes by performing a procedure to allocate book depreciation.

As presently configured, the book depreciation allocation procedure cannot process situs book depreciation on system-allocated assets in a manner that impacts only the vintage account data of the jurisdiction to which the situs book depreciation inures. As a result, the situs book depreciation must be accounted for separately as a tax class of its own, thereby rendering the jurisdictional vintage account data to which the EDIT is actually attached incomplete for the purposes of using the ARAM.

Q. How are the issues with situs book depreciation addressed by the RSGM?

A. Unlike the ARAM, book depreciation is not required at the jurisdictional level by vintage and tax class for amortization of EDIT when using the RSGM. The RSGM requires only the use of a remaining regulatory life for an asset or group of assets to amortize the EDIT on a straight-line basis.

To implement the RSGM, PacifiCorp categorized Utah-allocated protected EDIT at the level of detail presented in the Company's most recently filed depreciation study. The protected EDIT is then amortized straight-line over Utah's approved remaining regulatory life for each respective asset or group of assets. For tax years 2018 to 2020, the remaining lives are based on the 2013 depreciation study.[14] Beginning in 2021, the remaining lives will be updated to match those in the Company's 2018 depreciation study in Docket No. 18-035-36, which was approved on April 20, 2020, and then again for each depreciation study approved thereafter.[15] If the Commission approves regulatory lives different from those approved in the 2018 depreciation study or as otherwise proposed in this case, the protected EDIT amortization included in this case will need to be updated accordingly.

Q. Do PacifiCorp's facts meet the statutory requirements for using the RSGM?

A. Yes. Although there are uncertainties with respect to the proper application of section

[14] *In the Matter of the Application of Rocky Mountain Power for Authority to Change its Depreciation Rates Effective January 1, 2014*, Docket No. 13-035-02, Order Confirming Bench Ruling Approving Stipulation on Depreciation Rate Changes (Nov. 7, 2013).

[15] *Application of Rocky Mountain Power for Authority to Change its Depreciation Rates Effective January 1, 2021*, Docket No. 18-035-36, Report and Order (April 20, 2020).

13001(d) of the TCJA, PacifiCorp has carefully considered this matter and, based on its facts and circumstances, believes that the use of the RSGM is permitted as a normalization method of accounting.

Q. Does the Internal Revenue Service ("IRS") recognize the need for clarity with regard to the EDIT normalization requirements in light of the TCJA?

A. Yes. In Notice 2019-33, the IRS announced its intent to issue guidance to clarify the EDIT normalization requirements, which may include guidance on the use of the RSGM; the Company anticipates this guidance will be issued in 2020. In comments submitted in response to Notice 2019-33, the Edison Electric Institute has requested that the IRS issue transitional guidance that allows taxpayers to correct potential normalization violations on a prospective basis and that the violations be forgiven without penalty. If uncertainties still exist after the guidance is issued, the Company will evaluate the need to file a private letter ruling request.

VII. PENSION COSTS

Q. Please describe the status of PacifiCorp's defined benefit pension plans.

A. To reduce the risk profile of its defined benefit pension plans, PacifiCorp has, over time, shifted the accrual of new benefits to its defined contribution 401(k) plan. All non-represented employees hired after January 1, 2008, and all represented employees hired after June 30, 2013, receive retirement benefits solely through the 401(k) plan. Retirement plan benefits for represented employees are determined through the collective bargaining process through which the Company has maintained its focus on shifting to providing benefits through its 401(k) plan. The Company provided non-represented employees hired before January 1, 2008, the ability to receive their retirement through either the pension plan or the 401(k) plan. This choice was offered in 2008, and 41 percent of the eligible participants migrated to the 401(k) plan. The remaining non-represented employees in the defined benefit pension plan continued to receive benefit accruals until accruals were frozen on December 31, 2016.

Q. Does this case reflect costs associated with PacifiCorp's defined benefit pension plans?

A. Yes. The Company still incurs net periodic benefit costs for its defined benefit pension plans. The Company's net periodic benefit costs generally include interest costs associated with discounting the projected benefit obligation and amortization of net unrecognized gains and losses, offset by the expected return on plan investments. The level of these projected costs is driven by various assumptions, including the interest rate used to discount the liability, life expectancy and other demographics of the Company's plan participants, and the expected long-term rate of return based on the mix of investments. This filing reflects total-Company pension costs of $8.8 million, including a projected settlement loss of approximately $11.9 million during the 2021 test period.

Q. What is a settlement loss?

A. Accounting guidance provides for delayed recognition of certain gains and losses. These unrecognized costs include an accumulation of past actuarial gains and losses that result from changes in actuarial assumptions, such as the discount rate, and the difference between expected and actual experience — for example, asset returns that exceed or underperform the level assumed in determining net periodic benefit cost. Under the Financial Accounting Standards Board's Accounting Standards Codification

("ASC") 715, Compensation - Retirement Benefits[16] and ASC 980, Regulated Operations, the majority of the Company's unrecognized net loss is currently amortized over approximately 21 years, which represents the average remaining life expectancy of plan participants. A settlement loss occurs when the aggregate lump sum cash distributions in a calendar year exceed a defined threshold (service cost plus interest cost), requiring under ASC 715 immediate recognition in earnings of a portion of the unrecognized actuarial gains or losses. If not for this requirement, such portion of the net actuarial loss would eventually flow through expense as part of the ongoing amortization over the approximately 21-year period.

Q. Why are actuarial gains and losses an important component of on-going pension expense under ASC 715?

A. Actuarial gains and losses arise annually as remeasurement occurs each year-end under ASC 715 due to changes in assumptions, differences between expected and actual asset returns, and actuarial experience. As of December 31, 2019, the Company had $422 million of unrecognized net actuarial losses recorded as a regulatory asset that will generally be recognized to expense over the average remaining life of plan participants (currently approximately 21 years), making it a significant portion of the Company's annual pension expense. Recognition of actuarial gains and losses are amortized over time rather than in the year they occur, which can help minimize volatility in expense from year to year. However, as I described above, settlement accounting under ASC 715 can trigger accelerated recognition of a portion of the unrecognized net actuarial losses. The Company last recognized a settlement loss in

[16] Formerly known as "FAS 87."

2018 on a total-Company basis of $22 million, approximately $9.5 million of which was Utah’s share. In Docket No. 18-035-48, the Company requested approval of deferred accounting treatment related to this settlement loss. The Commission denied the Company's request, holding that the pension settlement costs were not unforeseeable or extraordinary sufficient to warrant a deferred accounting order.[17]

Q. Does the Company anticipate that settlement losses under ASC 715 will be triggered during the next few years and if so, what is the driver?

A. Yes. Recent history demonstrates that during periods of low interest rates, a higher percentage of participants elect lump sum distributions. Thus, with the very low interest rate environment present at the time the Company’s projections for this filing were compiled and the knowledge of what the Company experienced in 2018 when interest rates were similarly low, the Company anticipates that additional settlement losses will occur. Based on actuarial projections, settlement losses of $18.5 million and $11.9 million are forecast during 2020 and 2021, respectively, justifying the inclusion of these costs in base rates. The settlement loss projections were based on market conditions in early 2020.

In periods of low interest rates, the Company experiences lower interest cost on the benefit obligation, which keeps the threshold for determining settlement accounting at a low level. Table 7 below shows the settlement threshold for the last seven years along with the projections for 2020 and 2021. The declining threshold is primarily driven by the low interest rate environment. The Company is likely to be subject to a settlement charge each year that interest rates are sufficiently low.

[17] *Application of Rocky Mountain Power for an Accounting Order for Settlement Charges Related to its Pension Plans*, Docket No. 18-035-48, Order at 6-7 (May 22, 2019).

Table 7: Recent History and Projections of Settlement Threshold ($ in millions)

	2013	2014	2015	2016	2017	2018	2019	2020	Projected 2021
Service cost	$5.9	$5.3	$4.7	$4.1	0	0	0	0	0
Interest cost	$51.9	$54.0	$50.6	$51.8	$47.3	$41.1	$42.6	$34.4	$31.9
Settlement threshold (service cost + interest cost)	$57.8	$59.3	$55.3	$55.9	$47.3	$41.1	$42.6	$34.4	$31.9

In addition to a low settlement threshold, the Company has made assumptions about the number of participants who will take lump sum distributions upon retirement along with their estimated payout. For purposes of valuing the pension benefit obligation, the Company's actuaries generally assume (based on historical experience) that 60 percent of participants will elect lump sum distributions. However, in performing the annual remeasurement of the pension benefit obligation at December 31, 2019, the Company's actuaries assumed 80 percent of participants would elect lump sum distributions in 2020 in anticipation of an increase in the percentage of retiring participants electing lump sums due to the unprecedentedly low interest rates. For 2021, 60 percent of participants are assumed to elect lump sum distributions. In any given year, the actual percentage of participants electing lump sum distributions will differ from what was assumed.

Table 8 below shows the historical number of participants electing lump sum distributions and the resulting value paid out of the plan along with the projections for 2020 and 2021.

Table 8: Historical and Projected Lump Sum Distribution Information ($ in millions)

	2013	2014	2015	2016	2017	2018	2019	Projected 2020	Projected 2021
Lump Sum Distributions	$52.2	$22.0	$40.5	$31.9	$40.0	$52.3	$22.7	$50.8	$34.4
Distributions in Excess of Threshold	0	0	0	0	0	$ 11.2	0	$ 16.4	$ 2.5
Discount Rate	4.05%	4.8%	4%	4.4%	4.05%	3.6%	4.25%	3.25%	3.25%
Minimum Present Value Segment Rates(1)	1.02% 3.71% 4.67%	1.40% 4.66% 5.62%	1.40% 3.98% 5.04%	1.69% 4.11% 5.07%	1.47% 3.34% 4.30%	1.96% 3.58% 4.35%	3.21% 4.26% 4.55%	2.13% 3.07% 3.65%	2.04% 3.09% 3.68%
Number of Participants Electing Lump Sums	204	150	216	224	205	211	114	231	172
Percentage of Participants Electing Lump Sums	66.3%	50.2%	64.9%	68.7%	58.4%	73.3%	67.1%	80%	60%

1. Other than for 2021, represents the IRS's published minimum present value segment rates from September of the preceding year, which are used to value lump sum distributions taken in the subsequent year, in accordance with the Company's pension plan document. For example, the 2.13%/3.07%/3.65% presented under 2020 are the September 2019 rates applicable to lump sum distributions to be taken in 2020. Rates included for 2021 are based on the November 2019 rates published by the IRS, which were the most recently available at the time the projections were compiled. The December 2019 rates were 2.03%/3.06%/3.59%.

As of December 31, 2019, interest rates decreased significantly, resulting in a 3.25 percent discount rate used to perform the annual remeasurement of the Company's benefit obligation and determine the interest cost component of the Company's net periodic benefit cost for 2020. This compares to a 4.25 percent discount rate at December 31, 2018. As presented in Table 7, this decrease results in lower interest cost and thus a lower settlement loss threshold. As presented in Table 8, the applicable minimum present value segment rates for 2020 lump sum distributions are very low; thus, the Company projects higher lump sum distributions and the triggering of a settlement loss in 2020 of an estimated $18.5 million. Based on the current low interest rate environment, the Company projects a settlement loss of $11.9 million in 2021 using the assumptions presented in Table 8. When similar circumstances were present in 2018, the Company incurred a settlement loss of $22 million.

VIII. RATE TREATMENT NET PREPAID PENSION AND OTHER POST-RETIREMENT ASSETS

Q. What is the Company's proposed rate treatment for its prepaid pension and other post-retirement assets, net of accumulated deferred income taxes ("net prepaid pension and other post-retirement asset" or "net prepaid")?

A. The Company proposes inclusion of its net prepaid pension and other post-retirement asset in rate base with a return equal to the Company's weighted average cost of capital ("WACC"). Inclusion of the net prepaid in rate base would allow the Company to recover its prospective financing costs associated with the net prepaid.

Q. Please describe how the net prepaid pension and other post-retirement asset is computed and what it represents.

A. The prepaid pension and other post-retirement asset represents cumulative contributions made to the Company's defined benefit plans in excess of cumulative expense recognized for accounting purposes. These prepaid assets can also be computed by taking the Company's regulatory asset associated with unrecognized net periodic benefit cost for the plans less the net underfunded status of the plans. The prepaid assets are then reduced by associated accumulated deferred income tax liabilities to arrive at the Company's net prepaid pension and other post-retirement asset.

Q. What balance is the Company proposing to include in rate base associated with its net prepaid pension and other post-retirement asset?

A. The Company proposes to include $252.335 million in rate base based on the 13-month average of its net prepaid pension and other post-retirement asset reduced for joint owner cutback for the 13-month period ended December 31, 2021. This amount reflects PacifiCorp's prepaid pension asset of $326.557 million plus its other post-retirement prepaid asset of $7.046 million less associated accumulated deferred income tax liabilities of $81.268 million. This amount, along with the net prepaid pension and other post-retirement asset at December 31, 2019, is included in the exhibits to Mr. McDougal's direct testimony.

Q. What is the basis for including the net prepaid pension and other post-retirement asset in rate base?

A. Over the life of a plan, cumulative contributions and expense will be equal. However, at any point during the life of a plan, cumulative contributions and expense will differ. The prepaid concept arises from cumulative contributions to the plans exceeding cumulative pension and other post-retirement expense (also referred to as net periodic benefit cost). While the Company recovers its net periodic benefit cost through cost of service, the Company finances any difference between the amounts cumulatively contributed to the plans and the amounts cumulatively recognized as expense for accounting purposes with its blended capital. Thus, inclusion of the net prepaid pension and other post-retirement asset in rate base earning a return at the Company's authorized WACC would allow the Company to recover this financing cost.

Q. What factors contribute to contributions differing from net periodic benefit cost?

A. Contributions to the pension plans are generally driven by funding requirements under the Employee Retirement Income Security Act of 1974 ("ERISA"), which encompass the funding requirements of the federal Pension Protection Act of 2006. Ensuring minimums under these requirements are met mitigates impairing the tax exempt status of the plans and avoids triggering of benefit restrictions. Other factors, such as Internal Revenue Service funding limits and deductibility rules, influence the level of contributions to other post-retirement plans.

Net periodic benefit cost is computed in accordance with generally accepted accounting principles under ACS 715. Thus, at any point in time during the life of the plans, contributions will differ from the amounts recognized as net periodic benefit cost for accounting purposes. As noted, however, over the life of the plans, contributions and expense will be equal.

Q. What is the current and historical rate treatment of pension and other post-retirement net periodic benefit cost?

A. The Company currently recovers its net periodic benefit cost under ASC 715 by including the amount for the applicable test period in determining revenue requirement in its general rate case filings. No balancing account is utilized for pension and other post-retirement costs. Prior to the adoption of Financial Accounting Standards Board Statement No. 87 ("FAS 87") in 1987, the Company recovered pension costs based on contributions. At the time of adoption, the Company began recovering pension costs based on net periodic benefit cost under FAS 87 (later codified as ASC 715) with the cumulative difference between the two methods recovered over a five-year period.

Thus, the Company has effectively recovered pension costs over time on the basis of Generally Accepted Accounting Principles ("GAAP") expense leaving it to bear the costs to finance contributions in excess of expense. Prior to the adoption of the Financial Accounting Standards Board's Statement No. 106 (also later codified as ASC 715), other post-retirement costs were expensed and recovered on a pay-as-you-go basis. Upon adoption of the new guidance, recovery continued to be based on the Company's expense. Thus for other post-retirement costs, recovery has also been aligned to expense over time leaving the Company to finance any differences between contributions and expense.

Q. To the extent the net prepaid is in an accrued position, would inclusion in rate base continue to be appropriate?

A. Yes. As with any other rate base item where the difference between timing of cash payments and expense recognition differ, the item should be included in rate base whether in an asset or liability position. To the extent cumulative expense exceeds cumulative Company contributions to the plans, it would be appropriate to reduce rate base for the resulting net accrued position in order to pass the benefit to customers for having provided recovery of the expense in excess of cash outlays by the Company.

Q. Please clarify why the cumulative net prepaid should be included in rate base rather than only prospective differences between expense and contributions?

A. The cumulative difference between expense and contributions to date must be included in rate base in order to avoid skewed outcomes that would arise if only prospective differences between expense and contributions were to be included. For example, in a year where contributions to the plans are $0 and expense is $10, a net accrued position of $10 would result on a pre-tax basis. If only this new activity is included in rate base despite a historical net prepaid balance, customers would benefit from a rate base reduction while the Company would continue to incur financing costs on the historical difference between cumulative contributions and expense. Including the cumulative net prepaid in rate base today with a return based on the Company's WACC provides it the ability to recover only prospective financing costs associated with the net prepaid.

Q. How does negative expense impact the net prepaid pension and other post-retirement asset?

A. Negative net periodic benefit cost increases the net prepaid but remains appropriate to include in rate base. Since the Company recovers pension and other post-retirement benefits cost through cost of service, negative expense flows through to customers resulting in a lower cash position for the Company. The Company incurs financing costs on the difference between cumulative contributions and cumulative net periodic benefit cost regardless of whether that cost is positive or negative.

Q. Does historical capitalization of pension and other post-retirement cost impact the Company's proposal to include the associated net prepaid in rate base?

A. No. While the capitalized portion of net periodic benefit cost is included in rate base through in-service plant, there is no doubling up of rate base for this component. This is because the Company's net prepaid reflects the difference between cash contributions and expense under ASC 715 prior to capitalization as if that difference truly represented the Company's excess cash outlays. However, the Company only recovers the portion capitalized to in-service plant as the cost is depreciated over the plant's life. Thus, the combined inclusion in rate base of the capitalized portion of net periodic benefit cost through in-service plant and the net prepaid pension and other post-retirement asset would allow the Company to be made whole on its costs to finance the contributions in excess of expense recognized and recovered in rates.

Q. Does the fact that actual pension and other post-retirement benefit cost differed from that included in rates impact the appropriateness of the Company's proposal?

A. No. As with any other rate base item where no balancing account exists (e.g., investment in in-service plant, coal inventory), no adjustments are made for changes in the balances between general rate cases.

Q. Why is the Company's WACC the appropriate rate to apply to the net prepaid pension and other post-retirement asset?

A. The Company's blended capital structure of long-term debt and equity financing is the source of financing for the net prepaid just as it is for other rate base items such as investment in in-service plant. Thus, to provide a return at something less than the Company's WACC would result in the Company not recovering its costs to finance the difference between its cash outlays and the amounts charged to expense and recovered from customers.

Q. Does inclusion of the net prepaid in rate base shift additional risk to customers?

A. No. While much volatility exists with defined benefit plans due to asset returns that are impacted by market conditions and changes in underlying assumptions, such as the discount rate, these risks are encompassed in net periodic benefit cost and balanced with smoothing methods allowed under ASC 715. Including the net prepaid in rate base does not change these risks or who bears them. Inclusion of the net prepaid in rate base simply provides the Company the opportunity to recover its underlying financing costs associated with the plans.

VIII. CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I respectfully request the Commission adopt PacifiCorp's proposed capital structure with a common equity level of 53.67 percent. This capital structure balances the financial integrity of the Company and costs to customers by reflecting the minimum equity ratio necessary for PacifiCorp to maintain its ratings under current market conditions, especially given the passage of the TCJA. When combined with PacifiCorp's updated cost of long-term debt of 4.81 percent and the cost of equity of 10.20 percent recommended by Ms. Bulkley, this produces a reasonable overall cost of capital of 7.70 percent.

In addition, the Company recommends that the Commission acknowledge the reasonableness of PacifiCorp's treatment of its TCJA tax benefits in rates, and approve PacifiCorp's projected pension costs and prepaid pension balance included in this case.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(NLK-1)
Docket No. 20-035-04
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Pro forma Cost of Long-term Debt

May 2020

PACIFICORP
Electric Operations
Pro forma Ave Cost of Long-Term Debt Summary
12 months ended December 31, 2021

LINE NO.	DESCRIPTION	AMOUNT 5QE AVE 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**	**$8,205,000,000**	**($88,373,492)**	**($30,672,073)**	**$8,085,954,435**	**$401,824,290**	**4.758%**	**4.897%**	**24.4**	2
3										3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$193,750,000	($4,953,665)	($2,181,869)	$186,614,466	$3,128,066	1.459%	1.614%	30.0	4
5	Subtotal - Pollution Control Revenue Bonds	$24,400,000	($225,000)	($428,469)	$23,746,531	$376,736	1.432%	1.544%	29.9	5
6	**Total Pollution Control Revenue Bonds**	**$218,150,000**	**($5,178,665)**	**($2,610,338)**	**$210,360,997**	**$3,504,802**	**1.456%**	**1.607%**	**29.9**	6
7										7
8	Loss on Long Term Debt Reacquistions, without Refunding					$205,126				8
9	**Total Cost of Long Term Debt**	**$8,423,150,000**	**($93,552,157)**	**($33,282,411)**	**$8,296,315,432**	**$405,534,218**	**4.673%**	**4.815%**	**24.5**	9
10										10

Rocky Mountain Power
Exhibit RMP___(NLK-1) 2 of 3
Docket No. 20-035-04
Witness: Nikki L. Kobliha

PACIFICORP
Electric Operations
Pro forma Ave Cost of Long-Term Debt Summary
12 months ended December 31, 2021

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT 5QE AVE 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														2
3	3.850%	Series due Jun 2021	05/12/11	06/15/21	10	$400,000,000	$160,000,000	($1,500,455)	$0	$158,499,545	$99.062	3.963%	$6,340,800	3
4	2.950%	Series due Feb 2022	01/06/12	02/01/22	10	$350,000,000	$350,000,000	($2,732,350)	$0	$347,267,650	$99.219	3.040%	$10,640,000	4
5	2.950%	Series due Feb 2022 (2)	03/06/12	02/01/22	10	$100,000,000	$100,000,000	($173,129)	($4,970,793)	$94,856,079	$94.856	3.571%	$3,571,000	5
6	2.950%	Series due Jun 2023	06/06/13	06/01/23	10	$300,000,000	$300,000,000	($2,759,352)	$0	$297,240,648	$99.080	3.058%	$9,174,000	6
7	3.600%	Series due Apr 2024	03/13/14	04/01/24	10	$425,000,000	$425,000,000	($3,600,164)	($1,943,075)	$419,456,761	$98.696	3.757%	$15,967,250	7
8	3.350%	Series due Jul 2025	06/19/15	07/01/25	10	$250,000,000	$250,000,000	($2,441,421)	$0	$247,558,579	$99.023	3.466%	$8,665,000	8
9	3.500%	Series due Jun 2029	03/01/19	06/15/29	10	$400,000,000	$400,000,000	($2,874,181)	$0	$397,125,819	$99.281	3.584%	$14,336,000	9
10	2.700%	Series due Sep 2030	04/08/20	09/15/30	10	$400,000,000	$400,000,000	($2,880,000)	$0	$397,120,000	$99.280	2.780%	$11,120,000	10
11	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	11
12	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	12
13	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	13
14	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	14
15	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	15
16	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	16
17	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	17
18	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	18
19	4.100%	Series due Feb 2042	01/06/12	02/01/42	30	$300,000,000	$300,000,000	($3,724,911)	$0	$296,275,089	$98.758	4.173%	$12,519,000	19
20	4.125%	Series due Jan 2049	07/13/18	01/15/49	31	$600,000,000	$600,000,000	($6,984,085)	$0	$593,015,915	$98.836	4.193%	$25,158,000	20
21	4.150%	Series due Feb 2050	03/01/19	02/15/50	31	$600,000,000	$600,000,000	($7,938,771)	$0	$592,061,229	$98.677	4.227%	$25,362,000	21
22	3.300%	Series due Mar 2051	04/08/20	03/15/51	31	$600,000,000	$600,000,000	($10,134,000)	$0	$589,866,000	$98.311	3.388%	$20,328,000	22
23	**4.631%**	**Subtotal - Bullet FMBs**			**24**		**$7,785,000,000**	**($84,860,911)**	**($8,209,863)**	**$7,691,929,226**		**4.728%**	**$368,078,050**	23
24														24
25	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	$15,000,000	$12,000,000	($92,161)	($1,643,137)	$10,264,702	$85.539	10.066%	$1,207,920	25
26	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	$5,000,000	$4,000,000	($30,720)	($547,712)	$3,421,567	$85.539	9.889%	$395,560	26
27	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	27
28	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	28
29	**2.975%**	**Subtotal - Series C MTNs**			**11**		**$25,000,000**	**($186,718)**	**($3,423,203)**	**$21,390,079**		**9.926%**	**$2,481,450**	29
30														30
31	8.050%	Series E due Sep 2022	09/18/92	09/01/22	30	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	$87.820	9.257%	$1,388,550	31
32	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	32
33	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	33
34	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	34
35	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	35
36	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	36
37	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	37
38	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	38
39	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	39
40	**8.099%**	**Subtotal - Series E MTNs**			**30**		**$155,000,000**	**($1,227,725)**	**($16,164,025)**	**$137,608,250**		**9.210%**	**$14,275,770**	40
41														41
42	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	42
43	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	43
44	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	44
45	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	45
46	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	46
47	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	47
48	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	48
49	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	49
50	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	50
51	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	51
52	**7.044%**	**Subtotal - Series F MTNs**			**30**		**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**		**7.291%**	**$10,208,020**	52

PACIFICORP
Electric Operations
Pro forma Ave Cost of Long-Term Debt Summary
12 months ended December 31, 2021

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT 5QE AVE 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)	
53														53
54	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	54
55	**6.710%**	**Subtotal - Series G MTNs**			**30**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	55
56														56
57	**4.758%**	**Total First Mortgage Bonds**			**24**		**$8,205,000,000**	**($88,373,492)**	**($30,672,073)**	**$8,085,954,435**		**4.897%**	**$401,824,290**	57
58														58
59														59
60	1.463%	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	1.616%	$132,350	60
61	1.431%	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	1.610%	$1,963,234	61
62	1.572%	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	1.715%	$258,279	62
63	1.497%	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	1.616%	$343,562	63
64	1.413%	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	1.517%	$80,401	64
65	1.515%	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	1.592%	$350,240	65
66	**1.459%**	**Subtotal - Secured PCRBs**			**30**		**$193,750,000**	**($4,953,665)**	**($2,181,869)**	**$186,614,466**		**1.614%**	**$3,128,066**	66
67														67
68	1.432%	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	1.544%	$376,736	68
69	**1.432%**	**Subtotal - Unsecured PCRBs**			**30**		**$24,400,000**	**($225,000)**	**($428,469)**	**$23,746,531**		**1.544%**	**$376,736**	69
70														70
71	**1.456%**	**Total PCRB Obligations**			**30**		**$218,150,000**	**($5,178,665)**	**($2,610,338)**	**$210,360,997**		**1.607%**	**$3,504,802**	71
72														72
73			**REACQ**	**ORG MAT**										73
74			**DATE**	**DATE**										74
75		8.375% Series A QUIDS	11/17/00	06/30/35									$107,887	75
76		8.55% Series B QUIDS	11/17/00	12/31/25									$84,084	76
77		Carbon '94 PCRB Series	02/18/16	11/01/24									$13,155	77
78		**Long-Term Debt Reacquisition, without refunding amortization**											**$205,126**	78
79														79
80	**4.673%**	**Total Long-Term Debt**			**24**		**$8,423,150,000**	**($93,552,157)**	**($33,282,411)**	**$8,296,315,432**		**4.815%**	**$405,534,218**	80
81														81

Rocky Mountain Power
Exhibit RMP___(NLK-2)
Docket No. 20-035-04
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Arizona Public Service Co Letter to Commission

May 2020

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AZ CORP COMMISSION
DOCKET CONTROL

PINNACLE WEST
CAPITAL CORPORATION

LAW DEPARTMENT

Thomas L. Mumaw
Senior Attorney
(602) 250-2052
Direct Line

October 17, 2008

Arizona Corporation Commission
DOCKETED
OCT 17 2008
DOCKETED BY

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

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Appendix A

ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Commissioner
Direct Line: (602) 542-4143
Fax: (602) 542-0765
E-mail: kmayes@azcc.gov

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%

Rocky Mountain Power
Exhibit RMP___(NLK-3)
Docket No. 20-035-04
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

New Debt Issue Spreads

May 2020

PACIFICORP
Electric Operations
Pro FormaCost of Long-Term Debt Detail
12 months ended December 31, 2021

LINE NO.	INTEREST RATE	DESCRIPTION	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT AVE OUTSTANDING	ISSUANCE EXPENSES (1)	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)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
80	4.648%	**Total Long-Term Debt**		$8,423,150,000	($93,552,157)	($33,282,411)	$8,296,315,432		4.815%	$405,534,218	80
	4.635%	**Actual Post Acquistion Debt Issuances** (1)		$5,985,000,000	($61,539,086)	($6,913,867)	$5,916,547,047		4.764%	$285,114,050	
	5.203%	**Pro Forma Post Acquistion Debt Issuances**		$5,985,000,000	($54,852,486)	($6,913,867)	$5,923,233,647		5.309%	$317,748,500	
	5.052%	**Total Long-Term Debt - Pro Forma**		$8,423,150,000	($86,865,557)	($33,282,411)	$8,303,002,032		5.202%	$438,168,668	

(1) Issuance Expenses include issuance yield discounts

REDACTED
Rocky Mountain Power
Exhibit RMP___(NLK-4)
Docket No. 20-035-04
Witness: Nikki L. Kobilha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Redacted Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Credit Factors Utility Industry

May 2020

THIS ATTACHMENT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Rocky Mountain Power
Exhibit RMP___(NLK-5)
Docket No. 20-035-04
Witness: Nikki L. Kobliha

P

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Variable PCBR Rates

May 2020

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2021

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(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%
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%

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2021

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
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%
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%

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2021

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Mar-11	0.25%	0.24%	96%
Apr-11	0.22%	0.24%	106%
May-11	0.20%	0.20%	100%
Jun-11	0.19%	0.12%	62%
Jul-11	0.19%	0.07%	38%
Aug-11	0.21%	0.18%	83%
Sep-11	0.23%	0.18%	78%
Oct-11	0.24%	0.17%	69%
Nov-11	0.25%	0.18%	70%
Dec-11	0.28%	0.18%	62%
Jan-12	0.28%	0.18%	64%
Feb-12	0.25%	0.22%	86%
Mar-12	0.24%	0.20%	84%
Apr-12	0.24%	0.25%	104%
May-12	0.24%	0.22%	90%
Jun-12	0.24%	0.19%	78%
Jul-12	0.25%	0.17%	68%
Aug-12	0.24%	0.16%	68%
Sep-12	0.22%	0.18%	81%
Oct-12	0.21%	0.20%	93%
Nov-12	0.21%	0.20%	95%
Dec-12	0.21%	0.15%	71%
Jan-13	0.21%	0.10%	51%
Feb-13	0.20%	0.13%	63%
Mar-13	0.20%	0.13%	66%
Apr-13	0.20%	0.18%	92%
May-13	0.20%	0.18%	90%
Jun-13	0.19%	0.11%	57%
Jul-13	0.19%	0.08%	43%
Aug-13	0.18%	0.09%	47%
Sep-13	0.18%	0.09%	49%
Oct-13	0.17%	0.10%	61%
Nov-13	0.17%	0.13%	78%
Dec-13	0.17%	0.14%	82%
Jan-14	0.16%	0.12%	74%
Feb-14	0.16%	0.11%	74%
Mar-14	0.15%	0.11%	73%
Apr-14	0.15%	0.13%	87%
May-14	0.15%	0.12%	80%
Jun-14	0.15%	0.10%	67%
Jul-14	0.15%	0.09%	61%
Aug-14	0.16%	0.09%	61%
Sep-14	0.15%	0.09%	55%
Oct-14	0.15%	0.08%	55%
Nov-14	0.15%	0.09%	59%
Dec-14	0.16%	0.08%	50%
Jan-15	0.17%	0.06%	38%
Feb-15	0.17%	0.06%	36%
Mar-15	0.18%	0.06%	35%
Apr-15	0.18%	0.09%	50%
May-15	0.18%	0.15%	79%
Jun-15	0.19%	0.13%	69%
Jul-15	0.19%	0.10%	55%
Aug-15	0.20%	0.09%	46%
Sep-15	0.20%	0.09%	47%
Oct-15	0.19%	0.10%	50%
Nov-15	0.21%	0.09%	45%
Dec-15	0.35%	0.08%	24%
Jan-16	0.43%	0.09%	20%
Feb-16	0.43%	0.08%	20%
Mar-16	0.44%	0.19%	45%
Apr-16	0.44%	0.41%	94%
May-16	0.44%	0.41%	93%
Jun-16	0.45%	0.43%	95%
Jul-16	0.48%	0.43%	89%
Aug-16	0.51%	0.49%	96%
Sep-16	0.53%	0.71%	134%

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2021

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Oct-16	0.53%	0.77%	146%
Nov-16	0.56%	0.58%	103%
Dec-16	0.71%	0.66%	93%
Jan-17	0.77%	0.69%	89%
Feb-17	0.78%	0.66%	84%
Mar-17	0.93%	0.71%	77%
Apr-17	0.99%	0.90%	91%
May-17	1.01%	0.82%	81%
Jun-17	1.17%	0.83%	71%
Jul-17	1.23%	0.85%	69%
Aug-17	1.23%	0.79%	65%
Sep-17	1.23%	0.87%	71%
Oct-17	1.24%	0.93%	75%
Nov-17	1.29%	0.96%	75%
Dec-17	1.49%	1.25%	84%
Jan-18	1.56%	1.35%	86%
Feb-18	1.60%	1.10%	69%
Mar-18	1.80%	1.32%	73%
Apr-18	1.90%	1.75%	92%
May-18	1.95%	1.46%	75%
Jun-18	2.07%	1.33%	64%
Jul-18	2.08%	1.10%	53%
Aug-18	2.07%	1.53%	74%
Sep-18	2.18%	1.56%	72%
Oct-18	2.29%	1.60%	70%
Nov-18	2.32%	1.69%	73%
Dec-18	2.45%	1.70%	69%
Jan-19	2.51%	1.43%	57%
Feb-19	2.49%	1.64%	66%
Mar-19	2.49%	1.67%	67%
Apr-19	2.48%	1.90%	77%
May-19	2.44%	1.72%	70%
Jun-19	2.40%	1.79%	74%
Jul-19	2.31%	1.45%	63%
Aug-19	2.17%	1.45%	67%
Sep-19	2.04%	1.48%	72%
Oct-19	1.88%	1.41%	75%
Nov-19	1.74%	1.18%	68%
Dec-19	1.75%	1.34%	77%
Average			84%

	Forward 30 Day LIBOR*	Historical Floating Rate PCRB / 30 Day LIBOR	Forecast Floating Rate PCRB
	(1)	(2)	(1) * (2)
12/31/20	1.38%	84%	1.157%
3/31/21	1.34%	84%	1.128%
6/30/21	1.34%	84%	1.128%
9/30/21	1.34%	84%	1.128%
12/31/21	1.34%	84%	1.128%
5QE Ave			1.134%

* Source: Bloomberg L.P. (2/04/20)

Rocky Mountain Power
Exhibit RMP___(NLK-6)
Docket No. 20-035-04
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Cost of Preferred Stock

May 2020

PACIFICORP
Electric Operations
Cost of Preferred Stock
12 Months Ended December 31, 2020

Line No.	Description of Issue	Issuance Date	Call Price	Annual Dividend Rate	Shares O/S	Total Par or Stated Value O/S	Net Premium & (Expense)	Net Proceeds to Company	% of Gross Proceeds	Cost of Money	Annual Cost	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
1	**Serial Preferred, $100 Par Value**											1
2	7.00% Series	(a)	None	7.000%	18,046	$1,804,600	(b)	$1,804,600	100.000%	7.000%	$126,322	2
3	6.00% Series	(a)	None	6.000%	5,930	$593,000	(b)	$593,000	100.000%	6.000%	$35,580	3
4												4
5	**Total Cost of Preferred Stock**			**6.753%**	**23,976**	**$2,397,600**	**$0**	**$2,397,600**		**6.753%**	**$161,902**	5
6												6
7												7
8	(a) 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.											8
9	(b) Original issue expense/premium has been fully amortized or expensed.											9
10												10