UNS ELECTRIC, INC.
Schedule 3-C1 Workpaper Detail - TEAM
TOTAL COMPANY AND ACC JURISDICTION
DETAIL OF PRO FORMA ADJUSTMENTS AS SHOWN ON SCHEDULE 3-C1
For the Period XX XX, XXXX to December XX XX, XXXX
(Thousands of Dollars)

		Total Company		ACC Jurisdiction		
Line No.	Description	Decision xxxxx Income Tax	Adjusted Decision xxxxx Income Tax	Decision xxxxx Income Tax	Adjusted Decision xxxxx Income Tax	Line No.
		(A)	(B)	(C)	(D)	
1	Pre-Tax Operating Income	$ -	$ -	$ -	$ -	1
2	Allocated Interest Expense	-	-	-	-	2
3	Adjusted Operating Income	$ -	$ -	$ -	$ -	3
4	Income Tax Expense Before Adjustments	-	-	-	-	4
5	Income Tax Expense Adjustments					5
6	Permanent Differences	-	-	-	-	6
7	AZ Tax Credits net of Federal Benefit	-	-	-	-	7
8	Flow Through Expense	-	-	-	-	8
9	EDIT - Fed Plant Protected	-	-	-	-	9
10	EDIT - Fed Plant Unprotected	-	-	-	-	10
11	EDIT - State	-	-	-	-	11
12	EDIT - Fed Non-Plant	-	-	-	-	12
13	Other	-	-	-	-	13
14	Total Adjustments	$ -	$ -	$ -	$ -	14
15	Tax Expense	$ -	$ -	$ -	$ -	15
16	Tax Expense Pro Forma		$ -		$ -	16
17	Federal Tax Rate	0.000%	0.000%	0.000%	0.000%	17
18	Composite State Tax Rate	0.000%	0.000%	0.000%	0.000%	18
19	Federal Deduction for State Taxes	0.000%	0.000%	0.000%	0.000%	19
20	Composite Tax Rate	0.000%	0.000%	0.000%	0.000%	20

Docket No. E-04204A-22-0251

Decision No. 79277

Exhibit E

UNS Electric, Inc.
DOCKET NO. E-04204A-22-0251

UNS Electric, Inc.
~~2015~~Demand Side Management Adjustor Charge
Plan of Administration

Table of Contents

1. GENERAL DESCRIPTION

This document describes the plan for administering the Demand Side Management Adjustor Charge ("DSMAC") approved for UNS Electric, Inc. ("UNS Electric" or "Company") by the Arizona Corporation Commission ("Commission") pursuant to the Electric Energy Efficiency Standards, A.A.C. R14-2-2401, et seq.

The DSMAC described in this Plan of Administration ("POA") provides for the recovery of Demand Side Management ("DSM") program costs, including energy efficiency and demand response programs, and energy efficiency performance incentives. The DSMAC is applied to all customers' bills as a monthly kilowatt-hour ("kWh") charge.

2. DEFINITIONS

DSM - Demand-Side Management, the implementation and maintenance of one or more DSM programs.

DSM Program - One or more DSM measures provided as part of a single offering to customers.

DSMAC Tariff - The Commission-approved schedule of rates designed to recover UNS Electric's reasonable and prudent costs of complying with the Energy Efficiency Standards.

EEIP – Energy Efficiency Implementation Plan.

Energy Efficiency - The production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end-use customers.

Energy Efficiency Standard or Standard - The reduction in retail energy sales, in percentage of kWh, required to be achieved through UNS Electric's approved DSM programs as prescribed in A.A.C R14-2-2404.

Energy Savings - The reduction in a customer's energy consumption directly resulting from a DSM program, expressed in kWh.

MER – The 3rd party measurement, evaluation, and research process.

Net Benefits - The incremental benefits resulting from DSM minus the incremental costs of DSM.

Program Costs - The costs associated with the design, implementation, management and compliance, contained in UNS Electric's EEIP and incurred by the Company, which otherwise would not be incurred without the Commission's energy efficiency mandate and which are not recovered through base rates.

All other terms and definitions associated with the DSMAC are contained in A.A.C. R14-2-2401.

3. FILING AND PROCEDURAL DEADLINES

UNS Electric (UNSE) will develop a three-year DSM Implementation Plan to include DSM goals to be achieved in MWA and MWh over the three-year planning cycle and outline a portfolio of DSM programs to achieve those goals. At UNSE's request and upon ACC approval, the three-year DSM Implementation Plan can be renewed, revised, or extended as needed. The DSM Implementation Plan cycle described herein supersedes the requirements of A.A.C. R14-2-2405 to file implementation plans on June 1 of each odd yar, or annually at the election of each effected utility.

UNSE will propose any important updates to DSM programs and budgets for the upcoming program year in the March 1 Annual Progress Report filings. Updates will be based on actual program performance from the prior year and progress achieved toward the three-year savings goals. Unless otherwise directed by the Commission, these proposed modifications would take effect 60 days after the March 1 filing date.

~~Changes to the EE Implementation Plans will be filed with the Commission in accordance with the Standard, A.A.C R14-2-2405(A):~~

> ~~*"Except as provided in R14-2-2418, on June 1 of each odd year, or annually at the election of each affected utility, each affected utility shall file with Docket Control, for Commission review and approval, an implementation plan describing how the affected utility intends to meet the energy efficiency standard for the next one or two calendar years, as applicable, except that the initial implementation plan shall be filed within 30 days of the effective date of this Article."*~~

Requested changes to the DSMAC will be filed with the Commission with each three-year DSM Implementation Plan, and, at the election of the Company, may be filed annually each June 1st while the three-year DSM Implementation Plan is in effect.~~-in accordance with the following sections of the EE Standards:~~

~~A. Implementation Plans, A.A.C. R14-2-2405(B)(2):~~

> ~~*"Except for the initial implementation plan, which shall describe only the next calendar year, a description of how the affected utility intends to comply with this Article for the next two calendar years, including an explanation of any modification to the rates of an existing DSM adjustment mechanism or tariff that the affected utility believes is necessary."*~~

~~B. Implementation Plans, A.A.C. R14-2-2405(B)(5):~~

> ~~*"A DSM Tariff filing complying with R14-2-2406(A) or a request to modify and reset an adjustment mechanism complying with R14-2-2406(C), as applicable;"*~~

~~C. DSM Tariffs, A.A.C. R14-2-2406(C):~~

> ~~*"If an affected utility has an existing adjustment mechanism to recover the reasonable and prudent costs associated with implementing DSM programs, the affected utility may, in lieu of making a tariff filing under subsection (A), file a request to modify and reset its adjustment mechanism by submitting the information required under subsections (A)(1) and(3)".*~~

~~D. Adjustor Reset and Reporting Requirements Decision No. 72747 (January 20, 2012):~~

> ~~*"IT IS FURTHER ORDERED that, in any year during which the Company does not file an Implementation Plan, or does not address the DSM adjustor reset within its Implementation Plan, an adjustor reset application should be filed separately, no later than April 1."*~~

~~If UNS Electric does not file an EEIP in the even numbered year, the Company may file proposed modifications to the EEIP if UNS Electric or the Commission determines a change or addition is necessary.~~

4. RATE SCHEDULE APPLICABILITY

The DSMAC shall be applied monthly to every customer unless exempted by order of the Commission.

5. ALLOWABLE COSTS

Program Costs ("PC") recovered through the DSMAC include but are not limited to the following: DSM Program development, implementation, marketing and promotion, administrative and general, legal , reporting, training and technical assistance, marketing and communications, monitoring and metering , advertising, educational expenditures, customer incentives, research and development, data collection, tracking and information technology systems, self-direction costs, MER, demonstration facilities and all other activities required to design and implement cost-effective DSM Programs included in the EEIP and approved by the Commission.

UNS Electric includes wages and salaries for employees working to plan, implement, or manage DSM Programs in UNS Electric base rates. If, due to the lag between rate cases, actual labor costs for employees working to plan, implement, or manage DSM Programs, exceed the amount approved in base rates, the incremental labor cost will be allocated among programs and included into the calculation of the DSMAC.

If any DSM Programs generate revenue, any such revenue will be included as a credit in the calculation of the DSMAC.

6. PERFORMANCE INCENTIVE

The Performance Incentive ("PI"), as approved by the Commission in Decision No. 72747 (January 20, 2012), is calculated using the lessor of: (i) 8% of the calculated Net Benefits; or (ii) the annual kWh savings from all approved DSM Programs included in the 3rd party MER report, multiplied by $0.0125 per kWh.

7. TRUE-UP COMPONENT

The True-Up Component is intended to refund or recover the balance of Program Costs and Performance Incentives that have been under or over recovered during the previous EE Plan year. The True-Up Component will be included in the calculation of the subsequent year's DSMAC.

The True-Up Component will be calculated by subtracting actual Program Costs and Program Incentives from the DSMAC collections and accruals for the EE Plan year ending December 31.

8. CALCULATION OF THE DSM ADJUSTOR CHARGE

UNS Electric may file a revised DSMAC as part of its EE Implementation Plan or through a supplemental filing by April 1st. The DSMAC will be based on the sum of estimated Program Costs and Performance Incentives for the upcoming year and the True-Up Component divided by the previous calendar year's kWh sales. The DSMAC calculation will be included on Schedule 1.

The DSMAC will be calculated as follows:

UNS Electric, Inc.
DOCKET NO. E-04204A-22-0251

$$\text{DSMAC} = \frac{\text{PC} + \text{PI} + \text{TU}}{\text{Sales}}$$

Where:

PC	=	Program Costs as defined in Section 5 forecast for the upcoming year.
PI	=	Performance Incentives as defined in Section 6 forecast for the upcoming year.
TU	=	"True-Up" component balance as defined in Section 7.
Sales	=	kWh sales by rate class for the previous calendar year.

9. REVIEW PROCESS

The DSMAC, and the effective date, is subject to review and approval by the Commission pursuant to A.A.C. R14-2-2406(B).

10. SCHEDULES

The following schedules are attached to this Plan of Administration:

Schedule 1: DSMAC Calculations
Schedule 2: UNS Electric Operating Revenue
Schedule 3: DSMAC Balance

UNS ELECTRIC, INC.
SYSTEM RELIABILITY BENEFITS ("SRB") MECHANISM
PLAN OF ADMINISTRATION

Table of Contents

1. GENERAL DESCRIPTION

This document describes the plan of administration for the SRB approved for UNS Electric, Inc. ("UNSE") by the Arizona Corporation Commission ("Commission") in Decision No. XXXXX (DATE). The SRB provides for the recovery of SRB Capital Carrying Costs related to reliability investments made by UNSE and not already recovered in base rates or recovered through another Commission-approved mechanism. The SRB will be calculated based on the SRB Qualified Investments closed to plant-in-service per SRB Table 2.

2. DEFINITIONS

Annual SRB Adjustment – The Annual SRB Adjustment represents the SRB Capital Carrying Costs on the SRB Qualified Investments, with adjustments as applicable for the 3% year over year cap, earnings test, balancing account, and deferred amounts. The Annual SRB Adjustment is recovered in the subsequent twelve-month period and is assessed to customer's bills via the SRB $/kWh rate.

SRB Qualified Investments – Investments in Qualified Reliability Projects. Each SRB Qualified Investment shall: 1) be classified in one or more of the FERC Plant In-Service accounts listed in Section 3 of this document, or any other successor FERC account, upon going into service, and 2) be tracked by a specific project number.

Qualified Reliability Projects - Investments in generating and energy storage resources costing $25 million or more that are acquired by UNSE through an all-source request for proposal ("ASRFP") process.

SRB Capital Carrying Costs – Costs recovered through the SRB include a return on SRB Qualified Investments based on UNSE's Weighted Average Cost of Capital ("WACC") approved by the Commission in UNSE's most recent rate proceeding; depreciation expense; income taxes including applicable tax credits; property taxes; deferred income taxes and tax credits; and associated operating and maintenance ("O&M") costs. SRB Capital Carrying Costs are then reduced for a 5% Efficiency Credit.

SRB Table 1A – The schedule of ASRFPs which have been initiated and are in process. The schedule shall be limited to the details included in any applicable public announcement.

SRB Table 1B – The schedule of planned SRB eligible projects that have gone through the ASRFP process and have been publicly announced. The schedule shall include the following:

A. Type (e.g. energy storage, wind, solar, gas, etc.).
B. Size (MW).
C. Location.
D. Estimated in-service month and year.
E. Other project descriptions.

SRB Table 2 – The schedule of completed SRB eligible projects that have gone through the ASRFP process. The schedule shall include the following:

A. Project tracking number
B. Type (e.g. energy storage, wind, solar, gas, etc.).
C. Size (MW).
D. Location.
E. Actual in-service month and year.
F. Other project descriptions.
G. Total cost.
H. ACC jurisdictional cost.

SRB Surcharge Request – The Company's 1st SRB filing, and any subsequent SRB filings that includes additional projects in Table 2.

SRB Surcharge Update – SRB filings that do not include additional projects in Table 2. Such filings shall present updated information for Rate Schedules 1 through 4.

Total Retail kWh Sales – Total retail kWh sales served under applicable ACC jurisdictional rate schedules as reported in UNSE's FERC Form No. 1 for the prior calendar year.

3. SRB QUALIFIED INVESTMENTS - FERC ACCOUNTS

Each SRB Qualified Investment may be classified in one or more of the FERC Plant in Service Accounts listed below, any successor FERC account, or any other FERC Account approved by the Commission upon going into service. The FERC Plant in Service Accounts shall include the following:

Steam Production

- 310 – Land and Land Rights
- 311 – Structures and Improvements
- 312 – Boiler Plant Equipment
- 313 – Engines and Engine-Driven Generators

- 314 – Turbogenerator Units
- 315 – Accessory Electric Equipment
- 316 – Miscellaneous Power Plant Equipment

Nuclear production

- 320 Land and land rights
- 321 Structures and improvements
- 322 Reactor plant equipment
- 323 Turbogenerator units
- 324 Accessory electric equipment
- 325 Miscellaneous power plant equipment

Hydraulic Production

- 330 Land and land rights.
- 331 Structures and improvements.
- 332 Reservoirs, dams, and waterways.
- 333 Water wheels, turbines and generators.
- 334 Accessory electric equipment.
- 335 Miscellaneous power plant equipment.
- 336 Roads, railroads and bridges.

Other Production

- 340 Land and land rights.
- 341 Structures and improvements.
- 342 Fuel holders, producers, and accessories.
- 343 Prime movers.
- 344 Generators.
- 345 Accessory electric equipment.
- 346 Miscellaneous power plant equipment.

Energy Storage

- 348 Energy Storage Equipment – Production
- 351 Energy Storage Equipment - Transmission
- 363 Energy Storage Equipment - Distribution Steam Production:

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions. No other investments under the SRB are allowed without approval by the Commission in an order.

4. ANNUAL SRB ADJUSTMENT AND ANNUAL INCREMENTAL CAP

The Annual SRB Adjustment is applied to applicable customers' total bill via a $/kWh rate.

The Annual SRB Adjustment to be recovered is subject to an annual 3% year over year cap based on the total retail revenue requirement approved by the Commission in UNSE's most recent rate proceeding. If the Annual SRB Adjustment results in a surcharge in excess of the

3% year over year cap, any amount in excess of the 3% cap will be deferred for collection until the next SRB filing, but subject to the earnings test described in Section 9.

5. CALCULATION OF SRB $ PER KWH RATE

The SRB rate to be applied to customers' bills will be calculated by dividing the annual SRB Adjustment after Cap by Total Retail kWh Sales.

6. SRB BALANCING ACCOUNT

UNSE will maintain accounting records that accumulate the difference between the actual allowable SRB Annual Adjustment as compared to the actual revenues received by the Company through the SRB surcharge during the recovery period. The difference will be recorded to the SRB Balancing Account each month and will be provided in Rate Schedule 2 of the filing. If Annual SRB Adjustments are more or less than the revenues collected, the over or under collection will be subtracted from or added to the SRB calculation in the subsequent SRB filing.

7. SRB FILING AND PROCEDURAL DEADLINES

a. Progress Reports – The Company must file with Docket Control semi-annual status reports delineating the status of all SRB eligible projects in the form of Table 1A and Table 1B. Progress reports for the June 30th reporting period are due August 30th, and progress reports for the December 31st reporting period are due on February 28th.
b. At least 60 days prior to an SRB Surcharge Request, UNSE shall file notice with the Commission.
c. SRB Surcharge Requests – To obtain an SRB Surcharge the Company must file the following:
    a. SRB Tables 1A and 1B
    b. SRB Table 2
    c. SRB Rate Schedules 1 - 4
d. UNSE will maintain and provide Excel schedules with formulae intact supporting all SRB calculations.
e. UNSE may make no more than one SRB Surcharge Request every twelve months with no more than five SRB Surcharge Requests between rate case decisions.
f. UNSE shall file an SRB Surcharge Update for each year that does not include an SRB Surcharge Request, due every twelve months.
g. An SRB Balancing Account true-up must be filed with each SRB Surcharge Request, except the first, and with each SRB Surcharge Update.
h. Any SRB Surcharge in effect shall be reset to remove SRB eligible projects once such projects are included in UNSE's base rates.

Commission Staff and interested parties shall have the opportunity to review the SRB filing and supporting data. Staff will use its best efforts to process the matter such that a new SRB adjustment may go into effect within 90 days. However, the new SRB will not go into effect until approved by the Commission.

8. DEPRECIATION RATES

SRB Capital Carrying Costs shall be determined using applicable depreciation rate(s) which are equal to the depreciation rate(s) approved in UNSE's most recent rate case. If a resource addition does not have a comparable applicable depreciation rate, UNSE shall file a request for an approved depreciation rate within 120 days of the estimated resource in service date. Comparable applicable depreciation rate means, for example, that a new wind resource may adopt the depreciation rates for an existing wind resource. New resource types, such as a new type of energy storage technology, require a depreciation rate filing.

9. EARNINGS TEST

SRB Surcharge Requests shall include an earnings test. The earnings test shall:

a. Be based on the income statements, balance sheets, and other supporting information contained in the Company's most recent FERC Form 1.
b. Be based on the ACC jurisdictional allocations of UNSE's FERC Form 1 data. Allocations shall be performed in the same manner as the methods used in UNSE's most recent rate case.
c. Include references to all data used in the test. References include, but are not limited to:
    i. FERC Form 1 page, line, and column.
    ii. ACC Decision No., page, and line.
    iii. Company rate case standard filing schedule page, line, and column.
    iv. Company rate case workpaper.
    v. Other Company records necessary to perform the test. Such records shall be available for Commission Staff's review.
d. Determine an SRB Earnings Test Revenue Cap, and as a result, must exclude the SRB revenues contained in UNSE's FERC Form 1 income statement, while including the full annualized revenue requirement for the SRB Qualified Investments. The SRB Surcharge shall be based on the lessor of the SRB Earnings Test Revenue Cap or the 3% year over year cap. The excess amount shall be deferred for collection until a subsequent Surcharge Request, and subject to such future request's earnings test and year over year cap.
e. Not include any other income, expense, or rate base adjustments other than those necessary for parts b. and d. of this section.

10. COMPLIANCE SCHEDULES

UNSE will provide the following compliance schedules in support of its SRB rate filing:

- SRB Table 1A – Initiated ASRFPs
- SRB Table 1B – SRB Eligible Projects Pursuant to ASRFP Process
- SRB Table 2 – Completed SRB Eligible Projects
- Rate Schedule 1 - Annual SRB Capital Carrying Costs
- Rate Schedule 2 - SRB Balancing Account, Year Over Year Cap, Annual Adjustment and Rate Calculations
- Rate Schedule 3 – Estimated Residential Bill Impact
- Rate Schedule 4 – Earnings Test

UNS ELECTRIC, INC.
System Reliability Benefits
Table 1A: Initiated All Source Request for Proposals
As of Month. Day. Year

Line No.	(A) Detail A	(B) Detail B	(C) Detail C	(D) Detail D	(E) Detail E
1.	XXXX	XXXX	XXXX	XXXX	XXXX
2.	XXXX	XXXX	XXXX	XXXX	XXXX
3.	XXXX	XXXX	XXXX	XXXX	XXXX

UNS ELECTRIC, INC.
System Reliability Benefits
Table 1B: SRB Eligible Projects Pursuant to All Source Request for Proposal Process
As of Month. Day, Year

Line No.	(A) Type	(B) Size	(C) Location	(D) Estimated In-Service Month and Year	(E) Other Project Descriptions
1.	XXXX	XXXX	XXXX	MM/YY	XXXX
2.	XXXX	XXXX	XXXX	MM/YY	XXXX
3.	XXXX	XXXX	XXXX	MM/YY	XXXX

UNS ELECTRIC, INC.
System Reliability Benefits
Table 2: Completed SRB Eligible Projects
As of Month, Day, Year

Line No.	(A) Project Tracking Number	(B) Type	(C) Size	(D) Location	(E) In-Service Month and Year	(F) Other Project Descriptions	(G) Total Cost	(H) ACC Jurisdictional Cost
1.	XXXX	XXXX	XXXX	XXXX	MM/YY	XXXX	$ 0	$ 0
2.	XXXX	XXXX	XXXX	XXXX	MM/YY	XXXX	-	-
3.	XXXX	XXXX	XXXX	XXXX	MM/YY	XXXX	-	-
4.		Total					$ 0	$ 0

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UNS ELECTRIC, INC.
System Reliability Benefits
Rate Schedule 1: Annual SRB Capital Carrying Costs
As of Month, Day, Year

Line No.			
	SRB Qualified Net Plant		
1.	Qualified Investment Cost (Table 2 - Total of Column H)	$	0
2.	Accumulated Depreciation	$	0
3.	Accumulated Deferred Income Taxes and Investment Tax Credits	$	0
4.	Qualified Net Plant (Line 1 - Line 2 - Line 3)	$	0
5.	Pre-Tax Weighted Average Cost of Capital		0.00%
	SRB Capital Carrying Costs		
6.	Composite Return on SRB Qualified Net Plant (Line 4 * Line 5)	$	-
7.	Annual Depreciation Expense	$	0
8.	Annual Property Tax and Income Tax Credits (Not Included on Line 3).	$	0
9.	Annual O&M Expense	$	0
10.	Total Annual SRB Capital Carrying Costs (Line 6 + Line 7 + Line 8 + Line 9)	$	0
	Efficiency Credit		

UNS ELECTRIC, INC.
System Reliability Benefits
Rate Schedule 2: SRB Balancing Account, Year Over Year Cap, Annual Adjustment and Rate Calculations
As of Month, Day, Year

Line No.			
	SRB Balancing Account		
1.	SRB Adjustment Prior Year	$	-
2.	SRB Revenue Billed Prior Year	$	-
3.	SRB Balancing Account (Line 1 - Line 2)	$	-
	SRB Year Over Year Cap		
4.	Total Retail Revenue Requirement Approved in Decision XXXXX	$	-
5.	Annual Year Over Year Cap Percentage		3%
6.	Annual Year Over Year Cap Amount (Line 4 x Line 5)	$	-
7.	Prior Year Cap Amount (Prior Year Line 8)	$	-
8.	Current Year Cap Amount (Line 6 + Line 7)	$	-
	SRB Earnings Test Cap		
9.	Earnings Test Revenue Cap	$	-
	Annual SRB Adjustment		
10.	Current Year Annual SRB Capital Carrying Costs (Schedule 1, Line 13)	$	0
11.	SRB Balancing Account (Line 3)	$	-
12.	SRB Deferred Amounts (Prior Year Line 15)	$	-
13.	Total Annual SRB Adjustment Before Cap (Sum of Lines 10 - 12)	$	0
14.	Total Annual SRB Adjustment After Cap (Lessor of Line 8, Line 9, or Line 13)	$	-
15.	Annual SRB Adjustment Deferred	$	0
	SRB Rate		
16.	Total Company Retail Sales (kWh)		0
17.	Calculated SRB Rate ($/kWh) (Line 14 / Line 16)	$	-

UNS ELECTRIC, INC.
System Reliability Benefits
Rate Schedule 3: Estimated Residential Bill Impact
As of Month, Day, Year

	kWh	Billing Months
Summer kWh	0	0
Winter kWh	0	0
Monthly Weighted Average		0

Summer	Current Rates	Proposed Rates
Customer Charge (Single Phase)	$0.00	$0.00
Energy Charges		
First 500 kWh	$0.000000	$0.000000
501-1,000 kWh	$0.000000	$0.000000
1,001-3,500 kWh	$0.000000	$0.000000
>3,500	$0.000000	$0.000000
Power Supply Charges		
Base Power	$0.000000	$0.000000
PPFAC	$0.000000	$0.000000
SRB Charges		
SRB Charges	$0.000000	$0.000000

Summer	Current	Proposed	$ Difference	% Difference
	$0.00	$0.00	$0.00	0.00%
Blocks				
0	$0.00	$0.00	$0.00	0.00%
0	$0.00	$0.00	$0.00	0.00%
0	$0.00	$0.00	$0.00	0.00%
0	$0.00	$0.00	$0.00	0.00%
	$0.00	$0.00	$0.00	0.00%
	$0.00	$0.00	$0.00	0.00%
Subtotal	$0.00	$0.00	$0.00	0.00%
	$0.00	$0.00	$0.00	0.00%
Total Summer Bill	$0.00	$0.00	$0.00	0.00%

Winter	Current Rates	Proposed Rates
Customer Charge (Single Phase)	$0.00	$0.00
Energy Charges		
First 500 kWh	$0.000000	$0.000000
501-1,000 kWh	$0.000000	$0.000000
1,001-3,500 kWh	$0.000000	$0.000000
>3,500	$0.000000	$0.000000
Fuel Charges		
Base Power	$0.000000	$0.000000
PPFAC	$0.000000	$0.000000
SRB Charges		
SRB	$0.000000	$0.000000

Winter	Current	Proposed	$ Difference	% Difference
	$0.00	$0.00	$0.00	0.00%
Blocks				
0	$0.00	$0.00	$0.00	0.00%
0	$0.00	$0.00	$0.00	0.00%
0	$0.00	$0.00	$0.00	0.00%
0	$0.00	$0.00	$0.00	0.00%
	$0.00	$0.00	$0.00	0.00%
	$0.00	$0.00	$0.00	0.00%
Subtotal	$0.00	$0.00	$0.00	0.00%
	$0.00	$0.00	$0.00	0.00%
Total Winter Bill	$0.00	$0.00	$0.00	0.00%
Total Annual	$0.00	$0.00	$0.00	0.00%
Avg. Monthly Bill	$0.00	$0.00	$0.00	0.00%

UNS ELECTRIC, INC.
System Reliability Benefits
Rate Schedule 4: Earnings Test
As of Month, Day, Year

Line No.			
1.	Adjusted Original Cost Rate Base ("OCRB") as of December 31, XXXX	$	-
2.	Authorized Rate of Return from Decision No. XXXXX		0.00%
3.	Required Operating Income on Adjusted OCRB (Line 1 x Line 2)	$	-
4.	Return on FVI from Decision No. XXXXX	$	-
5.	Total Required Operating Income (Line 3 + Line 4)	$	-
6.	Adjusted Operating Income for the Year Ended December 31, XXXX	$	-
7.	Operating Income Deficiency (Line 5 - 6)	$	-
8.	Gross Revenue Conversion Factor		0.0000
9.	Earnings Test Revenue Cap (Line 7 x 8)	$	-

Attach supporting calculations for all amounts entered into this schedule.

Anna Tovar
COMMISSIONER

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ARIZONA CORPORATION COMMISSION
OFFICE OF COMMISSIONER ANNA TOVAR

January 29, 2024

Docket Control
Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

Re: In the matter of the application of UNS Electric, Inc. for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of UNS Electric, Inc. devoted to its operations throughout the State of Arizona and for related approvals (E-04204A-22-0251).

Dear Commissioners, Parties, and Stakeholders,

I could not support this Decision because I think the overall result is not in the best interest of customers. In my opinion, the Commission's decision has very little upside for customers. First, I think the adopted return on equity exceeded what was reasonable and prudent. There were three amendments on the table proposed by three different Commissioners that would have resulted in a more appropriate return on equity. None were adopted.

I also think the Commission failed to adequately protect low-income and residential customers. The recommended order proposed an innovative low-income bill credit program. I believe the Commission should not adopt double digit rate increases without also adopting low-income customer programs that keep pace. The Commission rejected the recommendation and instead, made it more difficult for low-income customers to pay their bills.

The Commission also had no appetite to address a rate design issue I raised. The Commission adopted a rate design that resulted in an average increase of approximately 13% for residential customers, but a mere 6.75% approximate increase for commercial and industrial customers. I believe the Commission should have redistributed the increase to give residential customers some relief.

Finally, I don't believe the system reliability benefit ("SRB") should have been adopted in this case. I applaud the effort to address gradualism and cut regulatory lag, however, I could not support the system reliability benefit in its current form. The Company equivocated when I asked if the SRB would save customers money when compared to the current approach to recovery. I could not support an adjustor that I believe is not in the best interest of customers.

As a result, I regrettably must dissent.

Sincerely,

Anna Tovar

Anna Tovar
Commissioner

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

In the Matter of the Application of PACIFICORP (U-901-E), for an Order Authorizing a General Rate Increase Effective January 1, 2023.	Application No. 22-05-___ (Filed May 5, 2022)

APPLICATION OF PACIFICORP (U-901-E) FOR AN ORDER AUTHORIZING A GENERAL RATE INCREASE

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Date: May 5, 2022

Attorneys for PacifiCorp

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

In the Matter of the Application of PACIFICORP (U-901-E), for an Order Authorizing a General Rate Increase Effective January 1, 2023.	Application No. 22-05-____ (Filed May 5, 2022)

APPLICATION OF PACIFICORP (U-901-E) FOR AN ORDER AUTHORIZING A GENERAL RATE INCREASE

Pursuant to Articles 2 and 3 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure (Rules) and Sections 451, 454, 491, 701, 728, and 729 of the California Public Utilities Code (Cal. Pub. Util. Code), PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company), respectfully submits this application requesting approval to increase its rates for electric service in California beginning January 1, 2023 (Application). As described below, PacifiCorp proposes an increase of approximately $27.9 million, or a 25.7 percent net increase, to its base electric rates in California. The revised rates will ensure PacifiCorp maintains financial integrity while the Company makes the necessary capital investments to transition to a cleaner energy future and continue its investment in wildfire mitigation and vegetation management.

I. BACKGROUND

PacifiCorp is a multi-jurisdictional utility providing retail electric service to customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. In northern California, PacifiCorp serves approximately 47,800 customers spread over more than 11,000 square miles in portions of Del Norte, Modoc, Shasta, and Siskiyou counties.

As described in the testimony of Mr. Matthew McVee, PacifiCorp is filing its first general rate case since 2018 (2019 GRC or 2019 Rate Case).[1] The Company is continuing its transition to a non-emitting energy resource mix while providing safe, reliable, and affordable electric service to its customers, which has been driven by public policy, emerging and maturing technologies, and new levels of customer engagement. Even though it has and continues to make a concerted effort to manage its controllable costs, since its 2019 Rate Case, the Company is facing increasing costs related to wildfire mitigation and vegetation management. PacifiCorp has also continued its efforts to transition to a non-emitting energy resource mix. This work, coupled with the investment required to protect its system and customers from the increasing wildfire threat and increasing costs of vegetation management, will help position the Company to continue to respond proactively and ensure delivery of safe, reliable, affordable electric service to its customers

II. SUMMARY OF APPLICATION

A. Revenue Requirement and Rate Design

As a regulated utility, PacifiCorp has a duty and an obligation to provide safe, adequate, and reliable service to customers in its California service territory while balancing costs, risks, and state energy policy objectives. PacifiCorp's proposed rate increase is due primarily to several factors: namely, the increased operating expenses and Company investments in wildfire mitigation and vegetation management. PacifiCorp understands the impact that a rate increase has on its customers, and, in order to mitigate future increases related to wildfire mitigation

[1] *In the Matter of the Application of PACIFICORP (U901-E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, Application (A.) 18-04-002 (filed April 12, 2018).

costs, the Company is proposing a mechanism that will allow it to recover these costs in between rate cases in order to smooth out rates and minimize rate shock.

PacifiCorp is proposing an increase of its currently authorized return on equity (ROE). Based on the evidence provided in the testimony and exhibits of Mr. Steven R. McDougal, PacifiCorp will earn an overall ROE in California of negative 0.17 percent for the test period under its current rate structure. This return is less than the company's currently authorized 10.0 percent ROE. The Company is requesting and increase to its ROE to 10.5 percent as supported by the testimony of Ms. Ann E. Bulkley in this proceeding. An overall price increase of approximately $27.9 million or 25.7 percent is required to produce the 10.5 percent ROE necessary to maintain PacifiCorp's financial integrity while making the necessary capital investments to transition to a cleaner energy future.

The $27.9 million increase represents an overall base revenue requirement increase of 27.8 percent, or a 25.7 percent increase on a net basis to PacifiCorp's California retail customers to become effective January 1, 2023. Based on the results of the proposed rate spread presented in the testimony and exhibits of Mr. Robert M. Meredith, PacifiCorp's proposed increase would result in the following percentage rate changes by customer class:

Customer Class	Proposed Base Price Change	Proposed Net Price Change
Residential	27.9%	25.8%
General Service		
Schedule A-25	27.9%	25.8%
Schedule A-32	27.8%	25.8%
Schedule A-36	27.9%	25.7%
Large General Service		
Schedule AT-48	27.8%	25.7%
Irrigation		
Schedule PA-20	27.9%	25.7%
Lighting	27.7%	21.9%
Overall	27.8%	25.7%

B. Post Test Year Adjustment Mechanism (PTAM) Attrition Factor

PacifiCorp requests authorization to continue the PTAM Attrition Factor adjustment as approved in A.18-04-002. The Commission has subsequently authorized the continuation of this mechanism in decisions following the 2019 Rate Case.[2] PacifiCorp proposes that the same mechanism previously approved by the Commission be used to adjust PacifiCorp rates effective January 1 of calendar years between rate cases. This request is explained in the testimony of Mr. McVee.

III. PROCEDURAL HISTORY

A. 2019 Rate Case

The Company filed its last general rate case in California on April 12, 2018 (A.18-04-002). In that application, PacifiCorp requested an increase to its authorized base electric revenue requirement of $1.06 million or 0.9 percent.[3] During the course of the proceeding, PacifiCorp revised its requested revenue requirement to $78,591,697 which represented a $0.8 million increase to rates that had been in effect.[4] Following a fully litigated proceeding, on February 18, 2020, the Commission issued Decision (D.) 20-02-025 that approved a decrease in revenue requirement, for a final revenue requirement of $71,951,494.[5]

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[2] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A.18-04-002, D.20-02-025 Appendix A, (Feb. 18, 2020), D.21-01-006 (Jan. 15, 2021)
[3] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A.18-04-002, Application and Exhibit PAC/1101, (McCoy Direct) (Apr. 12, 2018).
[4] *Id.*, Exhibit PAC/1901, (McCoy Rebuttal) (Nov. 20, 2018).
[5] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A.18-04-002, D.20-02-025, Ordering Paragraph 1, Appendix A, (Feb. 18, 2020).

B. Subsequent Applications to Modify

In D.20-02-025, the Commission directed the Company to file its next general rate case for test year 2022 in accordance with the three-year rate plan adopted in D.89-01-040.[6] The Commission also directed PacifiCorp to include in its next rate case or in an earlier application its retirement plans for all coal facilities serving California customers consistent with its Integrated Resource Plan (IRP) filings.[7]

On September 18, 2020, PacifiCorp requested that the Commission modify D.20-02-025 to grant it a one-year extension to file a general rate case and to allow for an additional Post Test Year Adjustment Mechanism (PTAM) for attrition in 2021 and provide for its use in 2022. In D.21-01-006, the Commission granted the Company's requested modification, including the change in test year from 2022 to 2023.[8]

A second petition for modification was filed on February 12, 2021, because of a delay in the issuance of the Company's 2021 IRP. Specifically, the Company requested a modification to D.20-02-025 that required the Company to include in its rate case for a 2022 test year or in an earlier application, its retirement plans for all coal facilities serving California customers. PacifiCorp requested that deadline for filing these documents be extended to the filing date of its 2023 general rate case. In D.21-07-012, the Commission granted the Company's request.[9]

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[6] *Id*, Ordering Paragraphs 11, 17, and 18.
[7] *Id.*, Ordering Paragraph 18.
[8] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A.18-04-002, D.21-01-006, Ordering Paragraphs 1 and 2, (Jan 15, 2021).
[9] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A.18-04-002, D.21-07-012, Ordering Paragraphs 1 and 2, (July 21, 2021).

V. STATUTORY AND REGULATORY REQUIREMENTS

A. Statutory and Other Authority (Rule 2.1)

Rule 2.1 requires that all applications state clearly and concisely the authorization or relief sought; cite by appropriate reference the statutory provision or other authority under which Commission authorization or relief is sought; and be verified by the applicant. The relief being sought is summarized in Section II above and is further described in the testimony and supporting exhibits accompanying this Application. The statutory and other authority under which this relief is being sought includes Articles 2 and 3 of the Rules, Sections 451, 454, 491, 701, 728, and 729 of the Cal. Pub. Util. Code, and prior decisions, orders, and resolutions of this Commission. This Application has been verified by an officer of PacifiCorp in accordance with the requirements of Rules 1.1 and 2.1.

B. Proposed Categorization, Need for Hearing, Issues to be Considered, and Proposed Schedule (Rule 2.1(c))

Rule 2.1(c) requires PacifiCorp to state "[t]he proposed category for the proceeding, the need for hearing, the issues to be considered, and a proposed schedule." PacifiCorp proposes that the Commission classify this proceeding as "ratesetting."[10] PacifiCorp acknowledges the need for evidentiary hearings in this matter and proposes the following procedural schedule:

Event	Estimated Timeline
Application Filed	May 5, 2022
Protests Due	30 days after filing appears on Commission's Daily Calendar
Response to Protests Due	10 days after the last day for filing a protest
Prehearing Conference	June 23, 2022
Scoping Memo Issued	July 14, 2022
Intervenor Testimony Due	August 9, 2022
PacifiCorp Rebuttal Testimony Due	September 2, 2022

[10] Rule 1.3(e) defines "Ratesetting" as "proceedings in which the Commission sets or investigates rates for a specifically named utility (or utilities), or establishes a mechanism that in turn sets the rates for a specifically named utility (or utilities). . ."

Event	Estimated Timeline
Evidentiary Hearings (anticipate 2 days)	September 20 – 21, 2022
Opening Briefs	October 7, 2022
Reply Briefs	October 10, 2022
Proposed Decision (PD) Issued	November 10, 2022
Comments on PD Due	November 30, 2022
Reply Comments on PD Due	December 5, 2022
Final Commission Decision (rates effective January 1, 2023)	December 15, 2022

C. Issues to be Considered and Relevant to Safety Considerations

The issues to be considered are described in this Application and the accompanying testimony, including the attached appendices.

In D.16-01-017, the Commission amended Rule 2.1(c) to require that applications clearly state the "relevant safety considerations." The Company is committed to promoting the health, safety, comfort and convenience of customers and the public at large. Safety for PacifiCorp employees, customers, and stakeholders is one of PacifiCorp's six core principles. PacifiCorp has developed and implemented various programs to enable the safety of its customers, employees, and stakeholders. In benchmarking with other electric utilities through the Edison Electric Institute, PacifiCorp has been consistently positioned in the top quartile among its peer companies with respect to safety performance.

PacifiCorp's safety strategy aligns with current best practices in safety management, including a dedication to thorough and effective employee and contractor training, and ongoing monitoring of safety practices in the field through job-site employee engagements by management and safety professionals, which are documented and analyzed to evaluate the effectiveness of the safety program and identify emerging risk trends. PacifiCorp continues to reduce and control safety risks through engineering controls such as battery-operated, strain-reducing tools, and safer design of vehicles and special equipment. The safety culture at

PacifiCorp is sustained by many safety endeavors. Employees and our unions are highly engaged in the development of company safety manuals and the selection of personal protective equipment. PacifiCorp maintains effective mechanisms for accountability to policies and procedures, but also embraces a learning approach to events to ensure management system and human factors are recognized and addressed to prevent future events. PacifiCorp also holds its contractors to a high standard of safety by requiring its contractors to register with a third-party evaluator of the contractor's safety performance.

The Company complies with all applicable safety codes, including, but not limited to, the National Electric Safety Code, the code of federal regulations and all corresponding state regulations pertaining to occupational health and safety. The Company audits its compliance by performing quarterly inspections, more extensive annual and biannual reviews, and through the analysis of field engagement findings and event data. The Company continuously communicates about safety in many ways including daily crew job briefing practice, daily "Safe & Secure" email messages, monthly safety meetings, and topic-specific safety bulletins. Safety committees perform an important function at PacifiCorp to ensure employee engagement and involvement in the safety management system.

The Company prioritizes safety for all resources and to the benefit of all employees, customers, and stakeholders.

D. Legal Name and Correspondence – Rules 2.1(a) and (b)

PacifiCorp is a public utility organized and existing under the laws of the state of Oregon. PacifiCorp's legal name is PacifiCorp. PacifiCorp engages in the business of generating, transmitting, and distributing electric energy in portions of northern California and in the states of Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232.

Communications regarding this Application should be addressed to:

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In addition, PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

E. Organization and Qualification to Transact Business – (Rule 2.2)

A certified copy of PacifiCorp's Articles of Incorporation, as amended, and presently in effect, was filed with the Commission in A.97-05-011, which resulted in Commission issuance of D.97-12-093 and is incorporated herein by reference pursuant to Rule 2.2.

F. Balance Sheet and Income Statement – (Rule 3.2(a)(1))

A copy of PacifiCorp's recent financial statements, contained in the Annual Report on Form 10-K, filed February 26, 2022, with the Securities and Exchange Commission, for the period ending December 31, 2021, is included herein as Appendix A. The Company notes that even though filed on February 26, 2022, the Form 10-K was posted to the Securities and Exchange Commission's website on February 28, 2022. In this Application, the Company will refer to the filing date of the Form 10-K.

G. Present and Proposed Rates – (Rule 3.2(a)(2) and (3))

Accompanying this application are Exhibits PAC/1100 through PAC/1109, the testimony and exhibits sponsored by Company witness Robert M. Meredith, which reflect the present and proposed rates.

H. List of Testimony and Appendices Accompanying this Application

PacifiCorp's submissions to support this Application include the following:

Appendix A is PacifiCorp's 10-K Annual Report for the period ending December 31, 2021, and filed with the Securities and Exchange Commission on February 26, 2022.

Appendix B is Berkshire Hathaway, Inc.'s definitive proxy statement (Form DEF 14A) filed with the Securities and Exchange Commission on March 11, 2022.

Exhibit PAC/100: Matthew McVee, PacifiCorp's Vice President, Regulatory Policy and Operations, presents an overview of PacifiCorp's application, describes the Company's request to continue certain authorized cost recovery mechanisms, explains the Company's proposal to revise the depreciable lives for certain coal-fueled generation units; and describes the Company's proposal to return to customers the revenues received from the sale of renewable energy certificates associated with the Pryor Mountain Wind

Project. Mr. McVee also introduces the other Company witnesses submitting testimony in support of the rate case filing.

Exhibits PAC/200 through PAC/211: Ann E. Bulkley, Principal at The Brattle Group, provides a comparison of PacifiCorp's business and financial risk compared to peer utilities, recommends a cost of equity, and provides supporting analyses.

Exhibits PAC/300 through PAC/308: Nikki L. Kobliha, PacifiCorp's Chief Financial Officer, provides the overall cost of capital recommendation for the Company, including a capital structure to maximize value and minimize risk and the current cost of debt. Ms. Kobliha also addresses the 2018 Depreciation Study.

Exhibits PAC/400: Shayleah J. LaBray, PacifiCorp's Vice President of Resource Planning and Acquisitions, describes the economic analysis performed to support PacifiCorp's decision to acquire and repower Foote Creek II, III and IV wind energy facilities. Ms. LaBray also provides information on the Company's retirement plans for all coal units serving California customers. Finally, she discusses the load forecast used in this filing.

Exhibit PAC/500: James Owen, PacifiCorp's Vice President of Environmental, Fuels, and Mining, explains how state and federal environmental requirements for PacifiCorp's coal-fueled power plants are accounted for in the Company's long-term resource planning process and how these requirements drive the retirement dates or in some cases, conversion dates of certain coal units.

Exhibits PAC/600 through PAC/602: Ryan D. McGraw, PacifiCorp's Vice President of Project Development, supports and explains the Company's decommissioning studies, the costs of which are incorporated in this proceeding.

Exhibits PAC/700 through PAC/702: Timothy J. Hemstreet, PacifiCorp's Managing Director of Renewable Energy Development, supports the prudency of the Company's efforts to acquire and repower the Foote Creek II, III, and IV wind energy facilities.

Exhibits PAC/800 through PAC/801: Allen Berreth, PacifiCorp's Vice President of Transmission and Distribution Operations, supports the Company's risk-based investment in certain transmission and distribution investments, including wildfire mitigation. Mr. Berreth also discusses vegetation management expenses.

Exhibits PAC/900 through PAC/907: Steven R. McDougal, PacifiCorp's Managing Director of Revenue Requirement, summarizes the overall 2023 test year revenue requirement, pro forma adjustments, and the rate base calculation methodology. Mr. McDougal also discusses the Company's inter-jurisdictional cost allocation methodology (2020 Protocol).

Exhibits PAC/1000 through PAC/1002: André T. Lipinski, PacifiCorp's Senior Pricing and Cost of Service Analyst, presents the functional revenue requirements and supports the marginal cost-of-service study used in this filing.

Exhibits PAC/1100 through PAC/1109: Robert M. Meredith, PacifiCorp's Director of Pricing and Tariff Policy, provides the Company's proposed rate spread, rate design, and tariff changes to recover the proposed 2023 revenue requirement to achieve fair, just, and reasonable prices for customers.

I. General Description of Property and Equipment – (Rule 3.2(a)(4))

Accompanying this Application are Exhibits PAC/900 through PAC/907, the testimony and exhibits sponsored by Mr. McDougal. Mr. McDougal's testimony and exhibits contain a general description of PacifiCorp's property and equipment, and its original cost, along with a statement of the applicable depreciation reserve.

J. Summary of Earnings – (Rule 3.2(a)(5))

Accompanying this Application are Exhibits PAC/900 through PAC/907, the testimony and exhibits sponsored by Mr. McDougal. Mr. McDougal's testimony and exhibits provide the summary of earnings on a depreciated rate base for the test period.

K. Earnings of PacifiCorp Stated for California Operations and for the Total Company – (Rule 3.2(a)(6))

Accompanying this Application are Exhibits PAC/900 through PAC/907, the testimony and exhibits sponsored by Mr. McDougal. Mr. McDougal's testimony and exhibits include a statement of earnings stated on both a total-company basis and California-allocated basis.

L. Method of Computing Depreciation Deduction – (Rule 3.2(a)(7))

For federal income tax purposes, PacifiCorp uses the applicable depreciation methods prescribed by the Internal Revenue Code in a manner that is intended to maximize the tax deduction for tax depreciation. The same applicable depreciation methods used by PacifiCorp for federal income tax purposes are used by PacifiCorp for the purposes of calculating federal income taxes in the test period for this ratemaking filing.

M. Annual Report – Subsequent Matters – (Rule 3.2(a)(8))

Pursuant to Cal. Pub. Util. Code §587 and D.97-12-088 (as modified), PacifiCorp filed its Affiliated Interest Report for Calendar Year 2020 with the Commission on May 27, 2021 (AI Report). A copy of Berkshire Hathaway, Inc.'s most recent definitive Proxy Statement filed March 11, 2022, with the Securities and Exchange Commission is included as Appendix B. Berkshire Hathaway, Inc. is the ultimate parent of PacifiCorp.

N. Statement of Basis for Requested Increase – (Rule 3.2 (a)(10))

The rate increase requested by PacifiCorp through this Application reflects and passes through to customers both increased costs and savings to the utility for providing electric service to its customers within California. PacifiCorp's proposed rate increase is primarily due to several factors, including, among other things, increased operating expenses and Company investments related to wildfire mitigation and vegetation management.

O. Public Notice – (Rule 3.2(b), (c), and (d))

The cities and counties that would be affected by the rate changes resulting from this Application include the cities and towns of Yreka, Crescent City, Alturas, Mount Shasta, Weed, Dunsmuir, Fort Jones, Dorris, and Tulelake. The counties affected by this Application are Siskiyou, Del Norte, Modoc, and Shasta. As provided in Rule 3.2(b), (c), and (d), notice of filing of this Application will be: (1) mailed to the appropriate officials of the State of California, specifically the Attorney General and Department of General Services, and the counties and cities listed above; (2) published in a newspaper of general circulation in each county in PacifiCorp's service territory within which the rate changes would be effective; (3) included with regular bills mailed to all customers affected by the proposed changes; and (4) mailed to any other persons whom PacifiCorp deems appropriate.

IV. CONCLUSION

PacifiCorp respectfully requests that the Commission issue an order, effective January 1, 2023, approving the rate increase proposed herein.

Respectfully submitted May 5, 2022, at San Francisco, California.

By: Carla Scarsella
Carla Scarsella

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Attorneys for PacifiCorp

OFFICER VERIFICATION

(Rule 1.11)

I am an officer of the reporting corporation herein, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on May 5, 2022, at Portland, Oregon.

Matthew McVee
Vice President, Regulatory Policy and Operations
PacifiCorp

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	CASE NO. PAC-E-21-07
MOUNTAIN POWER FOR	)	
AUTHORITY TO INCREASE ITS	)	Direct Testimony of Ann E. Bulkley
RATES AND CHARGES IN IDAHO	)	
AND APPROVAL OF PROPOSED	)	
ELECTRIC SERVICE SCHEDULES	)	
AND REGULATIONS	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-21-07

May 2021

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and affiliation.

A. My name is Ann E. Bulkley. I am a Senior Vice President employed by Concentric Energy Advisors, Inc. ("Concentric"). My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this direct testimony before the Idaho Public Utilities Commission ("Commission") on behalf of PacifiCorp d/b/a Rocky Mountain Power ("RMP" or the "Company"), which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy ("BHE").

Q. Please describe your education and experience.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with over 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. My resume and a summary of testimony that I have filed in other proceedings are provided as Exhibit No. 9.

Q. Please describe Concentric's activities in energy and utility engagements.

A. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting; resource planning; and energy contract negotiations. Our financial advisory activities include buy and sell-side merger, acquisition and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the appropriate Return on Equity ("ROE") for RMP's electric utility operations in Idaho and to provide an assessment of its proposed capital structure to be used for ratemaking purposes.[1] My analyses and recommendations are supported by the data presented in Exhibit No. 10 through Exhibit No. 19, which were prepared by me or under my direction.

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. As discussed in more detail in Section VII, I applied the Constant Growth Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), the Risk Premium Approach, and the Expected Earnings Analysis. My recommendation also takes into consideration: (1) RMP's capital expenditure requirements; (2) the regulatory environment in which RMP

[1] Throughout my direct testimony, I interchangeably use the terms "ROE" and "cost of equity."

operates; and (3) RMP's planned investments in renewable generation assets compared to its current generation portfolio. Finally, I considered RMP's proposed capital structure as compared to the capital structures of the proxy companies.[2] While I did not make any specific adjustments to my ROE estimates for any of these factors, I did take them into consideration in aggregate when determining where RMP's ROE falls within the range of analytical results.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized in eight sections. Section III provides a summary of my analyses and conclusions. Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital. Section V discusses current and prospective capital market conditions and the effect of those conditions on RMP's cost of equity. Section VI explains my selection of a proxy group of electric utilities. Section VII describes my analyses and the analytical basis for the recommendation of the appropriate ROE for RMP. Section VIII provides a discussion of specific business and regulatory risks that have a direct bearing on the ROE to be authorized for RMP in this case. Section IX discusses RMP's capital structure as compared with the capital structures of the utility operating company subsidiaries of the proxy group companies. Section X presents my conclusions and recommendations.

[2] The selection and purpose of developing a group of comparable companies will be discussed in detail in Section VI of my direct testimony.

III. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. My analyses and recommendations considered the following:

- The *Hope* and *Bluefield* decisions[3] that established the standards for determining a fair and reasonable authorized ROE, including consistency of the authorized return with other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the principle that the end result must lead to just and reasonable rates.
- The effect of current and prospective capital market conditions on the ROE estimation models and on investors' return requirements.
- The Company's regulatory, business, and financial risks relative to the proxy group of comparable companies and the implications of those risks in arriving at the appropriate ROE.

Q. Please explain how you considered those factors.

A. I have relied on several analytical approaches to estimate RMP's cost of equity based on a proxy group of publicly-traded companies. As shown in Figure 1, those ROE estimation models produce a wide range of results.

My conclusion as to where, within that range of results, RMP's cost of equity falls is based on market conditions, and the Company's business and financial risk relative to the proxy group. Although the companies in my proxy group are generally

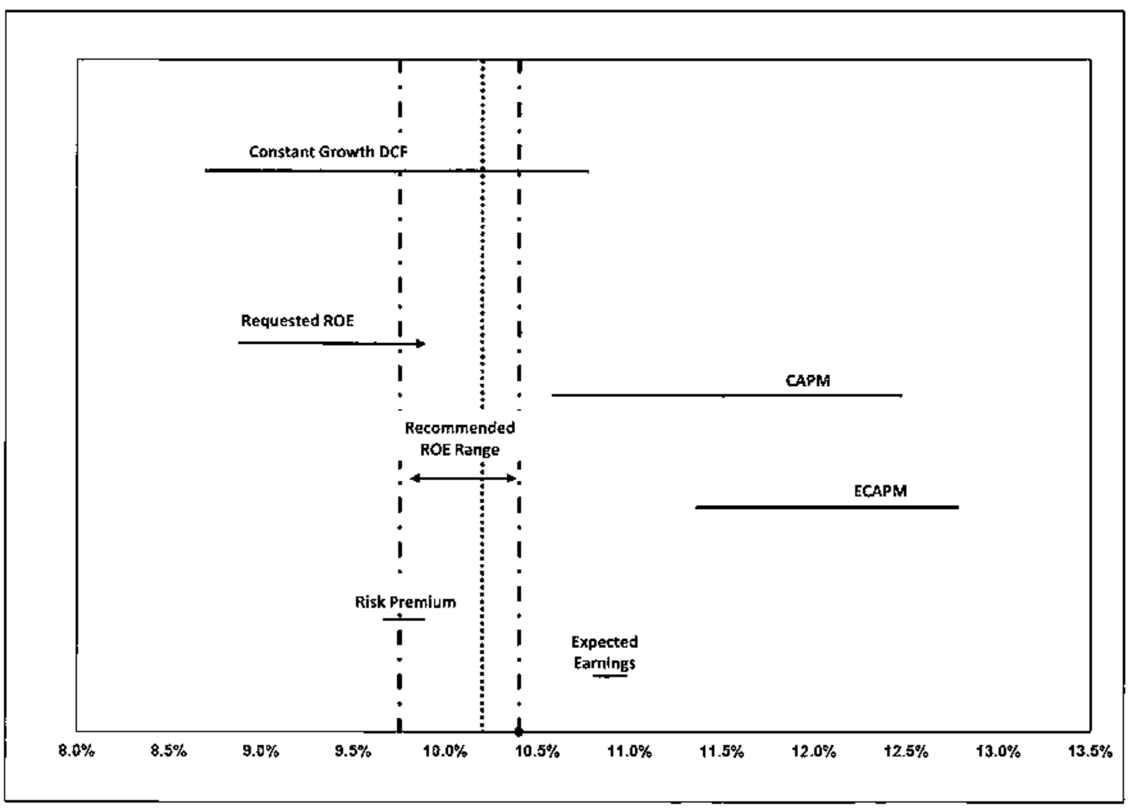
[3] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

comparable to RMP, the Company's electric business faces higher risk than the proxy group companies in several important ways that will be discussed later in my testimony. In order for RMP to compete for capital on reasonable terms, those additional risk factors should be reflected in the Company's authorized ROE.

Q. Please summarize the results of the ROE estimation models that you considered to establish the range of ROEs for RMP.

A. Figure 1 summarizes the range of results produced by the Constant Growth DCF, CAPM, ECAPM, Bond Yield Plus Risk Premium analysis, and Expected Earnings analyses.

Figure 1: Summary of Analytical Results



While it is common to consider multiple models to estimate the cost of equity, it is particularly important to do so when the range of results is wide, in order to appropriately consider the factors that have resulted in the diverging range of results. Based on current market conditions, my ROE recommendation considers the results of the DCF models, forward-looking CAPM and ECAPM analyses, a Risk Premium analysis, and an Expected Earnings analysis. I also consider company-specific risk factors and current and prospective capital market conditions.

Q. What is your recommended ROE for RMP?

A. Based on the analysis presented in Section IX of my testimony, I conclude that RMP's proposed 52.83 percent common equity is reasonable. To make this determination, I reviewed the capital structures of the utility subsidiaries of the proxy companies. As shown in Exhibit No. 19, the results of that analysis demonstrate that the average equity ratios for the utility operating companies of the proxy group range from 47.62 percent to 61.30 percent with an average of 52.75 percent. RMP's proposed common equity ratio of 52.83 percent closely approximates the average equity ratio for the utility operating subsidiaries of the proxy group companies and is well below the high end of the range.

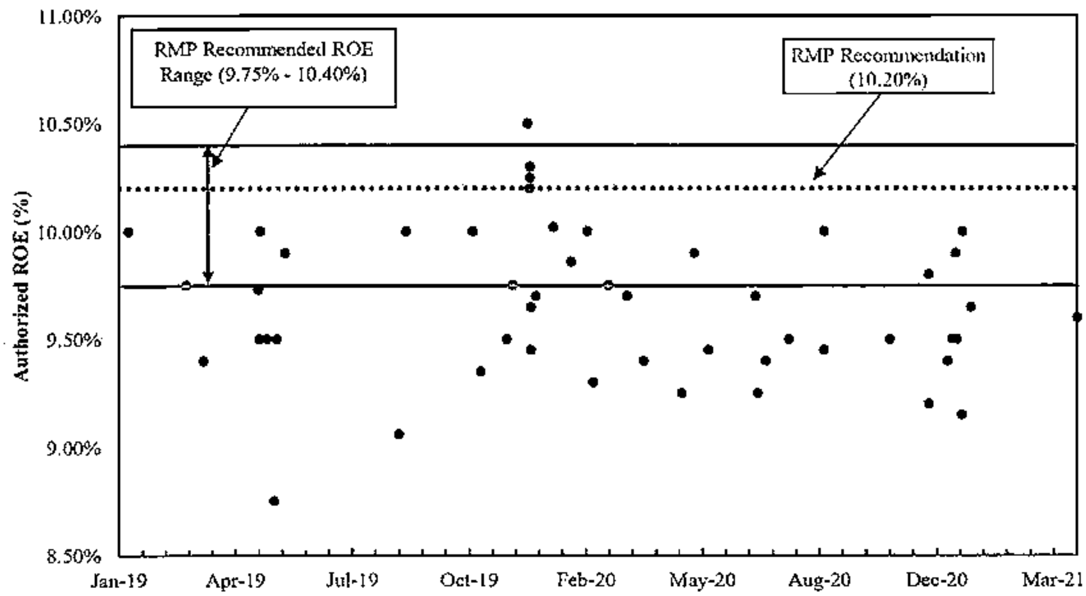
Furthermore, a fundamental aspect of the financial regulation of utilities is the assurance that the subject utility has a reasonable opportunity to earn a return on capital consistent with the return available on investments of similar risk. While this principle is most often discussed in terms of the allowed ROE, it is equally applicable to all aspects of the overall Rate of Return ("ROR"). The equity return, which is the product of the ROE and the equity ratio, (*i.e.*, the Weighted Return on Equity

("WROE")), ultimately defines the return to shareholders, and the product of the cost of debt and the debt ratio ensures that a company's debt obligations are met. Therefore, it is necessary to consider both the rates that are applied to debt and equity and the composition of the capital structure to determine the reasonableness of the ROR. Taken together, RMP's proposed common equity ratio of 52.83 percent and its requested ROE of 10.20 percent, result in a WROE of 5.39 percent. This return reasonably balances the interests of customers and shareholders by enabling RMP to maintain its financial integrity and therefore its ability to attract capital at reasonable terms and conditions under a variety of economic and financial market conditions.

Q. How does your recommended ROE compare with recently authorized ROEs for vertically integrated electric utilities?

A. As shown in Figure 2 below, the range that I have established is within the range of recently authorized ROEs. Furthermore, the Company's requested ROE of 10.20 percent is reasonable considering recently authorized ROEs and the relative risk of the Company as compared to the proxy group, which is discussed in greater detail in Section VII of my testimony.

Figure 2: Summary of Recently Authorized ROEs[4]



IV. REGULATORY GUIDELINES

Q. Please describe the guiding principles to be used in establishing the cost of capital for a regulated utility.

A. The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) that the end result, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[5]

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[4] Source: S&P Global. Includes only vertically integrated electric utility ROEs between January 1, 2019 and March 31, 2021. This data excludes a recent determination for Green Mountain Power (8.20 precent), because it was not a market-based determination, but rather was the result of a formula rate plan.

[5] *Hope*, 320 U.S. at 603; *Bluefield* , 262 U.S. at 692-93.

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes. In a 2010 RMP rate case, the Commission findings were based on the standards established in *Hope* and *Bluefield*:

> The standards for determining a fair cost of common equity for a regulated utility have been framed by two decisions of the U.S. Supreme Court: *Bluefield Water Works & Improvement Co. v. Public Serv. Commission of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). The standards to be considered provide that the authorized return should: (1) be sufficient to maintain financial integrity; (2) be sufficient to attract capital under reasonable terms; and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.[6]

This guidance is in accordance with the *Hope* and *Bluefield* decisions and the principles that I employed to estimate the ROE for RMP, including the principle that an allowed rate of return must be sufficient to enable regulated companies like RMP to attract capital on reasonable terms. Furthermore, the methodologies that I have employed are consistent with the Commission's recognition, as discussed below, that it is important to consider other information beyond the results of the financial model analysis to establish a rate of return on equity that is reasonable and reflects the investor-required return.

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[6] *In the matter of the application of PacifiCorp DBA Rocky Mountain Power for Approval of Changes to its Electric Service Schedules,* Case No. PAC-E-10-07, Order No. 32196, at 10, 2011 WL 770798 (Idaho P.U.C. February 28, 2011).

Q. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable electric utility service while maintaining its financial integrity. To the extent the Company has the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

Q. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other natural gas and electric utilities. Therefore, the ROE awarded to a utility sends an important signal to investors regarding the level of regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have an incentive to direct their capital to those investments. Thus, an authorized ROE significantly below authorized ROEs for other natural gas and electric utilities would inhibit RMP's ability to attract capital for investment.

Q. Has the Commission considered the authorized ROEs in other jurisdictions?

A. Yes. In RMP's 2010 case, the Commission relied on Staff's analysis of comparable earnings to determine the appropriate ROE for RMP: "The comparable earnings method evaluates returns earned by other companies, including utilities, to quantify an investor's expected return, taking into account the risks associated with a particular investment."[7] The earnings of other utilities are based on their ROEs.

Q. What methodologies has the Commission considered to determine an appropriate rate of return on common equity?

A. In RMP's 2010 case, the Commission considered multiple models, including DCF, comparable earnings, risk premium analysis, and the capital asset pricing model.[8]

Q. What are your conclusions regarding regulatory guidelines?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have the opportunity to recover the return of, and the market-required return on, its invested capital. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions; doing so balances the long-term interests of the utility and its customers.

The financial community carefully monitors the current and expected financial condition of utility companies and the regulatory framework in which they operate. In that respect, the regulatory framework is one of the most important factors in both debt and equity investors' assessments of risk. The Commission's order in this proceeding, therefore, should establish rates that provide RMP with the opportunity to earn a ROE that is: (1) adequate to attract capital at reasonable terms under a variety of economic and financial market conditions; (2) sufficient to ensure good financial

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[7] *Id.*
[8] *Id.*

management and firm integrity; and (3) commensurate with returns on investments in enterprises with similar risk. To the extent RMP is authorized to earn its market-based cost of capital, the proper balance is achieved between customers' and shareholders' interests.

V. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. The ROE estimation models rely on market data that are specific to the proxy group, in the case of the DCF model, or the market risk, in the case of the CAPM. The results of ROE estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the practitioner uses current and projected market data, specifically stock prices, dividends, growth rates, and interest rates in the ROE estimation models to estimate the required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the ROE estimation models. Accordingly, it is important to consider the effect of these conditions on the ROE estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, the ROE estimation may not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q. What factors affect the cost of equity for regulated utilities in the current and prospective capital markets?

A. The cost of equity for regulated utility companies is affected by several factors in the current and prospective capital markets, including: (1) the dramatic shifts in market conditions during 2020 and the expectations for 2021, and the effect of these changes on the assumptions used in the ROE estimation models; and (2) as the economy recovers from the COVID-19 recession, investors are expected to rotate into cyclical sectors; thus utilities, a defensive sector, are expected to underperform the market over the near-term. In this section, I discuss these factors and how they affect the models used to estimate the cost of equity for regulated utilities.

A. Current Market Conditions and Effect on Valuations

Q. Have you reviewed key indicators in the financial markets?

A. Yes. Market conditions were extremely volatile throughout 2020, and although the volatility has abated from the highs in 2020, volatility is still higher than the historical average. Throughout 2020 and into 2021, stock indices were volatile, reaching new threshold levels in early 2020 prior to the spread of the COVID-19 pandemic to the U.S, responding with significant volatility throughout 2020 to the uncertainty resulting from the global pandemic, and in 2021, more likely facing a "V" shaped economic recovery, stocks have rebounded. Further, as shown in Figure 3, interest rates faced a similar pattern, as the yield on the 30-year Treasury bond started January 2020 at 2.33 percent, yet since a low of 1.19 percent in August 2020, have been steadily increasing to an average of 2.41 percent as of the end of March 2021.

Figure 3: Yield on 30-Year Treasury Bond January 1, 2020- March 31, 2021[9]

The market response over the past 15 months has demonstrated that market conditions can significantly affect the assumptions used in the ROE estimation models and need to be considered in the development of any analysis. Further, the rapid changes that have been seen in market conditions demonstrate the need to ensure that utilities are positioned to have access to capital on reasonable terms in any market conditions.

Q. What steps have the Fed and Congress taken to stabilize financial markets and support the economy in 2020?

A. In the past year, the Federal Reserve has:

[9] Bloomberg Professional.

- decreased the Federal Funds rate twice in March 2020, resulting in a target range of 0.00 percent to 0.25 percent;
- increased its holdings of both Treasury and mortgaged-back securities;
- started expansive programs to support credit to large employers – the Primary Market Corporate Credit Facility to provide liquidity for new issuances of corporate bonds; and the Secondary Market Corporate Credit Facility to provide liquidity for outstanding corporate debt issuances; and
- supported the flow of credit to consumers and businesses through the Term Asset-Backed Securities Loan Facility.

In addition, Congress also passed the Coronavirus Aid, Relief, and Economic Security ("CARES") Act in March 2020, the Consolidated Appropriations Act, 2021 in December 2020 and the American Rescue Plan Act in March 2021, which included \$2.2. trillion, \$900 billion and \$1.9 trillion, respectively, in fiscal stimulus also aimed at mitigating the economic effects of COVID-19. These expansive monetary and fiscal programs have provided for greater price stability by mitigating the economic effects of the COVID-19 pandemic.

Q. Has the Federal Reserve signaled a continuation of its accommodating monetary policy?

A. Yes. On March 17, 2021, the Federal Reserve Chairman stated that, "[o]ur forward guidance for the federal funds rate, along with our balance sheet guidance, will ensure that the stance of monetary policy remains highly accommodative as the recovery progresses."[10] The Federal Reserve also indicated that it has kept the federal funds rate near zero and will continue to maintain its sizeable asset purchases of both treasuries and mortgage-backed securities until substantial further progress has been made toward its dual goals of maximum employment and price stability, noting that, "the economic recovery remains uneven and far from complete, and the path ahead remains uncertain."[11]

Q. What effect, if any, will the Federal Reserve's accommodative monetary policy have on long-term interest rates over the near-term?

A. Although the current accommodative monetary policy is expected to keep short-term interest rates low, the Federal Reserve has not committed to keeping long-term interest rates low. Long-term interest rates can and have increased even though monetary policy is accommodative. For example, the current yield on the 30-year Treasury bond has increased to nearly twice the yield on this instrument in August 2020, when bond yields were at their lowest.

Q. Have you reviewed any recent projections of economic activity for 2021?

A. Yes. Economic projections indicate the expectation for a strong recovery in 2021. The Federal Open Market Committee ("FOMC") issued its Summary of Economic Projections in March 2021, where the FOMC's median projection for GDP growth from Q4 2020 to Q4 2021 is 6.5 percent.[12] The Congressional Budget Office ("CBO") issued its outlook on economic conditions in February 2021. In that report, the CBO projected strong GDP growth for 2021 and significant strength in overall economic conditions:

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[10] FOMC Press Conference, March 17, 2021; https://www.federalreserve.gov/monetarypolicy/fomc.htm.
[11] *Ibid.*
[12] Federal Open Market Committee, Summary of Economic Projections, March 17, 2021, at 2.

- Real GDP growth of 3.7 percent, which is a significant change from the negative 2.5 percent in 2020.
- Inflation indicators nearing the 2.0 percent threshold in 2021-2022.
- Labor force expected to be restored to pre-pandemic levels in 2022.
- Interest rates on federal borrowing increasing in 2024.[13]

Further, consumer confidence has been projected to be at a high level, exceeding levels established prior to the pandemic.[14] Finally, Bloomberg recently forecasted growth of 6.9 percent, which would largely reverse the contraction seen in 2020, the definition of a "V" shaped recovery. Bloomberg also projects inflation to increase in the months ahead.[15] High growth is expected to drive an increase in U.S. bond yields and inflation in 2021, which may result in modest monetary tightening.[16] U.S. bond yields have already rebounded considerably in the past year, with 30-year Treasury bond yields up 114 basis points between April 1, 2020 and March 31, 2021, and further rebounding expected throughout the year. These trends indicate strong economic recovery over the next year, with robust consumer spending expected.

Q. Have you reviewed other market indicators to determine investors' expectations regarding the economy over the near-term?

A. Yes, I have. Specifically, I reviewed the yield curve, calculated as the difference between the yield on the 10-year Treasury Bond and the yield on the 2-year Treasury Bond from January 2015 through March 2021. I selected the 10-year Treasury Bond

[13] Congressional Budget Office, An Overview of the Economic Outlook 2021 to 2031, February 2021.
[14] IPSOS-Forbes Advisor U.S. Consumer Confidence Weekly Tracker, April 8, 2021.
[15] Bloomberg, "It's a 'V'- World Growth to Hit 60-Year High, April 13, 2021.
[16] Van Roye, Bjorn and Tom Orlik. "Tantrums, Spillovers and the $1.9T U.S. Stimulus." Bloomberg Briefs, accessed April 13, 2021.

yield to represent long-term interest rates and the yield on the 2-year Treasury Bond to represent short-term interest rates. As shown in Figure 4, the yield curve has been steepening, with the spread increasing to approximately 160 basis points, which is a level not seen since the middle of 2015. The steepening of the yield curve indicates that investors expect economic growth and inflation to increase in the near-term, and as a result they are rotating out of long-term government bonds to avoid being locked into to low interest rates for the long-term. The steep yield curve signals that higher yields are required by investors to invest in long-term government bonds.

Figure 4: 10-year Treasury Bond Yield Minus 2-year Treasury Bond Yield – January 2015 – March 2021[17]

[17] Federal Reserve Bank of St. Louis, 10-Year Treasury Constant Maturity Minus 2-Year Treasury Constant Maturity [T10Y2Y], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/T10Y2Y, March 31, 2021.

Q. What have equity analysts said about the steepening of the yield curve?

A. Several equity analysts have noted that the yield curve is steepening and is expected to continue to steepen into 2021, which is an indicator that the economy is entering the early expansion phase of the business cycle. For example, in a recent Bloomberg article, Morgan Stanley indicated that they expected a "V-shaped" economic recovery and therefore advised investors to underweight government bonds and overweight equities.[18] Similarly, Goldman Sachs strategists recently noted the following:

> As the economic recovery consolidates next year, we expect to see more differentiation across the curve, with policymakers committing to keeping front-end rates low, but higher expectations for real growth and inflation driving long-end rates higher," Goldman strategists including Zach Pandl wrote in the report, released Tuesday.
>
> This should be especially true in the U.S. due to the Federal Reserve's new average inflation targeting framework, which commits the central bank to holding off on rate hikes until inflation has reached its target and is on track to overshoot it.[19]

More recently, BTG Pactual Asset Management noted the following regarding increasing interest rates:

> "We're talking about a fair amount of stimulus -- both fiscal and monetary – going forward," BTG Pactual Asset Management's John Fath said, referring to the $1.9 trillion pandemic-relief bill and prospects for more, along with the Federal Reserve's pledge to stay accommodative. "We potentially could grow a lot faster and inflation could come into the horizon a lot quicker," which begets higher rates.[20]

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[18] Ossinger, Joanna. "Morgan Stanley Says Go Risk-On and 'Trust the Recovery' in 2021." Bloomberg.com, 15 Nov. 2020, www.bloomberg.com/news/articles/2020-11-16/morgan-stanley-says-go-risk-on-and-trust-the-recovery-in-2021.

[19] McCormick, Liz. "Goldman Goes All-In for Steeper U.S. Yield Curves as 2021 Theme." Bloomberg.com, 10 Nov. 2020, www.bloomberg.com/news/articles/2020-11-10/goldman-goes-all-in-for-steeper-u-s-yield-curves-as-2021-theme.

[20] Spratt, Stephen, et al. "Treasury Yields Leap Past Key Level to 1.64%, Highest in a Year." Bloomberg.com, Bloomberg, 12 Mar. 2021, www.bloomberg.com/news/articles/2021-03-12/treasury-yields-surge-to-test-key-level-in-sudden-selling-bout.

Finally, Citigroup also recently projected that the yield on the 10-year Treasury Bond is expected to increase in 2021, which prompted Citigroup's recommendation to overweight equities and favor cyclical sectors over defensive sectors, such as utilities.[21]

Q. How has the utility sector historically performed during periods in which the yield curve is steepening, and the economy is in the early stages of the business cycle?

A. Several market analysts have noted that utilities underperform when the economy is in the early stages of the business cycle. This is because utilities are considered a defensive sector for investors, meaning utilities are affected less by changes in the business cycle relative to other market sectors since consumers need utility services regardless of the phase of the business cycle. As such, utility stocks generally perform well during periods of uncertainty where the prospect of slowing economic growth increases.

In a recent report, Fidelity noted that the utility sector has historically been one of the worst performing sectors during the early phase of the business cycle with a geometric average return of -10.5 percent.[22] This conclusion is further supported by studies conducted by both Goldman Sachs and Deutsche Bank that examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (i.e., increases in bond yields

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[21] Keown, Callum. "10-Year Treasury Yields Will Rise Into 2021, Citi Says. This 'Aggressive' Equity Strategy Can Outperform." Barrons.com, 16 Nov. 2020, www.barrons.com/articles/10-year-treasury-yields-will-rise-into-2021-citi-says-this-aggressive-equity-strategy-can-outperform-51605543920.
[22] Fidelity Investments, "The Business Cycle Approach to Equity Sector Investing," 2020.

resulted in the decline of utility share prices).[23] This is important because if the utility sector underperforms over the near term, and prices of utility stocks decline, then the DCF model, which relies on historical averages of share prices, is likely to understate the cost of equity for the Company over the near term or the period that Company's rates will be in effect.

Barron's recently conducted its Big Money poll of 152 professional investors regarding the outlook for the next twelve months. The majority of respondents projected the yield on the 10-year Treasury Bond to be between 2.00 percent and 2.50 percent at the end of the next twelve months which is a significant increase from the current 30-day average 10-year Treasury Bond yield as of March 31, 2021 of 1.56 percent.[24] Furthermore, the utility sector was selected as the sector which will perform the worst over the next twelve months.[25] Therefore, the professional investors surveyed by Barron's are projecting that utilities will underperform the broader market in 2021.

Similarly, Charles Schwab has classified the utilities sector overall as "Underperform," noting that:

> The Utilities sector has tended to perform relatively better when concerns about slowing economic growth resurface, and to underperform when those worries fade. That's partly because of the sector's traditional defensive nature and steady revenues—people need water, gas and electric services during all phases of the business cycle. And low interest rates that typically come with a weak economy

[23] Lee, Justina. "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks." Bloomberg.com, 11 Mar. 2021, www.bloomberg.com/news/articles/2021-03-11/wall-street-is-rethinking-the-treasury-threat-to-big-tech-stocks.
[24] Jasinski, Nicholas. This Bull Market Is Far From Over, Pros Say. Where They're Investing Now. Barron's, 26 Apr. 2021, www.barrons.com/articles/stocks-have-more-room-to-rise-says-barrons-big-money-poll-51619222301?mod=past_editions.
[25] *Ibid.*

> provide cheap funding for the large capital expenditures required in this industry.
>
> However, valuations have been driven up in recent years as investors have reached for yield in this new era of low interest rates; this may decrease the sector' s traditional defensive characteristics. And while interest rates are expected to remain generally low, they could edge higher as the economy continues to expand. On the flip side, there is the potential for a renewed decline in the economy to push rates even lower, or there could be significant government funding to Utilities as part of clean-energy initiatives that would benefit the sector' s profit outlook.[26]

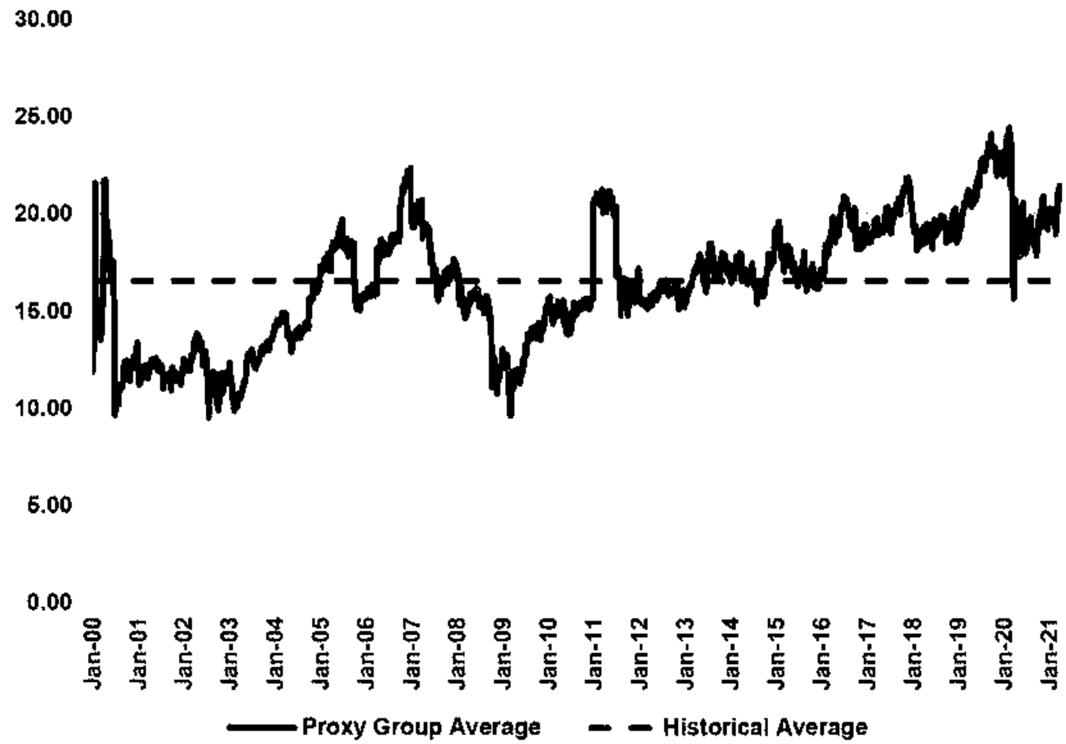
As Charles Schwab noted, the utility sector underperforms in periods of economic growth; however, given the high valuations of the utility sector, even if volatility were to increase, the utility sector might still underperform in a market setting where utilities had traditionally been overperformers.

Q. Are the valuations of the electric utilities stocks currently considered high?

Yes. The electric utility sector's valuations remain above the long-term historical average. As shown in Figure 5, the price-to-earnings ("P/E") ratio of the proxy group is currently approximately 21.3, or above the long-term average of the proxy group over this period of approximately 16.6.

[26] Charles Schwab, Utilities Sector Rating: Underperform, February 11, 2021.

Figure 5: P/E Ratios of Proxy Group Relative to the Long-Term Average, January 2000 – March 2021[27]



Q. What is the effect of high valuations of utility stocks on the DCF model?

A. High valuations have the effect of depressing dividend yields, which results in overall lower estimates of the cost of equity resulting from the DCF model. The relatively low dividend yields demonstrated over the longer historical period imply that the ROE calculated using historical market data in the DCF model may understate the forward-looking cost of equity.

[27] Bloomberg Professional.

Q. What are your conclusions regarding the effect of current market conditions on the cost of equity for RMP?

A. Given the uncertainty and volatility that has characterized capital markets over the past year, and the steady increase in interest rates since market lows in August 2020, it is reasonable that equity investors would now require a higher return on equity to compensate for the additional risk associated with owning common stock under these market conditions. Likewise, if electric and other utilities underperform the broader market going forward as expected by investors as the economy rebounds, this will indicate that investors see added risk associated with such investments, which will in turn imply an increase in the cost of equity.

Investors' current expectations regarding the economy highlights the importance of using forward-looking inputs in the models used to estimate the cost of equity. While the growth rate in the DCF model can be estimated using projections, the DCF model relies on historical average share prices. As discussed, relatively high current utility stock valuations result in low dividend yields for those companies, which means that DCF models using recent *historical* data are likely to underestimate investors' required return for RMP. Conversely, two out of three inputs (i.e., risk-free rate and market risk premium) in the CAPM can be estimated using forward-looking projections. Similarly, the Bond Yield Risk Premium and Expected Earnings analyses also use forward-looking data. Therefore, the CAPM is likely to capture more effectively the economic conditions expected by investors over the near-term. This highlights the importance of considering the results of each of the models to reflect investors' expectations of market conditions over the period that the rates established in this proceeding will be in effect.

Q. What conclusions do you draw from your analysis of capital market conditions?

A. The important conclusions regarding capital market conditions are:

- The assumptions used in the ROE estimation models have been affected by recent, historically atypical market conditions. Therefore, it is important to allow the results of multiple ROE estimation models to inform the decision on the appropriate ROE for RMP in this proceeding.
- Recent market conditions reflect short-term exogenous shocks that are not expected to persist over the long term. As a result, the recent atypical market conditions do not reflect the market conditions that are expected to be present when the rates for RMP will be in effect.
- With currently relatively high electric stock valuations, rising interest rates, analysts' expectations of a steepening yield curve, and strength in economic conditions in 2021 as the economy begins to rebound, it is increasingly important to consider a rate of return that supports the Company's cash flow metrics to enable RMP the ability to attract capital at reasonable terms during the period that rates will be in effect.

VI. PROXY GROUP SELECTION

Q. Why have you used a group of proxy companies to estimate the Cost of Equity for RMP?

A. In this proceeding, I am estimating the cost of equity for an electric utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and given that RMP's electric operations in Idaho do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to RMP in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process.

Even if RMP were a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to RMP, and thus provide a reasonable basis to derive an estimate of the appropriate ROE for RMP.

Q. Please provide a brief profile of RMP.

A. RMP is an electric utility, which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. PacifiCorp provides electric utility service to approximately 2.0 million residential, commercial, and industrial customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.[28] In Idaho, RMP provides electric service to approximately 84,500 residential, commercial, and industrial customers.[29] As of December 31, 2020, RMP had a net utility electric plant allocated to Idaho of $1.048 billion.[30] RMP's electric operations in Idaho represented 6.5 percent of PacifiCorp's electric sales in 2020.[31] PacifiCorp currently has an investment grade

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[28] Berkshire Hathaway 2020 Form 10-K at 3.
[38] Data provided by PacifiCorp.
[39] Data provided by PacifiCorp.
[40] Data provided by PacifiCorp.

long-term rating of A (Outlook: Stable) from S&P and A3 (Outlook: Stable) from Moody's.[32]

Q. How did you select the companies included in your proxy group?

A. I began with the group of 37 domestic companies that Value Line classifies as electric utilities and I simultaneously applied the following screening criteria to exclude companies that:

- pay consistent quarterly cash dividends, because companies that do not cannot be analyzed using the Constant Growth DCF model;
- have investment grade long-term issuer ratings from S&P and/or Moody's;
- are covered by at least two utility industry analysts;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- own regulated generation assets that are in rate base;
- have more than 5 percent of owned regulated generation capacity come from regulated coal-fired power plants;
- derive more than 60 percent of their total operating income from regulated operations;
- derive more than 60 percent of regulated operating income from regulated electric operations;
- were not parties to a merger or transformative transaction during the analytical periods relied on; and

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[32] SNL Financial. Accessed April 20, 2021.

- have a mean Constant DCF ROE of at least 7 percent.

Q. Please explain why you excluded companies from your proxy group with a mean Constant Growth DCF result less than 7 percent?

A. It is appropriate to exclude companies from the proxy group with a mean Constant Growth DCF result below a specified threshold at which equity investors would consider such returns to provide an insufficient return increment above long-term debt costs. For example, the average credit rating for the companies in my proxy group is BBB+.[33] The average yield on Moody's Baa-rated utility bonds for the 30 trading days ending March 31, 2021, was 3.67 percent.[34] Thus, I have eliminated companies from my proxy group with mean Constant Growth DCF results lower than 7.00 percent because such returns would provide equity investors a risk premium only 333 basis points above Baa-rated utility bonds.

Q. Did your 7 percent risk premium screen result in the exclusion of any additional companies from your electric proxy group?

A. Yes, it did. IDACORP, Inc. had mean DCF result for the 30-day average price scenario of 6.30 percent, and thus was excluded from the proxy group.

Q. What is the composition of your proxy group?

A. My proxy group consists of the companies shown in Figure 6.

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[33] The average credit rating is calculated by assigning a numerical scale of 1 to 22 to the range of S&P and Moody's rating tiers. For the proxy group the average is 8.0. This corresponds to a rating of BBB+ on the S&P scale.
[34] Source: Bloomberg Professional.

Figure 6: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
DTE Energy Company	DTE
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL

VII. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. The overall rate of return for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required ROE determined?

A. The required ROE is estimated using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the Company's Cost of Equity falls within the range of results. The key consideration in determining the Cost of Equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group) in particular.

Q. What methods did you use to determine the Company's ROE?

A. I considered the results of the Constant Growth DCF model, the CAPM and ECAPM analysis, a Bond Yield Plus Risk Premium methodology, and an Expected Earnings analysis. In addition, I considered the range of recently authorized ROEs for electric utilities, which is generally consistent with the Commission's prior consideration of a comparable earnings analysis. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q. Why is it important to use more than one analytical approach?

A. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[35] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[36] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches.

Q. Do current market conditions increase the importance of using more than one analytical approach?

A. Yes. Low interest rates and the effects of the investor "flight to quality" can be seen in high utility share valuations, relative to historical levels and relative to the broader market. Higher utility stock valuations produce lower dividend yields and result in lower cost of equity estimates from a DCF analysis. Low interest rates also affect the CAPM in two ways: (1) the risk-free rate is lower, and (2) because the market risk premium is a function of interest rates (i.e., it is the return on the broad stock market less the risk-free interest rate), the risk premium should move higher when interest rates are lower. Therefore, it is important to use multiple analytical approaches to moderate the impact that the current low interest rate environment is having on the ROE estimates for the proxy group and, where possible, consider using projected market data in the models to estimate the return for the forward-looking period.

Q. Has the Commission recognized that it is important to consider the results of multiple ROE estimation models?

A. Yes. As discussed above, it is my understanding that in determining the authorized ROE for a company, the Commission has supported consideration of the evidence presented

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[35] Tom Copeland, Tim Koller and Jack Murrin, <u>Valuation: Measuring and Managing the Value of Companies</u>, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

[36] Eugene Brigham, Louis Gapenski, <u>Financial Management: Theory and Practice</u>, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

by the parties in the rate case which has included a range of ROEs from models such as the DCF, CAPM, Risk Premium and Comparable Earnings.[37]

Q. What are your conclusions about the results of the DCF and CAPM models?

A. Recent market data that is used as the basis for the assumptions for both models have been affected by market conditions. As a result, relying exclusively on historical assumptions in these models, without considering whether these assumptions are consistent with investors' future expectations, will underestimate the cost of equity that investors would require over the period that the rates in this case are to be in effect. In this instance, relying on the historically low dividend yields that are not expected to continue over the period that the new rates will be in effect will underestimate the ROE for RMP.

Furthermore, as discussed in Section V above, Treasury bond yields have experienced unprecedented volatility in recent months due to the economic effects of COVID-19 and the subsequent intervention into the Treasury bond market by the Federal Reserve. However, long-term interest rates have increased since August 2020 and this trend is expected to continue over the near-term as the economy enters the recovery phase of the business cycle. Therefore, the use of current averages of Treasury bond yields as the estimate of the risk-free rate in the CAPM is not appropriate since recent market conditions are not expected to continue over the long-term. Instead, analysts should rely on projected yields of Treasury Bonds in the CAPM. The projected Treasury Bond yields results in CAPM estimates that are more

[37] *In the matter of the application of PacifiCorp DBA Rocky Mountain Power for Approval of Changes to its Electric Service Schedules*, Case No. PAC-E-10-07, Order No. 32196 at 10-12 (Feb. 28, 2011).

reflective of the market conditions that investors expect during the period that the Company's rates will be in effect.

B. Constant Growth DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty}$$

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty}$$

[1]

Where P_0 represents the current stock price, $D1 \ldots D\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g$$

$$k = \frac{D_0(1+g)}{P_0} + g$$

[2]

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the Constant Growth DCF model?

A. The Constant Growth DCF model requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate.

To the extent that any of these assumptions is violated, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A. The dividend yield in my Constant Growth DCF model is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended March 31, 2021.

Q. Why did you use 30-, 90-, and 180-day averaging periods?

A. In my Constant Growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the ROE is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long-term. However, the averaging periods that I use rely on historical data that are not consistent with the forward-looking market expectations. Therefore, the results of my Constant Growth DCF model using historical data may underestimate the forward-looking cost of equity. As a result, I place more weight on the mean to mean-high results produced by my Constant Growth DCF model.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes, I did. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its Constant Growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. It, therefore, is important to incorporate a variety of sources of long-term earnings growth rates into the Constant Growth DCF model.

Q. Which sources of long-term earnings growth rates did you use?

A. My Constant Growth DCF model incorporates three sources of long-term earnings growth rates: (1) consensus estimates from Zacks Investment Research; (2) consensus estimates from Thomson First Call (provided by Yahoo! Finance); and (3) Value Line Investment Survey.

C. DCF Model Results

Q. How did you calculate the range of results for the DCF model?

A. I calculated the low results for the DCF model using the minimum growth rate (*i.e.*, the lowest of the First Call, Zacks, and Value Line earnings growth rates) for each of the proxy group companies. Thus, the low results reflect the minimum DCF result for the proxy group. I used a similar approach to calculate the high results, using the highest growth rate for each proxy group company. The mean results were calculated using the average growth rates from all three sources.

Q. Please summarize the results of your DCF analysis.

A. Figure 7 summarizes the results of my DCF analyses. As shown in Figure 7, the mean DCF results range from 9.85 percent to 9.93 percent and the mean high results are in the range of 10.73 percent to 10.82 percent. While I also summarize the mean low DCF results, I do not believe that the low DCF results provide a reasonable spread over the expected yields on Treasury bonds to compensate investors for the incremental risk related to an equity investment.

Figure 7: Constant Growth Discounted Cash Flow Results[38]

	Mean Low	Mean	Mean High
30-Day Average	8.66%	9.85%	10.73%
90-Day Average	8.69%	9.88%	10.77%
180-Day Average	8.74%	9.93%	10.82%

D. CAPM Analysis

Q. Please briefly describe the Capital Asset Pricing Model.

A. The CAPM is a risk premium approach that estimates the Cost of Equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. This second component is the product of the market risk premium and the Beta coefficient, which measures the relative riskiness of the security being evaluated.

[38] *See* Exhibit No. 12.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market ROE;
β = Beta coefficient of an individual security;
r_f = the risk-free rate of return; and
r_m = the required return on the market as a whole.

In this specification, the term $(r_m - r_f)$ represents the market risk premium. According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$\beta = \frac{\text{Covariance}(r_e, r_m)}{\text{Variance}(r_m)} \quad [4]$$

The variance of the market return (*i.e.*, *Variance* (r_m)) is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the general market (*i.e.*, *Covariance* (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, Beta represents the risk of the security relative to the general market.

Q. What risk-free rate did you use in your CAPM analysis?

A. I relied on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds (*i.e.*, 2.31 percent);[39] (2) the projected 30-year U.S. Treasury bond yield for Q3 2021 through Q3 2022 of 2.60 percent;[40] and (3) the projected 30-year U.S. Treasury bond yield for 2022 through 2026 of 2.80 percent.[41]

Q. Would you place more weight on one of these scenarios?

A. Yes. Based on current market conditions, I place more weight on the results of the projected yields on the 30-year Treasury bonds. As discussed previously, the estimation of the cost of equity in this case should be forward-looking because it is the return that investors would receive over the future rate period. Therefore, the inputs and assumptions used in the CAPM analysis should reflect the expectations of the market at that time. While I have included the results of a CAPM analysis that relies on the current average risk-free rate, this analysis fails to take into consideration the effect of the market's expectations for interest rate increases on the cost of equity.

Q. What Beta coefficients did you use in your CAPM analysis?

A. As shown on Exhibit No. 13, I used the average Beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. The Bloomberg Beta coefficients are calculated based on ten years of weekly returns relative to the S&P 500 Index. Value Line's calculation is based on five years of weekly returns relative to the New York Stock Exchange Composite Index.

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[39] Bloomberg Professional, as of March 31, 2021.
[40] Blue Chip Financial Forecasts, Vol. 40, No. 4, April 1, 2021, at 2.
[41] Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020, at 14.

Additionally, as shown in Exhibit No. 14, I also considered an additional CAPM analysis which relies on the long-term average utility Beta coefficient for the companies in my proxy group. The long-term average utility Beta coefficient was calculated as an average of the Value Line Beta coefficients for the companies in my proxy group from 2011 through 2020.

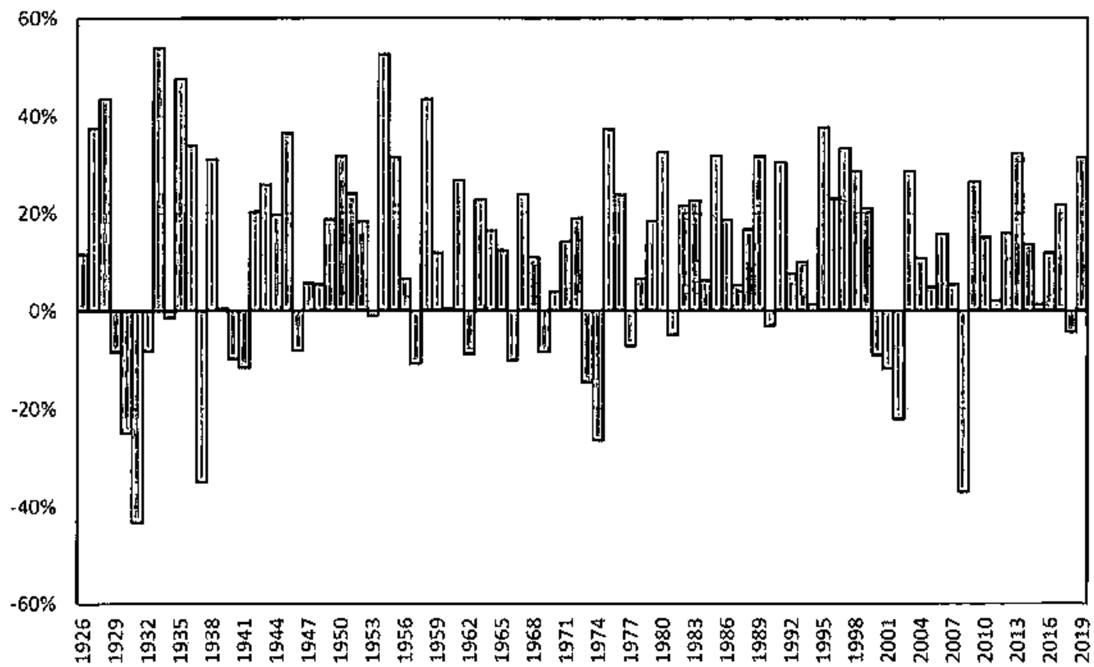
Q. How did you estimate the market risk premium in the CAPM?

A. I estimated the Market Risk Premium ("MRP") as the difference between the implied expected equity market return and the risk-free rate. The expected return on the S&P 500 Index is calculated using the Constant Growth DCF model discussed earlier in my testimony for the companies in the S&P 500 Index for which dividend yields and Value Line long-term earnings projections are available. Based on an estimated market capitalization-weighted dividend yield of 1.50 percent and a weighted long-term growth rate of 12.11 percent, the estimated required market return for the S&P 500 Index is 13.71 percent. The implied market risk premium over the current 30-day average of the 30-year U.S. Treasury bond yield, and projected yields on the 30-year U.S. Treasury bond, ranges from 10.91 percent to 11.40 percent.

Q. How does the current expected market return of 13.71 percent compare to observed historical market returns?

A. Given the range of annual equity returns that have been observed over the past century (shown in Figure 8), a current expected return of 13.71 percent is not unreasonable. In 47 out of the past 94 years (or roughly 50 percent of observations), the realized equity return was at least 13.71 percent or greater.

Figure 8: Realized U.S. equity market returns (1926-2019)[42]



Q. Did you consider another form of the CAPM in your analysis?

A. Yes. I have also considered the results of an ECAPM or alternatively referred to as the Zero-Beta CAPM[43] in estimating the cost of equity for RMP. The ECAPM calculates the product of the adjusted Beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

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[42] Depicts total annual returns on large company stocks, as reported in the 2020 Duff and Phelps SBBI Yearbook.

[43] See e.g., Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 189.

k_e = the required market ROE;

β = Adjusted Beta coefficient of an individual security;

rf = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In essence, the Empirical form of the CAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low Beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted Betas; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[44]

As with the CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier as the risk-free rate, and the Bloomberg, Value Line, and long-term average Beta coefficients.

Q. What are the results of your CAPM analyses?

A. As shown in Figure 9 (*see also* Exhibit No. 13 and Exhibit No. 14), relying on the long-term average beta, the results of the CAPM are 10.58 percent to 10.72 percent. The entire range of the CAPM analysis is from 10.58 percent to 12.47 percent. The ECAPM analysis results range from 11.36 percent to 12.78 percent.

[44] *Id.*, at 191.

Figure 9: CAPM Results

	Current Risk-Free Rate (2.31%)	Q3 2021 – Q3 2022 Projected Risk-Free Rate (2.60%)	2022-2026 Projected Risk-Free Rate (2.80%)
CAPM			
Value Line Beta	12.41%	12.44%	12.47%
Bloomberg Beta	11.48%	11.53%	11.57%
Long-term Avg. Beta	10.58%	10.66%	10.72%
ECAPM			
Value Line Beta	12.73%	12.76%	12.78%
Bloomberg Beta	12.03%	12.08%	12.11%
Long-term Avg. Beta	11.36%	11.42%	11.47%

E. Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. This approach is based on the fundamental principle that because bondholders have a superior right to be repaid, equity investors bear a residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a "risk-free" class of bonds.

Q. Are there other considerations that should be addressed in conducting this analysis?

A. Yes, there are. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates. That is, as interest rates increase, the equity risk premium decreases, and vice versa. Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. In my analysis, I used actual authorized returns for electric utility companies and corresponding long-term Treasury yields as the historical measure of the cost of equity to determine the risk premium. If we let authorized ROEs for electric utilities serve as the measure of required equity returns and define the yield on the long-term U.S. Treasury bond as the relevant measure of interest rates, the risk premium simply would be the difference between those two points.[45]

Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A. Yes, it is. Investors are aware of ROE awards in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors.

[45] *See* e.g., S. Keith Berry, Interest Rate Risk and Utility Risk Premia during 1982-93, Managerial and Decision Economics, Vol. 19, No. 2 (March 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. See also Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return, Financial Management, Spring 1986, at 66.

Q. What did your Bond Yield Plus Risk Premium analysis reveal?

A. As shown in Figure 10 below, from 1992 through March 2021, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

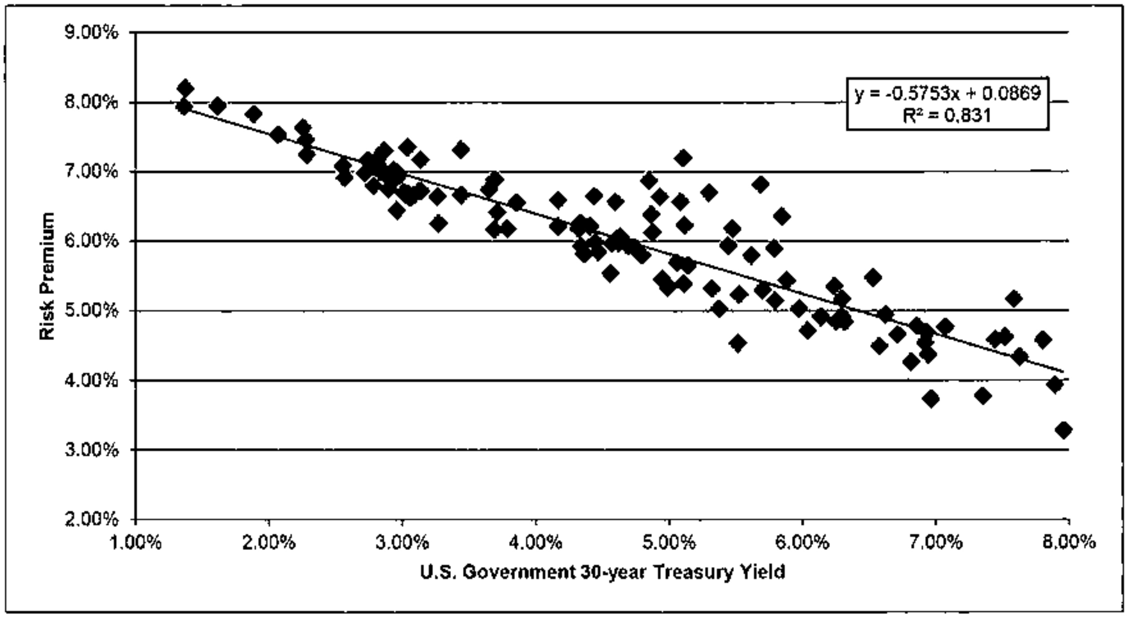
b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding allowed ROEs were derived from 654 vertically integrated electric utility rate cases from 1992 through March 2021 as reported by Regulatory Research Associates ("RRA").[46] This equation's coefficients were statistically significant at the 99.00 percent level.

[46] This analysis began with a total of 1,287 electric utility cases, which were screened to eliminate limited issue rider cases, transmission cases, distribution only cases, and cases that did not specify an authorized ROE. After applying those screening criteria, the analysis was based on data for 654 cases.

Figure 60: Risk Premium Results



As shown on Exhibit No. 15, based on the current 30-day average of the 30-year U.S. Treasury bond yield (i.e., 2.31 percent), the risk premium would be 7.37 percent, resulting in an estimated ROE of 9.67 percent. Based on the near-term (Q3 2021 – Q3 2022) projections of the 30-year U.S. Treasury bond yield (i.e., 2.60 percent), the risk premium would be 7.20 percent, resulting in an estimated ROE of 9.80 percent. Based on longer-term (2022 – 2026) projections of the 30-year U.S. Treasury bond yield (i.e., 2.80 percent), the risk premium would be 7.08 percent, resulting in an estimated ROE of 9.88 percent.

Q. How did the results of the Bond Yield Risk Premium inform your recommended ROE for RMP?

A. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE for RMP. As noted above, investors consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The Risk Premium analysis considers this comparison by estimating the return expectations of investors based on the current and past ROE awards of electric utilities across the U.S.

F. Expected Earnings Analysis

Q. Have you considered any additional analysis to estimate the cost of equity for the Company?

A. Yes. I have considered an Expected Earnings analysis based on the projected ROEs for each of the proxy group companies.

Q. What is an Expected Earnings analysis?

A. The Expected Earnings methodology is a comparable earnings analysis that calculates the earnings that an investor expects to receive on the book value of a stock. The Expected Earnings analysis is a forward-looking estimate of investors' expected returns. The use of an Expected Earnings approach based on the proxy companies provides a range of the expected returns on a group of risk comparable companies to the subject company. This range is useful in helping to determine the opportunity cost of investing in the subject company, which is relevant in determining a company's ROE.

Q. Have any regulators considered the use of an Expected Earnings analysis?

A. Yes. In its order in Docket No. ER12111052 for Jersey Central Power and Light Company, the New Jersey Board of Public Utilities ("NJ Board") noted that rate of return experts use a number of models including the DCF, CAPM, Risk Premium, and Comparable Earnings to estimate the return required by investors. Specifically, the Board noted:

> In determining the cost of equity capital for a regulated utility, rate of return experts typically use a variety of financial models to simulate

> the returns assertedly required by investors. These include Discounted Cash Flow (DCF) models, Risk Premium models, Capital Asset Pricing Models (CAPM), Comparable Earnings models and variations thereof. However, it is widely acknowledged that these economic models constitute estimates, which, although probative, are not necessarily precise. The imprecision in the estimates provided by these models is more pronounced as a result of the current economic environment still recovering from the Great Recession, characterized by some as the worst economy since the Great Depression.[47]

The Indiana Utility Regulatory Commission ("IURC") has also allowed the use of Expected Earnings, stating in another rate case, for example:

> Four models were used to determine a cost of equity: DCF; CAPM; Risk Premium; and Expected Earnings. Each was discussed in varying degrees by the Parties in this Cause. The expert witnesses of each Party used the same proxy group of seventeen electric utility companies to conduct their respective analyses. While Dr. Avera also submitted analyses using a proxy group of non-utility companies, we give little weight to those analyses due to the inherent differences between regulated utilities and non-utility companies operating in a free-market system.[48]

The IURC further supported the use of Expected Earnings in its authorized rate decision, citing the projected returns, in this case over the following 3 to 5 years:

> Vectren South submitted evidence supporting an 11.5% ROE but moderated its request to 10.7% to limit the amount of the proposed increase in this case. The OUCC proposes an ROE of 9.25% and the Industrial Group proposes an ROE of 9.85%. Vectren South must compete for capital attraction with other utilities. The expert witnesses of each party have used the same proxy group of 17 electric utility companies. Dr. Avera's exhibits show that these companies are projected by Value Line to have returns on average common equity of 11.5% over the next 3 to 5 years. In his Sustainable Growth Rate DCF calculation, Mr. Gorman has projected a return on year-end equity for

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[47] *JCP&L Co. – Base Rate 2012 Increase Adjustments Rates and Charges for Electric Service*, BPU Docket No. ER12111052, OAL Docket No. PUC16310-12, Order Adopting Initial Decision with Modifications and Clarifications, at 71 (NJ Board March 18, 2015).

[48] . *Petition of Southern Indiana Gas and Electric Company for Approval of and Authorization for Rate Increase* Cause No. 43839, Order, at 28 (Ind. U.R.C. April 27, 2011).

these companies of 10.87%. Vectren South currently has an authorized ROE of 10.40%. (Emphasis added)[49]

Q. How did you develop the Expected Earnings approach?

A. I relied on Value Line projections of the return on equity capital for the proxy companies for the period from 2024-2026.[50] I adjusted those projected ROEs to account for the fact that the ROEs reported by Value Line are calculated on the basis of common shares outstanding at the end of the period, as opposed to average shares outstanding over the period. As shown in Exhibit No. 16, the Expected Earnings analysis for the proxy group results in a mean of 10.98 percent and median of 10.81 percent.

VIII. REGULATORY AND BUSINESS RISKS

Q. Do the mean DCF, CAPM, Risk Premium and Expected Earnings results for the proxy group provide an appropriate estimate of the Cost of Equity for RMP?

A. No. These results provide only a range of the appropriate estimate of the Company's Cost of Equity. There are additional factors that must be taken into consideration when determining where the Company's Cost of Equity falls within the range of analytical results. I have also considered the regulatory risk faced by RMP in determining the overall risk profile of the Company as compared with the proxy group and RMP's projected level of capital expenditures.

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[49] *Id.*, at 28.

[50] Due to the timing of the release of the Value Line Reports, Year 0 and Years 4-6 are 2019 and 2023-2025 for AVA, NWE, PNW, POR and XEL, respectively, and Year 0 and Years 4-6 are 2020 and 2024-2026 for all other proxy group companies.

A. Capital Expenditure Plan

Q. Please summarize the PacifiCorp's projected capital expenditure requirements.

A. PacifiCorp's current projections for 2022 through 2026 include approximately \$11.2 billion in capital investments for the period.[51] Based on PacifiCorp's net utility plant of approximately \$20.9 billion as of December 31, 2020, the \$11.2 billion anticipated capital expenditures are approximately 53.41 percent.[52]

Q. How is the Company's risk profile affected by its substantial capital expenditure requirements?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for a significant amount of capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks

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[51] Berkshire Hathaway 2020 Form 10-K at 113 (2022-2023); 2024-2026 estimated as average of 2022-2023.
[52] Berkshire Hathaway 2020 Form 10-K at 230.

> that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[53]

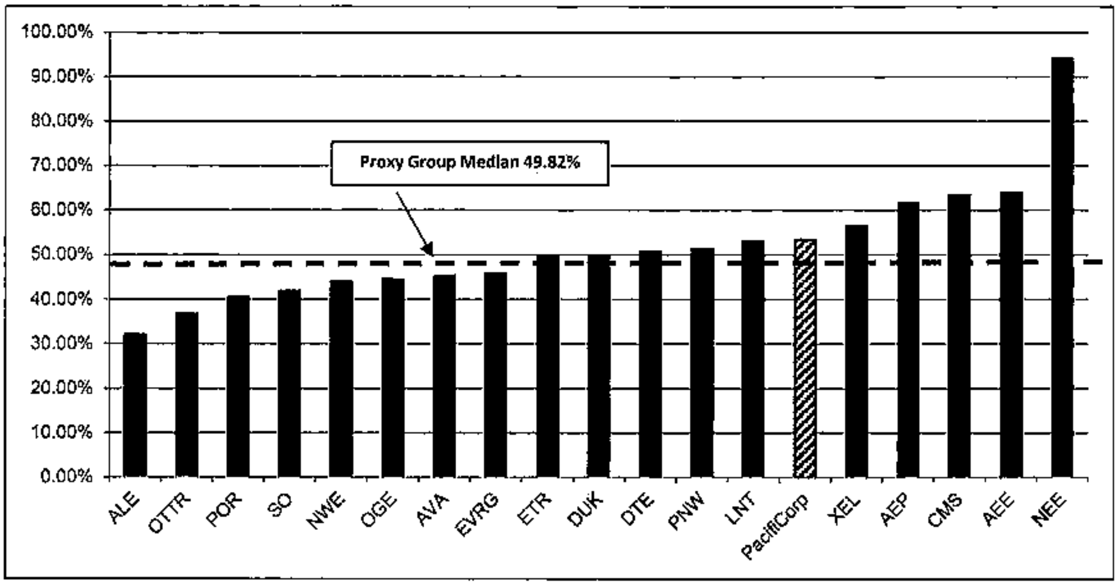
Therefore, to the extent that RMP's rates do not continue to permit the recovery of its capital investments on a regular basis, the Company would face increased recovery risk and thus increased pressure on its credit metrics.

Q. How do PacifiCorp's capital expenditure requirements compare to those of the proxy group companies?

A. As shown in Exhibit No. 17, I calculated the ratio of expected capital expenditures to net utility plant for PacifiCorp and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2022-2026 by its total net utility plant as of December 31, 2020. As shown in Exhibit No. 17 (*see also* Figure 12 below), PacifiCorp's ratio of capital expenditures as a percentage of net utility plant of 53.41 percent is approximately 1.07 times the median for the proxy group companies of 49.82 percent. This result indicates greater risk to the Company, relative to the companies in the proxy group.

[53] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

Figure 71: Comparison of Capital Expenditures – Proxy Group Companies



Q. How does RMP's ability to recover capital expenditures compare with the proxy companies?

A. RMP has the ability to recover major capital expenditures on a case by case basis, for instance through the Resource Tracking Mechanism ("RTM"), which is consistent with the cost recovery of significant infrastructure investments by the proxy group companies. As shown in Exhibit No. 18, 51.72 percent of the proxy group utilities recover costs through capital tracking mechanisms. On this basis, RMP is comparable to the proxy group companies.

B. Regulatory Risk Assessment

Q. Please explain how the regulatory environment affects investors' risk assessments.

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers. Utilities must finance their operations and require the opportunity to earn a reasonable return on their invested capital to maintain their financial profiles. RMP is no exception. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions. Equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. Please explain how credit rating agencies consider regulatory risk in establishing a company's credit rating.

A. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework, and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[54]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[55] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[56]

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[54] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.
[55] Standard & Poor's Global Ratings, Ratings Direct, U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others, June 25, 2018, at 2.
[56] *Id.*, at 1.

Q. Have you performed a regulatory risk assessment of Idaho as compared to the jurisdictions in which the proxy group companies operate?

A. Yes. Specifically, I examined the following factors that affect the business risk of RMP and the proxy group companies: (1) test year convention; (2) rate base convention; (3) fuel cost recovery; (4) use of revenue decoupling mechanisms or other clauses that mitigate volumetric risk; and (5) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Exhibit No. 18 and are summarized below.

- Test year convention: RMP uses a historical test year adjusted for known and measurable changes in Idaho, while 36.78 percent of the operating companies held by the proxy group that provide service in jurisdictions that use a fully or partially forecast test year.
- Rate Base: RMP is relying on a year-end rate base in this proceeding, which is consistent with approximately 39 percent of the operating subsidiaries held by the proxy group.
- Fuel and Energy Cost Recovery: RMP has an Energy Cost Adjustment Mechanism ("ECAM") to recover power costs. However, while traditional fuel cost recovery mechanisms allow all variances between projected fuel costs and actual fuel costs to be recovered from or refunded to customers, the ECAM for RMP only allows recovery of 90 percent of the difference between projected and actual fuel costs. As a result, the ECAM does not fully mitigate the power cost risk for RMP. This is important to recognize because fuel and purchased power costs typically account for a significant percentage of the total operating

costs for a regulated utility. Moreover, according to SNL Financial, there are only seven states (i.e., Hawaii, Idaho, Missouri, Montana, Oregon, Washington and Wyoming) that have fuel cost recovery mechanisms with sharing bands.[57] The remaining 43 states either have restructured and the electric utilities do not own generation or have fuel cost recovery mechanisms with a true-up between actual and forecasted fuel costs. Finally, 91.86 percent of the operating companies held by my proxy group are allowed to pass through fuel costs and purchased power costs directly to customers, without deadbands and sharing bands.

- Volumetric Risk: RMP does not have protection against volumetric risk in Idaho. In contrast, 49.43 percent of the operating companies held by the proxy group have some form of protection against volumetric risk through either a partial or full revenue decoupling mechanism that mitigates the effect of fluctuations in volume on revenues.
- Capital Cost Recovery: Despite being able to recover costs on a case by case basis, RMP does not have an ongoing and structured capital tracking mechanism to recover major new capital investments between rate cases. A total of 51.72 percent of the operating companies held by the proxy group have some form of capital cost recovery mechanism in place.

[57] Source: SNL Financial, Commission Profiles as of May 11, 2020.

Q. Has RRA provided recent commentary regarding its regulatory ranking for RMP?

A. Yes. In April 2020, RRA updated its evaluation of the regulatory environment in Idaho indicating an average ranking based on the recovery mechanisms and decoupling mechanisms that have been implemented for several utilities:

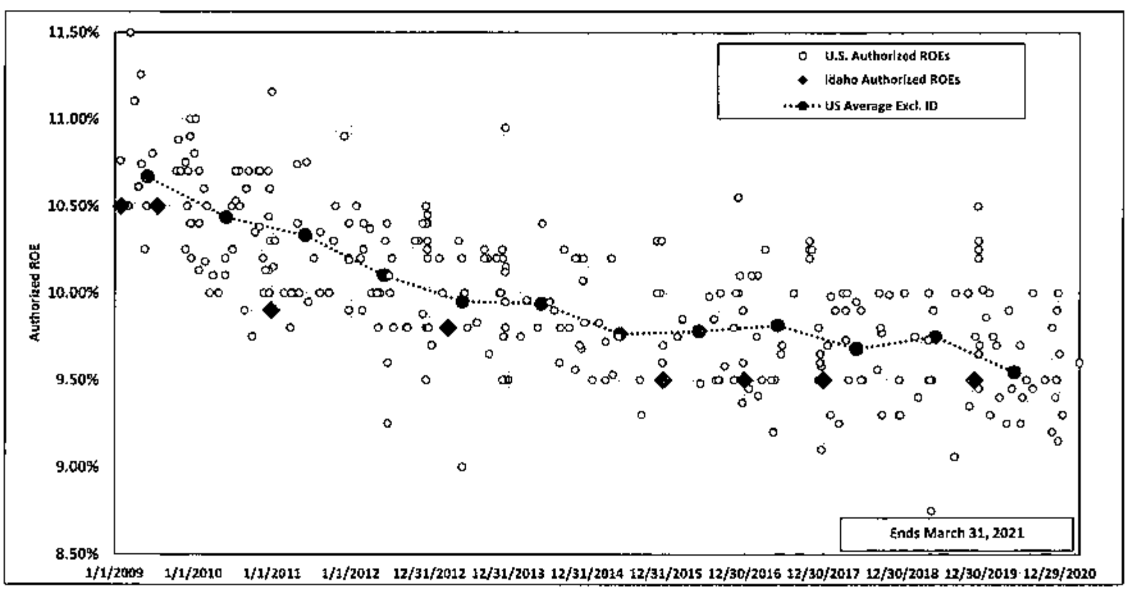
> Idaho regulation is relatively balanced from an investor viewpoint according to Regulatory Research Associates, a group within S&P Global Market Intelligence. Recent rate proceedings have been resolved via settlements, the vast majority of which have been silent with respect to rate-of-return parameters. However, historically, when the PUC established equity returns for the utilities, the returns specified were below prevailing industry-wide averages at the time authorized. One utility operates under and earnings sharing mechanism that effectively allows the company to retain earnings up to a 10% ROE, which is above current industry average return authorizations. The state's electric utilities remain vertically integrated and are regulated under a traditional paradigm. At times, the PUC has utilized a partially forecast test period. State law permits electric utilities to request "binding" ratemaking treatment from the commission for the recovery of costs associated with new power generation or transmission facilities, and in accordance with the law, an electric utility was granted ratemaking assurances for one facility. Power cost adjustment mechanisms are in effect for the state's electric utilities; these mechanisms contain symmetrical sharing provisions. Decoupling mechanisms are in place for certain electric utilities, and gas utilities operating in the state recover commodity costs through semiautomatic adjustment clauses. Utility mergers generally have been approved by the PUC without onerous restrictions. Regulatory Research Associates continues to accord Idaho an Average/2 ranking.[58]

[58] Source: S&P Global, Regulatory Research, accessed April 20, 2021.

Q. How do recent returns in Idaho compare to the authorized returns in other jurisdictions?

A. As noted in RRA's evaluation above, the authorized ROEs for electric and natural gas utilities in Idaho, while partially the result of settlement agreements approved by the Commission, have been below the average authorized ROEs for electric and natural gas utilities across the U.S. Figure 12 below shows the authorized returns for vertically integrated electric utilities in other jurisdictions since January 2009, and the returns authorized in Idaho. As shown in Figure 12, the authorized returns in Idaho have historically been below the average authorized ROE for vertically integrated electric utilities in other jurisdictions.

Figure 82: Comparison of Idaho and U.S. Authorized Electric Returns[59]



[59] Source: S&P Global Market Intelligence.

Q. Is there any reason that the Commission should be concerned about authorizing equity returns that are at the low end of the range established by other state regulatory jurisdictions?

A. Yes. Credit rating agencies take the authorized ROE into consideration in the overall risk analysis of a company. Therefore, to the extent that the returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. For example, Moody's recently downgraded ALLETE, Inc. from A3 to Baa1 for reasons that included the less than favorable outcome in Minnesota Power's last rate case in Minnesota. Moody's viewed Minnesota Power's recent rate case decision as credit negative for reasons which included: (1) the below average authorized ROE of 9.25 percent which resulted in a reduction of approximately $20 million between the requested and approved revenue requirement; (2) the disallowance of certain expenses such as prepaid pension expenses; and (3) the decision to not adopt the annual rate review mechanism ("ARRM") which if adopted would have mitigated the effect of industrial customers scaling back production in response to changes in economic conditions.[60]

In addition, FitchRatings recently downgraded CenterPoint Energy Houston Electric's ("CEHE") Long-Term Issuer Default rating from A- to BBB+ and revised the rating outlook from Stable to Negative following the approval of an unfavorable outcome in a recent rate case in Texas. FitchRatings indicated that the unfavorable outcome signals a more challenging environment in Texas for CEHE and that the

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[60] Moody's Investors Service, Credit Opinion: ALLETE, *Inc*. Update following downgrade, at 3 (April 3, 2019).

authorized ROE and equity ratio, as well as tax reform refunds will create pressure on credit metrics. FitchRatings also indicated that further negative rating action could be possible if the company's FFO leverage remains above 5x.[61]

RMP must compete for capital with other utilities and businesses; therefore, placing RMP at the low end of authorized ROEs outside Idaho over the longer term can negatively impact its access to capital.

Q. How should the Commission use the information regarding authorized ROEs in other jurisdictions in determining the ROE for RMP?

A. As discussed above, the companies in the proxy group operate in multiple jurisdictions across the U.S. Since RMP must compete directly for capital with investments of similar risk, it is appropriate to review the authorized ROEs in other jurisdictions. The comparison is important because investors are considering the authorized returns across the U.S. and are likely to invest equity in those utilities with the highest returns. Furthermore, investors are also likely to consider business and financial risks for a company like RMP which faces increased risk as a result of its capital expenditure plan and limited cost recovery mechanisms. Therefore, authorizing an ROE for RMP that is equivalent to the average authorized ROE for other vertically integrated electric utilities is not sufficient to compensate investors for the added risk of RMP. As such, it is important that the Commission consider, as I have in my recommendation, the additional risk of RMP and place the authorized ROE for RMP towards the high end of authorized ROEs for other vertically integrated electric utilities.

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[61] FitchRatings, Fitch Downgrades CenterPoint Energy Houston Electric to BBB+; Affirms CNP; Outlooks Negative, February 19, 2020.

Q. What are your conclusions regarding the perceived risks related to the Idaho regulatory environment?

A. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Many of the companies in the proxy group have more timely cost recovery through fuel cost recovery mechanisms, fully forecasted test years, year-end rate base in all cases, capital cost recovery trackers, and revenue stabilization mechanisms than RMP has in Idaho. Additionally, authorized ROEs in Idaho have been below the average authorized ROEs for electric and gas utilities across the U.S. Considering all of the similarities and differences, I conclude that the authorized ROE for RMP should be higher than the proxy group mean.

C. Generation Ownership

Q. How does the business risk of vertically integrated electric utilities compare to the business risk of other regulated utilities?

A. According to Moody's, generation ownership causes vertically integrated electric utilities to have higher business risk than either electric transmission and distribution companies, or natural gas distribution or transportation companies.[62] As a result of this higher business risk, integrated electric utilities typically require a higher ROE or percentage of equity in the capital structure than other electric or gas utilities.

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[62] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 21-22.

Q. Are there other risk factors specific to vertically integrated electric utilities that the credit rating agencies consider when determining the credit rating of a company that owns generation?

A. Yes. As discussed above, Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. The third factor, diversification, which Moody's assigns a 10.00 percent weighting in the overall assessments of a company's business risk, considers the fuel source diversity of a utility with generation. Moody's notes:

> For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.[63]

For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.[64]

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[63] *Id.*, at 16.
[64] *Id.*, at 16.