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IDAHO PUBLIC
UTILITIES COMMISSION

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-23-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-23-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	DIRECT TESTIMONY
NATURAL GAS SERVICE TO ELECTRIC	)	OF PATRICK D. EHRBAR
AND NATURAL GAS CUSTOMERS IN THE	)	IN SUPPORT OF
STATE OF IDAHO	)	STIPULATION

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

I. INTRODUCTION

Q. Please state your name, employer, and business address.

A. My name is Patrick D. Ehrbar and I am employed as the Director of Regulatory Affairs for Avista Utilities ("Company" or "Avista"), at 1411 East Mission Avenue, Spokane, Washington.

Q. Have you previously filed direct testimony in this proceeding?

A. No, I have not.

Q. Please provide information pertaining to your educational background and professional experience?

A. I am presently assigned to the Regulatory Affairs Department as the Director of Regulatory Affairs. I am a 1995 graduate of Gonzaga University with a Bachelor of Business Administration degree. In 1997 I graduated from Gonzaga University with a Master of Business Administration degree. I started with Avista in April 1997 as a Resource Management Analyst in the Company's Demand Side Management (DSM) department. Later, I became a Program Manager, responsible for energy efficiency program offerings for the Company's educational and governmental customers. In 2000, I was selected to be one of the Company's key Account Executives, where I was responsible for, among other things, being the primary point of contact for numerous commercial and industrial customers.

I joined the State and Federal Regulation Department as a Senior Regulatory Analyst in 2007. Responsibilities in that role included being the discovery coordinator for the Company's rate cases, line extension policy tariffs, as well as miscellaneous regulatory issues. In November 2009, I was promoted to Manager of Rates and Tariffs, and later promoted to be Senior Manager of Rates and Tariffs. My primary areas of responsibility included electric and natural gas rate design, decoupling, power cost and natural gas rate adjustments, customer usage and revenue analysis, and tariff administration. In October 2017, I was promoted to my present position, where I am responsible for all matters related to general rate cases, tariff filings, rulemakings, and other regulatory activities.

Q. What is the scope of this testimony?

A. The purpose of my testimony is to describe and support the non-revenue requirement portions of the Stipulation and Settlement ("Stipulation"), filed on June 14, 2023 between the Staff of the Idaho Public Utilities Commission ("Staff'), Clearwater Paper Corporation ("Clearwater"), Idaho Forest Group, LLC ("Idaho Forest"), and Walmart Inc. These entities are collectively referred to as the "Settling Parties" and singularly as a "Settling Party." The remaining joint party, the Idaho Conservation League / NW Energy Coalition ("ICL/NWEC"), did not join in the Settlement. In my testimony I will explain the Settlement components related to Rate Spread and Rate Design, and certain Other Settlement Items.

Q. Are you sponsoring any exhibits?

A. No, I am not. Company witness Ms. Andrews is sponsoring Exhibit No. 19, which is a copy of the Stipulation and Settlement filed on June 14, 2023, with the Commission.

II. RATE SPREAD & RATE DESIGN

Q. Please explain the settlement terms relating to electric and natural gas cost of service.

A. In this case, for electric operations, the Company prepared an electric cost of service analysis that incorporated, among other things, a system load factor peak credit method of classifying production costs, allocating 100% of transmission costs to demand, and allocating transmission costs on a twelve-month coincident peak allocation factor. The Parties do not agree on any particular cost of service methodology. In recognition, however, that certain rate schedules are generally above their relative cost of service, the Parties agree that Schedule 25P should receive 35% of the overall percentage base rate changes. Schedules 1, 21/22 and 31/32 should receive 130% of the overall percentage base rate changes and the remaining revenue requirement will be spread to Schedules 11/12, 25, and Street and Area Lights.

For natural gas, the Settling Parties agreed to apply the margin increase on September 1, 2023 and September 1, 2024 solely to Schedule 101.

Q. How did the Stipulation address rate design?

A. For settlement purposes, the Parties agreed to the rate design changes proposed by Company witness Mr. Miller in his direct testimony for the September 1, 2023, and September 1, 2024, base rate increases with two exceptions. First, the basic charge for Schedule 31/32 will increase from $13.00 to $18.00 in Rate Year 1 and from $18.00 to $20.00 in Rate Year 2. Second, the primary voltage discount will increase from $0.20 per kW to $0.30 per kW in Rate Year 1, and from $0.30 per kW to $0.40 per kW in Rate Year 2 for all applicable rate schedules. Appendix F of the Stipulation (Exhibit No. 19) provides a summary of the current and proposed rates and charges for both electric and natural gas service.

Q. Do the agreed upon rate design changes include increases to the residential basic charges for Schedules 001 and 101?

A. Yes. For Rate Year 1 the residential basic charge will increase from

$7.00 per month to $15.00 per month, and for Rate Year 2 will go from $15.00 per month to $20.00 per month for both electric and natural gas customers.

Q. Did the Company provide support for the basic charge levels in its opening testimony?

A. Yes. As discussed by Company witness Mr. Miller, a significant portion of the Company's costs are fixed and do not vary with customer usage. These costs include distribution plant and operating costs to provide reliable service to customers. For electric, the total customer allocated costs, as shown in Company witness Mr. Garbarino's Exhibit No. 16, Schedule 3, Page 4, line 26, those costs are $19.24 per customer per month. Factoring in distribution demand cost per customer per month of $23.84, as shown in Mr. Garbarino's Exhibit No. 16, Schedule 3, Page 4, line 29, the total customer and distribution demand monthly cost is $43.08.

For natural gas, the total customer allocated costs, as shown in Company witness Mr. Anderson's Exhibit No. 17, Schedule 6, Page 4, line 24, those costs are $21.96 per customer per month at current rates. Factoring in distribution demand cost per customer per month of $7.56, as shown in Mr. Anderson's Exhibit No. 17, Schedule 2, Page 8, the total customer and distribution demand monthly cost is $29.51. These are essentially fixed costs that are allocated based on the number of customers served. Given the large disparity between the level of customer and demand costs and the present level of the basic charge, it is appropriate to recover more of these fixed customer costs through the basic charge. The result of a basic charge that does not adequately recover the fixed costs of customers is those costs are then recovered through a higher volumetric charge. The effect of a low basic charge is that customers with low monthly usage are being subsidized by customers with higher monthly usage.

While the Company acknowledges that these rate design changes supported by the Settling Parties will impact some customers bills more than others, the changes to both the electric and natural gas basic charges will better align customers rates with the actual fixed costs to serve customers and reduce the intra-class subsidization that presently exists within customers rates.

Q. Did the Commission recently approve an in increase in the residential customer service charge for Rocky Mountain Power?

A. Yes. In Order No. 35802 the Commission approved Rocky Mountain Power's request to increase the Customer Service Charge from $8.00 to $29.25 per month, over five years. In its Order supporting the increase to the Customer Service Charge the Commission stated:

> *This represents a gradual step toward accurately assigning costs, which is a fair component of rate design as the misalignment of costs can create revenue recovery distortions and give an incorrect perception of the cost and value of the Company's services. While certain customers may end up paying more per month under the modified Customer Service Charge, this modification helps to ensure all customers are paying a proper amount of the fixed costs required to serve them. We believe there may be additional benefits for customers who will likely see their summer and winter bills more levelized.*

Q. Please explain the other rate design issues agreed upon in the Settlement Stipulation.

A. Avista agrees to conduct a Primary Voltage Discount study prior to its next general rate case filing. The purpose of the study will be to inform the proper Primary Voltage Discount levels in the Company's next general rate case. Second, the Company agrees to evaluate the rate design of Schedule 111, including the minimum charge level, and include any changes or modification in its next general rate case filing.

Q. What is the effect on retail rates, by rate schedule, of the proposed settlement?

A. Table Nos. 1 and No. 2 reflect the agreed-upon percentage increases by schedule for electric service:

Table No. 1 – Electric Change for Rate Year 1

Rate Schedule	Increase in Base Revenue	Increase in Billing Revenue
Residential Schedule 1	10.4%	11.8%
General Service Schedules 11/12	2.9%	3.0%
Large General Service Schedules 21/22	10.4%	10.8%
Extra Large General Service Schedule 25	2.9%	3.0%
Clearwater Paper Schedule 25P	2.8%	2.9%
Pumping Service Schedules 31/32	10.4%	10.9%
Street & Area Lights Schedules 41-48	2.9%	2.9%
Overall	**8.0%**	**8.7%**

Table No. 2 – Electric Change for Rate Year 2

Rate Schedule	Increase in Base Revenue	Increase in Billing Revenue
Residential Schedule 1	1.9%	2.1%
General Service Schedules 11/12	0.4%	0.5%
Large General Service Schedules 21/22	1.9%	1.9%
Extra Large General Service Schedule 25	0.4%	0.5%
Clearwater Paper Schedule 25P	0.5%	0.5%
Pumping Service Schedules 31/32	1.9%	2.0%
Street & Area Lights Schedules 41-48	0.4%	0.4%
Overall	**1.4%**	**1.6%**

Table Nos. 3 and No. 4 reflect the agreed-upon percentage changes by schedule for natural gas service:

Table No. 3 – Natural Gas Change for Rate Year 1

Rate Schedule	Increase in Margin Revenue	Increase in Billing Revenue
General Service Schedule 101	3.3%	1.6%
Large General Service Schedules 111/112	0.0%	0.0%
Interrupt. Sales Service Schedules 131/132	0.0%	0.0%
Transportation Service Schedule 146	0.0%	0.0%
Overall	**2.7%**	**1.2%**

Table No. 4 – Natural Gas Change for Rate Year 2

Rate Schedule	Increase in Margin Revenue	Increase in Billing Revenue
General Service Schedule 101	0.01%	0.00%
Large General Service Schedules 111/112	0.00%	0.00%
Interrupt. Sales Service Schedules 131/132	0.00%	0.00%
Transportation Service Schedule 146	0.00%	0.00%
Overall	**0.01%**	**0.00%**

Q. What are the residential bill impacts if the Commission approves the Settlement Stipulation?

A. Effective September 1, 2023, an electric residential customer using an average of 927 kilowatt hours per month would see a $10.15, or 11.9%, increase per month for a revised monthly bill of $95.55. Effective September 1, 2024, an electric residential customer would see a $2.06, or 2.2%, increase per month for a revised monthly bill of $97.61.

Effective September 1, 2023, a natural gas residential customer using an average of 64 therms per month would see a $1.20, or 1.6%, increase per month for a revised monthly bill of $74.62. Effective September 1, 2024, a natural gas residential customer would see a $0.03, or 0.0%, increase per month for a revised monthly bill of $74.65.

III. OTHER ELEMENTS OF THE STIPULATION

Q. Please explain the settlement terms relating to the Power Cost Adjustment (PCA) authorized level of expenses.

A. The new level of power supply revenues, expenses, retail load and Load Change Adjustment Rate resulting from the September 1, 2023 settlement revenue requirement, for purposes of monthly PCA mechanism calculations, are detailed in Appendix A of the Stipulation (Exhibit No. 19). The Settling Parties agree to the following:

i. Authorized Net Power Supply. The Settling Parties agree to leave system power supply expense as approved in Case No. AVU-E-21-01 totaling $149,279,000 (Power Supply), adjusted to reflect these items: (a.) 90% Palouse Wind and Rattlesnake Flat Wind; and (b.) Remove Columbia Basin Hydro Transmission Project, discussed below, resulting in a revised system net power supply expense of $177,585,000.

a. Palouse and Rattlesnake Flat Wind. As noted in ¶ 7. j. ii. of the Stipulation, the Settling Parties agree to include the Palouse Wind and Rattlesnake Flat Wind Power PPA in base rates at 90%. 90% of actual net power costs for these projects will then be compared to this 90% base amount to calculate the base-to-actual difference that will be reflected in the PCA mechanism. This adjustment increases system net power supply expense $29,313,000.

b. Remove Columbia Basin Hydro Transmission Costs. As noted in ¶ 7. j. iii. in the Stipulation, the Settling Parties agree to remove the cost of Columbia Basis Hydro Transmission costs. This adjustment decreases system net power supply expense by $1,007,000.

ii. Authorized Transmission Revenues. The Settling Parties agree to leave system transmission revenues as approved in Case No. AVU-E-21-01 totaling $23,471,000.

iii. Adjust Columbia Basin and Chelan 2023 – 2033 Contracts. The Settling Parties agree that the actual cost of the Chelan and the Columbia Basin contracts will be included in the PCA using the lower of market cost or contract cost, with the PCA description and methodology as follows:

a. Avista agrees to protect Idaho customers against its executed contracts resulting from the 2022 All-Source RFP with Columbia Basin Hydro (CBH) and Chelan Public Utility District (Chelan), from the potential of costs of each contract being higher than the spot-market value of power. Avista will ensure the cost of each contract does not exceed the time-valued delivery of power calculated on a daily basis using the on and off-peak prices at the Mid-Columbia trading hub, as reported by the Intercontinental Exchange's on- and off-peak firm energy indices. The Settling Parties agree to meet and confer to determine a calculation method prior to the Company filing its 2024 PCA application.

b. Avista will recover some or all of the approximately $1.007 million annual cost of Columbia Basin Hydro transmission not included in base rates to the extent that market prices are higher than the Columbia Basin Hydro generation contract price as determined in section iii.a. above. The Settling Parties agree to meet and confer to determine the calculation method prior to the Company filing its 2024 PCA.

Q. Please explain the settlement terms relating to the authorized base for the Electric and Natural Gas Fixed Cost Adjustment Mechanism.

A. The new level of baseline values for the electric and natural gas fixed cost adjustment mechanism resulting from the September 1, 2023 and September 1, 2024 settlement revenue requirement are detailed in the Stipulation as follows:

- Appendix B – 2023 Electric FCA Base
- Appendix C – 2024 Electric FCA Base
- Appendix D – 2023 Natural Gas FCA Base
- Appendix E – 2024 Natural Gas FCA Base

Q. Does this conclude your direct testimony?

A. Yes, it does.