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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-21-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-21-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	DIRECT TESTIMONY
NATURAL GAS SERVICE TO ELECTRIC	)	OF
AND NATURAL GAS CUSTOMERS IN THE	)	JEFF A. SCHLECT
STATE OF IDAHO	)	
	)	

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

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

A. My name is Jeff A. Schlect. I am employed by Avista Corporation as Senior Manager, FERC Policy and Transmission Services. My business address is 1411 East Mission, Spokane, Washington.

Q. Please briefly describe your educational background and professional experience.

A. I am a 1988 graduate of Washington State University with a degree in Electrical Engineering. I spent five years with Puget Sound Energy in distribution engineering and operations positions prior to joining the Company in 1993 as a Transmission Planning Engineer. Over the past 26 years, in addition to stints in Customer Service and Power Supply, I have worked primarily in the Transmission Operations area with responsibilities covering Federal Energy Regulatory Commission (FERC) transmission policy and compliance with open access transmission regulations, transmission contracts, transmission and generation interconnection processes, and regional transmission policy coordination. I have authored testimony in Bonneville Power Administration (BPA) power and transmission rate proceedings, testimony in general rate cases in Idaho and Washington, and provided comment before the U.S. Senate Subcommittee on Water and Power. In my current role I have responsibility for all transmission revenue and expenses and provide support to the Company's transmission capital planning process.

Q. What is the scope of your testimony?

A. My testimony presents Avista's transmission revenues and expenses included in the Company's request for rate relief over the Two-Year Rate Plan effective September 1, 2021 and ending August 31, 2023.

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Q. Are you sponsoring any exhibits?

A. Yes. Exhibit No. 10, Schedule 1 provides the transmission expense and revenue during the Two-Year Rate Plan effective September 1, 2021. Additionally, supporting workpapers for each of the expense and revenue items have been included with the Company's filed case.

II. TRANSMISSION EXPENSES FOR TWO-YEAR RATE PLAN

Q. Please describe the adjustments to the twelve-months-ended December 31, 2019 test year transmission expenses, to arrive at transmission expenses included in this case effective September 1, 2021.

A. Adjustments were made in this filing to incorporate updated information for any changes in transmission expenses from the 2019 test year to that used in this case effective September 1, 2021. As noted in Exhibit No. 10, Schedule 1, Rate Year 1 (September 1, 2021 through August 31, 2022) Pro Forma level of transmission expenses are used during the Two-Year Rate Plan (September 1, 2021 – August 31, 2023), as these amounts will be known by the new rate effective date beginning September 1, 2021, and are not expected to change materially during Rate Year 2 (September 1, 2022 through August 31, 2023). As described below, transmission expenses effective September 1, 2021 are expected to be $681,000 less than in the 2019 test year on a system basis. Company witness Ms. Andrews pro forms the Idaho share of this level of transmission expense within her requested revenue requirement in this case. The changes in expenses and a description of each is summarized in Table No. 1 below, and an explanation of each change follows the table. Each expense item described below is at a system level and is included in Exhibit No. 10, Schedule 1.

Table No. 1: Transmission Expense Adjustment

Transmission Expense Adjustment			
			System(1)
ColumbiaGrid General Funding			$ (62,000)
ColumbiaGrid PEFA			(157,000)
ColumbiaGrid Order 1000			(25,000)
NorthernGrid			87,000
NERC CIP			21,000
PEAK Reliability			(928,000)
RC West			383,000
Total Transmission Expense Adjustment			**$ (681,000)**
(1) Represents the change in expenses above or below the 2019 historical test year level.			

Avista became a member of the ColumbiaGrid regional transmission organization in 2006. Following extensive regional discussions to develop a combined regional transmission planning organization encompassing both the ColumbiaGrid and Northern Tier Transmission Group footprints, the NorthernGrid structure was developed and ultimately accepted by the Federal Energy Regulatory Commission (FERC) effective April 1, 2020. Following completion of its final transmission planning cycle, ColumbiaGrid ceased operations as of December 31, 2020. NorthernGrid contracts with the Northwest Power Pool to perform a number of its administrative functions and some activities previously performed by ColumbiaGrid are expected to be absorbed by the transmission planning staffs of the NorthernGrid participants. In total, the Company's coordinated regional transmission planning expenses in the 2019 test year were $260,000. With the transition to NorthernGrid, these expenses are expected to be reduced by $157,000 to a total of $103,000 during the rate period, as described below.

- **ColumbiaGrid General Funding (-$62,000)** – As noted above, with the dissolution of ColumbiaGrid at the end of 2020, the Company will have no ColumbiaGrid general funding expenses during the rate period.

- **ColumbiaGrid PEFA (-$157,000)** – As noted above, with the dissolution of ColumbiaGrid at the end of 2020, the Company will have no ColumbiaGrid PEFA (Planning and Expansion Functional Agreement) expenses during the rate period.

- **ColumbiaGrid Order 1000 (-$25,000)** – As noted above, with the dissolution of ColumbiaGrid at the end of 2020, the Company will have no ColumbiaGrid Order 1000 expenses during the rate period.

- **NorthernGrid (+$87,000)** – With FERC's acceptance of the Company's revised open access transmission tariff language, effective April 1, 2020, to incorporate the new NorthernGrid regional transmission planning structure, the Company now meets its coordinated regional transmission planning requirements, as set forth in FERC Order 890, through NorthernGrid.[1] The Company's NorthernGrid expenses during the 2019 test year were for initial developmental activities. Based upon its 2020 expenses, the Company expects its NorthernGrid expenses to be $103,000 during the rate period. Accordingly, the Company's expected NorthernGrid expenses are an additional $87,000 over its level of NorthernGrid expenses during the 2019 test year.

[1] As outlined in the Company's Attachment K to its Open Access Transmission Tariff, NorthernGrid coordinates regional grid expansion planning among the transmission entities in the NorthernGrid area. The goal of grid expansion planning is to determine reasonable solutions to transmission grid issues pertaining to serving load and complying with reliability standards. While the Company is required by FERC to participate in a coordinated regional planning process, the biennial transmission planning process under NorthernGrid is enhanced by the participation of state representatives and many non-FERC jurisdictional entities, including BPA, with whom the Company has more transmission interconnections than with any other entity.

Additional changes to transmission expenses, totaling a net reduction of $524,000, are also necessary to reflect the proper rate period level of transmission expense, as follows:

- **NERC Critical Infrastructure Protection (CIP) (+$21,000)** – The Company has purchased several software and hardware products to assist in protecting critical transmission control systems from intrusion and to meet applicable North American Electric Reliability Corporation (NERC) standards. These products provide for physical security, intrusion detection, virus protection and vulnerability assessment. The Company's NERC CIP expenses are expected to be $73,000 during the rate period, an increase of $21,000 from the 2019 test year actual expenses of $52,000.

- **Peak Reliability – Reliability Coordination (-$928,000)** – In mid-year 2018, Peak Reliability announced that it would cease performing reliability coordination services at the end of 2019. The Company subsequently began work, along with many other Balancing Authorities in the west, to transition obtaining its required reliability coordination services from Peak Reliability to the California Independent System Operator (CAISO). The Company's Peak Reliability expense during the 2019 test year were $928,000. With the dissolution of reliability coordination services from Peak Reliability effective at the end of 2019, the Company will have no expenses for Peak Reliability during the rate period.

- **RC West – Reliability Coordination (+$383,000)** – With the dissolution of Peak Reliability, the Company has transitioned to obtaining its reliability coordination services from RC West, a functional arm of the CAISO. The Company is required to obtain reliability coordination services under NERC standards. The Company's RC West expenses during the 2019 test year of $29,000 were to obtain Hosted Advanced Network Application (HANA) services to meet other NERC standards, separate from the requirement to obtain reliability coordination services. Based upon 2020 RC West expenses, the Company expects its reliability coordination expenses to be $412,000 during the rate period, an increase of $383,000 over the 2019 test year actual expense of $29,000.

III. TRANSMISSION REVENUES FOR TWO-YEAR RATE PLAN

Q. Please describe the adjustments to 2019 test year transmission revenues to arrive at transmission revenues included in this case effective September 1, 2021.

A. Adjustments have been made in this filing to incorporate updated information for transmission revenue from the 2019 test year to that used in this case effective September 1, 2021. As noted in Exhibit No. 10, Schedule 1, Rate Year 1 (September 1, 2021 through August 31, 2022) Pro Forma level of transmission revenues are used during the Two-Year Rate Plan (September 1, 2021 – August 31, 2023), as these amounts will be known by the new rate effective date beginning September 1, 2021, and are not expected to change materially during Rate Year 2 (September 1, 2022 through August 31, 2023).[2] Each revenue item described below is at a system level and is included in Exhibit No. 10, Schedule 1. Ms. Andrews has pro formed the transmission revenues within the revenue requirement in this case. The reduction in transmission revenues is $2,030,000 effective September 1, 2021, with Idaho's share totaling $698,000.[3 / 4]

Table No. 2 provides a detailed summary of the changes in transmission revenues, as well as a listing of transmission revenues not changing at this time. An explanation of each follows the table.

[2] Transmission Revenues (FERC Account 456 other Electric Revenue) are included and tracked as a part of the Company's Power Cost Adjustment (PCA). The total transmission revenue of $16.221 million is therefore included in Company witness Mr. Kalich Exhibit No. 9, Schedule 5 reflecting the proposed PCA net base power supply expense, offset by transmission revenues, representing the proposed "Total Authorized Expense" on a system (Idaho and Washington) basis. Idaho's share of the net power supply revenues and expenses is equal to 34.36% of the system total, based on the Production/Transmission (P/T) ratio updated annually in December.

[3] As discussed by Ms. Andrews, transmission revenues are adjusted in Pro Forma Transmission Adjustment (3.00T) from the 2019 historical test period level of $18.251 million to the pro forma level of $16.221 million – an overall reduction of $2.030 million on a system basis, or $0.698 million Idaho share.

[4] After the completion of the Company's revenue requirement in this case, it was determined the change in transmission revenues in Pro Forma Transmission Revenues and Expenses Adjustment 3.00T in Ms. Andrews' Exhibit No. 5, Schedule 1 included an error. The Company will correct this error during the process of this case. Correcting this error increases transmission revenues $25,000 and decreases the Company's requested revenue requirement $26,000. This correction has no impact on the Company's proposed Power Cost Adjustment base.

Table No. 2: Transmission Revenue Adjustment

Transmission Revenue Adjustment	System[1]
Transmission Service	
OASIS (Non-Firm and ST Firm)	$ (812,000)
Bonneville Power Administration	29,000
Consolidated Irrigation District	0
East Greenacres Irrigation District	0
Grant County PUD No. 3	0
Spokane Tribe of Indians	(11,000)
Seattle City Light/Tacoma Power (Main Canal)	0
Seattle City Light/Tacoma Power (Summer Falls)	0
Pacificorp (Dry Gulch)	(22,000)
City of Spokane Waste to Energy	0
Stimson Lumber Company	0
Hydro Technology Systems	0
Deep Creek Energy LLC	0
Kootenai Electric Cooperative	0
Parallel Capacity Support	
Bonneville Power Administration	0
Operations and Maintenance (O&M)	
Columbia Basin Hydropower	0
Palouse Wind	0
Adams Neilson Solar	0
Rattlesnake Flat	70,000
Ancillary Services	
Bonneville Power Administration	(1,410,000)
Consolidated Irrigation District	0
East Greenacres Irrigation District	0
Spokane Tribe of Indians	0
Kootenai Electric Cooperative	0
Low-Voltage Facilities	
Consolidated Irrigation District	1,000
East Greenacres Irrigation District	12,000
Spokane Tribe of Indians	5,000
Bonneville Power Administration	108,000
	$ (2,030,000)

(1) Represents the change in revenue above or below the 2019 historical test year level.

The Company provides transmission service to wholesale customers under the jurisdiction of the FERC. The components of what has traditionally been known as "wheeling" service include: (i) transmission service over the Company's transmission facilities that are operated at or above 115kV, (ii) operations and maintenance (O&M) charges associated with Company transmission assets for which an interconnection customer provided contributions in aid to construction, (iii) ancillary services (generation-related services that are required to be offered in conjunction with transmission service), and (iv) low-voltage wheeling services over substation and distribution facilities that are operated below 115kV.

- **OASIS Non-Firm and Short-Term Firm Transmission Service (-$812,000)** – OASIS is an acronym for Open Access Same-time Information System. This is the system used by electric transmission providers for selling available transmission capacity to eligible customers. The terms and conditions under which the Company sells its transmission capacity via its OASIS are pursuant to FERC regulations and Avista's Open Access Transmission Tariff. Consistent with prior Avista general rate cases, the Company calculates its rate year adjustments using a three-year average of actual OASIS Non-Firm and Short-Term Firm revenue. OASIS transmission revenue may vary significantly depending upon a number of factors, including current wholesale power market conditions, forced or planned generation resource outage situations in the region, the current load-resource balance status of regional load-serving entities, and the availability of parallel transmission paths for prospective transmission customers.

  The use of a three-year average is intended to strike a balance in mitigating both long-term and short-term impacts to OASIS revenue. A three-year period is intended to be long enough to mitigate the impacts of non-substantial temporary operational conditions (for generation and transmission) that may occur during a given year, and short-enough so as to not dilute the impacts of long-term transmission and generation topography changes (e.g., major transmission projects which may impact the availability of the Company's transmission capacity or competing transmission paths, and major generation projects which may impact the load-resource balance needs of prospective transmission customers). If there are known events or factors that occurred during the period that would cause the average to not be representative of future expectations, then adjustments may be made to the three-year average methodology. However, volatility in OASIS revenue from year-to-year can be expected, entirely outside the scope and purview of the Company as a transmission provider. For example, the Company experienced several months of higher-than-normal OASIS revenues between November 2018 and March 2019 due most likely to the loss of a major natural gas transportation pipeline in western British Columbia. It appears that the impact of this event upon the dispatch of generation resources in the region facilitated increased short-term use of the Company's transmission system. In this filing, the Company is using a three-year average for the time period of January 2017 to December 2019. The OASIS revenue for the 2019 test year was $5.474 million and the three-year average calculated for the rate period is $4.662 million, or a reduction of $812,000.

- **<u>Bonneville Power Administration – Transmission</u> (+$29,000)** – The Company provides Network Integration Transmission Service to the Bonneville Power Administration (BPA) under a series of thirteen agreements serving BPA's utility customers connected to the Company's transmission system. Network Service revenue is based upon a rolling 12-month average of BPA's loads. BPA Network Service revenue was $6.413 million for the 2019 test year. Based upon a three-year average over the 2017-2019 period, the Company expects BPA Network Service revenue to be $6,442,000 during the rate period, or $29,000 greater than during the 2019 test year.

- **<u>Consolidated Irrigation District – Transmission</u> ($0)** – The Company provides Long-Term Firm Point-to-Point Transmission Service to the Consolidated Irrigation District under an agreement effective through September 30, 2021. The Company expects a new follow-on long-term agreement to become effective October 1, 2021. Consolidated Irrigation transmission revenue was $32,000 for the 2019 test year and the Company expects there will be no change during the rate period.

- **<u>East Greenacres Irrigation District – Transmission</u> ($0)** – The Company provides Long-Term Firm Point-to-Point Transmission Service to East Greenacres Irrigation District under an agreement effective through September 30, 2024. East Greenacres transmission revenue was $11,000 for the 2019 test year and the Company expects there will be no change during the rate period.

- **<u>Grant County PUD – Transmission</u> ($0)** – The Company provides long-term transmission service to Grant County PUD for service to its Coulee City and Wilson Creek loads connected to the Company's transmission system. Revenue under the Power Transfer Agreement was $28,000 for the 2019 test year. Based upon a three-year average over the 2017-2019 period, the Company expects there will be no substantive change during the rate period.

- **<u>Spokane Tribe of Indians – Transmission</u> (-$11,000)** – The Company provides Long-Term Firm Point-to-Point Transmission Service to the Spokane Tribe of Indians under an agreement that became effective January 1, 2020 and will be effective through December 31, 2024. Point-to-point transmission charges under the Company's federal load transmission service contracts need to align with what the customer would be expected to pay under a Network Integration Transmission Service agreement. Accordingly, the transmission rate under the new agreement with the Spokane Tribe was adjusted downward to meet this condition. Spokane Tribe transmission revenue was $29,000 for the 2019 test year and the Company expects it to be $18,000 during the rate period, a reduction of $11,000.

- **Seattle and Tacoma – Main Canal Transmission** **($0)** – The Company provides Long-Term Firm Point-to-Point Transmission Service to the City of Seattle and Tacoma Power, under agreements effective through October 31, 2026, to transfer output from the Main Canal hydroelectric project, net of local Grant County PUD load service, to the Company's transmission interconnections with Grant County PUD. Service is provided during the eight months of the year (March through October) in which the Main Canal project operates, and the agreements include a three-year ratchet demand provision. Revenues under these agreements totaled $350,000 during the 2019 test year and the Company expects there will be no change during the rate period.

- **Seattle and Tacoma – Summer Falls Transmission** **($0)** – The Company provides long-term use-of-facilities transmission service to the City of Seattle and Tacoma Power, under agreements effective through October 31, 2024, to transfer output from the Summer Falls hydroelectric project across the Company's Stratford Switching Station facilities to the Company's Stratford interconnection with Grant County PUD. Charges under these use-of-facilities arrangements are based upon the Company's investment in its Stratford Switching Station and are not impacted by the Company's transmission service rates under its Open Access Transmission Tariff. Revenues under these two agreements totaled $180,000 in the 2019 test year and the Company expects there will be no change during the rate period.

- **PacifiCorp – Dry Gulch Transmission** **(-$22,000)** – The Company provides long-term transmission service under a use-of-facilities agreement with PacifiCorp for use of the Company's Dry Gulch Substation. The agreement includes a twelve-month rolling ratchet provision. Revenue under the Dry Gulch agreement was $278,000 during the 2019 test period. Based upon a three-year average over the 2017-2019 period, the Company expects PacifiCorp Dry Gulch revenue to be $256,000 during the rate period, or $22,000 lower than during the 2019 test year.

- **City of Spokane – Waste to Energy Transmission** **($0)** – The City of Spokane pays a use-of-facilities charge for the ongoing use of its interconnection to the Company's transmission system. Use-of-facilities charges were $28,000 for the 2019 test year and the Company expects there to be no change during the rate period.

- **<u>Stimson Lumber PURPA</u> ($0)** – Low-voltage facilities associated with the Company's Plummer Substation are dedicated for use by Stimson Lumber under a PURPA arrangement. Low-voltage use-of-facilities revenue was $9,000 for the 2019 test year and there will be no change during the rate period.

- **<u>Hydro Tech Systems PURPA</u> ($0)** – Low-voltage facilities in the Company's Greenwood Substation are dedicated for use by the Meyers Falls generation project under a PURPA arrangement. Low-voltage use-of-facilities revenue was $6,000 during the 2019 test year and there will be no change during the rate period.

- **<u>Deep Creek PURPA</u> ($0)** – The Company owns and operates low voltage facilities that are dedicated for use by the Deep Creek generation project under a PURPA arrangement. Low-voltage use-of-facilities revenue was less than $1,000 during the 2019 test year and there will be no change during the rate period.

- **<u>Kootenai Electric Cooperative – Transmission</u> ($0)** – The Company provides Long-Term Firm Point-to-Point Transmission Service to Kootenai Electric Cooperative under an agreement effective through March 31, 2024. Transmission revenue was $72,000 for the 2019 test year and the Company expects there will be no change during the rate period.

- **<u>Columbia Basin Hydropower</u> ($0)** – The Company provides operations and maintenance services on the Stratford-Summer Falls 115kV Transmission Line to Columbia Basin Hydropower (formerly known as the Grand Coulee Project Hydroelectric Authority) under a contract signed in March 2006. These services are provided for a fixed annual fee. Annual charges under this contract were $8,000 in the 2019 test year and there will be no change during the rate period.

- **<u>Palouse Wind O&M</u> ($0)** – Per the Company's interconnection agreement with the Palouse Wind project, the interconnection customer pays O&M fees associated with directly-assigned interconnection facilities owned and operated by the Company. O&M revenue for the 2019 test year was $52,000 and the Company expects there will be no change during the rate period.

- **<u>Adams Neilson Solar O&M</u> ($0)** – Per the Company's interconnection agreement with the Adams Neilson Solar project, the interconnection customer pays O&M fees associated with directly-assigned interconnection facilities owned and operated by the Company. O&M revenue for the 2019 test year was $9,000 and the Company expects there will be no change during the rate period.

- **Rattlesnake Flat O&M (+$70,000)** – Per the Company's interconnection agreement with the Rattlesnake Flat Wind project, the interconnection customer will begin paying O&M fees associated with directly-assigned interconnection facilities owned and operated by the Company. The Rattlesnake Flat Wind project reached commercial operation in December 2020. The Company expects revenue of approximately $70,000 during the rate period.

- **Bonneville Power Administration – Parallel Capacity Support ($0)** – The Company and BPA executed a Parallel Capacity Support Agreement effective February 1, 2017, and with a minimum term extending to December 31, 2026, in which the Company provides BPA with parallel transmission capacity in support of BPA's integration of several wind resource projects. Revenue was $924,000 during the 2019 test year and there will be no change during the rate period.

- **Bonneville Power Administration – Ancillary Services (-$1,410,000)** – The Company provides Ancillary Services to BPA under its Network Integration Transmission Service agreements. BPA provided notice to the Company that it intends to self-supply operating reserves under these agreements. Following substantial negotiations, BPA's self-supply of operating reserves became the subject of FERC Docket No. EL20-36-000 wherein FERC ruled primarily in BPA's favor with respect to the implementation of self-supplied operating reserves. BPA will begin its self-supply of operating reserves on or about March 1, 2021. BPA Ancillary Services revenue was $2,464,000 during the 2019 test year and the Company expects this revenue to be approximately $1,054,000 during the rate period, a reduction of $1,410,000.

- **Consolidated Irrigation District – Ancillary Services ($0)** – The Company provides Ancillary Services to the Consolidated Irrigation District under its Long-Term Firm Point-to-Point Transmission Service agreement. Ancillary Service revenue was $9,000 for the 2019 test year and the Company expects there will be no change during the rate period.

- **East Greenacres Irrigation District – Ancillary Services ($0)** – The Company provides Ancillary Services to East Greenacres Irrigation District under its Long-Term Firm Point-to-Point Transmission Service agreement. Ancillary Service revenue was $6,000 for the 2019 test year and the Company expects there will be no change during the rate period.

- **Spokane Tribe of Indians – Ancillary Services ($0)** – The Company provides Ancillary Services to the Spokane Tribe of Indians under its Long-Term Firm Point-to-Point Transmission Service agreement. Ancillary Service revenue was $6,000 for the 2019 test year and the Company expects there will be no change during the rate period.

- **Kootenai Electric Cooperative – Ancillary Services** **($0)** – The Company provides Ancillary Services to Kootenai Electric Cooperative under its Long-Term Firm Point-to-Point Transmission Service agreement. Ancillary Service revenue was $23,000 for the 2019 test year and the Company expects there will be no change during the rate period.

- **Consolidated Irrigation District – Low-Voltage** **(+$1,000)** – The Company provides transfer service over low voltage facilities to Consolidated Irrigation District under the Electric Distribution Services Agreement, effective through September 30, 2021. Per the rate adjustment provisions in this agreement the Company adjusted charges upward effective April 1, 2020. Low-voltage charges were $88,000 during the 2019 test period and the Company expects them to be $89,000 during the rate period, an increase of $1,000.

- **East Greenacres Irrigation District – Low-Voltage** **(+$12,000)** – The Company provides transfer service over low voltage facilities to East Greenacres Irrigation District under the Electric Distribution Services Agreement, which became effective January 1, 2020, and will be effective through September 30, 2024. Low-voltage charges were $51,000 during the 2019 test period and charges under the new agreement will be $63,000 during the rate period, an increase of $12,000.

- **Spokane Tribe of Indians – Low-Voltage** **(+$5,000)** – The Company provides transfer service over low voltage facilities to the Spokane Tribe of Indians under the Electric Distribution Services Agreement, which became effective January 1, 2020 and will be effective through December 31, 2024. Low-voltage charges were $20,000 during the 2019 test period and charges under the new agreement will be $25,000 during the rate period, an increase of $5,000.

- **Bonneville Power Administration – Low-Voltage** **(+$108,000)** – The Company provides transfer service over low-voltage facilities to BPA under its Network Integration Transmission Service agreements. BPA low-voltage revenue was $1,680,000 during the 2019 test year. The Company recently obtained FERC acceptance of new charges for a new point of delivery under one of the agreements. The Company expects BPA low-voltage facilities charges to be $1,788,000 during the rate period, or $108,000 greater than during the 2019 test year.

Q. Does this complete your pre-filed direct testimony?

A. Yes, it does.