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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-10-01 DIRECT TESTIMONY OF SCOTT J. KINNEY

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

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

A. My name is Scott J. Kinney. I am employed by Avista Corporation as Director, Transmission Operations. My business address is 1411 East Mission, Spokane, Washington.

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

A. I graduated from Gonzaga University in 1991 with a B.S. in Electrical Engineering. I am a licensed Professional Engineer in the State of Washington. I joined the Company in 1999 after spending eight years with the Bonneville Power Administration. I have held several different positions in the Transmission Department. I started at Avista as a Senior Transmission Planning Engineer. In 2002, I moved to the System Operations Department as a supervisor and support engineer. In 2004, I was appointed as the Chief Engineer, System Operations. In June of 2008 I was selected to my current position as Director, Transmission Operations.

Q. What is the scope of your testimony?

A. My testimony describes Avista's pro forma period transmission revenues and expenses. I also discuss the Transmission and Distribution expenditures that are part of the capital additions testimony provided by Company witness Mr. Dave DeFelice. Company witness Ms. Andrews incorporates the Idaho share of the net transmission expenses and the transmission and distribution capital additions.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit 8, Schedule 1. Schedule 1, provides the transmission pro forma adjustments.

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II. PRO FORMA TRANSMISSION EXPENSES

Q. Please describe the pro forma transmission expense revisions included in this filing.

A. Adjustments were made in this filing to incorporate updated information for any changes in transmission expenses from the 2009 test year to the October 2010 to September 2011 Pro forma period. Each expense item described below is at a system level, with the exception of the $71,000 Grid West adjustment which is

Idaho only, and is included in Exhibit 8, Schedule 1. Supporting workpapers for each expense item described below have been provided with the Company's filing.

Northwest Power Pool (NWPP) – Avista pays its share of the NWPP operating costs. The NWPP serves the electric utilities in the Northwest by supporting regional transmission planning coordination and providing coordinated transmission operations, generation reserve sharing and Columbia River water coordination. Actual 2009 transmission-related NWPP expenses were $36,000 and a $4,000 adjustment was made to the pro forma period to reflect planned NWPP expenses allocated to the Company.

Colstrip Transmission – Avista is required to pay its portion of the O&M costs associated with its share of the Colstrip transmission system pursuant to the joint Colstrip contract. In accordance with NorthWestern Energy's (NWE) proposed Colstrip transmission plan provided to the Company, NWE will bill Avista $589,000 for Avista's share of the Colstrip O&M expense during the pro forma period. This is an increase of $98,000 from the actual expense of $491,000 incurred during the 2009 test year.

ColumbiaGrid RTO – Avista became a member of the ColumbiaGrid regional transmission organization (RTO) in 2006. ColumbiaGrid's purpose is to enhance transmission system reliability and efficiency, provide cost-effective coordinated regional transmission planning, develop and facilitate the implementation of solutions relating to improved use and expansion of the interconnected Northwest transmission system, reduce transmission system congestion, and support effective market monitoring within the Northwest and the entire Western interconnection. Avista supports ColumbiaGrid's general developmental and regional coordination activities under a General Funding Agreement and supports specific functional activities under the Planning and Expansion Functional Agreement and the OASIS Functional Agreement. The current General Funding Agreement for ColumbiaGrid expires September 30, 2010. The Company expects to execute a successor General Funding Agreement in the spring of 2010 to provide for ongoing funding of ColumbiaGrid general development activities while shifting a portion of ColumbiaGrid's administrative costs to its other functional agreements. Accordingly, while ColumbiaGrid is engaging in significant new developmental activities in coordination with other regional organizations (e.g. the review of consolidated balancing area operations and the development of revised scheduling practices to accommodate the impacts of intermittent generation), the Company's expected ColumbiaGrid general funding expenses will decrease.

Avista's ColumbiaGrid general funding expenses for the 2009 test year were $202,000 while pro forma period general funding expenses are expected to be $192,000. This amount is the Company's best estimate at this time until the successor General Funding Agreement is approved in the Spring of 2010.

ColumbiaGrid Transmission Planning - The ColumbiaGrid Planning and Expansion Functional Agreement (PEFA) was accepted by the Federal Energy Regulatory Commission (FERC) on April 3, 2007 and Avista entered into the PEFA on April 4, 2007. Coordinated transmission planning activities under the PEFA allow the Company to meet the coordinated regional transmission planning requirements set forth in FERC's Order 890 issued in February 2007, and outlined in the Company's Open Access Transmission Tariff, Attachment K. Funding under the PEFA is on a two-year cycle with provisions to adjust for inflation. Actual PEFA expenses for the 2009 test year were $142,000. The Company's PEFA expenses for the pro forma period are expected to reach the maximum total payment obligation of $215,000, reflecting ColumbiaGrid's final staffing levels to support the PEFA and the allocation of a portion of ColumbiaGrid's administrative expenses to this functional agreement. This amount is the Company's best estimate at this time until the successor General Funding Agreement is approved in the Spring of 2010.

<u>ColumbiaGrid Open Access Same-Time Information System (OASIS)</u> - Avista entered into the ColumbiaGrid OASIS Functional Agreement in February of 2008. This agreement provides for the development of a common Open Access Same-time Information System (OASIS) which would give transmission customers the ability to purchase transmission capacity from all ColumbiaGrid members via a single common OASIS site instead of having to submit multiple transmission service requests to each member individually on each member's respective OASIS sites. Avista's 2009 test year expenses of $35,000 reflected initial developmental activities under this functional agreement. Avista's ColumbiaGrid OASIS expenses for the pro forma period are expected to be $80,000, reflecting operational capability of the ColumbiaGrid OASIS and the allocation of a portion of ColumbiaGrid's administrative expenses to this functional agreement. This amount is the Company's best estimate at this time until the successor General Funding Agreement is approved in the Spring of 2010.

<u>Grid West (ID Direct)</u> - Included in transmission expense is an annual amount of $71,000 to recover costs associated with Grid West (and its forerunner, RTO West).

Avista signed an initial funding agreement in 2000, as did all other Pacific Northwest investor-owned electric utilities, to provide funding for the start-up phase of Grid West (then named "RTO West"). Grid West had planned to repay the loans to Avista and other funding utilities through surcharges to customers once it became operational. With the dissolution of Grid West, this repayment did not occur. As a result, Avista filed an application with the Commission to defer these costs. The Commission approved, on October 24, 2006, in Order No. 30151, the Company's request for an order authorizing deferred accounting treatment for loan amounts made to Grid West. In its Order the IPUC found these costs to be "prudent and in the public interest" and required the Company to begin amortization of the Idaho share of the loan principal ($422,000) beginning January 2007, for five years. During the pro forma period Avista will amortize a total of $71,000 associated with Grid West development costs.

<u>Electric Scheduling and Accounting Services</u> - The $12,000 decrease in the pro forma period compared to test year expense for electric scheduling and accounting services is a result of continued reductions in services provided by third party vendors. These services are no longer required because of the development of an internal accounting program and the development of a regional

transmission interchange tool by the Western Electricity Coordinating Council (WECC). These new applications replace the services provided by third parties.

<u>NERC Critical Infrastructure Protection</u> – The Company has purchased two software products to assist in protecting critical transmission system data from intrusion and to meet applicable North American Electric Reliability Corporation (NERC) standards. The Company expects no change from the actual 2009 test year expense of $25,000.

<u>OASIS Expenses</u> – These OASIS expenses are associated with travel and training costs for transmission pre-scheduling and OASIS personnel. This travel is required to monitor and adhere to NERC reliability standards and FERC OASIS requirements. The costs associated with OASIS expenses in the pro forma period are $5,000 more than in the 2009 test year. This increase is a result of training required for two new replacement transmission scheduling employees and the implementation of new OASIS functions required by FERC associated with network and native load transmission service.

<u>Power Factor Penalty</u> – Power factor penalty costs are associated with the Bonneville Power Administration's (Bonneville) General Transmission Rate Schedule Provisions. Bonneville charges a power factor penalty at all interconnections with Avista that exceed a given threshold

for reactive power flow during each month. If the reactive flow from Bonneville's transmission system into Avista's system or from Avista's system to Bonneville's system exceeds a given threshold, then Bonneville bills Avista according to its rate schedule. The charge includes a 12-month rolling ratchet provision. Avista currently pays Bonneville a power factor penalty at several points of interconnection. Avista incurred $167,000 of power factory penalty charges in 2008 and $124,000 during the 2009 test year. The Company's pro forma expenses are set at $146,000 representing an average of the power factor penalty charges incurred in 2008 and 2009.

<u>WECC – System Security Monitor and WECC Administration & Net Operating Committee Fees</u> – The Company's total WECC fees have increased, and are expected to continue to increase, from year to year. The increase is driven primarily by compliance with mandatory national reliability standards. WECC is responsible for monitoring and measuring Avista's compliance with the standards and therefore has substantially increased its staff and other resources to meet this FERC requirement. The Company's 2009 test year WECC assessments were $159,000 for system security monitoring and $329,000 for dues and net Operating Committee fees, for a total 2009 WECC assessment of

$488,000. The Company paid its 2010 WECC assessments in January 2010: $168,000 for system security monitoring and $370,000 for dues and net Operating Committee fees, for a total WECC assessment of $538,000. The Company's pro forma expenses have been set equal to these amounts paid in January 2010.

<u>WECC - Loop Flow</u> – Loop Flow charges are spread across all transmission owners in the West to compensate utilities that make system adjustments to eliminate transmission system congestion throughout the operating year. WECC Loop Flow charges can vary from year to year since the costs incurred are dependent on transmission system usage and congestion. Therefore a five-year average is used to determine future Loop Flow costs. Based upon the WECC Loop Flow charges incurred by the Company during the five-year period from 2005 through 2009, pro forma Loop Flow expenses are expected to be $34,000. This is $6,000 less than actual 2009 test year charges of $40,000.

<u>III. PRO FORMA TRANSMISSION REVENUES</u>

Q. Please describe the pro forma transmission revenue revisions included in this filing.

A. Adjustments have been made in this filing to incorporate updated information associated with known changes in transmission revenue for the 2010/2011 pro forma period as compared to the 2009 test year. Each revenue item described below is at a system level and is included in Exhibit 8, Schedule 1. In particular, in December 2009 the Company successfully attained FERC acceptance for an increase in generally applicable transmission rates under Avista's Open Access Transmission Tariff, effective January 1, 2010. The Company was able to increase its point-to-point transmission service rates by 43% (long-term firm point-to-point rates increased from $16.79/kW-year to $24.00/kW-year) and was able to increase its annual FERC transmission revenue requirement applicable to network transmission service (e.g. borderline wheeling service provided to Bonneville) by 73%. Accordingly, adjustments have been made in the pro forma period to reflect these increases in transmission rates. Supporting workpapers for each revenue item described below have been provided with the Company's filing.

Borderline Wheeling – Total borderline wheeling revenues for the 2009 test year were $5,552,000. Total borderline wheeling revenue in the pro forma period has been set at $7,838,000, which reflects a four-year average (2006 through 2009) of revenues from borderline wheeling service provided to Bonneville and adjustments to reflect the impact of new transmission rates on the Company's borderline wheeling contracts with Bonneville and Avista's other borderline wheeling customers, which include Grant County PUD, East Greenacres Irrigation District, the Spokane Tribe of Indians and Consolidated Irrigation District. Each of these contracts are described further below.

a) <u>Borderline Wheeling - Bonneville Power Administration</u>

Actual test year revenue from borderline wheeling service provided to Bonneville was $5,334,000. Avista typically uses a five-year average of actual annual revenue to estimate future borderline wheeling revenue from Bonneville. This helps levelize the revenue requirement since it is based on a rolling twelve-month average of Bonneville's load ratio share usage of the Company's transmission system. For this case Avista is only using a four-year average since 2006 through 2009 are the only years operating under new contracts signed with Bonneville that became effective January 1, 2006. This four-year average of borderline wheeling service provided to Bonneville is $5,113,000. This revenue covers borderline wheeling service to Bonneville over both transmission and low-voltage facilities. As a result of the Company's recent FERC transmission rate case, the FERC transmission revenue requirement, to which Bonneville's load ratio share usage of the Company's transmission system is applied, was increased by 73%. Accordingly, the low-voltage revenue component of the four-year average remains the same while the transmission revenue component of the four-year average has been increased by 73% for the 2011 pro forma period, resulting in a revenue figure of $7,597,000 for borderline wheeling service to Bonneville.

b) <u>Borderline Wheeling - Grant County PUD</u> - The Company provides borderline wheeling service to two Grant County PUD substations under a Power Transfer Agreement executed in 1980. Charges under this agreement are not impacted by the Company's transmission service rates under Avista's Open Access Transmission Tariff so the Company is not proposing any adjustment from the 2009 test year revenue of $27,000.

c) <u>Borderline Wheeling - East Greenacres Irrigation District</u> - The Company restructured its contract to provide borderline wheeling service to the East Greenacres Irrigation District in April, 2009, resulting in monthly wheeling revenue of $5,000. Revenue under this agreement for the 2009 test year was $51,000. Revenue for the pro forma period has been increased to $60,000 to reflect the terms of the restructured contract over the entire pro forma rate period.

d) Borderline Wheeling - Spokane Tribe of Indians and Consolidated Irrigation District - The Company provides borderline wheeling service over both transmission and low-voltage facilities to the Spokane Tribe of Indians and Consolidated Irrigation District. Total transmission and low-voltage wheeling revenue under these contracts for the 2009 test year was $140,000. Revenues associated with the transmission components of these contracts have been adjusted for the pro forma period to reflect the 43% increase in the Company's long-term firm point-to-point transmission service rate. Accordingly, pro forma period revenue under these two contracts is set at $154,000.

OASIS Non-Firm and Short-Term Firm Transmission Service - OASIS is an acronym for Open Access Same-time Information System. This is the system used by electric transmission providers for selling and scheduling 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 FERC Open Access Transmission Tariff. OASIS revenues vary from year to year depending upon a variety of factors, including electric energy market conditions, load and resource conditions of regional electric utilities, and available transmission capacity (ATC) on adjacent transmission provider systems. Due to these uncertainties, Avista has, in previous rate cases, used the most recent five-year average as being representative of future expectations for OASIS revenue unless there are known events or factors for which adjustments are appropriate. In this filing, the Company is using the most recent five-year average and is proposing an adjustment to reflect the results of the Company's recent FERC transmission rate case.

OASIS revenues for the 2009 test year were $2,962,000 and the five-year average of OASIS revenues from 2005 through 2009 is $3,067,000. For the pro forma period the Company proposes a 22% increase over the five-year average to reflect the potential for recovering additional OASIS revenue under the Company's new transmission rates accepted by FERC which became effective January 1, 2010.

While the Company is able to increase its non-firm and short-term firm transmission service rates by 43% as a result if its FERC rate case, the Company expects to be limited in its ability to successfully sell capacity at its maximum rates. Bonneville, the predominant transmission provider in the region, operates its transmission system in parallel with the Company's transmission system. Bonneville's current hourly point-to-point transmission service rate is $4.33/MWh with a loss factor of 1.9%. Avista's new maximum hourly point-to-point transmission service rate is $5.77/MWh with a loss factor of 3%. Where Bonneville's system has available parallel capacity, the Company would expect to have limited opportunity to sell transmission capacity above an hourly rate of $4.33/MWh. Increasing the Company's transmission rate to match Bonneville's current rate (notwithstanding the fact that the Company's loss factor is 58% higher than Bonneville's which would further limit the Company's ability to compete with parallel capacity on Bonneville's system) would add only about one-fifth (0.33 / 1.77 = 19%) of the Company's potential rate increase, resulting in an estimated increase in OASIS revenue of 8%. Nevertheless, the Company is estimating an increase in short-term firm and non-firm OASIS revenue comparable to implementing half of the potential rate increase. Accordingly, the Company proposes an OASIS revenue amount of $3,741,000 for the pro forma period, an amount $779,000, or 22%, greater than the most recent five-year average of $2,962,000.

Seattle and Tacoma Revenues Associated with the Main Canal Project - Effective March 1, 2008, the Company entered into long-term point-to-point transmission service arrangements with the City of Seattle and the City of Tacoma 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 $193,000 during the 2009 test year. Adjusting for the increase in the Company's transmission rate as a result of its FERC rate case, revenues under these agreements are expected to be $276,000 during the pro forma period.

Seattle and Tacoma Revenues Associated with the Summer Falls Project - Effective March 1, 2008, the Company entered into long-term use-of-facilities arrangements with the City of Seattle and the City of Tacoma 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 this use-of-facilities arrangement 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 contracts totaled $74,000 in the 2009 test year and are expected to remain the same for the pro forma period.

PacifiCorp Dry Gulch - Revenue under the Dry Gulch use-of-facilities agreement has been adjusted to $249,000 for the pro forma period, which is a $43,000 increase from the 2009 test year actual revenue of $206,000. The current methodology used to forecast Dry Gulch revenue is a five-year average of actual revenue. A five-year average is used since the revenue can vary from year to year depending upon PacifiCorp's monthly peak demands. The contract includes a twelve-month rolling ratchet demand provision and charges under this agreement are not impacted by the Company's open access transmission service tariff rates. The five-year average of revenue was calculated using years 2005 through 2009.

Spokane Waste to Energy Plant - No adjustments to Spokane Waste to Energy Plant revenue of $160,000 were made for the pro forma period compared to the 2009 test year. This revenue is the result of a long-term transmission service agreement with the City of Spokane that expires December 31, 2011. Charges under this agreement are not impacted by the Company's open access transmission service tariff rates.

<u>Vaagen Wheeling</u> – The Vaagen generation plant was permanently damaged by fire in November, 2009. Pursuant to its terms and conditions, the Vaagen wheeling contract was terminated effective December 1, 2009. Revenues under this contract were $97,000 during the 2009 test year but have been adjusted to zero for the pro forma period.

<u>Grant County PUD</u> – Revenues from a long-term firm point-to-point transmission service agreement with Grant County PUD during the 2009 test year were $56,000. This agreement expires December 31, 2010. Accordingly, associated revenue for the pro forma period has been reduced to $42,000.

<u>Grand Coulee Project Hydroelectric Authority</u> – The Company provides operations and maintenance services on the Stratford – Summer Falls 115kV Transmission Line to 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 totaled $8,100 in the 2009 test year and will remain the same for the pro forma period.

<u>PP&L Series Capacitors</u> – PP&L Series Capacitor revenue under this 1978 agreement was reduced from $5,000 in the

test year to zero in the pro forma period since the 20-year amortization of the original contract expired in June 2009.

<u>NaturEnergy Dynamic Signal</u> – The Company was reimbursed during the 2009 test year for expected one-time expenses related to connecting a NaturEnergy dynamic signal via the WECC ICCP system to Avista's SCADA-EMS system. Accordingly, the 2009 test year revenue of $10,000 has been adjusted to zero for the pro forma period.

<u>FERC Settlement</u> – The Company received a settlement benefit from the FERC in 2009 relating to the Western energy crisis of 2000-2001. This 2009 test year revenue of $115,000 has been adjusted to zero for the pro forma period.

<u>IV. TRANSMISSION AND DISTRIBUTION CAPITAL PROJECTS</u>

Q. Please describe the Company's capital <u>transmission</u> projects that will be completed in 2010.

A. Avista continuously needs to invest in its transmission system to maintain reliable customer service and meet mandatory reliability standards. The 2010 capital transmission projects are being constructed to meet either compliance requirements, improve system reliability, fix broken equipment, or replace aging equipment that is anticipated to fail.

Included in the compliance requirements are the North American Electric Reliability Corporation (NERC) standards, which are national standards that utilities must meet to ensure interconnected system reliability. Beginning June 2007 compliance with these standards was made mandatory and failure to meet the requirements could result in monetary penalties of up to $1 million per day per infraction. The majority of the reliability standards pertain to transmission planning, operation, and equipment maintenance. The standards require utilities to plan and operate their transmission systems in such a way as to avoid the loss of customers or impact to neighboring utility systems due to the loss of transmission facilities. The transmission system must be designed and operated so that the loss of up to two facilities simultaneously will not impact to the interconnected transmission system. These requirements drive the need for Avista to continually invest in its transmission system. Avista is required to perform system studies in both the near term (1-5 years) and long term (5-10 years). If a potential violation is observed in the future years, then Avista must develop a project plan to ensure that the violation is fixed prior to it becoming a reality. Avista budgets for the future projects and ensures that the design and construction of the required projects are completed prior to the time they are needed. Avista will always have a need to develop these compliance related projects as system load grows, new generation is interconnected and the system functionality and usage changes.

Avista capital Transmission project requirements are developed through system planning studies, engineering analysis, or scheduled upgrades or replacements. The larger specific projects that are developed through the system planning study process typically go through a thorough internal review process that includes multiple stakeholder review to ensure all system needs are adequately addressed. Smaller projects are selected to meet specific system needs or equipment replacement. However, both project cost and system benefits are considered in the selection of the final projects.

The major capital transmission costs (system) for projects to be completed in 2010 are approximately $18.888 million as described below.

The specific projects scheduled for 2010 completion related to reliability compliance projects will cost $13.372 million (again, on a system basis) and include:

Reliability Compliance Projects:

- Lolo 230 kV Substation ($1.450 million): This project involves the rebuild of the existing Lolo substation to increase the capacity of the substation bus, breakers, and supporting equipment to match the upgraded capacity of the transmission lines that connect to the substation. The new Lolo substation design significantly improves reliability and operating flexibility. The Lolo Substation project was constructed in phases to allow operational flexibility due to system reliability concerns associated with other scheduled construction in the area. Phase 1 was completed in 2007 and the remainder of the project ($1.45 million) was completed in February 2010. The Lolo Substation project costs were developed by the Engineering Department and approved through the capital budget process. This project is required to meet Reliability Compliance under NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, and TPL-003-0a R1-R3.

- Spokane/Coeur d'Alene area relay upgrade ($1.250 million): This project involves the replacement of older protective 115 kV system relays with new micro-processor relays to increase system reliability by reducing the amount of time it takes to sense a system disturbance and isolate it from the system. This is a five year project and is required to maintain compliance with mandatory reliability standards. This project is required to meet Reliability Compliance under NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3.

- Nez Perce 115 kV Substation Rebuild and Capacitor Bank ($3.575 million): This project involves the complete rebuild of the Nez Perce substation based upon its degraded condition. The project also includes the addition of a shunt capacitor bank to provide voltage support to the area for critical contingencies to ensure compliance with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3.

- SCADA Replacement ($0.800 million): The System Control and Data Acquisition (SCADA) system is used by the system operators to monitor and control the Avista transmission system. The SCADA system will be upgraded in 2010 to a new version provided by our SCADA vendor. The current application version is no longer supported by the vendor. The upgrade will ensure Avista has adequate control and monitoring of its Transmission facilities. This portion of the project is required to meet Reliability Compliance under NERC Standards: TOP-001-1, TOP-002-2a R5-R10, R16, TOP-005-2 R2, TOP-006-2 R1-R7. Several Remote Terminal Units (RTUs) located at substations throughout Avista's service territory will also be replaced. The RTUs are part of the transmission control system.

- System Replace/Install Capacitor Bank ($0.750 million): This project includes the construction of a 115 kV capacitor bank at Airway Heights to support local area voltages during system outages. The project is required to meet reliability compliance with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3, and provide improved service to customers. The project is scheduled to be completed by July of 2010.

- Airway Heights-Silver Lake (North Fairchild Tap) 115kV Transmission Line ($0.975 million): This work is necessary to upgrade the final 2.5 miles of the ten mile long transmission line from #2/0 ACSR to 556 kcm Aluminum (100 MVA-Summer) conductor. The line upgrade will meet compliance requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Additionally, this work will increase service reliability to an essential military facility (North Fairchild Air Force Base). Using 2009 actual loads, the new conductor will reduce line losses by 71 MWh on an annual basis, establishing a yearly offset savings of $7,100 (based on a $100/MWh avoided energy cost); these savings have been reflected in the proposed revenue requirement.

- Mos230-Pullman 115 Reconductor ($1.300 million): Year two of this multi-year project continues to upgrade the transmission line from 1/0 copper to 556 kcm Aluminum (100 MVA-Summer) conductor in order to mitigate thermal overloads experienced during heavy summer load conditions. The line upgrade will meet compliance requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Using 2009 actual loads, the new conductor will reduce line losses by 151 MWh on an annual basis, establishing a yearly offset savings of $15,100 (based on a $100/MWh avoided energy cost); these savings have been reflected in the proposed revenue requirement.

<u>Environmental Regulation Projects:</u>

- Beacon Storage Yard ($0.750 million): The Beacon Storage Yard is a location where circuit breakers and power transformers are stored and staged for rotation into existing substations as replacements or for new construction. This site is near the Spokane River and this project work will provide an oil containment system to protect the local environment. In 2009, the Company constructed the bulk of the Beacon Substation Equipment Storage Yard for a total spend and transfer to plant of $948k. In 2010, the remainder of the yard and a building to securely house the mobile substations and battery trailer will be completed and transferred to plant.

Contractual Required Projects:

- Colstrip Transmission ($0.503 million): As a joint owner of the Colstrip Transmission projects, Avista pays its ownership share of all capital improvements. Northwestern Energy either performs or contracts out the capital work associated with the joint owned facilities.

- Tribal Permits ($0.519 million): The Company has approximately 300 right-of-way permits on tribal reservations that need to be renewed. The costs include labor, appraisals, field work, legal review, GIS information, negotiations, survey (as needed), and the actual fee for the permit.

Reliability Improvement Projects:

- Boulder-Rathdrum 115kV Transmission Line ($1.500 million): Year two of this multi-year project to integrate the local load service of Idaho Road Substation will upgrade transmission connectivity from a "tap" configuration to considerably more reliable "loop" feed by installing approximately four miles of transmission line with 795 kcm Aluminum (125 MVA-Summer) conductor. Using 2009 actual loads, the new conductor will reduce line losses by 100 MWh on an annual basis, establishing a yearly offset savings of $10,000 (based on a $100/MWh avoided energy cost), which has been incorporated into the Company's revenue requirement.

The Company will also spend approximately $5.516 million in transmission system equipment replacements associated with storm damage or aging/obsolete equipment. A brief description of the larger projects included in these replacement efforts are given below.

Replacement Projects:

- Transmission Minor Rebuilds ($1.250 million): These projects include minor transmission rebuilds as a result of age or damage caused by storms, wind, fire, and the public. These smaller projects are required to operate the transmission system safely and reliably. Facilities will need to be replaced when damaged in order to maintain customer load service. In 2009 the Company spent $2.206 million on these minor rebuild projects as a result of damage caused by weather or the public.

- Power Circuit Breakers ($0.485 million): The Company transfers all circuit breakers to plant upon receiving them. Breakers purchased in 2010 will be installed at Otis Orchards (WA) Switching Station. Planned replacements in 2010 include a 115 kV breaker at Stratford (WA) Switching Station and a 230 kV breaker at Noxon Rapids Switchyard.

- Pine Creek - Replace 115 kV Circuit Switcher & Cap Bank ($0.570 million): The project scope and preliminary engineering design work for this project was started in 2008 and included replacing the circuit switcher and one 13 kV recloser due to equipment age. After further investigation the project was expanded to replace the other two 13 kV reclosers, the cap bank, deteriorated station control wiring, and removal of the small panel house including the obsolete Remote Terminal Unit (RTU). A total of $0.57 million directly related to Transmission (115 kV circuit switcher, Capacitor Bank, control wiring, Remote Terminal Unit) will be transfered to plant in 2010.

- Otis Orchards - 115 kV Breaker and Line Relay Replacements ($0.650 million): This project will replace the 115 kV breakers and associated 115 kV line relays at the existing Otis Orchards substation. Four of the breakers are over 50 years old and have reached the end of their useful lives. The line relaying must be replaced with new microprocessor relays to provide the high speed tripping required for mandatory reliability standards. The relay replacements are part of the Spokane/Coeur d'Alene area relay upgrade project previously discussed.

- Replacement Programs ($2.044 million): Avista has several different equipment replacement programs to improve reliability by replacing aged equipment that is beyond its useful life. These programs include transmission and substation air switch upgrades, arrestor upgrades, restoration of substation rock and fencing, recloser replacements, replacement of obsolete circuit switchers, substation battery replacement, interchange meter replacements, high voltage fuse upgrades, replacement of fuses with circuit switchers, and voltage regulator replacements. All of these individual projects improve system reliability and customer service.

- Other Small Transmission Projects ($.517 million): These projects include various other smaller transmission system equipment replacement projects.

Q. Please describe the Company's <u>distribution</u> projects in the State of Idaho that will be completed in 2010.

A. Distribution Projects in Idaho (including transformation) for 2010 total $8.255 million. These projects are necessary to meet capacity needs of the system, improve reliability, and rebuild aging distribution substations and feeders. The following projects make up the $8.255 million.

- Appleway Substation ($1.980 million) - Appleway 115-13 kV Substation is a wood substation serving most of the City of Coeur d'Alene. The station has reached the end of its useful life and additional capacity is required. The new station will include 2-30 MVA transformers and six 13 kV feeders. Approximately $416k was spent in 2009 for grading, fencing, and the start of foundation work. It is estimated that $1.75 million will be staged into plant in 2010 with the remainder of the project completed in 2011.

- Deary Substation ($1.405 million) - Deary 115-24 kV Substation is a wood substation scheduled to be rebuilt as a steel substation in 2010. Engineering, site grading, and fencing were completed in 2009.

Approximately $490k has been spent on this project as of the end of 2009. The foundations, structures, equipment, and electrical work will be completed by the end of Q3 2010.

- Power Transformer Distribution ($4.740 million system / $1.815 million Idaho) – Transformers are transferred to plant upon receiving them. These transformers are being purchased to replace existing spares that will be installed as either replacements or new installations.

- System - Dist Reliability - Improve Worst Feeders ($0.700 million): Based on a combination of reliability statistics, including CAIDI, SAIFI, and CEMI (Customers Experiencing Multiple Interruptions), feeders have been selected for reliability improvement work. This work is expected to improve the reliability of these feeders. The improvements at Clark Fork (ID) will include $250k for a new substation feeder bay and associated equipment.

- Distribution – CdA East & North ($0.905 million) – These are all Idaho distribution projects. These represent four discrete feeder reconductor projects as determined by SynerGee modeling as thermally constrained.

- Rathdrum Transformer and 233 Feeder Addition ($0.900 million) – This project added a second 115-13 kV, 20 MVA Distribution Power Transformer and a new 13 kV feeder serving the greater Rathdrum-Post Falls area. The project was required for system reliability and to allow for better system operational flexibility and maintenance scheduling. The work started in 2009 and was completed in February 2010.

- Pine Creek – Replace 115 kV Circuit Switcher & Cap Bank ($0.300 million): The project scope and preliminary engineering design work for this project was started in 2008 and included replacing the circuit switcher and one 13 kV recloser due to equipment age. After further investigation the project was expanded to replace the other two 13 kV reclosers, the cap bank, deteriorated station control wiring, and removal of the small panel house including the obsolete RTU. Distribution costs associated with the recloser replacement will be $0.30 million.

- Potlatch (ID) Transformer Replacement ($0.250 million): Transformer 1 at Potlatch Substation in Potlatch, ID, must be replaced due to environmental concerns. The transformer was received in 2009 and transferred to plant. These costs are the associated labor costs to install the new transformer.

The Company also will spend approximately $22.872 million (system) in equipment replacements and minor rebuilds associated with aging distribution equipment discovered through inspections, feeders with poor reliability performance, replacements from storm damage, or relocation of feeder sections resulting from road moves. A brief description of the projects included in these replacement efforts is given below.

- Electric Distribution Minor Blanket Projects ($7.000 million): This effort includes the replacement of poles and cross-arms on distribution lines in 2010 as required, due to storm damage, wind, fires, or obsolescence. The company spent $9.22 million in 2009 for these projects.

- Wood Pole Replacement Program and Capital Distribution Feeder Repair ($6.884 million): The distribution wood-pole management program is a strength evaluation of a certain percentage of the pole population each year. We have over 240,000 distribution poles and 34,500 transmission poles in our electric system. Depending on the test results for a given pole, that pole is either considered satisfactory, reinforced with a steel stub, or replaced. As feeders are inspected as part of the wood-pole management program, issues are identified unrelated to the condition of the pole. This project also funds the work required to resolve those issues (i.e. leaking transformers, transformers older than 1964, failed arrestors, missing grounds, damaged cutouts). Since the pre-World War II buildup wood poles have reached the end of their useful life, Avista's Wood Pole Management program was put into place to prevent the Pole-Rotten events and Crossarm – Rotten events from increasing. So far, the Wood Pole Management Program has helped keep Pole-Rotten and Crossarm-Rotten events in check. The Company spent $8.276 million on these efforts in 2009.

- Electric Underground Replacement ($4.000 million): This effort involves replacing the first generation of Underground Residential District (URD) cable, which has been ongoing for the past several years. This program focuses on replacing a vintage and type of cable that has reached its end of life and contributes significantly to URD cable failures. The Company spent $3.69 million in 2009. The incremental savings in Operation and Maintenance expenses seen in 2009 compared to 2008 was $120,000 due to reduced number of URD Primary Cable fault reductions. For the pro forma period, we anticipate that we will see the same incremental savings as 2009, which has been included as an offset for the Electric Underground Replacement project.

- T&D Line Relocation ($2.348 million): The relocation of transmission and distribution lines as required due to road moves requested by State, County or City governments. The Company spent $2.2 million in 2009 on line relocations associated with road moves.

- Failed Electric Plant ($2.000 million): Replacement of distribution equipment throughout the year as required due to equipment failure. The Company spent $3.44 million in 2009.

- Other Small Distribution projects ($0.640 million): These projects include various smaller distribution project equipment replacements and minor rebuilds, such as the distribution feeder reconductor project identified as "thermally constrained" portions of the feeder trunk lines located in Pullman and Lewis Clark valley.

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

A. Yes, it does.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-10-01
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 8
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	SCOTT J. KINNEY
	)	

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

Avista Corporation
- Energy Delivery -
Pro Forma Transmission Revenue/Expenses
($000s)

Line No.			2009 Actual	Adjusted	Oct 2010 - Sep 2011 Pro Forma Period
		556 OTHER POWER SUPPLY EXPENSES			
1		NWPP	36	4	40
		560-71.4, 935.3-.4 TRANSMISSION O&M EXPENSE			
2		Colstrip O&M - 500kV Line	491	98	589
3		ColumbiaGrid Development	202	-10	192
4		ColumbiaGrid Planning	142	73	215
5		ColumbiaGrid OASIS	35	45	80
6		ColumbiaGrid DSRFA	2	-2	0
7		Grid West (ID)	71	0	71
8		Total Account 560-71.4, 935.3-.4	943	204	1,147
		561 TRANSMISSION EXP-LOAD DISPATCHING			
9		Elect Sched & Acctg Srv (CASSO/OATI)	172	-12	160
		566 TRANSMISSION EXP-OPRN-MISCELLANEOUS			
10		NERC CIP	25	0	25
11		OASIS Expenses	4	5	9
12		BPA Power Factor Penalty	124	22	146
13		WECC - Sys. Security Monitor	159	9	168
14		WECC Admin & Net Oper Comm Sys	329	41	370
15		WECC - Loop Flow	40	-6	34
16		Total Account 556	681	71	752
17		**TOTAL EXPENSE**	1,832	267	2,099
		456 OTHER ELECTRIC REVENUE			
18		Borderline Wheeling	5,552	2,286	7,838
19		Seattle/Tacoma Main Canal	193	83	276
20		Seattle/ Tacoma Summer Falls	74	0	74
21		OASIS nf & stf Whl (Other Whl)	2,962	779	3,741
22		PP&L - Dry Gulch	206	43	249
23		Spokane Waste to Energy Plant	160	0	160
24	*	Vaagen Wheeling	97	-97	0
25	*	Grant County PUD	56	-14	42
26		Grand Coulee Project	8	0	8
27	*	PP&L Series Cap -1978	5	-5	0
28	**	NaturEner Pwr Watch	10	-10	0
29	**	FERC Settlement	115	-115	0
30		Total Account 456	9,438	2,950	12,388
31		**TOTAL REVENUE**	9,438	2,950	12,388
32		**TOTAL NET EXPENSE**	-7,606	-2,683	-10,289

* Contracts ended in either 2009 or 2010.
** One time events.

Exhibit No. 8
Case No. AVU-E-10-01
S. Kinney, Avista
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