Exhibit No. ___(BAC-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-16________

DIRECT TESTIMONY OF

BRYAN A. COX

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Bryan A. Cox. I am employed by Avista Corporation as Director, Operations West. My business address is 1411 East Mission, Spokane, Washington.

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

A. I am a 1992 graduate of Gonzaga University with a degree in Mathematics and a 2009 graduate of the University of Washington's Foster School of Business with a Masters Degree in Business Administration. I joined the Company in 1997 and have spent 18 years in various technical and leadership positions in Information Technology, Natural Gas Delivery, Strategic Planning, and Gas and Electric Construction Services. Over the last two years I have led the West Electric Operations group which delivers service to most of our Washington operations as well as more recently the System Operations Department. I am a member of the Capital Planning Group that manages the five year Company capital budget.

Q. What is the scope of your testimony?

A. My testimony presents Avista's transmission revenues and expenses for 2017 and 2018. I also discuss Avista's Transmission capital expenditures, for the period January 2016 through the June 2018 rate period. As explained by Company witness Ms. Andrews, the Company is basing its electric revenue increase requested in this case on its electric Attrition Study. However, as explained by Company witness Ms. Smith, the Company is also presenting a traditional electric Pro Forma Study using a modified historical test period with limited pro forma adjustments (modified test year Pro Forma), including Washington's share of certain transmission capital projects I have described later in my testimony. I am also presenting explanation and documentation supporting transmission capital projects that are incorporated into Ms. Smith's 2017 Cross Check Study, as well as the Company's Cross Check Study for the January - June 2018 six-month period.[1]

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. Exhibit No. __(BAC-2) provides the transmission revenue and expense adjustments.

[1]As discussed by Ms. Andrews, the electric Attrition Studies analysis includes Washington's share of the 2017 and June 2018 rate year transmission revenues described within my testimony. These revenues are included in Ms. Andrews' electric Attrition Studies, Exhibit Nos. __(EMA-2) and __(EMA-4), page 4, column [I]. Washington's share of the transmission revenues are also included in the Energy Recovery Mechanism (ERM) authorized base. See Company witness Mr. Johnson Exhibit No. __(WGJ-5) for the "ERM Authorized Power Supply Expenses" included in this case.

II. TRANSMISSION EXPENSES FOR 2017 and 2018 (6 months)

Q. Please describe the adjustments to the twelve months ended September 30, 2015 test year transmission expenses to arrive at transmission expenses for the 2017 – June 2018 ending rate period.

A. Adjustments were made in this filing to incorporate updated information for any changes in transmission expenses from the October 2014 through the September 2015 test year to the 2017 rate year. No material changes were necessary for the incremental period ending June 2018 from the 2017 levels proposed by the Company. The changes in expenses and a description of each is summarized in Table No. 1, and an explanation of each change follows the table.

TABLE NO. 1
Transmission Expense Adjustment

	2017 Test Year (System)(1)	12ME 06.2018 Test Year (System)(2)
NWPP	$ 21,000	$ -
Colstrip O&M 500kV Lines	(16,000)	-
ColumbiaGrid Transmission Funding	57,000	-
ColumbiaGrid Transmission Planning	15,000	-
Order 1000 Functional Agreement	(25,000)	-
NERC CIP	(32,000)	-
PEAK Reliability	194,000	-
WECC Dues	22,000	-
WECC Loop Flow	-	-
Total Change in Transmission Expense	**$ 236,000**	**$ -**

(1) Represents the change in expense above or below the 2014-2015 historical test year level.

(2) Represents the change in expense above or below the December 31, 2018 rate year level.

Northwest Power Pool (NWPP) (2017: $21,000; 2018: $0) – Avista pays its share of the NWPP operating costs. The NWPP serves the electric utilities in the Northwest by facilitating coordinated power system operations and planning, including contingency generation reserve sharing, Columbia River water coordination and providing support to coordinated regional transmission planning. Avista's share of the costs for 2017 is $83,000, an increase of $21,000 over the 2014-15 test year. This increase in expense is primarily related to increased labor and analytical support required in the development of new standards intended to provide consistency in operations between various states in our region.

Colstrip Transmission (2017: -$16,000; 2018: $0) – Avista is required to pay its portion of the O&M costs associated with its joint ownership share of the Colstrip transmission system pursuant to the Colstrip Transmission Agreement. Under this agreement, NorthWestern Energy (NWE) operates and maintains the Colstrip transmission system. In accordance with NWE's proposed Colstrip transmission plan provided to the Company, NWE will bill Avista an estimated $312,000 for Avista's share of the Colstrip O&M expense during the 2017 rate year. This is a decrease of $16,000 from the actual expense of $328,000 incurred during the 2014-15 test year.

ColumbiaGrid Transmission Funding (2017: $57,000; 2018: $0) – Avista became a member of the ColumbiaGrid regional transmission organization 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, and support effective market monitoring within the Northwest and the entire Western interconnection. Avista supports ColumbiaGrid's general developmental and regional coordination activities under the ColumbiaGrid Funding Agreement and supports specific functional activities under the Planning and Expansion Functional Agreement and the FERC Order 1000 Functional Agreement. Avista's ColumbiaGrid general funding expenses for the 2014-15 test year were $85,000 while 2017 rate year general funding expenses are planned to be $142,000. This increase is primarily due to an increase in labor expenses due to organizational changes and filling of previously open positions.

<u>ColumbiaGrid Transmission Planning</u> (2017: $15,000; 2018: $0) – 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 its coordinated regional transmission planning requirements set forth in FERC Order 890 issued in February 2007, and as outlined in the Company's Open Access Transmission Tariff. Actual PEFA expenses for the 2014-15 test year were $158,000. The Company's PEFA expenses for 2017 are $173,000, reflecting ColumbiaGrid's staffing levels to support the PEFA.

<u>ColumbiaGrid Order 1000 Functional Agreement</u> (2017: -$25,000; 2018: $0) – FERC Order 1000 requirements are implemented under the Amended and Restated Order 1000 Functional Agreement, signed on November 11, 2014 (Order 1000 Agreement). This contract called for a $50,000 payment late in 2014 that covered two years of payments for 2015 and 2016. Beginning in 2017, this contract calls for an annual payment of $25,000.

<u>NERC Critical Infrastructure Protection (CIP)</u> (2017: -$32,000; 2018: $0) – The Company has purchased several software and hardware products to assist in protecting critical transmission control systems from intrusion and to meet applicable NERC standards. These products provide for physical security, intrusion detection, virus protection and

vulnerability assessment. The Company's NERC CIP expenses for 2017 are $75,000, a decrease of $32,000 from the 2014-15 test year actual expenses of $107,000.

<u>OASIS Expenses</u> (2017: $0; 2018: $0) – These Open Access Same-time Information System (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, regional criteria development, FERC OASIS requirements and OASIS user group forums with software vendor OATI. Issues regarding the software are discussed and requests are made with the vendor for additional features that will be needed for compliance standards mandated by NERC, NASB and FERC. Expenses during the 2014-15 test year were $15,000 and these are expected to remain unchanged for 2017.

<u>Peak Reliability – Reliability Coordination</u> (2017: $194,000; 2018: $0) – The Company's Peak Reliability (PEAK) fees are scheduled to increase from the amount paid in the historical test year of $484,000, to $678,000 in the 2017 rate year. The large increase is attributable to the FERC requirement that the western interconnection reliability coordination function be corporately and physically separated from other WECC functions. This "bifurcation" was primarily the result of a transmission system outage in the Pacific Southwest on September 8, 2011. A reference to the disturbance including "Causes and Recommendations" may be found at http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf. PEAK's budget is approved by its independent board of directors and is allocated to the members of PEAK based net energy used to serve load within a member's balancing area. Detailed allocation information is available on PEAK's website www.peakrc.com.

WECC – Administration Dues (2017: $22,000; 2018: $0) – WECC is the designated Regional Entity under federal statute responsible for coordinating and promoting Bulk Electric System reliability throughout the western interconnection. WECC is responsible for monitoring and measuring Avista's compliance with reliability standards and has substantially increased its staff and other resources to meet these FERC requirements. The Company's 2014-15 test year WECC dues and fees were $421,000. The Company's total for dues and fees in the 2017 rate year are expected to be $443,000.

WECC - Loop Flow (2017: $0; 2018: $0) – 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. Loop Flow expenses for the 2014-15 test year were $41,000. Loop Flow expenses are expected to be unchanged for the 2017 rate year.

Addy Substation (2017: $0; 2018: $0) – The Company pays operation and maintenance fees to Bonneville associated with a 115kV circuit breaker in Bonneville's Addy Substation that provides a direct interconnection for Avista's retail load. In the test year the expenses were $9,000 and these are anticipated to remain unchanged for 2017.

Hatwai Substation (2017: $0; 2018: $0) – The Company pays operation and maintenance fees to Bonneville associated with a 230kV circuit breaker owned by Avista but located in Bonneville's Hatwai Substation. In the test year the expenses were $23,000 and these are expected to remain unchanged for 2017.

III. TRANSMISSION REVENUES FOR 2017 – 2018 (6 months)

Q. Please describe the adjustments to 2014-2015 test year transmission revenues to arrive at transmission revenues for the 2017 and June 2018 ending rate periods.

A. Adjustments have been made in this filing to incorporate updated information for transmission revenue during the 2017 and incremental 6 month period ending June 2018 as compared to the historical test year. Each revenue item described below is at a system level and is included in Exhibit No.__ (BAC-2). With the exception of the Morgan Stanley point-to-point transmission service contract revenue, no material change in revenue is expected for the incremental 6 month period ending June 30, 2018. Table No. 2 below provides a summary of the changes in transmission revenues, and an explanation of each change follows the table.

TABLE NO. 2
Transmission Revenue Adjustment

	2017 Test Year (System)(1)	12ME 06.2018 Test Year (System)(2)
Borderline Wheeling Transmission	$ 271,000	$ -
Borderline Wheeling - Low Voltage	-	-
Borderline Wheeling Ancillary Revenues	(6,000)	-
Seattle/Tacoma Main Canal	-	-
OASIS Nonfirm & Short-term Firm	(690,000)	-
Seattle and Tacoma - Main Canal Project	-	-
Seattle and Tacomoa - Summer Falls Project	-	-
PacifiCorp - Dry Gulch Wheeling	(17,000)	-
Spokane Waste to Energy Plant	-	-
Grand Coulee Project Hyroelectric Authority	-	-
First Wind Transmission	(200,000)	-
Palouse Wind O & M	-	-
Stimson Lumber Agreement	-	-
Bonneville Power Administration - Parallel Capacity Support	-	-
Morgan Stanley Capital Group		(300,000)
Kootenai Electric Cooperative Fighting Creek (KEC)	-	-
	$ (642,000)	**$ (300,000)**

(1) Represents the change in expense above or below the 2014-2015 historical test year level.

(2) Represents the change in expense above or below the December 31, 2018 rate year level.

Borderline Wheeling – Transmission (2017: $271,000; 2018: $0) – The Company provides borderline wheeling service (wheeling service over transmission and low-voltage distribution facilities for service to loads of other utilities within the Company's transmission system footprint) to the Bonneville Power Administration (BPA), Consolidated Irrigation District, East Greenacres Irrigation District, Spokane Tribe of Indians and Grant County PUD (transmission only). Total revenue for the transmission portion of borderline wheeling activities for the 2014-2015 test year was $5,982,000. Total revenue in the 2017 rate year is estimated to be $6,253,000, representing an increase of $271,000 from the test year. Revenue estimates for each transmission customer are determined as follows:

- **Bonneville Power Administration** – Network Integration Transmission Service revenue is estimated based upon a three-year average for the 2013 to 2015 time period, resulting in a figure of $6,153,000 for the 2017 and 2018 rate year compared to $5,887,000 for the 2014-2015 test year. The Company has in the past used a five-year average for estimating BPA borderline wheeling revenue but is proposing to use a three-year average at this time in order to be consistent with the three-year average used in all other instances where the Company estimates transmission revenues that are based upon variable customer load figures (e.g. Grant County PUD and PacifiCorp Dry Gulch).
- **Grant County PUD** – Power Transfer Agreement revenue is estimated using a three-year average (2013-2015) resulting in a figure of $28,000 for the 2017 rate year compared to $28,000 for the 2014-2015 test year.
- **Consolidated Irrigation District** – Point-to-Point Transmission Service revenue for the 2014-2015 test year was $32,000. The current contract will expire on September

30, 2016 but a follow-on contract is expected to be in place resulting in revenue that is expected to remain substantially unchanged during the 2017 rate year.

- **East Greenacres Irrigation District** – Point-to-Point Transmission Service revenue for the 2014-2015 test year was $11,000. Under the current contract (with a term through September 30, 2019) this revenue is expected to remain unchanged for 2017.
- **Spokane Tribe** – Point-to-Point Transmission Service revenue for the 2014-2015 test year was $24,000. Under the current contract (with a term through December 31, 2019) this revenue is expected to be $29,000 for 2017.

Borderline Wheeling – Low Voltage (2017: $0; 2018: $0) – Total revenues for the low voltage portion of borderline wheeling activities for the 2014-2015 test year was $1,079,000. Total revenue in the 2017 rate year is estimated to remain substantially the same. Revenue estimates for each transmission customer are as follows:

- **Bonneville Power Administration** – Wheeling revenue over low-voltage facilities for the 2014-2015 test year was $907,900. Revenue for the 2017 rate year is expected to remain substantially the same.
- **Consolidated Irrigation District** – Electric Distribution Service revenue for the 2014-2015 test year was $80,000. The current contract will expire September 30, 2016 but a follow-on contract is expected to be in place resulting in revenue that is expected to remain substantially unchanged during the 2017 rate year.
- **East Greenacres Irrigation District** – Electric Distribution Service revenue for the 2014-2015 test year was $51,000. Under the current contract (with a term through September 30, 2019) this revenue is expected to remain unchanged for 2017.

- **Spokane Tribe** – Electric Distribution Service revenue for the 2014-2015 test year was $20,000. Under the current contract (with a term through December 31, 2019) this revenue is expected to remain unchanged for 2017.

Borderline Wheeling – Ancillary Services (2017: -$6,000; 2018: $0) – The Company provides various ancillary services in association with long-term firm transmission service provided under its Open Access Transmission Tariff. Ancillary services revenue for the 2014-2015 test year was $1,627,500. Revenue in the 2017 rate year has been set at $1,621,500, representing a decrease of $6,000 from the test year. Ancillary services are necessary to support the transmission of electric power from one point to another given the obligations of balancing areas and transmitting utilities within those balancing areas to maintain reliable operation of the interconnected transmission system. The revenue estimate is based upon an ancillary services rate of $8.94 per kW multiplied by billing determinants of 2% (regulation and frequency response), 1.5% (Operating Reserves – Spinning) and 1.5% (Operating Reserves – Supplemental), applied to a three-year average of a customer's monthly peak loads. Revenue estimates for each transmission customer are as follows:

- **Bonneville Power Administration** – Using three-year average load figures for the 2013-2015 time period, ancillary services revenue is estimated to be $1,606,000 for the 2017 rate year compared to $1,612,000 for the 2014-2015 test year.
- **Consolidated Irrigation District** – Using three-year average load figures for the 2013-2015 time period, ancillary services revenue is estimated to be $6,500 for the 2017 rate year compared to $6,500 for the 2014-2015 test year.

- **East Greenacres Irrigation District** – Using three-year average load figures for the 2013-2015 time period, ancillary services revenue is estimated to be $4,500 for the 2017 rate year compared to $4,500 for the 2014-2015 test year.
- **Spokane Tribe** – Using three-year average load figures for the 2013-2015 time period, ancillary services revenue is estimated to be $4,500 for the 2017 rate year compared to $4,500 for the 2014-2015 test year.

<u>OASIS Non-Firm and Short-Term Firm Transmission Service</u> (2017: -$690,000; 2018: $0) – 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. 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 (<u>e.g.</u>, 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. For example, during the 2014-2015 test period, a single power marketer purchased short-term firm and non-firm transmission capacity from the Company in amounts significantly exceeding any prior activity. This single customer had purchased, on average, approximately $760,000 of such services over the previous three years. During the calendar year encompassing the majority of the test period, this same customer purchased $1,650,000 of transmission service, 217% of its previous years' average. While this example does not fully explain the differential between test period and pro-forma period OASIS revenues in this filing, the example underscores the fact that OASIS revenue can be volatile, entirely outside the scope and purview of the Company as a transmission provider. In this filing, the Company is using a three year average for the time period of January 2013 to December 2015. The OASIS revenue for the 2014-15 test year was $3.517 million and the three-year average results in 2017 rate year revenue of $2.827 million.

<u>Seattle and Tacoma – Main Canal Project</u> (2017: $0; 2018: $0) – Effective March 1, 2008, and continuing through October 31, 2026, 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. Both contracts run to October 31, 2026. Revenues under these agreements totaled $360,000 during the test year and are expected to remain unchanged for 2017.

<u>Seattle and Tacoma – Summer Falls Project</u> (2017: $0; 2018: $0) – Effective March 1, 2008, and continuing through October 31, 2024, 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 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 contracts totaled $74,000 in the 2014-15 test year and are expected to remain unchanged for 2017.

<u>PacifiCorp Dry Gulch</u> (2017: -$17,000; 2018: $0) – Revenue under the Dry Gulch use-of-facilities agreement has been adjusted to $230,000 for the 2017 rate year, which is a $17,000 decrease from the 2014-15 test year actual revenue of $247,000. The Company is calculating its adjustment using a three-year average of actual revenue. Revenue under the Dry Gulch Transmission and Interconnection Agreement with PacifiCorp varies depending upon PacifiCorp's loads served via the Dry Gulch Interconnection and the operating conditions of PacifiCorp's transmission system in this area. The use of a three-year average is intended to mitigate the impacts of potential annual variability in the revenues under the contract. 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.

Spokane Waste to Energy Plant (2017: $0; 2018: $0) – Spokane Waste to Energy pays a use-of-facilities charge for the ongoing use of its interconnection to Avista's transmission system. The 2017 rate year revenue associated with the use-of-facilities charge is $28,000, the same as the 2014-15 test year.

Grand Coulee Project Hydroelectric Authority (2017: $0; 2018: $0) – 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 2014-15 test year and will remain the same for the 2017 rate year.

First Wind (2017: -$200,000; 2018: $0) – First Wind signed a transmission service contract with the Company based on its initial intent to sell the output from a wind facility to an entity other than Avista. Avista has since signed a power purchase agreement with First Wind which voided its need for transmission service. First Wind has delayed its use of the 100 MW of reserved transmission service up to the maximum of five years. Unless First Wind develops another generation project or is able to re-market the capacity, Avista expects this agreement to be terminated during 2016. The 2014-15 test year included a $200,000 extension of service payment. No revenue associated with this agreement is expected during the 2017 rate year.

Palouse Wind O&M (2017: $0; 2018: $0) – Per Avista'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 Avista. O&M revenue for the 2014-15 test year was $52,000. Revenue during the 2017 rate year is expected to remain unchanged.

Stimson Lumber Agreement (2017: $0; 2018: $0) – Low-voltage facilities associated with the Company's Plummer Substation are dedicated for use by Stimson Lumber resulting in low voltage use-of-facilities revenue of $9,000 during the 2014-15 test year. The 2017 rate year revenue from this agreement is expected to remain unchanged.

Hydro Tech Systems Agreement (2017: $0; 2018: $0) – Low-voltage facilities in the Company's Greenwood Substation are dedicated for use by the Meyers Falls generation project resulting in low voltage use-of-facilities revenue of $6,000 during the 2014-15 test year. Revenue during the 2017 rate year is expected to remain unchanged.

Bonneville Power Administration – Parallel Capacity Support (2017: $0; 2018: $0) – Avista and Bonneville executed a Parallel Operation Agreement on December 12, 2012, wherein Avista provides Bonneville with parallel transmission capacity in support of Bonneville's integration of several wind resource projects. Avista provides ongoing parallel capacity support under the agreement at a monthly charge of $266,000. Revenue for the 2014-15 test year was $3,192,000. Bonneville has indicated its intent to construct additional transmission facilities to bypass Avista's system and terminate this agreement. If BPA chooses to bypass Avista's system, it will take some time to complete construction. If the Company learns that BPA will bypass Avista's system prior to June 30, 2018, the Company will update transmission revenue in the Company's power supply update as discussed by Company witness Mr. Johnson. The 2017 rate year reflects the same revenue of $3,192,000.

Morgan Stanley – Point-to-Point Transmission Service (2017: $0; 2018: -$600,000) – Morgan Stanley Capital Group has purchased 25 MW of Long-Term Firm Point-to-Point Transmission Service from January 1, 2013 to December 31, 2017. The 2014-15 test year revenues were $300,000 and will remain unchanged for 2017, but will reduce $300,000 for the 6-month period ending June 30, 2018.

Kootenai Electric Cooperative Fighting Creek (KEC) (2017: $0; 2018: $0) – KEC has purchased 3 MW of Long-Term Firm Point-to-Point Transmission Service from April 1, 2014 to March 31, 2019. The 2014-15 test year included revenues of $88,000 that will remained unchanged for 2017.

IV. TRANSMISSION CAPITAL PROJECTS

Q. Please explain how the Company prepared it's case with regards to transmission capital projects.

A. The Company started with the historical test period ending September 30, 2015 and included actual transfers to plant for the last quarter of 2015 incorporated in Company witness Ms. Schuh's and Ms. Smith's Pro Forma Adjustments. The Company then reviewed the planned capital projects for 2016 and determined a threshold for pro forma capital projects according to the Company's most recent WUTC Order 05[2]. The Company has identified transmission projects for the modified test year Pro Forma that are one-half of one percent of the Company's rate base – i.e., $6.3 million or greater. The remaining planned capital projects for 2016 through the first half of 2018 reflect the cross check

[2] Dockets UE-150204 and UG-150205 (Consolidated), Order 05, Paragraph 39 and 40.

adjustments included in Ms. Smith's electric Cross Check Study. For further discussion regarding the modified test year Pro Forma adjustments and the Cross Check adjustments please see Ms. Schuh's testimony and Ms. Smith's testimony.

Q. Please discuss the drivers for the Company's capital transmission projects that will be completed from January 1, 2016 through June 30, 2018.

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

Compliance requirements are driven by 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 customers experiencing outages or adversely impacting, neighboring utility systems due to the loss of transmission facilities. Therefore, the transmission system must be designed so that the loss of up to two facilities simultaneously will not impact the interconnected transmission system. The transmission system must be operated at all times such that a loss of a facility will not result in a System Operating Limit exceedance (voltage, thermal or stability limit). If such an exceedance occurs, it must be mitigated prior to the loss of the next facility. The mitigation efforts can include system configuration changes, generation changes, or removal of firm load from the transmission system. These requirements drive the need for Avista to continually invest in its transmission system. Avista is required to perform system planning 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 real-time operating issue. Avista plans for the future projects and attempts to ensure that the design and construction of the required projects are completed prior to the time they are needed. Avista continues to have a need to develop these compliance-related projects as system load grows, new generation is interconnected (including wind and solar), and the system functionality and usage changes.

Q. How does Avista's Transmission Department prioritize capital projects before they are submitted to the capital planning group?

A. 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. For the smaller specific projects, projects are selected to meet specific system needs or equipment replacement. Both project costs and system benefits are considered in the selection of the final projects within the transmission department.

Q. Please provide a brief description of the transmission-related capital projects that are included in the Company's modified test year Pro Forma Study, and

those included in the Company's Cross Check Studies for January 1, 2016 through June 30, 2018?

A. As shown in Table No. 3 below for 2016 the Company has included transmission projects in the modified test year Pro Forma totaling $11.5 million (on a system basis). The remaining capital transmission projects are included in the Cross Check Studies for 2016, 2017 and through June 30, 2018, and total $48.9 million, $57.8 million, and $7.0 million, respectively, on a system basis. The following table and descriptions have been divided into four different areas that are driving the transmission-related capital projects in this case: Reliability Improvements, Reliability Compliance, Contractual Requirements, and Reliability Replacements. Details about the transmission-related capital projects are discussed below.

TABLE NO. 3
Transmission Capital Projects (System)

Business Case Name	2016 $(000's)	2017 $(000's)	6 Mos. Ended June 2018 $ (000's)
Modified Test Year Pro Forma Projects:			
Reliability Improvements:			
Noxon Switchyard Rebuild	**$ 11,500**		
Cross Check Projects:			
Reliability Compliance Projects:			
Transmission - NERC Low Priority Mitigation	$ 1,675	$ 3,000	
Transmission - NERC Medium Priority Mitigation	2,576	1,000	
SCADA - SOO & BUCC	1,002	1,044	460
Environmental Compliance	50	50	21
Contractual Requirements:			
Tribal Permits and Settlements	314	281	126
Colstrip Transmission	568	398	216
Reliability Improvements:			
Noxon Switchyard Rebuild		6,700	
Substation - Station Rebuilds	4,260	5,640	
Westside Rebuild Phase One	2,525		
S Region Voltage Control	5,000		
SCADA Completion		1,000	2,000
Transmission - Reconductors and Rebuilds	17,559	20,830	
Spokane Valley Transmission Reinforcement	1,340	7,200	
Reliability Replacements:			
Storms	1,000	1,000	502
Substation - Capital Spares	5,200	4,565	1,515
Substation - Asset Mgmt. Capital Maintenance	4,100	4,100	1,670
Transmission - Asset Management	1,772	1,000	515
	$ 48,942	**$ 57,808**	**$ 7,025**
Total Planned Transmission Capital Projects	**$ 60,442**	**$ 57,808**	**$ 7,025**

The following planned transmission reliability improvement project is included in the Company's <u>modified test year Pro Forma Study</u> using thresholds defined in Commission Order 05[3]:

Noxon Switchyard Rebuild – 2016: $11,500,000

The existing Noxon Rapids 230 kV Switchyard requires reconstruction due to the present age and condition of the equipment in the station. The existing bus has suffered a number of recent failures and is configured as a single bus with a tiebreaker separating the East and West buses. The station is the interconnection point of the Noxon Rapids Hydroelectric development as well as a principal interconnection point between Avista and BPA, and as such is a significant asset in the reliable operation of the Western Montana Hydro Complex. Equipment outages within the Station (planned or unplanned) can cause significant curtailments of the local generation output. Due to the significance of the station, a complete rebuild will require coordination with Avista's Energy Resources Department and neighboring utilities, primarily BPA. The Noxon Switchyard Rebuild Project is proposed to be a Greenfield Double Bus Double Breaker 230 kV switching station to replace the existing Noxon Switchyard. See Exhibit No.__(KKS-5), Section 7, pages 44 through 52 for the business case and other information related to this project. Additional workpapers have also been provided with the Company's filing.

The following projects are included in the Company's <u>Cross Check Study</u> for the years 2016, 2017 and half of 2018: (For the following capital projects, see Exhibit No.__(KKS-5) for business cases supporting these projects, as well as additional workpapers for certain projects filed with the Company's case)

I. <u>Reliability Compliance Projects:</u>

Transmission – NERC Low Priority Mitigation – 2016: $1,675,000; 2017: $3,000,000

This program reconfigures insulator attachments, and/or rebuilds existing transmission line structures, or removes earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2010 North American Electric Reliability Corporation's (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings". This Capital Program covers mitigation work on Avista's "Low Priority" 115kV transmission lines. Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have been adopted into the State of Washington's Administrative Code (WAC 296-46B-010).

[3] *Id.*

Transmission - NERC Medium Priority Mitigation – 2016: $2,576,000; 2017: $1,000,000

This program reconfigures insulator attachments, and/or rebuilds existing transmission line structures, or removes earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2010 North American Electric Reliability Corporation's (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings". This Capital Program covers mitigation work on Avista's "Medium Priority" 230 kV and 115 kV transmission lines. Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have been adopted into the State of Washington's Administrative Code (WAC 296-46B-010).

SCADA –SOO&BUCC –2016: $1,002,000; 2017: $1,044,000; January – June 2018: $460,000

This program replaces and/or upgrades existing electric and natural gas control center telecommunications and computing systems as they reach the end of their useful lives, require increased capacity, or cannot accommodate necessary equipment upgrades due to existing constraints. Included are hardware, software, and operating system upgrades, as well as deployment of capabilities to meet new operational standards and requirements. Some system upgrades may be initiated by other requirements, including NERC reliability standards, growth, and external projects (e.g. Smart Grid). Examples of upgrades to be completed under this program are Critical Infrastructure Protection version 5 (NERC requirement), Gas Control Room Management (PHMSA requirement), WECC RC Advanced Applications, and Technology Refresh (network and storage).

Environmental Compliance – 2016: $50,000; 2017: $50,000; January – June 2018: $21,000

This item includes implementation of Forest Service Special Use Permits, waste oil disposal, including PCBs, and environmental compliance requirements related to storm water management, water quality protection, property cleanup and related issues.

II. <u>Contractual Requirements:</u>

Tribal Permits – 2016: $314,450; 2017: $281,000; January – June 2018: $126,000

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.

Colstrip Transmission – 2016: $568,044; 2017: $397,862; January – June 2018: $216,000

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.

III. <u>Reliability Improvements:</u>

Noxon Switchyard Rebuild –2017: $6,700,000

This project is described in detail above in the Pro Forma section.

Substation – Distribution Station Rebuilds – 2016: $4,260,296; 2017: $5,640,000;

This program replaces and/or rebuilds existing substations as they reach the end of their useful lives, require increased capacity, or cannot accommodate necessary equipment upgrades due to existing physical constraints. Included are Wood Substation rebuilds as well as upgrading stations to current design and construction standards. Some station rebuilds may be initiated by other requirements, including obligation to serve, growth, and external projects. Examples of substation rebuilds to be completed under this program in the next five years are Kamiah (Wood Substation), 9th & Central, Gifford and Southeast (Equipment Additions), Ford and Sprague (Service Life Retirement) and Hallett & White (Growth).

Westside Rebuild Phase I –2016: $2,525,000

Phase I of this project will extend the existing Westside Substation 115 kV and 230 kV buses to allow for a new 250 MVA Autotransformer. This installation will eliminate transformer overload contingencies in the Spokane area. This is a three phase project to complete the remainder of the station rebuild.

South Region Voltage Control – 2016: $5,000,000

Avista's south region 230 kV, primarily around Lewiston-Clarkston, experiences excessive high voltage during light load periods. Voltages exceed equipment ratings over 35% of the time. Operation of equipment outside of equipment ratings imposes potential legal and regulatory risks to the Company on top of increasing large scale outage possibilities. With automatic control, existing overvoltages can be reduced, if not eliminated, on the 230 kV buses at Dry Creek, Lolo and North Lewiston as well as Moscow and Shawnee.

SCADA Completion – 2017: $1,000,000; January – June 2018: $2,000,000

This project will complete the installations of SCADA and EMS/DMS capability to all Avista substations. This will provide System Operations with clear visibility, indication and control at every substation. In addition, Grid Modernization will have the necessary communication infrastructure for complete installation and operation on all distribution feeders. System Planning, Asset Management, Operations and Engineering will have real time and historical data to support efficient, flexible and safe operation and design of the system for the future.

Transmission Reconductors and Rebuilds – 2016: $17,559,000; 2017: $20,830,000

This program reconductors and/or rebuilds existing transmission lines as they reach the end of their useful lives, require increased capacity, or present a risk management issue. Projects include: ER 2423 – System Transmission: Rebuild Condition; ER 2457 – Benton Othello 115 kV Recondition; ER 2550 – Burke-Thompson A&B 115kV Transmission Rebuild Proj; ER 2556 – CDA-Pine Creek 115kV Transmission Line: Rebuild; ER 2557 – 9CE-Sunset 115kV Transmission Line: Rebuild; ER 2564 – Devils Gap-Lind 115kV Transmission Rebuild Proj; ER 2577 – Benewah-Moscow 230kV – Structure Replacement; ER 2576 – Addy-Devils Gap 115kV – Rec/Rbld 266 & 397 Cond; ER 2582 – Beacon-Bell-Francis&Cdr-Waikiki 115kV – Reconfig; ER 2597 – Cabinet-Noxon 230kV Transm Line Rebuild Project.

Spokane Valley Transmission Reinforcement – **2016: $1,340,032; 2017: $7,200,000**

The Spokane Valley Transmission Reinforcement Project includes rebuilding 4.4 miles of the Beacon - Boulder #2 115 kV Transmission Line, constructing the new Irvin Switching Station, rebuilding 1.75 miles of the Irvin - Opportunity 115 kV Tap, installing four 115 kV circuit breakers at Opportunity Substation, and constructing a new 2.2 mile 115 kV transmission line from Irvin to Millwood/Inland Empire Paper. The completion of these projects is required to mitigate existing and future performance and reliability issues of the Transmission System in the Spokane Valley. Opportunity Substation was completed and energized in 2015; the Irvin-Millwood line was completed in 2014; Irvin Substation construction will break ground in 2016 and is expected to be energized in 2017; and the Beacon-Boulder line will then be able to be rebuilt.

IV. Reliability Replacements:

Storms -2016: $1,000,000; 2017: $1,000,000; January – June 2018: $502,000

This program will replace cross arms, poles and structures as required due to storms, and fires on distribution and transmission lines.

Substation – Capital Spares – 2016: $5,200,000; 2017: $4,565,000; January – June 2018: $1,515,000

This program maintains our fleet of Power Transformers and High Voltage Circuit Breakers. This fleet of critical apparatus is capitalized upon receipt and placed in service for both planned and emergency installations as required. The annual program expenditures may vary significantly in years when a 230/115 autotransformer is purchased. In years without an autotransformer purchase, only minor variations will occur based on planned projects as well as replenishing apparatus fleet levels required for adequate capital spares. These are long lead time items so sufficient levels need to be maintained.

Substation Asset Management Capital Maintenance – 2016: $4,100,000; 2017: $4,100,000; January – June 2018: $1,670,000

Avista has several different equipment replacement programs to improve reliability by replacing aged equipment that is beyond its useful life. These programs include transmission air switch upgrades, restoration of substation rock and fencing, recloser replacements, replacement of obsolete circuit switchers, substation battery replacement, meter replacements and upgrades, relay replacements, high voltage fuse upgrades, transformer replacements, breaker replacements, installation of diagnostic monitors, substation air switch replacements, and voltage regulator replacements. All of these individual projects improve system reliability and customer service. The equipment is replaced when it is approaching the end of its useful life.

Transmission – Asset Management – 2016: $1,772,260; 2017: $1,000,000; January – June 2018: $515,000

This item includes Transmission Minor Rebuilds in ER 2057, and Air Switch Replacements in ER 2254. Transmission Minor Rebuilds are developed using data received from the prior year's Wood Pole Inspection Program. Minor Rebuilds may also use data received from annual Aerial Patrol Inspections. Both inspection programs are undertaken to maintain compliance with NERC Standard FAC-501-WECC-1. Air Switch Replacements are made based either on condition, capacity, or functionality issues. Prioritization of installations and replacements are made from information provided by Avista System Operations, Operations Offices, or Substation Engineering.

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

A. Yes it does.