Exhibit No. ___(BAC-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-15________

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 17 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 the 2016 rate year. I also discuss Avista's Transmission and Distribution capital expenditures, for the period October 2014 through the 2016 rate year. As explained by Company witness Ms. Andrews, the Company's proposed electric retail revenue increase in this case is based on its electric Attrition Study. However, as a "cross check" to the Company's request, Ms. Smith has also prepared an electric Pro Forma Cross Check Study, which incorporates

Washington's share of the pro forma 2016 rate year adjustments for transmission revenues, expenses and capital additions described further in my testimony. [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 Study analysis includes Washington's share of the 2016 rate year transmission revenues described within my testimony. These revenues are included in Ms. Andrews' electric Attrition Study, Exhibit No. __(EMA-2), 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 2016

Q. Please describe the adjustments to the twelve months ended September 30, 2014 test year transmission expenses to arrive at transmission expenses for the 2016 rate year.

A. Adjustments were made in this filing to incorporate updated information for any changes in transmission expenses from the October 2013 through the September 2014 test year to the 2016 rate year. 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

	***2016 Rate Year (System)**
Northwest Power Pool (NWPP)	$ 17,000
Colstrip Transmission	36,000
Columbia Grid Development	39,000
ColumbiaGrid Transmission Planning	86,000
ColumbiaGrid OASIS	(4,000)
Transmission Line Ratings Confirmation Plan (NERC Alert)	(48,000)
Electric Schedule & Accounting Services (OATI)	18,000
NERC CIP	-
OASIS Expenses	8,000
BPA Power Factor Charge	37,000
PEAK Reliability	505,000
WECC Annual Dues	(11,000)
WECC - Loop Flow	16,000
Addy (BPA substation)	-
Hatwai (BPA substation)	-
Total Change in Transmission Expense	**$ 699,000**

*Representing the change in expense above or below the 2013-14 historical test year level.

Northwest Power Pool (NWPP) ($17,000) – 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 2016 is $76,000, an increase of $17,000.

Colstrip Transmission ($36,000) – 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 $303,000 for Avista's share of the Colstrip O&M expense during the 2016 rate year period. This is an increase of $36,000 from the actual expense of $267,000 incurred during the 2013-14 test year.

ColumbiaGrid Development/RTO ($39,000) – 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 Fourth Funding Agreement, signed July 1, 2010, 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 2013-14 test year were $126,000 while 2016 rate year general funding expenses are planned to be $165,000.

ColumbiaGrid Transmission Planning ($86,000) – 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. Additional FERC Order 1000 requirements are implemented under the Order 1000 Functional Agreement which was executed by Avista on December 13, 2013, followed by the Amended and Restated Order 1000 Functional Agreement, signed on November 11, 2014 (Order 1000 Agreement).

Funding under the PEFA and Order 1000 Agreement is on a two-year cycle with provisions to adjust for inflation. Actual PEFA expenses for the 2013-14 test year were $162,000. The Company's PEFA and Order 1000 agreement expenses for 2016 are $248,000, reflecting ColumbiaGrid's staffing levels to support the PEFA and additional Order 1000 activities and the reallocation of a portion of ColumbiaGrid's administrative expenses (previously paid under the general funding agreement) to these functional agreements.

ColumbiaGrid OASIS Agreement (-$4,000) – This contract, and its associated expense, was terminated due to lack of use by the parties to the agreement and their transmission customers.

Transmission Line Ratings Confirmation Plan (NERC Alert) (-$48,000) – The Transmission Line Ratings Confirmation Plan was developed to address a "NERC Alert" issued on October 7, 2010. The North American Electric Reliability Corporation (NERC) issued a "Recommendation to Industry addressing Consideration of Actual Field Conditions in Determination of Facility Ratings" based on a vegetation contact conductor-to-ground fault by another Transmission Owner. The NERC Alert was issued to provide the industry an opportunity to review actual field conditions and compare them to design values to ensure system reliability. Avista initiated a three year program to perform Light Detection and Ranging (LIDAR) surveying of all Avista 230kV transmission lines and five (5) 115kV transmission lines. A total of 1400 miles of transmission lines were evaluated. Per Order No. 06, Docket UE-11086 and UE-11087, the Company amortized these costs over a three-year period beginning in 2011. This project was completed in 2013, so there are no planned expenses for this project in the 2016 rate year.

<u>Electric Scheduling and Accounting Services</u> ($18,000) – The $18,000 increase in expense from the historical rate test year to the 2016 rate year for electric scheduling and accounting services is a result of annual increases and additional services provided by our third party vendor. These services are required to assist in meeting the requirements of the NERC mandatory reliability standards. The rate year scheduling and accounting costs are $211,000, reflecting an increase of $18,000 from the actual test year expense of $193,000.

<u>NERC Critical Infrastructure Protection</u> ($0) – The Company has purchased two software products to assist in protecting critical transmission system data from intrusion and to meet applicable NERC standards. The Company's 2016 rate year expense of $50,000 is in line with the actual test year expense of $50,000.

<u>OASIS Expenses</u> ($8,000) – 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 criterion development, and FERC OASIS requirements. The increase in costs for the 2016 rate year is due to a timing difference on when actual travel occurred during the test year months, and the ability of the technical users to attend training based upon work demands.

Bonneville Power Factor Charge ($37,000) – Power factor charge costs are associated with the Bonneville Power Administration's (Bonneville) General Transmission Rate Schedule Provisions. Bonneville charges a power factor charge 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 charge at several points of interconnection. Avista incurred $43,000 of power factor charges during the historical test year. The Company's 2016 rate year expenses are expected to be $80,000, representing an average of the power factor charges incurred in the three-year period of November 2011 to October 2014.

Peak Reliability – Reliability Coordination ($505,000) – The Company's Peak Reliability (Peak) fees are scheduled to increase from the amount paid in the historical test year of $116,000, to $621,000 in the 2016 rate year. The large increase is attributable to the FERC requirement that the WECC reliability coordination function be corporately and physically separated from the remaining WECC requirements and obligations. This "bifurcation" is 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. Another reason for the large variance is that Peak was not fully staffed during the test period. Expenses will ramp up during 2015 to the 2016 amount.

<u>WECC – Administration Dues</u> (-$11,000) – 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 the standards and has substantially increased its staff and other resources to meet these FERC requirements. The Company's test year WECC dues and fees were $496,000. The Company's total for dues and fees in the 2016 rate year are expected to be $485,000. Similar to Peak, there is not a direct comparison to prior years because of the aforementioned FERC mandated bifurcation of the reliability coordination portion of WECC's responsibilities.

<u>WECC - Loop Flow</u> ($16,000) – 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 2013-14 test year were $34,000. Loop Flow expenses are estimated to be $50,000 in the 2016 rate year.

<u>Addy Substation</u> ($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 the 2016 rate year.

Hatwai Substation ($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 will remain unchanged for the 2016 rate year.

III. TRANSMISSION REVENUES FOR 2016

Q. Please describe the adjustments to 2013-2014 test year transmission revenues to arrive at transmission revenues for the 2016 rate year.

A. Adjustments have been made in this filing to incorporate updated information for transmission revenue during the 2016 rate year 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). 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

	***2016 Rate Year (System)**
Borderline Wheeling Transmission & Low Voltage	$ (197,000)
Seattle/Tacoma Main Canal	46,000
Seattle/ Tacoma Summer Falls	-
OASIS nf & stf Whl (Other Whl)	646,000
PP&L - Dry Gulch	(1,000)
Spokane Waste to Energy Plant	-
Grand Coulee Project	-
Palouse Wind Transmission	-
Palouse Wind O & M	-
Stimson Lumber	-
BPA Parallel Operating Agreement	-
Morgan Stanley Capital Group	-
Hydro Tech Systems - Meyers Falls	-
Kootenai Electric	38,000
	$ 532,000

*Representing the change in revenue above or below the twelve months ended September 30, 2014 test year level.

Borderline Wheeling Transmission and Low Voltage (-$197,000) - Total borderline wheeling revenues for the test year were $8,240,000. Total borderline wheeling revenue in the 2016 rate year is estimated to be $8,043,000. The total decrease of $197,000 consists of the individual components explained below:

- Borderline Wheeling – Bonneville – Transmission (-$213,000) - Total Network Integration Transmission Service revenues from Bonneville for the test year were $7,170,000. Total revenue in the 2016 rate year has been set at $6,957,000, representing a decrease of $213,000 from the test year. In the past, pro forma borderline wheeling revenue from Bonneville has been developed using a five-year rolling average since a large portion of the revenue is dependent upon actual usage. However, with billing adjustments implemented in 2009 and new transmission rates and contracts that went into effect in 2010, only the use of revenue data from January 2010 forward would properly reflect pro forma revenue. Therefore, the 2016 rate year revenue has been set equal to the four-year average of 2010 through 2013 actual revenue.
- Borderline Wheeling – Bonneville – Low Voltage ($7,000) – Low voltage wheeling revenue from Bonneville during the test year was $928,000. The 2016 rate year revenue has been set equal to the four-year average of 2010 through 2013 actual revenue resulting in revenues of $935,000.
- Borderline Wheeling – Spokane Tribe of Indians ($2,000) – The Company's contracts to provide borderline wheeling service over both transmission and low-voltage facilities to the Spokane Tribe of Indians expired December 31, 2014. Total transmission and low-voltage wheeling revenue under these contracts for the test

year was $51,000 ($33,000 transmission and $18,000 low voltage). The expected annual 2016 rate year revenue under the new agreements, effective January 1, 2015, is $53,000 ($33,000 transmission and $20,000 low voltage).

- Borderline Wheeling – East Greenacres Irrigation District ($7,000) – The Company's contracts to provide borderline wheeling service to the East Greenacres Irrigation District expired September 30, 2014. Total transmission and low-voltage wheeling revenue under these contracts for the test year was $60,000 ($17,000 transmission and $43,000 low voltage). The expected annual 2016 rate year revenue under new the agreements, effective October 1, 2014, is $67,000 ($15,000 transmission and $52,000 low voltage).
- Borderline Wheeling – Consolidated Irrigation District ($0) – The Company provides borderline wheeling service over both transmission and low-voltage facilities to the Consolidated Irrigation District under two agreements that run through September 30, 2016. Total transmission and low-voltage wheeling revenue under these contracts for the test year was $119,000 ($39,000 transmission and $80,000 low voltage), and is expected to remain unchanged in the 2016 rate year.
- Borderline Wheeling – Grant County PUD ($0) – 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 a five-year average is used to determine the 2016 rate year revenue of $28,000. The test year revenue was $28,000.

Seattle and Tacoma – Main Canal Project ($46,000) – 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 $315,000 during the test year. Revenues for the 2016 rate year are expected to be $361,000 based on an increase in the ratchet demand.

<u>Seattle and Tacoma – Summer Falls Project</u> ($0) – 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 test year and are expected to remain unchanged for the 2016 rate year.

<u>OASIS Non-Firm and Short-Term Firm Transmission Service</u> ($646,000) – OASIS is an acronym for Open Access Same-time Information System. This is the system used by electric transmission providers for selling available transmission capacity to eligible customers. The terms and conditions under which the Company sells its transmission capacity via its OASIS are pursuant to FERC regulations and Avista's Open Access Transmission Tariff. 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 it is intended to be 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). However, 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. In this filing, the Company is using a three year average for the time period of November 2011 to October 2014. The OASIS revenue for the test year was $2.275 million and the three-year average results in 2016 rate year revenue of $2.921 million.

<u>PacifiCorp Dry Gulch</u> (-$1,000) – Revenue under the Dry Gulch use-of-facilities agreement has been adjusted to $219,000 for the 2016 rate year, which is a $1,000 decrease from the test year actual revenue of $220,000. 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.

<u>Spokane Waste to Energy Plant</u> ($0) –Spokane Waste to Energy pays a use-of-facilities charge for the ongoing use of its interconnection to Avista's transmission system. The 2016 rate year revenue associated with the use-of-facilities charge is $28,000, the same as the test year.

<u>Grand Coulee Project Hydroelectric Authority</u> ($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 test year and will remain the same for the 2016 rate year.

<u>Palouse Wind</u> ($0) – Palouse 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 Palouse Wind which voided its need for transmission service. Palouse Wind intends to delay use of the 100 MW of reserved transmission service for up to five years, unless they are able to re-market the capacity. However, according to Avista's Open Access Transmission Tariff and the contract signed with Avista, Palouse Wind must pay an annual reservation fee equal to one month's service charge to extend its start date for service. The test year included a $200,000

extension of service payment and the 2016 rate year also includes an expected payment amount of $200,000, per the terms of Avista's Tariff.

Palouse Wind O&M ($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 test year was $52,000. Revenue during the 2016 rate year is expected to remain unchanged.

Stimson Lumber Agreement ($0) – Low-voltage facilities associated with the Company's Plummer Substation are dedicated for use by Stimson Lumber resulting in annual low voltage use-of-facilities revenue of $9,000. The 2016 rate year revenue from this agreement is also $9,000.

Hydro Tech Systems Agreement ($0) – Low-voltage facilities in the Company's Greenwood Substation are dedicated for use by the Meyers Falls generation project resulting in annual low voltage use-of-facilities revenue of $6,000 during the test year. The 2016 rate year revenue from this agreement is also $6,000.

Bonneville Power Administration – Parallel Capacity Support ($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 test year was $3,192,000. The 2016 rate year reflects the same amount of $3,192,000.

Morgan Stanley – Point-to-Point Transmission Service ($0) – 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 test year included revenues of $600,000, and the 2016 rate year reflects the same amount of $600,000.

Kootenai Electric Cooperative Fighting Creek (KEC) ($38,000) – KEC has purchased 3 MW of Long-Term Firm Point-to-Point Transmission Service from April 1, 2014 to March 31, 2019. The test year included revenues of $50,000. Revenue for the 2016 rate year will increase to $88,000.

IV. TRANSMISSION AND DISTRIBUTION CAPITAL PROJECTS

Q. Please provide the basis for the Company's capital transmission projects that will be completed from October 1, 2014 through December 31, 2016.

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.

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 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. If such an exccedance occurs, it must be mitigated prior to the loss of the next facility. This mitigation 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 will continue to 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. For the smaller specific projects, Avista doesn't perform a traditional cost-benefit analysis. 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.

Q. Did the Company consider any efficiency gains or offsets when evaluating the transmission projects to include in the Company's case?

A. Yes. The Company evaluated each project and determined that some of the 2014, 2015 and 2016 capital transmission projects will result in efficiency gains and potential offsets or savings, and the Company has included those where applicable. The primary offsets result in loss savings from reconductoring heavily-loaded transmission or distribution facilities. For these projects, an analysis was performed to determine the savings. The assumed avoided energy cost to determine the savings was $44 MWh, which is the 20 year life cycle cost calculated in Avista's 2013 Integrated Resource Plan (*see page iii*). However, not all projects will result in loss savings or other offsets. Avista has maintenance schedules for certain equipment. These maintenance cycles range from 5-15 years depending on the equipment. Unless the replacement of equipment occurs in the same year as the scheduled maintenance, there will not be any savings.

Although one might think that the replacement of equipment may reduce the failure rate of equipment and reduce after-hours labor costs, newly-installed equipment can get out of alignment, or require other adjustments. Significant system failures also occur during large weather-related events caused by wind, lightning, and snow. Furthermore, each year as we replace old equipment with new, the remainder of our system gets another year older, which continues to generate additional failures on our system.

Q. Please describe each of the transmission projects planned for the period October 1, 2014 to December 31, 2016.

A. The major capital transmission investment (on a system basis) for projects to be completed from October 1, 2014 to December 2016 are shown in Table No. 3 and described below.

TABLE NO. 3
ELECTRIC TRANSMISSION (SYSTEM)

	October-December 2014 $(000's)		2015 $(000's)		2016 $ (000's)	
	System	O&M Offsets	System	O&M Offsets	System	O&M Offsets
I. Reliability Compliance:						
Substation - 115 kV Line Relay Upgrades	$ 262	$	$ 1,525	$	$	$
Transmission - NERC High Priority Mitigation	1,900	-		-		-
Transmission - NERC Low Priority Mitigation	250	-	500	-	2,000	-
Transmission - NERC Medium Priority Mitigation	1,717	-	3,294	-	2,251	-
SCADA - SOO & BUCC	1,229	-	1,020	-	1,002	-
Total Reliability Compliance	**5,358**	**-**	**6,339**	**-**	**5,253**	**-**
II. Contractual Requirements:						
Colstrip Transmission/PNACI	75	-	491	-	497	-
Tribal Permits and Settlements	110	-	1,430	-	316	-
Clearwater Sub Upgrades	506	-	500	-	500	-
		-		-		-
Total Contractual Requirements	**691**	**-**	**2,421**	**-**	**1,312**	**-**
III. Reliability Improvements:						
Substation - Distribution Station Rebuilds	23	-	275	-	3,565	-
Spokane Valley Transmission Reinforcement	1,900	-	2,900	-	7,440	-
Moscow 230 Substation Rebuild	6,363	8		-		-
Noxon Switchyard Rebuild		-	8,325	-	500	-
Westside Rebuild Phase One		-		-	1,780	-
Total Reliability Improvements	**8,285**	**8**	**11,500**	**-**	**13,285**	**-**
IV. Reliability Replacement:						
Storms	427	-	1,000	-	890	-
Substation - Asset Mgmt. Capital Maintenance	74	-	1,200	-	3,300	-
Substation - Capital Spares	245	-	3,900	-	4,915	-
Transmission - Asset Management	1,279	-	1,709	-	1,772	-
Total Reliability Replacement:	**2,026**	**-**	**7,809**	**-**	**10,877**	**-**
V. Reliability Compliance and Improvements:						
Environmental Compliance	8	-	350	-	350	-
Reconductors and Rebuilds	10,686	53	11,763	43	21,161	43
Total Reliability Compliance and Improvements	**10,694**	**53**	**12,113**	**43**	**21,511**	**43**
	$ 27,054	**$ 61**	**$ 40,183**	**$ 43**	**$ 52,239**	**$ 43**

I. Reliability Compliance Projects:

Substation – 115kV Line Relay Upgrades – 2014: $ 262,000; 2015: $1,525,000

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 to seven 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, and TPL-003-0a R1-R3 and will be completed in 2015.

Transmission - NERC High Priority Mitigation – 2014: $1,900,000

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, 2012 North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings". This Capital Program (ER2560) covers mitigation work on Avista's "High Priority" 230 kV transmission lines, including: Benewah-Pine Creek (BI CT203), Cabinet-Noxon (BI AT203), Cabinet-Rathdrum (BI CT202), Hatwai-North Lewiston (BI LT205), Lolo-Oxbow (BI LT202), and Noxon-Pine Creek (BI AT202). 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).

Transmission – NERC Low Priority Mitigation – 2014: $250,000; 2015: $500,000; 2016: $2,000,000

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, 2012 North American Electric Reliability Corporations (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).

Transmission - NERC Medium Priority Mitigation – 2014: $1,717,000; 2015: $3,294,000; 2016: $2,251,000

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, 2012 North American Electric Reliability Corporations (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 – 2014: $1,229,000; 2015: $1,020,000; 2016: $1,002,000
This program replaces and/or upgrades existing electric and 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).

II. Contractual Requirements:

Colstrip Transmission – 2014: $ 75,000; 2015: $491,000; 2016: $497,000
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.

Tribal Permits – 2014: $110,000; 2015: $1,430,000; 2016: $316,000
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.

Clearwater Substation Upgrade – 2014: $506,000; 2015: $500,000; 2016: $500,000
This project includes a series of station upgrades to improve 115 kV system reliability in the Lewiston area. This part of the project will construct a new 115 kV line terminal in order to install a new bus sectionalizing breaker. In addition, the project replaces an older 115 kV oil circuit breaker and installs standard 115 kV air switches in place of the existing sliding link bus switches, which are dangerous to operate and a reliability concern.

III. Reliability Improvements:

Substation – Distribution Station Rebuilds – 2014: $23,000; 2015: $275,000; 2016: $3,565,000

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 Big Creek and Kamiah (Wood Substations), 9th & Central, Gifford and Southeast (Equipment Additions) and Hallett & White (Growth).

Spokane Valley Transmission Reinforcement – 2014: $1,900,000; 2015: $2,900,000; 2016: $7,440,000

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 is presently under construction; the Irvin-Millwood line is under construction; Irvin Substation construction will break ground in 2015 and be energized in 2016; and the Beacon-Butler line will then be able to be rebuilt.

Moscow 230 Substation Rebuild – 2014: $6,363,000

This project completely rebuilt the Moscow 230 kV Substation. The new station includes gas circuit breakers for both the 230 kV and 115 kV yards, a new 250 MVA Autotransformer, two 115 kV Capacitor Banks, a new panel house, and a station configuration that allows for future additions. The primary driver for this project was the capacity of the existing 125 MVA Autotransformer. System planning studies showed an imminent thermal overload of the 56 year old unit in the event we had a failure of the Shawnee Autotransformer. Considering these two units serve the entire Pullman-Moscow area, this project was critically important to Avista's ability to serve our customers. After revenue requirement was finalized, it was determined that offsets exist for this business case. The level of offsets for the 2016 rate period is $7,920 on a system level and $5,149 Washington Electric. The new transformer results in loss savings of 720 MWH annually based on average loading. Assuming an avoided energy cost of $44/MWH, the total 2014 savings is [(720 MWH x $44/MWH) / (12 months)] * 3 months = $7,920 system and Washington's allocation is $5,149.

Noxon Switchyard Rebuild – 2015: $8,325,000; 2016: $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.

Westside Rebuild Phase I –2016: $1,780,000

Phase I of this project will extend the existing Westside Substation and the 115 kV and 230 kV buses to allow for a new 250 MVA Autotransformer. This installation will eliminate overloads tie breaker failure contingencies in the Spokane area. This is a three phase project.

IV. <u>Reliability Replacements:</u>

Storms -2014: $427,000; 2015: $1,000,000; 2016: $890,000

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

Substation Asset Management Capital Maintenance – 2014 : $74,000; 2015: $1,200,000; 2016: $3,300,000

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 useful life has been exceeded.

Substation – Capital Spares – 2014: $245,000; 2015: $3,900,000; 2016: $4,915,000

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.

Transmission – Asset Management – 2014: $1,279,000; 2015: $1,709,000; 2016: $1,772,000

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.

V. Reliability Compliance and Improvements:

Environmental Compliance – 2014: $8,000; 2015: $350,000; 2016: $350,000

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.

Transmision Reconductors and Rebuilds – 2014: $10,686,000; 2015: $11,763,000; 2016: $21,161,000

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 2310 - West Plains Transmission Reinforcement (Garden Springs-Sunset Rebuild), ER 2550 - Pine Creek-Burke-Thompson, ER 2557-9CE-Sunset Rebuild, ER 2423-System Condition Rebuild (Bronx-Cabinet Rebuild), ER 2457-Benton-Othello Rebuild, ER 2556-CDA-Pine Creek Rebuild, ER 2564- Devils Gap-Lind Structure Replacement, ER 2574-Chelan-Stratford River Crossing Rebuild, ER 2582-BEA-BEL-F&C-WAI Reconfiguration, ER 2577-BEN-M23 Structure Replacement.

O&M Offsets exist for several items included in this project. To calculate the amount of savings to be reflected in our rate year, reduced line losses are multiplied against the avoided energy cost of $44 per MWh to arrive at the total energy savings.

Burke-Pine Creek will experience reduced line losses of 252 MWh for 2014. This amount is multiplied by the avoided energy cost to arrive at a savings of $11,088 on a system level and $7,200 Washington Electric.

Benton-Othello 115 will experience a reduction in line losses of 1,424 MWh which, after applying the avoided energy cost per MWh of $44, equates to $62,700 of offsets on a system basis and $40,800 Washington Electric.

Bronx-Cabinet will experience reductions in line losses of 755 MWH in both 2015 and 2016 (1,510 total). This equates to an offset amount of $66,440 on a system level and $43,300 Washington Electric.

Q. Please describe each of the distribution projects planned for October 1, 2014 through December 31, 2016.

A. Distribution specific projects in Washington (including transformation) are necessary to meet capacity needs of the system, improve reliability, and rebuild aging distribution substations and feeders. The major capital distribution costs for projects to be completed from October 1, 2014 to December 31, 2016 are shown in Table No. 4 and described below.

TABLE NO. 4
Electric Distribution

	October-December 2014 $(000's)			2015 $(000's)			2016 $ (000's)		
	System	**WA**	**WA Offsets**	**System**	**WA**	**WA Offsets**	**System**	**WA**	**WA Offsets**
I. Distribution Projects:									
Distribution Grid Modernization	4,252	3,378	-	10,925	7,105	-	11,000	7,153	-
Distribution Wood Pole Management	1,198	941	-	11,000	7,219	-	11,000	7,219	43
Meter Minor Blanket	1,039	678		5,806	3,808		5,806	3,808	
Segment Reconductor and FDR Tie Program	2,689	2,506	-	2,920	2,641	-	2,675	2,246	-
Spokane Electric Network	441	441	-	2,300	2,300	-	2,298	2,298	-
Substation - Asset Mgmt. Capital Maintenance	155	139	-	1,508	980	-	1,519	988	(106)
Substation - Capital Spares	6	6	-	1,200	1,076	-	1,200	1,076	-
Substation - New Distribution Stations	412	412	-	2,026	2,026	-	75	75	-
Worst Feeders	1,351	878	-	1,999	1,300	-	2,000	1,301	-
Harrington 4 kV Cutover	-	-	-	2,025	2,025	-	1,000	1,000	-
Washington AMI	-	-	-		-	-	32,243	32,243	155
Total Distribution Projects	**11,544**	**9,380**	**-**	**41,710**	**30,480**	**-**	**70,815**	**59,407**	**92**
II. Distribution Replacement Projects									
Distribution Line Protection	147	140	-	125	81	-	125	81	-
Distribution Minor Rebuild	1,545	1,320	-	8,300	5,292	-	8,300	5,292	-
Distribution Transformer Change-Out Program	597	511	-	4,700	3,584	-	4,700	3,584	-
Environmental Compliance	38	29	-	150	114	-	150	114	-
Electric Replacement/Relocation	437	359	-	2,400	1,350	-	2,500	1,406	-
Primary URD Cable Replacement	74	66	-	1,000	716	-	-	-	(522)
Reconductors and Rebuilds	-	-	-	2,500	1,626	-	2,500	1,626	-
Storms	530	455	-	2,000	1,275	-	1,900	1,211	-
Substation - Distribution Station Rebuilds	5,850	3,771	-	2,112	2,000	-	2,284	952	-
Franchising for WSDOT	759	759	-	427	427	-	494	494	-
Street Light Management	-	-	-	1,500	975	305	1,500	975	166
Total Distribution Replacement Projects	**9,976**	**7,411**	**-**	**25,215**	**17,441**	**305**	**24,453**	**15,737**	**(356)**
III. Smart Grid Projects									
Smart Grid Demonstration Project	554	554	-	-	-	-	-	-	-
Spokane Smart Circuit	192	192	-		-	-		-	-
Total Smart Grid Projects	**746**	**746**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Distribution Excluding Idaho	**22,266**	**17,536**		**66,924**	**47,921**	**305**	**95,268**	**75,143**	**(264)**
IV. Idaho Distribution Pojects (not included in this case)									
Lewiston Mill Road	1,950	-	-	-	-	-	-	-	-
Distribution Grid Modernization	258	-	-	75	-	-	-	-	-
Distribution Minor Rebuild	376	-	-	-	-	-	-	-	-
Distribution Transformer Change-Out Program	93	-	-	-	-	-	-	-	-
Distribution Wood Pole Management	359	-	-	-	-	-	-	-	-
Electric Replacement/Relocation	53	-	-	-	-	-	-	-	-
Primary URD Cable Replacement	50	-	-	-	-	-	-	-	-
Storms	105	-	-	-	-	-	-	-	-
Substation - Asset Mgmt. Capital Maintenance	8	-	-	-	-	-	-	-	-
Substation - Distribution Station Rebuilds	278	-	-	-	-	-	-	-	-
Worst Feeders	6	-	-	-	-	-	-	-	-
Moscow 230 Substation Rebuild	47	-	-	-	-	-	-	-	-
Meter Minor Blanket	14	-	-	-	-	-	-	-	-
Segment Reconductor and FDR Tie Program	770	-	-	814	-	-	1,135	-	-
Total Idaho Distribution Projects	**4,367**	**-**	**-**	**889**	**-**	**-**	**1,135**	**-**	**-**
Total Distribution Including Idaho Direct	**$ 26,633**	**$ 17,536**	**$ -**	**$ 67,814**	**$ 47,921**	**$ 305**	**$ 96,403**	**$ 75,143**	**(264)**

I. Distribution Projects:

Distribution Grid Modernization – 2014: $3,378,000; 2015: $7,105,000; 2016: $7,153,000 Washington

In 2012, Avista began a program to upgrade distribution feeders to reduce energy losses, improve operation of the feeders and increase long-term reliability. The program will replace poles, transformers, conductors and other equipment on rural and urban feeders. As part of the work, elements of Avista's Smart Grid will be installed as appropriate on these feeders. Electric circuits are selected based on a selection criteria including: 1) age of asset, 2) opportunity for line loss savings, 3) outage/reliability metrics, 4) opportunity for automation to increase efficiency and reliability, and 5) workforce resource availability. Once selected, circuits are analyzed by engineering staff to determine the scope of work including structure replacement, line reroutes, conversion from overhead to underground, automation scheme, transformer & equipment replacement, and reconductor segments. This program along with other asset management programs, uses the Distribution Feeder Management Plan to provide direction and guidance to designers and construction personnel.

Distribution Wood Pole Management – 2014: $941,000; 2015: $7,219,000; 2016: $7,219,000 Washington

The distribution wood pole management program evaluates wood pole strength of a certain percentage of the wood pole population each year such that the entire system is inspected every 20 years. Avista has over 240,000 distribution wood poles and 33,000 transmission wood poles in its electric system. Depending on the test results for a given pole, the pole is either considered satisfactory, needing to be reinforced with a steel stub, or needing to be replaced. In addition to pole condition and strength, inspection crews inspect crossarms, insulators, transformers, guy wires, ground and bonding wires, primary and secondary conductors. This project also funds the work required to resolve those issues (i.e., potentially leaking transformers, transformers containing more than or equal to 1 ppm polychlorinated biphenyls (PCBs), failed arresters, missing grounds, damaged cutouts, failed insulators and other visible issues). Transformers older than 1981 have the potential to have oil that contains polychlorinated biphenyls (PCBs). These older transformers present increased risk because of the potential to leak oil that contains PCBs. Poles installed during the pre-World War II buildup 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. The Company estimates the cost of an event associated with a bad wood pole based on crew response and labor is approximately $600. For 2016 we anticipate a reduction of 110 events. We estimate that the O&M offset for 2016 due to Wood Pole Management work is $66,000. This translates to a Washington offset of $43,000.

Meter Minor Blanket – 2014: $ 678,000; 2015: $3,808,000; 2016: $3,808,000 Washington

The existing power line carrier system for reading meters has failed and is not repairable. This project will replace the existing TURTLE meters with TWACs meters and replace substation equipment with TWACs equipment.

Segment Reconductor and Feeder Tie program – 2014: $2,506,000; 2015: $2,641,000; 2016: $2,246,000 Washington

This project improves the capacity and reliability of the Company's distribution grid through targeted reconductoring/rebuild projects. In Washington State there are thirteen (13) projects. These projects are identified, prioritized, and coordinated through the combined effort of Avista's central system planning function together with the assistance of regional operating engineer analysis and study. This is an on-going effort to identify and mitigate the capacity constrained portions of Avista's 18,000 mile distribution grid. In addition to circuit capacity projects, Avista constructs several new feeder tie points annually in order to effect seasonal and or permanent load shifts from either heavily loaded circuits or to relieve substation transformer loading.

Spokane Electric Network – 2014: $441,000; 2015: $2,300,000; 2016: $2,298,000 Washington

Avista owns and maintains an underground electric secondary network that serves the core business district of downtown Spokane. Network feeder lines are separated into four (4) sub-nets. Each is capable of suffering the loss of one trunk line (N-1) without losing any connected load. Secondary networks are a common feature in most mid to large size cities including Tacoma and Seattle. Avista secondary requires specialized material, equipment, tooling, and manpower to perform maintenance repairs, planned replacements, and capacity growth projects. The scope of annual capital replacements and additions includes: 7,500 feet of secondary cable, 7,500 feet of primary cable, 15 manholes, and 5 vaults/vault roofs. In 2015, the Walt Worthy convention center hotel will open with an expected load of 25,000 amperes (120/208). Well over 1 mile of cable was installed to support that project.

Substation Asset Management Capital Maintenance – 2014: $139,000; 2015: $980,000; 2016: $988,000 Washington

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 its useful life has been exceeded. The System-Install Autotransformer Diagnostic Monitor program is one of the projects included in

Substation Asset Management Capital Maintenance. This program includes additional incremental costs in 2016 of $162,000 of which $106,000 is Washington's share. This amount is the net of additional potential O&M costs of $170,300 less the positional annual O&M savings of $8,217. These additional O&M Costs have been included in the Company's O&M Offset adjustment.

Substation – Capital Spares – 2014: $6,000; 2015: $1,076,000; 2016: $1,076,000 Washington

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 an Autotransformer (230/115 kV) 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 – New Distribution Stations – 2014: $412,000; 2015: $2,026,000; 2016: $75,000 Washington

This program adds new distribution substations to the system in order to serve new and growing load as well as for increased system reliability and operational flexibility. New substations under this program will require planning and operational studies, justifications, and approved project diagrams prior to funding. Planned new substation projects include Tamarack (NE Moscow), Greenacres and Irvin (Spokane Valley), and Lewiston Mill Road.

Worst Feeders – 2014: $878,000; 2015: $1,300,000; 2016: $1,301,000 Washington

In 2009 Avista initiated a program to target the reinforcement of the most underperforming electric circuits. This program is coordinated with regional engineers and focus treatment on those feeders (FDRs) whose sustained outage statistics (SAIFI) and customer experiencing multiple interruption (CEMI) are at the top of the 'worst performing FDR list'. Most of these circuits are rural in nature and many involve dozens of miles of tree/forest exposed line routes. In 2015, the circuits served from Gifford, Colville, and Roxboro will be targeted for reliability projects. Project scope often involves the installation of midline breaker devices and may involve circuit hardening, conversion from overhead to underground, or circuit rerouting.

Harrington to 4kV cutover – 2015: $2,025,000; 2016: $1,000,000 Washington

The Harrington, WA area is the last area Avista serves at the legacy 4 kV voltage. This voltage is obsolete for serving utility distribution systems and we have very limited spare equipment to continue service at this voltage. The substation is very old and the transformer will be difficult and time consuming to replace if it fails. We do not have 4 kV on our mobile substations, so all the customers served by

Harrington feeders will be out of service until the transformer is replaced. This could easily be up to 48 hours. This is a needed upgrade to our standard distribution class voltage and equipment that was delayed in 2014 due to resources, and was pushed into 2015 and 2016. Minor system efficiencies also result. In conjunction with the substation work, Avista crews will change out primary distribution lines from 4kV to 13.2 kV and replace several hundred line transformers principally in the town of Harrington.

Washington Advanced Metering Infrastructure (AMI) Project – 2016: $41,000,000 (Electric $32,243,000; Natural Gas $8,757,000) Washington
This project will replace existing metering systems in Washington State with an advanced metering system. The replacement will install an AMI metering system that will include: Meters, Network, Back office systems, and data repository. The project will take multiple years to complete. There will be O&M savings that will come from the reduced field operation costs around the billing process, and adds resources to the Electric Metershop to operate and maintain the metering systems. O&M savings start in stages as the metering technology is deployed. The first reduction will be in reading and collection costs as areas are completed. These savings in 2016 are estimated to be approximately $197,000 on a system level of which $155,000 is allocated to Washington Electric.

II. Distribution Replacement Projects

Distribution Line Protection – 2014: $140,000; 2015; $81,000; 2016: $81,000 Washington
Avista's Electric Distribution system is configured into a trunk and lateral system. Lateral circuits are protected via fuse-links and operate under fault conditions to isolate the lateral in order to minimize the number of affected customers in an outage. Engineering recommends treatment of the removal and replacement of Chance Cutouts, the removal and replacement of Durabute cutouts and the installation of cut-outs on un-fused lateral circuits. This is a targeted program to ensure adequate protection of lateral circuits and to replace known defective equipment.

Distribution Minor Rebuild – 2014: $1,320,000; 2015: $5,292,000 ; 2016: $5,292,000 Washington
This program is for distribution minor rebuilds as requested by the customer or initiated by Avista. Examples of construction work includes replacing meters, services, transformers, primary overhead or underground lines, or devices. This also includes addressing trouble related jobs (i.e. replacing burnt or damaged poles).

Distribution Transformer Change Out Program - 2014: $511,000; 2015: $3,584,000; 2016: $3,584,000 Washington
The Distribution Transformer Change-Out Program has three main drivers. First, the pre-1981 distribution transformers that are targeted for replacement average 42 years

of age and are a minimum of 30 years old. Their replacement will increase the reliability and availability of the system. Secondly, the transformers to be replaced are inefficient compared to current standards. Thirdly, pre-1981 transformers have the potential to have PCB containing oil. The transformers to be removed early in the programs are those that are most likely to have PCB containing oil and their replacement will reduce the risk of PCB containing oil spills.

Environmental Compliance- 2014: $29,000; 2015: $114,000; 2016: $114,000 Washington

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.

Electric Replacement/Relocation – 2014: $359,000; 2015: $1,350,000; 2016: $1,406,000 Washington

This annual program will replace sections of existing infrastructure that require replacement due to relocation or improvement of streets or highways. Requirements may come from our franchise agreements, permits, or WA DOT. Avista installs many of its facilities in public right-of-way under established franchise agreements. Avista is required under the franchise agreements, in most cases, to relocate its facilities when they are in conflict with road or highway improvements.

Primary URD Cable Replacement – 2014: $66,000; 2015: $716,000 Washington

This program involves replacing the first generation of Underground Residential District (URD) cable. This project has been ongoing for the past several years and 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 estimates the cost of each underground outage to be $3,850. With the downward trend in underground outages, it is projected that 45 outages will occur in 2015, as compared to 72 in 2012. A five year plan to inspect and maintain our padmount equipment will add $800,000 per year to O&M spending for the first five years. Washington's allocation of these additional O&M costs is $522,000. These additional costs have been included in the Company's O&M Offset adjustment.

Reconductors and Rebuilds – 2015: $1,626,00; 2016: $1,626,000 Washington

This program reconductors and/or rebuilds existing transmission or distribution lines as they reach the end of their useful lives, require increased capacity, or present a risk management issue. Projects include: ER 2310 - West Plains Transmission Reinforcement, ER 2550 - Pine Creek-Burke-Thompson, ER 2557 - 9CE-Sunset Rebuild, ER 2423 - System Condition Rebuild, ER 2457 - Benton-Othello Rebuild, ER2556 - CDA-Pine Creek Rebuild, ER 2564 - Devils Gap-Lind Major Rebuild, ER 2574 - Chelan-Stratford River Crossing Rebuild, ER 2576 - Addy-Devils Gap Reconductor, ER 2575 - Garden Springs-Silver Lake Rebuild, ER 2582 - BEA-BEL-F&C-WAI Reconfiguration, and ER 2577 - BEN-M23 Rebuild.

Storms – 2014: $455,000; 2015: $1,275,000; 2016: $1,211,000 Washington
Weather events associated with wind, lightning, rain, and snow create a number of outage situations. Estimated capital spend is based on historical averages.

Substation – Distribution Station Rebuilds – 2014: $3,771,000; $2015: $2,000,000; 2016: $952,000 Washington
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 Big Creek, Kamiah, and North Lewiston (Wood Substations), 9th & Central, 10th & Stewart, and Stratford (Life Cycle), Blue Creek (Productivity), and Lewiston Mill Road (Growth).

Franchising for Washington State Department of Transportation – 2014: $759,000; 2015: $427,000; 2016: $494,000 Washington
Avista is working closely with the Washington Department of Transportation to renew crossing and encroachment permits. As part of that process, we are realigning or modifying existing infrastructure to comply with state clear zone, conductor clearance, and other regulations regarding the location of poles, guy wires, pad mounted equipment, and overhead conductors.

Street Light Management – 2015: $975,000; 2016: $975,000 Washington
This program is a five year planned replacement of bulbs and 10 year planned replacement of photocells. Currently, components of the existing street lights are not being replaced and are only replaced when they fail. We anticipate there will be O&M savings in 2015 in the amount of $468,000 ($305,000 WA) and an additional offset in 2016 of $254,000 ($165,500 WA). The offsets occur due to converting 100 Watt street lights from High Pressure Sodium. The savings come from eliminating the labor, equipment, material, and overhead costs associated with repairing older lights.

III. Smart Grid Projects

Smart Grid Demonstration Project – 2014: $554,000
This Smart grid project has brought smart grid technology to electric distribution facilities that serve nearly 13,000 customers in the City of Pullman. Avista is analyzing the realization of benefits from smart grid technologies in reduced system losses and lower operating costs. Customers are starting to realize benefits from improved service reliability, improved energy data enabling efficient energy usage, and energy savings from conservation voltage reduction (CVR).

Spokane Smart Circuit – 2014: $192,000

This project installed a Distribution Management System (DMS) that allows real time system information to be used to control the distribution system. Intelligent end devices such as capacitor banks, air switches and reclosers were installed that provide sensing and control of the distribution circuits. Substation control and communication equipment were upgraded to allow for the control and aggregation of field data. A wireless mesh network was installed to provide backhaul from end devices to the substations. The project automates distribution equipment on 58 feeders and in 14 substations.

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

A. Yes it does.