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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-15-05 DIRECT TESTIMONY OF BRYAN A. COX

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

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, Transmission Operations. 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 and 2017 two-year rate period. I also discuss Avista's Transmission and Distribution capital expenditures, for the period January 2015 through the 2017 rate year. Company witness Ms. Andrews has included these adjustments in her Pro Forma adjustments, which incorporates Idaho's share of both pro forma 2016 and 2017 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 an exhibit?

A. Yes. Exhibit No. 9, Schedule 1, provides the transmission revenue and expense adjustments for 2016 and 2017.

[1] Idaho's share of the transmission revenues are also included in the Power Cost Adjustment (PCA) authorized base. See Company witness Mr. Johnson's Exhibit No. 6, Schedule 1, for the PCA proposed net power supply expenses included in this case.

II. TRANSMISSION EXPENSES FOR 2016 AND 2017

Q. Please describe the adjustments to the twelve months ended December 31, 2014 test year transmission expenses to arrive at transmission expenses for the 2016 and 2017 rate years.

A. Adjustments were made in this filing to incorporate updated information for any changes in transmission expenses from the January 2014 through December 2014 test year to the 2016 rate year, and for incremental changes in expenses from the 2016 rate year to the 2017 rate year. Each expense item described below is at a system level and is included in Exhibit No. 9, Schedule 1. The changes in expenses and a description of each are summarized in Table No. 1, below, and an explanation of each change follows the Table.

TABLE NO. 1
Transmission Expense Adjustment

	(1) 2016 Rate Year (System)	**(2) 2017 Rate Year (System)**
Northwest Power Pool (NWPP)	$ 18,000	$ 3,000
Colstrip Transmission	7,000	(7,000)
ColumbiaGrid Funding	62,000	5,000
ColumbiaGrid Planning and Expansion Agreement (PEFA)	68,000	5,000
Order 1000 Functional Agreement	(50,000)	25,000
NERC Critical Infrastructure Protection(CIP)	(8,000)	-
OASIS Expenses	8,000	-
BPA Power Factor Charge	(56,000)	-
PEAK Reliability	453,000	93,000
WECC Administration Dues	(46,000)	72,000
WECC - Loop Flow	(34,000)	-
Addy (BPA substation)	-	-
Hatwai (BPA substation)	-	-
Total Change in Transmission Expense	**$422,000**	**$196,000**

(1) Represents the change in expense above or below the December 31, 2014 historical test year level.

(2) Represents the change in expense above or below the December 31, 2016 rate year level.

Northwest Power Pool (NWPP) (2016: $18,000; 2017: $3,000) – 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 $18,000. Avista's share of the costs for 2017 is $79,000, an incremental increase of $3,000 from 2016.

Colstrip Transmission (2016: $7,000; 2017: $-7,000) – 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 $7,000 from the actual expense of $296,000 incurred during the 2014 test year. This amount is expected to return to the $296,000 expense level in 2017, reducing expenses by $7,000 for the 2017 rate year.

ColumbiaGrid Funding (2016: $62,000; 2017: $5,000) – 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. Avista's ColumbiaGrid general funding expenses for the 2014 test year were $126,000, while 2016 and 2017 rate year general funding expenses are expected to be $188,000 and $193,000, respectively.

<u>ColumbiaGrid Planning and Expansion Agreement (PEFA)</u> (2016: $68,000; 2017: $5,000) – 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.

Actual PEFA expenses for the 2014 test year were $146,000. The Company's PEFA for 2016 and 2017 are $214,000 and $219,000, respectively, and reflect

ColumbiaGrid's increasing staffing levels to support PEFA activities and the reallocation of a portion of ColumbiaGrid's administrative expenses (previously paid under the general funding agreement) to these functional agreements.

Order 1000 Functional Agreement (2016: -$50,000; 2017: $25,000) – 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). The 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.

NERC Critical Infrastructure Protection (2016: -$8,000) – 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, vulnerability assessment, electronic perimeter security and backup/recovery of critical control systems. The

Company’s 2016 and 2017 rate year expense is $50,000, a decrease of $8,000 from the 2014 actual test year expense.

OASIS Expenses (2016: $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 to $8,000 for the 2016 and 2017 rate years is due to the availability of the necessary training in relation to the technical users’ individual schedules. The absence of any travel expenses in the test year was due, in large part, to Avista hosting an OASIS schedulers meeting in Spokane (for which costs of approximately $6,330 were attributed to another account) instead of traveling to this meeting.

Bonneville Power Factor Charge (2016: -$56,000) – Power factor charge costs are associated with the Bonneville Power Administration’s (Bonneville) General Transmission Rate Schedule Provisions. Avista is aware of Bonneville’s Initial Proposal in its BP-16 Rate Case, filed December 10, 2014, that is proposing eliminating this Power Factor Charge. Accordingly, Avista has removed this expense for the 2016 and 2017 rate years.

Peak Reliability – Reliability Coordination (2016: $453,000; 2017: $93,000) – The Company's Peak Reliability (Peak) fees are scheduled to increase from the amount paid in the historical test year, $168,000, to $621,000 in the 2016 rate year and $714,000 in the 2017 rate year. The large increase in 2016 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. The increase in 2017 of $93,000 is based upon Peak's projections of its funding requirement.

WECC – Administration Dues (2016: -$46,000; 2017: $72,000) – 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 $531,000. The Company's totals for dues and fees in the 2016 and 2017 rate years are expected to be $485,000 and $557,000, respectively. 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.

WECC - Loop Flow (2016: -$34,000) – 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 2014 test year were $34,000. These expenses were rolled into the WECC annual dues beginning in 2015.

Addy Substation ($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 and 2017 rate years.

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 are expected to remain unchanged for the 2016 and 2017 rate years.

III. TRANSMISSION REVENUES FOR 2016 AND 2017

Q. Please describe the adjustments to 2014 test year transmission revenues to arrive at transmission revenues for the 2016 and 2017 rate years.

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, and to reflect incremental 2017 revenues compared to 2016 levels. Each revenue item described below is at a system level and is included in Exhibit No. 9, Schedule 1. 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

	(1) 2016 Rate Year (System)	(2) 2017 Rate Year (System)
Borderline Wheeling Transmission	$103,000	$ -
Borderline Wheeling Low Voltage	8,000	-
Borderline Wheeling Ancillary Revenues	666,000	-
Seattle/Tacoma Main Canal	41,000	(3,000)
Seattle/ Tacoma Summer Falls	-	-
OASIS nf & stf Whl (Other Whl)	41,000	-
PP&L - Dry Gulch	(12,000)	-
Spokane Waste to Energy Plant	-	-
Grand Coulee Project	-	-
Palouse Wind Transmission	-	2,200,000
Palouse Wind O & M	-	-
Stimson Lumber	-	-
BPA Parallel Operating Agreement	-	-
Morgan Stanley Capital Group	-	-
Hydro Tech Systems - Meyers Falls	-	-
Kootenai Electric	15,000	-
BPA Excess Transmission Sales	(529,000)	-
	$333,000	**$2,197,000**

(1) Represents the change in revenue above or below the twelve months ended December 31, 2014 test year level.

(2) Represents the incremental change in revenue above or below the twelve months ended December 31, 2016 rate year level.

Borderline Wheeling – Transmission (2016: $103,000) - The Company provides borderline wheeling service (wheeling service over transmission facilities for service to loads of other utilities within the Company’s system footprint). Total revenue for the transmission portion of borderline wheeling activities for the test year was $6,233,000. Total revenue in the 2016 and 2017 rate years has been set at $6,336,000, representing an increase of $103,000 from the test year. Revenue projections from each are determined as follows:

- **Bonneville Power Administration** - Network Integration Transmission Service revenue is determined based upon a three-year average for the 2012 to 2014 time period, resulting in a figure of $6,236,000 for the 2016 and 2017 rate years compared to $6,126,000 for the test year. The Company has in the past used a five-year average for determining 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 determines transmission revenues that are based upon variable customer load figures (e.g. Grant County PUD and PacifiCorp Dry Gulch). By changing from the five-year average to the three-year average in this filing, revenue is increased by $35,000, from $6,201,000 to $6,236,000.
- **Grant County PUD** – Power transfer revenue is determined using a three-year average (2012-2014) resulting in a figure of $28,000 for the 2016 and 2017 rate years compared to $29,000 for the test year.

- **Consolidated Irrigation District** – Point-to-Point Transmission Service revenue for the 2014 test period was $32,000. Under the current contract (with a term from 10/1/2011 to 9/30/2016) and an expected follow-on contract this revenue is expected to remain substantially the same during the 2016 and 2017 rate years.
- **East Greenacres Irrigation District** – Point-to-Point Transmission Service revenue for the 2014 test period was $15,000. Under the current contract (with a term from 10/1/2014 to 9/30/2019) this revenue will be $11,000 for the 2016 and 2017 rate years.
- **Spokane Tribe** – Point-to-Point Transmission Service revenue for the 2014 test period was $30,000. Under a new contract (with a term from 1/1/2015 to 12/31/2019) this revenue will be $29,000 for the 2016 and 2017 rate years.

Borderline Wheeling – Low Voltage (2016: $8,000) – The Company provides borderline wheeling service (wheeling service over low-voltage distribution facilities for service to loads of other utilities within the Company's system footprint). Total revenues for the low voltage portion of borderline wheeling activities for the test year was $1,072,000. Total revenue in the 2016 and 2017 rate years has been set at $1,080,000, representing an increase of $8,000 from the test year, including the following components:

- **Bonneville Power Administration** – Wheeling revenue over low-voltage facilities for the 2014 test period was $929,000. Revenue for the 2016 and 2017 rate years is expected to remain substantially the same.
- **Consolidated Irrigation District** – Electric Distribution Service revenue for the 2014 test period was $80,000. Under the current contract (with a term from 10/1/2011 to 9/30/2016) and an expected follow-on contract, this revenue is expected to remain substantially the same during the 2016 and 2017 rate years.
- **East Greenacres Irrigation District** – Electric Distribution Service revenue for the 2014 test period was $45,000. Under the current contract (with a term from 10/1/2014 to 9/30/2019) this revenue will be $51,000 for the 2016 and 2017 rate years, an increase of $6,000.
- **Spokane Tribe** – Electric Distribution Service revenue for the 2014 test period was $18,000. Under a new contract (with a term from 1/1/2015 to 12/31/2019)

this revenue will be $20,000 for the 2016 and 2017 rate years.

Borderline Wheeling – Ancillary Revenues ($666,000) – 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 test year was $919,000. Revenue in the 2016 and 2017 rate years has been set at $1,585,000, representing an increase of $666,000 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 projection 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 customer's monthly peak load. The components of the ancillary revenues for 2016 and 2017 are as follows:

- **Bonneville Power Administration** - Ancillary services revenue is estimated based upon three-year average load figures for the 2012-2014 time period, resulting in estimated revenues of $1,570,000 for the 2016 and 2017 rate years compared to $906,000 for the 2014 test year. Prior to October 1, 2014, when a change in WECC reliability standards became effective, BPA self-provided all of its operating reserve obligations. This revenue increase is the result of BPA now paying the Company for the operating reserves.

- **Consolidated Irrigation District** – Ancillary services revenue was $6,000. Under the current contract (with a term from 10/1/2011 to 9/30/2016) and an expected follow-on contract, this revenue is expected to remain substantially the same during the 2016 and 2017 rate years.
- **East Greenacres Irrigation District** – Ancillary services revenue is estimated based upon three-year average load figures for the 2012-2014 time period, resulting in estimated revenue of $4,000 for the 2016 and 2017 rate years compared to $4,000 for the 2014 test year.
- **Spokane Tribe** - Ancillary services revenue is estimated based upon three-year average load figures for the 2012-2014 time period, resulting in estimated

revenue of $5,000 for the 2016 and 2017 rate years compared to $3,000 for the 2014 test period.

Seattle and Tacoma – Main Canal Project (2016: $41,000; 2017: -$3,000) 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 $320,000 during the test year. Revenues for the 2016 and 2017 rate years are expected to be $361,000 and $358,000 respectively, based on ratchet demand estimates.

Seattle and Tacoma – Summer Falls Project ($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 and 2017 rate years.

OASIS Non-Firm and Short-Term Firm Transmission Service (2016: $41,000) – 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 (e.g., major transmission projects which may impact the availability of the Company's transmission capacity or competing transmission paths, and major generation projects which may impact the load-resource balance needs of prospective transmission customers). 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 January 2012 to December 2014. The OASIS revenue for the test year was $2.861 million and the three-year average results in 2016 and 2017 rate year revenues of $2.902 million.

PacifiCorp Dry Gulch (2016: -$12,000) – Revenue under the Dry Gulch use-of-facilities agreement has been adjusted to $220,000 for the 2016 and 2017 rate years, which is a $12,000 decrease from the test year actual revenue of $232,000. 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 and 2017 rate year revenues associated with the use-of-facilities charge are $28,000 in each respective year, 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 at a fixed annual fee. Annual charges under this contract totaled $8,100 in the test year and will remain the same for the 2016 and 2017 rate years.

Palouse Wind (2016: $0; 2017: $2,200,000) – 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 (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. After 2016, Palouse Wind may not make any further requests to delay commencement of service under the terms of the Tariff. Accordingly, the Company must project the commencement of service as of January 1, 2017, notwithstanding Palouse Wind's ability to pay for service that it may not use, increasing revenues expected for the 2017 rate year to $2,400,000, an increase of $2,200,000.

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 and 2017 rate years 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 and 2017 rate year revenues from this agreement are also $9,000 per year.

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 and 2017 rate years reflect the same amount, $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 and 2017 rate years reflect the same amount, $600,000.

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 and 2017 rate year revenues from this agreement are also $6,000.

Kootenai Electric Cooperative Fighting Creek (KEC) (2016: $15,000) – 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 $73,000. Revenue for the 2016 and 2017 rate years will increase to $88,000.

BPA Excess Transmission Sales (2016: -$529,000) – In December of 2013, with the completion of a new 230kV interconnection with the Bonneville Power Administration

(BPA), the Company was able to directly integrate its Lancaster Generating Station into its transmission system. As a result of this effort, the Company was also able to terminate a 150MW Point-to-Point (PTP) transmission contract with the Bonneville Power Administration. The termination language of the PTP contract specified certain notification periods for termination. Pursuant to its terms, this contract could not be terminated until August of 2014. During the nine months between completion of the Lancaster interconnection project and the effective termination date of the PTP contract, the Company actively re-marketed its BPA PTP capacity that was considered surplus to its load service requirements. This marketing effort resulted in a cost offset (revenue) of approximately $529,000 in 2014. The 150MW of PTP transmission capacity was terminated in August of 2014. This cost offset will not continue beyond the test period, therefore 2016 and 2017 revenues associated with this item will be $0.

IV. TRANSMISSION AND DISTRIBUTION CAPITAL PROJECTS

Q. Please provide the basis for the Company's capital transmission projects that will be completed from January 1, 2015 through December 31, 2017.

A. Avista must continuously invest in its transmission system to maintain reliable customer service and meet mandatory reliability standards. The capital transmission projects are 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 exceedance 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 both the design and construction of the required projects are completed prior to the time the projects 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 reviews 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 2015, 2016 and 2017 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.

Appropriate maintenance and replacement strategies generally improve system reliability over several years on the assets they target. However, several other factors can impact the overall reliability, such as weather and external forces, and can cause significant variation. 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 January 1, 2015 to December 31, 2017.

A. The major capital transmission investment (on a system basis) for projects to be completed from January 1, 2015 to December 2017 are shown in Table No. 3 and described below.

TABLE NO. 3
ELECTRIC TRANSMISSION (SYSTEM)

	2015		2016		2017
	System	O&M Offsets	System	O&M Offsets	System
I. Reliability Compliance:					
Substation - 115 kV Line Relay Upgrades	$ 1,230	$ -	$ -	$ -	$ -
Transmission - NERC Low Priority Mitigation	500	-	2,000	-	3,000
Transmission - NERC Medium Priority Mitigation	3,306	-	2,251	-	-
SCADA - SOO & BUCC	1,061	-	1,002	-	1,044
Total Reliability Compliance	**6,097**	**-**	**5,253**	**-**	**4,044**
II. Contractual Requirements:					
Colstrip Transmission/PNACI	491	-	497	-	516
Tribal Permits and Settlements	1,430	-	316	-	297
Clearwater Sub Upgrades	500	-	500	-	-
Total Contractual Requirements	**2,421**	**-**	**1,313**	**-**	**813**
III. Reliability Improvements:					
Substation - Distribution Station Rebuilds	250	-	3,565	-	2,865
Spokane Valley Transmission Reinforcement	3,468	-	7,440	-	-
Noxon Switchyard Rebuild	9,906	-	500	-	7,700
Westside Rebuild Phase One	-	-	1,780	-	-
South Region Voltage Control	-	-	4,900	-	-
Lewiston Mill Rd. 115 kV Substation	684	-	-	-	-
Total Reliability Improvements	**14,308**	**-**	**18,185**	**-**	**10,565**
IV. Reliability Replacement:					
Storms	1,000	-	890	-	883
Substation - Asset Mgmt. Capital Maintenance	1,647	-	3,300	-	3,300
Substation - Capital Spares	3,250	-	4,915	-	1,200
Transmission - Asset Management	1,813	-	1,772	-	1,780
Total Reliability Replacement:	**7,710**	**-**	**10,877**	**-**	**7,163**
V. Reliability Compliance and Improvements:					
Environmental Compliance	434	-	350	-	350
Reconductors and Rebuilds	11,776	15	21,161	15	18,327
Total Reliability Compliance and Improvements	**12,210**	**15**	**21,511**	**15**	**18,677**
	$ 42,746	**$ 15**	**$ 57,139**	**$ 15**	**$ 41,262**

I. Reliability Compliance Projects:

Substation – 115kV Line Relay Upgrades – 2015: $1,230,000; 2016:$0; 2017:$0

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 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 Low Priority Mitigation – 2015: $500,000; 2016: $2,000,000; 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, 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.

Transmission - NERC Medium Priority Mitigation – 2015: $3,306,000; 2016: $2,251,000; 2017: $0

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.

SCADA–SOO&BUCC – 2015: $1,061,000; 2016: $1,002,000; 2017: $1,044,000

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 – 2015: $491,000; 2016: $497,000; 2017: $516,000

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 – 2015: $1,430,000; 2016: $316,000; 2017: $297,000

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 – 2015: $500,000; 2016: $500,000; 2017: $0

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 – 2015: $250,000; 2016: $3,565,000; 2017: $2,865,000

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 Idaho substation rebuilds to be completed under this program in the next five years are Big Creek, South Lewiston and Kamiah.

Spokane Valley Transmission Reinforcement – 2015: $3,468,000; 2016: $7,440,000; 2017: $0

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-Boulder line will then be able to be rebuilt.

Noxon Switchyard Rebuild – 2015: $9,906,000; 2016: $500,000; 2017: $7,700,000

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 – 2015: $0; 2016: $1,780,000; 2017: $0

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 for credible bus outages and tie breaker failure contingencies in the Spokane area. This is the first phase of a three phase project.

South Region Voltage Control – 2015: $0; 2016: $4,900,000; 2017: $0

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 230kV buses at Dry Creek, Lolo, and N.Lewiston, as well as Moscow and Shawnee.

Lewiston Mill Rd. 115 kV Substation – 2015: $684,000; 2016: $0; 2017: $0

A new 115-13 kV substation is required to serve the sawmill for the Idaho Forest Group in Lewiston near Clearwater Paper Co. This new substation will have one 20 MVA transformer, 115 kV Circuit Switcher, panelhouse, full SCADA/Communications, and two 13 kV distribution feeder bays. The transmission will tap the existing Clearwater-Lolo #2 line with associated air switches for isolation. This substation is required for Avista to serve this customer.

IV. Reliability Replacements:

Storms - 2015: $1,000,000; 2016: $890,000; 2017: $883,000

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 – 2015: $1,647,000; 2016: $3,300,000 ; 2017: $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.

Substation – Capital Spares – 2015: $3,250,000; 2016: $4,915,000; 2017: $1,200,000

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. Acquisition of these capital items requires long lead times, so sufficient levels of safety-stock must be maintained to avoid service interruptions.

Transmission – Asset Management – 2015: $1,813,000; 2016: $1,772,000; 2017: $1,780,000

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 – 2015: $434,000; 2016: $350,000; 2017: $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.

Transmission Reconductors and Rebuilds – 2015: $11,776,000; 2016: $21,161,000; 2017: $18,327,000

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 (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 2564 - Devils Gap-Lind Structure Replacement, ER 2574-Chelan-Stratford River Crossing Rebuild, 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.

Benton-Othello 115 will experience an incremental reduction in line losses of 225 MWh in both 2015 and 2016 – 450 MWh total. After applying the avoided energy cost per MWh of $44, this equates to $19,800 ($6,990 Idaho) of total offsets on a system basis.

Bronx-Cabinet will experience incremental reductions in line losses of 755 MWh in both 2015 and 2016 (1,510 total). This equates to total offsets of $66,440 on a system level ($23,450 Idaho Electric).

Q. Please describe each of the distribution projects planned for January 1, 2015 through December 31, 2017.

A. Distribution specific projects in Idaho 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 January 1, 2015 to December 31, 2017 are shown in Table No. 4 and described below.

TABLE NO. 4
Electric Distribution

	2015			2016			2017	
	System	ID	ID Savings/ (Costs)	System	ID	ID Savings/ (Costs)	System	ID
I. Distribution Projects:								
Distribution Grid Modernization	$14,081	$10,114	$ -	$11,000	$ 6,300	$ -	$13,000	$10,300
Distribution Wood Pole Management	11,000	3,011	-	11,000	3,011	23	12,000	3,289
Meter Minor Blanket	5,806	1,121	-	5,806	1,121	-	4,977	971
Segment Reconductor and FDR Tie Program	3,894	1,017	-	3,809	1,562	-	4,175	1,141
Substation - Asset Mgmt. Capital Maintenance	2,679	935	-	1,519	530	(57)	1,551	541
Substation - Capital Spares	1,200	115	-	1,200	115	-	800	76
Substation - New Distribution Stations	1,995	-	-	75	9	-	2,323	723
Worst Feeders	2,435	739	-	2,000	698	-	2,000	698
Total Distribution Projects	**43,090**	**17,051**	**-**	**36,409**	**13,345**	**(34)**	**40,826**	**17,740**
II. Distribution Replacement Projects								
Distribution Line Protection	125	44	-	125	44	-	125	44
Distribution Minor Rebuild	8,300	2,601	-	8,300	2,601	-	8,300	2,601
Distribution Transformer Change-Out Program	4,700	1,282	-	4,700	1,282	-	1,100	300
Environmental Compliance	150	41	-	150	41	-	-	-
Electric Replacement/Relocation	2,403	1,479	-	2,500	1,479	-	2,600	1,479
Primary URD Cable Replacement	1,000	800	-	-	-	(282)	-	-
Reconductors and Rebuilds	2,892	1,009	-	2,500	872	-	2,500	872
Storms	2,000	539	-	1,900	512	-	2,000	539
Substation - Distribution Station Rebuilds	2,297	119	-	2,284	1,797	-	3,315	1,697
Street Light Management	1,500	133	165	1,500	191	90	1,500	191
Total Distribution Replacement Projects	**25,367**	**8,047**	**165**	**23,959**	**8,819**	**(193)**	**21,440**	**7,724**
Total Distribution Idaho Distribution	**$68,457**	**$25,098**	**$ 165**	**$60,368**	**$22,165**	**$ (227)**	**$62,266**	**$25,464**

I. Distribution Projects:

Distribution Grid Modernization – Idaho - 2015: $10,114,000; 2016: $6,300,000; 2017: $10,300,000

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 – Idaho - 2015: $3,011,000; 2016: $3,011,000; 2017: $3,289,000

The distribution wood pole management program evaluates wood pole strength of 5% of the wood pole population each year such that the entire system is inspected every 20 years. Avista has approximately 237,000 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, and 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 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. Pre-81 transformers are replaced if the pole is replaced. In 2017 WPM will begin to replace all pre-81 transformers regardless of whether the pole needs to be replaced. Poles installed during the pre-World War II buildup have reached the end of their useful lives. 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 an Idaho offset of $23,000.

Meter Minor Blanket – Idaho – 2015: $1,121,000; 2016: $1,121,000; 2017: $971,000

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 – Idaho - 2015: $1,017,000; 2016: $1,562,000; 2017: $1,141,000

This project improves the capacity and reliability of the Company's distribution grid through targeted reconductoring/rebuild projects. In Idaho, 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.

Substation Asset Management Capital Maintenance – Idaho - 2015: $935,000; 2016: $530,000; 2017: $541,000

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 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 $57,000 is Idaho’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 – Idaho - 2015: $115,000; 2016: $115,000; 2017: $76,000

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 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. Acquisition of these capital items requires long lead times, so sufficient levels of safety-stock must be maintained to avoid service interruptions.

Substation – New Distribution Stations – Idaho - 2015: $0; 2016: $9,000; 2017: $723,000

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 – Idaho - 2015: $739,000; 2016: $698,000; 2017: $698,000

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.

II. Distribution Replacement Projects

Distribution Line Protection – Idaho - 2015; $44,000; 2016: $44,000; 2017: $44,000

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 – Idaho - 2015: $2,601,000; 2016: $2,601,000; 2017: $2,601,000

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 – Idaho - 2015: $1,282,000; 2016: $1,282,000; 2017: $300,000

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 oil containing PCBs. The transformers to be removed early in the programs are those that are most likely to have PCBs in the oil and their replacement will reduce the risk of oil spills containing PCBs.

Environmental Compliance – Idaho - 2015: $41,000; 2016: $41,000; 2017: $0

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 – Idaho - 2015: $1,479,000; 2016: $1,479,000; 2017: $1,479,000

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 the Idaho Transportation Department. 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 – Idaho - 2015: $800,000; 2016: $0; 2017: $0

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. Idaho’s allocation of these additional O&M costs is $282,000 in 2016. These additional costs have been included in the Company’s O&M Offset adjustment.

Reconductors and Rebuilds – Idaho - 2015: $1,009,000; 2016: $872,000; 2017: $872,000

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 – Idaho - 2015: $539,000; 2016: $512,000; 2017: $539,000

Weather events associated with wind, lightning, rain, and snow create a number of outage situations. This program addresses these outage situations. Estimated capital spend is based on historical averages.

Substation – Distribution Station Rebuilds – Idaho - 2015: $119,000; 2016: $1,797,000; 2017: $1,697,000

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 Idaho substation rebuilds to be completed under this program in the next five years are Big Creek, South Lewiston and Kamiah.

Street Light Management – Idaho - 2015: $133,000; 2016: $191,000; 2017: $191,000

This program is a five year planned replacement of fixtures and 10 year planned replacement of photocells. We anticipate there will be O&M savings in 2015 of $468,000 ($165,000 ID) and an additional offset in 2016 of $254,000 ($90,000 ID), resulting in a total offset of $722,000 ($255,000 ID). The offsets result from the conversion to 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.

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

A. Yes it does.