Exhibit No. ___(SJK-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-10________

DIRECT TESTIMONY OF

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

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

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

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

Q. What is the scope of your testimony?

A. My testimony describes Avista's pro forma period transmission revenues and expenses. I also discuss the transmission and distribution expenditures that are part of the capital additions testimony provided by Company witness Mr. DeFelice, as well as the Company's Asset Management Program (including the additional vegetation management expenses included in the Company's case). Company witness Ms. Andrews incorporates the Washington share of the net transmission expenses, the transmission and distribution capital additions, and the electric distribution vegetation management expenses proposed in this case.

Q. Are you sponsoring any exhibits?

A. Yes. Exhibit No. __(SJK-2) provides the transmission pro forma adjustments. Exhibit No. __(SJK-3) through Exhibit No. __(SJK-6) provides supporting documentation for the 2010 transmission and distribution capital project additions pro formed into the Company's case.

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II. PRO FORMA TRANSMISSION EXPENSES

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

A. Adjustments were made in this filing to incorporate updated information for any changes in transmission expenses from the January 2009 to December 2009 test year to the 2011 pro forma rate period. Each expense item described below is at a system level, with the exception of the $79,000 Grid West adjustment which is Washington only, and is included in Exhibit No.__ (SJK-2). Supporting workpapers for each expense item described below have been provided with the Company's filing.

<u>Northwest Power Pool (NWPP)</u> – Avista pays its share of the NWPP operating costs. The NWPP serves the electric utilities in the Northwest by supporting regional transmission planning coordination and providing coordinated transmission operations, generation reserve sharing and Columbia River water coordination. Actual 2009 transmission-related NWPP expenses were $36,000 and a $4000 adjustment was made to the pro forma period to reflect planned 2011 NWPP expenses allocated to the Company.

<u>Colstrip Transmission</u> – Avista is required to pay its portion of the O&M costs associated with its share of the Colstrip transmission system pursuant to the joint Colstrip contract. In accordance with NorthWestern Energy's (NWE) proposed Colstrip transmission plan provided to the Company, NWE estimates it will bill Avista $585,000 for Avista's share of the Colstrip O&M expense during the pro forma period. This is an increase of $94,000 from the actual expense of $491,000 incurred during the 2009 test year.

<u>ColumbiaGrid RTO</u> – Avista became a member of the ColumbiaGrid regional transmission organization (RTO) in 2006. ColumbiaGrid's purpose is to enhance transmission system reliability and efficiency, provide cost-effective coordinated regional transmission planning, develop and facilitate the implementation of solutions relating to improved use and expansion of the interconnected Northwest transmission system, reduce transmission system congestion, and support effective market monitoring within the Northwest and the entire Western interconnection. Avista supports ColumbiaGrid's general developmental and regional coordination activities under a General Funding Agreement and supports specific functional activities under the Planning and Expansion Functional Agreement and the OASIS Functional Agreement. The current General Funding Agreement for ColumbiaGrid expires September 30,

2010. The Company expects to execute a successor General Funding Agreement in the spring of 2010 to provide for ongoing funding of ColumbiaGrid general development activities while shifting a portion of ColumbiaGrid's administrative costs to its other functional agreements. Accordingly, while ColumbiaGrid is engaging in significant new developmental activities in coordination with other regional organizations (e.g. the review of consolidated balancing area operations and the development of revised scheduling practices to accommodate the impacts of intermittent generation), the Company's expected ColumbiaGrid general funding expenses will decrease. Avista's ColumbiaGrid general funding expenses for the 2009 test year were $202,000 while pro forma period general funding expenses are expected to be $180,000. This amount is the Company's best estimate at this time until the successor General Funding Agreement is approved in the Spring of 2010.

ColumbiaGrid Transmission Planning – The ColumbiaGrid Planning and Expansion Functional Agreement (PEFA) was accepted by the Federal Energy Regulatory Commission (FERC) on April 3, 2007 and Avista entered into the PEFA on April 4, 2007. Coordinated transmission planning activities under the PEFA allow the Company to meet the coordinated regional transmission planning requirements set forth in FERC's Order 890 issued in February 2007, and outlined in the Company's Open Access Transmission Tariff, Attachment K. Funding under the PEFA is on a two-year cycle with provisions to adjust for inflation. Actual PEFA expenses for the 2009 test year were $142,000. The Company's PEFA expenses for the pro forma period are expected to reach the maximum total payment obligation of $220,000, reflecting ColumbiaGrid's final staffing levels to support the PEFA and the allocation of a portion of ColumbiaGrid's administrative expenses to this functional agreement. This amount is the Company's best estimate at this time until the successor General Funding Agreement is approved in the Spring of 2010.

ColumbiaGrid Open Access Same-Time Information System (OASIS) – Avista entered into the ColumbiaGrid OASIS Functional Agreement in February of 2008. This agreement provides for the development of a common Open Access Same-time Information System (OASIS) which would give transmission customers the ability to purchase transmission capacity from all ColumbiaGrid members via a single common OASIS site instead of having to submit multiple transmission service requests to each member individually on each member's respective OASIS sites. Avista's 2009 test year expenses of $35,000 reflected initial developmental activities under this functional agreement. Avista's ColumbiaGrid OASIS expenses for the pro forma period are expected to be $86,000, reflecting operational capability of the ColumbiaGrid OASIS and the allocation of a portion of ColumbiaGrid's administrative expenses to this functional agreement. This amount is the Company's best estimate at this time until the successor General Funding Agreement is approved in the Spring of 2010.

Grid West (WA Direct) – Included in the transmission expense for the pro forma period is an amount of $79,000 to complete recovery of deferred costs associated with Grid West (and its forerunner, RTO West). Avista's total deferred Grid West expense was approximately $1.2 million including interest through March 31, 2006 (a $796,000 Washington share). This amount is being amortized on a five-year basis from July 2006 through June 2011 with no interest or carrying costs.

Electric Scheduling and Accounting Services – The $12,000 decrease in the pro forma period compared to test year expense for electric scheduling and accounting services is a result of continued reductions in services provided by third party vendors. These services are no longer required because of the development of an internal accounting program and the development of a regional transmission interchange tool by the Western Electricity Coordinating Council (WECC). These new applications replace the services provided by third parties.

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

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

Power Factor Penalty – Power factor penalty costs are associated with the Bonneville Power Administration's (Bonneville) General Transmission Rate Schedule Provisions. Bonneville charges a power factor penalty at all interconnections with Avista that exceed a given threshold for reactive power flow during each month. If the reactive flow from Bonneville's transmission system into Avista's system or from Avista's system to Bonneville's system exceeds a given threshold, then Bonneville bills Avista according to its rate schedule. The charge includes a 12-month rolling ratchet provision. Avista currently pays Bonneville a power factor penalty at several points of interconnection. Avista incurred $167,000 of power factor penalty charges in 2008 and $124,000 during the 2009 test year. The Company's pro forma 2011 expenses are set at $146,000 representing an average of the power factor penalty charges incurred in 2008 and 2009.

WECC – System Security Monitor and WECC Administration & Net Operating Committee Fees – The Company's total WECC fees have increased, and are expected to continue to increase, from year to year. The increase is driven primarily by compliance with mandatory national reliability standards. WECC is responsible for monitoring and measuring Avista's compliance with the standards, and therefore has substantially increased its staff and other resources to meet this FERC requirement. The Company's 2009 test year WECC assessments were $159,000 for system security monitoring and $329,000 for dues and net Operating Committee fees, for a total 2009 WECC assessment of $488,000. The Company paid its 2010 WECC assessments in January 2010: $168,000 for system security monitoring and $370,000 for dues and net Operating Committee fees, for a total WECC assessment of $538,000. The Company's pro forma 2011 expenses have been set equal to these amounts paid in January 2010.

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

III. PRO FORMA TRANSMISSION REVENUES

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

A. Adjustments have been made in this filing to incorporate updated information associated with known changes in transmission revenue for the 2011 pro forma period as compared to the 2009 test year. Each revenue item described below is at a system level and is included in Exhibit No.__ (SJK-2). In particular, in December 2009 the Company successfully attained FERC acceptance for an increase in generally applicable transmission rates under Avista's Open Access Transmission Tariff, effective January 1, 2010. The Company was able to increase its point-to-point transmission service rates by 43% (long-term firm point-to-point rates increased from $16.79/kW-year to $24.00/kW-year) and was able to increase its annual FERC transmission revenue requirement applicable to network transmission service (e.g. borderline wheeling service provided to Bonneville) by 73%. Accordingly, adjustments have been made in the pro forma period to reflect these increases in transmission rates. Supporting workpapers for each revenue item described below have been provided with the Company's filing.

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

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

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

c) Borderline Wheeling – East Greenacres Irrigation District – The Company restructured its contract to provide borderline wheeling service to the East Greenacres Irrigation District in April, 2009, resulting in monthly wheeling revenue of $5,000. Revenue under this agreement for the 2009 test year was $51,000. Revenue for the 2011 pro forma period has been increased to $60,000 to reflect the terms of the restructured contract over the entire pro forma rate period.

d) Borderline Wheeling – Spokane Tribe of Indians and Consolidated Irrigation District – The Company provides borderline wheeling service over both transmission and low-voltage facilities to the Spokane Tribe of Indians and Consolidated Irrigation District. Total transmission and low-voltage wheeling revenue under these contracts for the 2009 test year was $140,000. Revenues associated with the transmission components of these contracts have been adjusted for the pro forma period to reflect the 43% increase in the Company's long-term firm point-to-point transmission service rate for the Spokane Tribe of Indians and Consolidated Irrigation District. Accordingly, 2011 pro forma period revenue under these two contracts is set at $154,000.

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

OASIS revenues for the 2009 test year were $2,962,000 and the five-year average of OASIS revenues from 2005 through 2009 is $3,067,000. For the 2011 pro forma period the Company proposes a 22% increase over the five-year average to reflect the potential for recovering additional OASIS revenue under the Company's new transmission rates accepted by FERC which became effective January 1, 2010.

While the Company is able to increase its non-firm and short-term firm transmission service rates by 43% as a result if its FERC rate case, the Company expects to be limited in its ability to successfully sell capacity at its maximum rates. Bonneville, the predominant transmission provider in the region, operates its transmission system in parallel with the

Company's transmission system. Bonneville's current hourly point-to-point transmission service rate is $4.33/MWh with a loss factor of 1.9%. Avista's new maximum hourly point-to-point transmission service rate is $5.77/MWh with a loss factor of 3%. Where Bonneville's system has available parallel capacity, the Company would expect to have limited opportunity to sell transmission capacity above an hourly rate of $4.33/MWh. Increasing the Company's transmission rate to match Bonneville's current rate (notwithstanding the fact that the Company's loss factor is 58% higher than Bonneville's which would further limit the Company's ability to compete with parallel capacity on Bonneville's system) would add only about one-fifth (0.33 / 1.77 = 19%) of the Company's potential rate increase, resulting in an estimated increase in OASIS revenue of 8%. Nevertheless, the Company is estimating an increase in short-term firm and non-firm OASIS revenue comparable to implementing half of the potential rate increase. Accordingly, the Company proposes an OASIS revenue amount of $3,741,000 for the 2011 pro forma period, an amount $779,000, or 22%, greater than the most recent five-year average of $2,962,000.

<u>Seattle and Tacoma Revenues Associated with the Main Canal Project</u> – Effective March 1, 2008, the Company entered into long-term point-to-point transmission service arrangements with the City of Seattle and the City of Tacoma to transfer output from the Main Canal hydroelectric project, net of local Grant County PUD load service, to the Company's transmission interconnections with Grant County PUD. Service is provided during the eight months of the year (March through October) in which the Main Canal project operates and the agreements include a three-year ratchet demand provision. Revenues under these agreements totaled $193,000 during the 2009 test year. Adjusting for the increase in the Company's

transmission rate as a result of its FERC rate case, revenues under these agreements are expected to be $276,000 during the 2011 pro forma period.

Seattle and Tacoma Revenues Associated with the Summer Falls Project – Effective March 1, 2008, the Company entered into long-term use-of-facilities arrangements with the City of Seattle and the City of Tacoma to transfer output from the Summer Falls hydroelectric project across the Company's Stratford Switching Station facilities to the Company's Stratford interconnection with Grant County PUD. Charges under this use-of-facilities arrangement are based upon the Company's investment in its Stratford Switching Station and are not impacted by the Company's transmission service rates under its Open Access Transmission Tariff. Revenues under these two contracts totaled $74,000 in the 2009 test year and are expected to remain the same for the 2011 pro forma period.

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

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

Vaagen Wheeling – The Vaagen generation plant was permanently damaged by fire in November, 2009. Pursuant to its terms and conditions, the Vaagen wheeling contract was terminated effective December 1, 2009. Revenues under this contract were $97,000 during the 2009 test year but have been adjusted to zero for the 2011 pro forma period.

Grant County PUD – Revenues from a long-term firm point-to-point transmission service agreement with Grant County PUD during the 2009 test year were $56,000. This agreement expires December 31, 2010. Accordingly, associated revenue for the 2011 pro forma period has been adjusted to zero.

Grand Coulee Project Hydroelectric Authority – The Company provides operations and maintenance services on the Stratford – Summer Falls 115kV Transmission Line to the Grand Coulee Project Hydroelectric authority under a contract signed in March 2006. These services are provided for a fixed annual fee. Annual charges under this contract totaled $8,100 in the 2009 test year and will remain the same for the 2011 pro forma period.

PP&L Series Capacitors – PP&L Series Capacitor revenue under this 1978 agreement was reduced from $5,000 in the test year to zero in the pro forma period since the 20-year amortization of the original contract expired in June 2009.

NaturEnergy Dynamic Signal – The Company was reimbursed during the 2009 test year for expected one-time expenses related to connecting a NaturEnergy dynamic signal via the WECC Inter Company Communication Protocol system to Avista's SCADA system.

Accordingly, the 2009 test year revenue of $10,000 has been adjusted to zero for the 2011 pro forma period.

FERC Settlement – The Company received a settlement benefit from the FERC in 2009 relating to the Western energy crisis of 2000-2001. This 2009 test year revenue of $115,000 has been adjusted to zero for the 2011 pro forma period.

IV. TRANSMISSION AND DISTRIBUTION CAPITAL PROJECTS

Q. Please describe the Company's capital transmission projects that will be completed in 2010?

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

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

Avista transmission capital 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. 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 2010 capital transmission projects will result in efficiency gains and potential offsets or savings, and the Company has included those where applicable, as noted in the descriptions of the individual projects below. The primary offsets result in loss savings from reconductoring heavily loaded transmission and distribution facilities. For these projects, an analysis was performed to determine the forecasted savings. However not all projects will result in quantifiable loss savings or other offsets. Avista has maintenance schedules for certain equipment, but will only see savings in the pro forma period if that specific piece of equipment that is to be replaced had maintenance expense in 2009, which will not occur in the rate period. Avista maintenance cycles range from 5-15 years depending on the equipment. Therefore it is not unusual to see no maintenance during the test period for these capital projects.

The other potential offsets from these capital projects could come from the avoidance of an unexpected failure of equipment causing a call-out of employees after hours. Avista tries to replace equipment prior to its failure but can’t exactly predict when equipment will fail. A newly installed switch can fail just like an older switch. Significant system failures occur during large weather-related events caused by wind, lightning, and snow. These events can’t be predicted. Therefore, Avista can’t guarantee any offsets or savings from avoidance of equipment failures in the pro forma period.

Finally, it should be remembered that all transmission costs (total historical and pro formed - revenue, expense and net rate base) are subject to the Production (and Transmission) Property Adjustment, which reduces all production/transmission costs by adjusting rate year costs to match test year loads. Mr. DeFelice discusses further the Production (and Transmission) Property Adjustment and Ms. Andrews incorporates this offset in her pro forma calculations.

Q. Please describe each of the transmission projects included in the Company’s filing for 2010.

A. The major capital transmission costs (system) for projects to be completed in 2010 are approximately $18.888 million as described below. See Exhibit No.__(SJK-3) and Exhibit No.__(SJK-4) for supporting documentation.

The specific projects scheduled for 2010 completion related to reliability compliance projects will cost $13.372 million and are described below.

Reliability Compliance Projects:

- Lolo 230 kV Substation ($1.450 million): This project involves the rebuild of the existing Lolo substation to increase the capacity of the substation bus, breakers, and supporting equipment to match the upgraded capacity of the transmission lines that connect to the substation. The new Lolo substation design significantly improves reliability and operating flexibility. The Lolo Substation project was constructed in phases to allow operational flexibility due to system reliability concerns associated with other scheduled construction in the area. Phase 1 was completed in 2007 and the remainder of the project ($1.45 million) was completed in February 2010. The Lolo Substation project costs were developed by the Engineering Department and approved through the capital budget process. This project is required to meet Reliability Compliance under NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, and TPL-003-0a R1-R3. There are no offsets or savings associated with the rebuild of the Lolo substation. Avista did not have any scheduled maintenance for the substation during the test period. (See Exhibit No. __(SJK-3), page 1 and Exhibit No. __(SJK-4), Schedule 1)

- Spokane/Coeur d'Alene area relay upgrade ($1.250 million): This project involves the replacement of older protective 115 kV system relays with new micro-processor relays to increase system reliability by reducing the amount of time it takes to sense a system disturbance and isolate it from the system. This is a five year project and is required to maintain compliance with mandatory reliability standards. This project is required to meet Reliability Compliance under NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Any positive offsets in reduced maintenance costs associated with this replacement effort are offset by increased NERC testing requirements per standard PRC-005-1. (See Exhibit No. __(SJK-3), pages 2-3, and Exhibit No. __(SJK-4), Schedule 2)

- Nez Perce 115 kV Substation Rebuild and Capacitor Bank ($3.575 million): This project involves the complete reconstruction of the Nez Perce substation based upon its degraded condition. The project also includes the addition of a shunt capacitor bank to provide voltage support to the area for critical contingencies to ensure compliance with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. There are no anticipated offsets or savings associated with this substation rebuild. Avista did not have any scheduled maintenance for the substation during the test period. (See Exhibit No. __(SJK-3), pages 4-5, and Exhibit No. __(SJK-4), Schedule 3)

- SCADA Replacement ($0.800 million): The System Control and Data Acquisition (SCADA) system is used by the system operators to monitor and control the Avista transmission system. The SCADA system will be upgraded in 2010 to a new version provided by our SCADA vendor. The current application version is no longer supported by the vendor. The upgrade will ensure Avista has adequate control and monitoring of its Transmission facilities. This portion of the project is required to meet Reliability Compliance under NERC Standards: TOP-001-1, TOP-002-2a R5-R10, R16, TOP-005-2 R2, TOP-006-2 R1-R7. Several Remote Terminal Units (RTUs) located at substations throughout Avista's service territory will also be replaced. The RTUs are part of the transmission control system. There are no offsets or savings associated with this upgrade project, because the Company already pays the application vendor a set annual maintenance fee for support. (See Exhibit No. __(SJK-3), pages 6-7, and Exhibit No. __(SJK-4), Schedules 4-5)

- System Replace/Install Capacitor Bank ($0.750 million): This project includes the construction of a 115 kV capacitor bank at Airway Heights to support local area voltages during system outages. The project is required to meet reliability compliance with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3, and provide improved service to customers. The project is scheduled to be completed by July of 2010. There are no loss savings or other offsets associated with this new equipment installation. (See Exhibit No. __(SJK-3), page 8, and Exhibit No. __(SJK-4), Schedule 6)

- Airway Heights-Silver Lake (North Fairchild Tap) 115 kV Transmission Line ($0.975 million): This work is necessary to upgrade the final 2.5 miles of the ten mile long transmission line from #2/0 ACSR to 556 kcm Aluminum (100 MVA-Summer) conductor. The line upgrade will meet compliance requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Additionally, this work will increase service reliability to an essential military facility (North Fairchild Air Force Base). Using 2009 actual loads, the new conductor will reduce line losses by 71 MWh on an annual basis, establishing a yearly offset savings of $7,100 (based on a $100/MWh avoided energy cost); these savings have been reflected in the proposed revenue requirement. (See Exhibit No. __(SJK-3), pages 9-10, and Exhibit No. __(SJK-4), Schedule 7)

- Mos230-Pullman 115 Reconductor ($1.300 million): Year two of this multi-year project continues to upgrade the transmission line from 1/0 copper to 556 kcm Aluminum (100 MVA-Summer) conductor in order to mitigate thermal overloads experienced during heavy summer load conditions. The line upgrade will meet compliance requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Using 2009 actual loads, the new conductor will reduce line losses by 151 MWh on an annual basis, establishing a yearly offset savings of $15,100 (based on a $100/MWh avoided energy cost); these savings have been reflected in the proposed revenue requirement. (See Exhibit No. __(SJK-3), pages 11-12, and Exhibit No. __(SJK-4), Schedule 8)

Environmental Regulation Projects:

- Beacon Storage Yard ($0.750 million): The Beacon Storage Yard is a location where circuit breakers and power transformers are stored and staged for rotation into existing substations as replacements or for new construction. This site is near the Spokane River and this project work will provide an oil containment system to protect the local environment. In 2009, the Company constructed the bulk of the Beacon Substation Equipment Storage Yard for a total cost of $948,000. In 2010, the remainder of the yard and a building to securely house the mobile substations and battery trailer will be completed and transferred to plant. There are no offsets for this project because it is required to protect against environmental contamination. (See Exhibit No. __(SJK-3), page 13, and Exhibit No. __(SJK-4), Schedule 9)

Contractual Required Projects:

- Colstrip Transmission ($0.503 million): As a joint owner of the Colstrip Transmission projects, Avista pays its ownership share of all capital improvements. Northwestern Energy either performs or contracts out the capital work associated with the jointly owned facilities. There are no offsets or savings to incorporate for this project. (See Exhibit No. __(SJK-3), pages 14-15, and Exhibit No. __(SJK-4), Schedule 10)

- Tribal Permits ($0.519 million): The Company has approximately 300 right-of-way permits on tribal reservations that need to be renewed. The costs include labor, appraisals, field work, legal review, GIS information, negotiations, survey (as needed), and the actual fee for the permit. This work is required to maintain right of ways, therefore there are no offsets or savings that will be achieved. (See Exhibit No. __(SJK-3), pages 16-17, and Exhibit No. __(SJK-4), Schedule 11)

Reliability Improvement Projects:

- Boulder-Rathdrum 115kV Transmission Line ($1.500 million): Year two of this multi-year project to integrate the local load service of Idaho Road Substation will upgrade transmission connectivity from a "tap" configuration to a considerably more reliable "loop" feed by installing approximately four miles of transmission line with 795 kcm Aluminum (125 MVA-Summer) conductor. Using 2009 actual loads, the new conductor will reduce line losses by 100 MWh on an annual basis, establishing a yearly offset savings of $10,000 (based on a $100/MWh avoided energy cost), which has been incorporated into the Company's revenue requirement. (See Exhibit No. __(SJK-3), pages 18-19, and Exhibit No. __(SJK-4), Schedule 12)

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

Replacement Projects:

- Transmission Minor Rebuilds ($1.250 million): These projects include minor transmission rebuilds as a result of age or damage caused by storms, wind, fire, and the public. These smaller projects are required to operate the transmission system safely and reliably. Facilities will need to be replaced when damaged in order to maintain customer load service. In 2009 the Company spent $2.206 million on these minor rebuild projects as a result of damage caused by weather or the public. These costs are caused by events outside of our control. There are no offsets or savings associated with these minor rebuild efforts, due to the unexpected nature of the events. (See Exhibit No. __(SJK-3), pages 20-22, and Exhibit No. __(SJK-4), Schedules 13-14)

- Power Circuit Breakers ($0.485 million): The Company transfers all circuit breakers to plant upon receiving them. Breakers purchased in 2010 will be installed at Otis Orchards (WA) Switching Station. Other planned replacements in 2010 include a 115 kV breaker at Stratford (WA) Switching Station and a 230 kV breaker at Noxon Rapids Switchyard. Avista performs breaker maintenance on a 15 year cycle. None of these breakers were scheduled for maintenance during the test period, so there are no cost savings associated with these replacements. (See Exhibit No. __(SJK-3), pages 23-25, and Exhibit No. __(SJK-4), Schedules 15-16)

- Pine Creek – Replace 115 kV Circuit Switcher & Cap Bank ($0.570 million): The project scope and preliminary engineering design work for this project was started in 2008 and included replacing the circuit switcher and one 13 kV recloser due to equipment age. After further investigation the project was expanded to replace the other two 13 kV reclosers, the cap bank, deteriorated station control wiring, and removal of the small panel house including the obsolete Remote Terminal Unit (RTU). A total of $0.57 million directly related to Transmission (115 kV circuit switcher, Capacitor Bank, control wiring, RTU) will be transfered to plant in 2010. No specific maintenance associated with the replaced equipment occurred during the test period, nor were there other offsets during the test period. Therefore, no offsets are available for this replacement work. (See Exhibit No. __(SJK-3), pages 26-27, and Exhibit No. __(SJK-4), Schedule 17)

- Otis Orchards – 115 kV Breaker and Line Relay Replacements ($0.650 million): This project will replace the 115 kV breakers and associated 115 kV line relays at the existing Otis Orchards substation. Four of the breakers are over 50 years old and have reached the end of their useful lives. The line relaying must be replaced with new microprocessor relays to provide the high speed tripping required for mandatory reliability standards. The relay replacements are part of the Spokane/Coeur d'Alene area relay upgrade project previously discussed. The breakers that are being replaced were not scheduled for maintenance during the test period. Therefore, no offsets or savings are available for this project. (See Exhibit No. __(SJK-3), pages 28-29, and Exhibit No. __(SJK-4), Schedule 18)

- Replacement Programs ($2.044 million): Avista has several different equipment replacement programs to improve reliability by replacing aged equipment that is beyond its useful life. These programs include transmission and substation air switch upgrades, arrestor upgrades, restoration of substation rock and fencing, recloser replacements, replacement of obsolete circuit switchers, substation battery replacement, interchange meter replacements, high voltage fuse upgrades, replacement of fuses with circuit switchers, and voltage regulator replacements. All of these individual projects improve system reliability and customer service. The equipment under these replacement programs are usually not maintained on an annual basis. The equipment is replaced when useful life has been exceeded. The equipment did not fail during the test period and there was no specific identifiable maintenance on this equipment during the test period. Therefore there are no specific O&M offsets related to this investment. (See Exhibit No. __(SJK-3), pages 30-50, and Exhibit No. __(SJK-4), Schedules 19-29)

- Other Small Transmission Projects ($.517 million): These projects include various other smaller transmission system equipment replacement projects. (See Exhibit No. __(SJK-3), page 51, and Exhibit No. __(SJK-4), Schedule 30)

The total offsets or savings, including those from the Production (and Transmission) Property Adjustment included for all transmission projects, total $140,000.

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

A. Distribution projects in Washington (including transformation) for 2010 total $7.816 million. These projects are necessary to meet capacity needs of the system, improve reliability, and rebuild aging distribution substations and feeders.

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

A. Yes. The Company evaluated each project and determined that some of the 2010 capital distribution projects will result in efficiency gains and potential offsets or savings, and the Company has included those where present. In addition to any specific project O&M offsets included (and noted in the description of the individual project below), in order to be conservative (as to not over-collect the project cost from customers), the Company has also applied to <u>each pro forma distribution project</u> a "load adjustment factor," which reduces each pro forma distribution project by adjusting rate year costs to match test year loads. This load adjustment factor offset was included as a reduction to O&M distribution expense. Mr. DeFelice discusses further the "load adjustment factor" included in the "2010 Capital Additions" adjustment and Ms. Andrews incorporates this offset in her pro forma calculations.

Q. Please describe each of the distribution projects included in the Company's filing for 2010.

A. The following projects make up the $7.816 million of 2010 distribution projects included in the Company's case. See Exhibit Nos.__(SJK-5), pages 1-8, and Exhibit Nos.__(SJK-6), Schedules 1-5, for supporting documentation for each of the projects described below.

- Power Transformer Distribution ($4.74 million system / $2.926 million Washington) – Transformers are transferred to plant upon receiving them. These transformers are being purchased to replace existing spares that will be installed in 2010 as either replacements or new installations. The purchased transformers will either remain as system spares or placed into service as part of proposed 2011 projects. (See Exhibit No. __(SJK-5), page 1, and Exhibit No. __(SJK-6), Schedule 1)

- Othello and Chewelah Transformer Replacements ($0.95 million) – Since the transformers were purchased and received in 2009, the transformer costs have already been transferred to plant. The costs shown here are all labor costs to install the new transformers at each location. One of the existing transformers at the Othello substation needs to be replaced because of concerns that if it fails it could have an impact on the environment. The transformer at Chewelah Substation is at the end of its useful life, and is near capacity. In order to increase the capacity, a 115 kV Circuit Switcher and Air Switch needs to be installed requiring relaying and SCADA to be added to the station. Replacing Chewelah transformer #1 will save $80,500 per year in energy savings due to the inefficiencies of the current transformer. By replacing this transformer, load losses will be reduced. The 2011 O&M offset of $80,500 has been included to offset the cost of this project. (See Exhibit No. __(SJK-5), pages 2-3, and Exhibit No. __(SJK-6), Schedule 2)

- Northeast Substation ($0.90 million) - Northeast Substation is being rebuilt to eliminate high fault duty issues caused by the present substation configuration where the two parallel 20 MVA transformers feed the 4-feeder bay switchgear. This project also rebuilds the distribution structures to Avista's present outdoor substation feeder standards, eliminating old metalclad switchgear. The station rebuild is being done to eliminate the risk of equipment failure. We have not experienced any increased maintenance at this substation so we do not anticipate any offsets or savings associated with this project. (See Exhibit No. __(SJK-5), page 4, and Exhibit No. __(SJK-6), Schedule 3)

- Distribution – Spokane North & West ($1.89 million) – Nine Distribution feeder upgrade/reconductor projects were identified by Distribution Planning as being thermally constrained. In order to maintain system reliability and service of customer load, these feeders will be reconductored during 2010. The reconductor efforts will result in some loss savings due to the installation of a larger conductor, establishing a yearly offset savings of approximately $42,800 (based on a $100/MWh avoided energy cost and certain other assumptions). This estimated savings was not available at the time the Company's revenue requirement was finalized, and therefore is not currently reflected in the proposed revenue requirement. (See Exhibit No. __(SJK-5), pages 5-6, and Exhibit No. __(SJK-6), Schedule 4)

- System - Distribution Reliability - Improve Worst Feeders ($1.15 million): Based on a combination of reliability statistics, including CAIDI, SAIFI, and CEMI (Customers Experiencing Multiple Interruptions), several feeders have been selected for reliability improvement work. This work will improve the reliability of these feeders and overall service to customers in these areas. The projects were selected based on poor reliability performance not on cost savings. (See Exhibit No. __(SJK-5), pages 7-8, and Exhibit No. __(SJK-6), Schedule 5)

The Company also will spend approximately $24.0 million (system) in distribution equipment replacements and minor rebuilds associated with aging distribution equipment discovered through inspections, feeders with poor reliability performance, replacements from storm damage, or relocation of feeder sections resulting from road moves. A brief description of the projects included in these replacement efforts is given below. See Exhibit Nos.__(SJK-5), pages 9-19, and Exhibit Nos.__(SJK-6), Schedules 6-13, for supporting documentation for each of the projects described below.

- Electric Distribution Minor Blanket Projects ($7.0 million): This effort includes the replacement of poles and cross-arms on distribution lines in 2010 as required, due to storm damage, wind, fires, or obsolescence. The Company spent $9.22 million in 2009 for these projects. These projects and costs are caused by events outside of our control and have to be fixed to provide service to our load. There is no way to determine offsets or savings associated with these minor rebuild efforts at this time because the Company cannot predict when a car will hit a pole or when weather will damage equipment, and because the replaced equipment may be 30 years old or just installed. (See Exhibit No. __(SJK-5), page 9, and Exhibit No. __(SJK-6), Schedule 6)

- Wood Pole Replacement Program and Capital Distribution Feeder Repair ($6.884 million): The distribution wood-pole management program is a strength evaluation of a certain percentage of the pole population each year. We have over 240,000 distribution poles and 34,500 transmission poles in our electric system. Depending on the test results for a given pole, that pole is either considered satisfactory, reinforced with a steel stub, or replaced. As feeders are inspected as part of the wood-pole management program, issues are identified unrelated to the condition of the pole. This project also funds the work required to resolve those issues (i.e. leaking transformers, transformers older than 1964, failed arrestors, missing grounds, damaged cutouts). Since the pre-World War II buildup wood poles have reached the end of their useful life, Avista's Wood Pole Management program was put into place to prevent the Pole-Rotten events and Crossarm – Rotten events from increasing. So far, the Wood Pole Management Program has helped keep Pole-Rotten and Crossarm-Rotten events in check. The Company has projected savings from the Wood Pole Management, which came from reducing the growth in failures related to poles and crossarms. Looking at 2007 to 2009 data, Crossarm-Rotten Events went from 46 events to 23 events, however, Pole-Rotten events climbed from 25 events to 44 events in 2008 and 2009. Thus, no net offsets are anticipated from the Wood Pole Management program for the 2011 rate period. As the replacement program matures and reduces failures, future offsets are anticipated. The Company spent $8.276 million on these efforts in 2009. (See Exhibit No. __(SJK-5), pages 10-11, and Exhibit No. __(SJK-6), Schedule 7)

- Electric Underground Replacement ($4.0 million): This effort involves replacing the first generation of Underground Residential District (URD) cable, which has been ongoing for the past several years. This program focuses on replacing a vintage and type of cable that has reached its end of life and contributes significantly to URD cable failures. The

Company spent $3.69 million in 2009. The incremental savings in Operation and Maintenance expenses seen in 2009 compared to 2008 was $120,000 due to reduced number of URD Primary Cable fault reductions. In 2011, we anticipate that we will see the same incremental savings as 2009, which has been included as an offset for the Electric Underground Replacement project. (See Exhibit No. __(SJK-5), page 12, and Exhibit No. __(SJK-6), Schedule 8)

- T&D Line Relocation ($2.348 million): Relocation of transmission and distribution lines as required due to road moves requested by State, County or City governments. The Company spent $2.2 million in 2009 on line relocations associated with road moves. There are no offsets or savings determined for these projects because the age and status of the equipment being moved are not known. (See Exhibit No. __(SJK-5), page 13, and Exhibit No. __(SJK-6), Schedule 9)

- Failed Electric Plant ($2.0 million): Replacement of distribution equipment throughout the year as required due to equipment failure. The Company spent $3.44 million in 2009. There are no offsets or savings that can be determined for these projects because the age and status of the equipment being replaced are not known. The Company must replace the equipment to maintain customer load service. (See Exhibit No. __(SJK-5), page 14, and Exhibit No. __(SJK-6), Schedule 10)

- Spokane Electric Network Increase Capacity ($1.356 million): These projects are associated with the Downtown Spokane electric network. The projects involve the installation of vaults, cables, network transformers and protectors, as required, to maintain reliable service to existing customers by replacing overloaded and deteriorated equipment. (See Exhibit No. __(SJK-5), pages 15-16, and Exhibit No. __(SJK-6), Schedule 11)

- Other Small Distribution projects ($.39 million): These projects include various smaller distribution project equipment replacement and minor rebuilds, such as the distribution feeder reconductor project identified as “thermally constrained” portions of the feeder trunk lines located in Pullman and Lewis Clark valley. (See Exhibit No. __(SJK-5), pages 17-19, and Exhibit No. __(SJK-6), Schedules 12-13)

The total offsets or savings for all distribution projects, including the offsets included from the load adjustment factor applied to all new distribution plant, total $417,000.

V. AVISTA’S ASSET MANAGEMENT PROGRAM

Q. Please describe the Company’s overall Asset Management Program plan.

A. Like most U.S. utilities, after World War II Avista's growth required installing or updating equipment to meet rising electrical demand. Substations were built or modified to meet increasing loads. The transmission system expanded to bring new generating plant output to population centers. Distribution systems grew and voltage levels were increased to meet new housing and industrial needs.

As mentioned previously, Avista's installed equipment is aging, and more components are reaching the end of their useful life. Equipment has become obsolete, and manufacturers no longer support the aged equipment or produce replacement parts, which makes it impractical to rebuild the equipment. Recognizing the increasing cost of aging equipment failure, Avista launched its Asset Management (AM) effort in March 2004.

This AM program, through a process which combines technology and information in a manner that integrates data from a myriad of sources into a comprehensive plan, manages key electric transmission and distribution assets throughout their life to provide the best value for our customers. For example, this plan includes replacement or maintenance programs that minimize life cycle costs of our assets and the cost to generate and deliver energy. By minimizing life cycle costs, we're able to maximize system reliability and value for our customers.

The foundation for the plan involves determining the future failure rates and impacts to the environment, reliability, safety, customers, costs, labor, spare parts, time, and other consequences. This failure rate model then becomes the baseline to compare all other options, to assure the most efficient use of Company resources.

This Asset Management Program is the foundation from which the pro forma capital additions I have just described were developed. Another element of the Asset Management Program for which we have proposed a pro forma adjustment is vegetation management.

Q. Please describe the vegetation management portion of the Asset Management Program and the amounts for which the Company is requesting an increase in costs above its historical test period.

A. Avista's vegetation management (VM) program maintains the distribution and transmission systems clear of trees and other vegetation. In addition, the VM program provides safety clearances for the public from trees and also reduces customer outages caused by trees, weather, snow/ice, wind and to a lesser extent squirrel caused outages. Avista's electric distribution system includes over 7,800 distribution circuit miles of which 5,200 are in Washington and 2,600 are in Idaho. The Transmission System includes 1,535 circuit miles of 115 kV Transmission Lines and 685 circuit miles of 230 kV Transmission Lines mainly in Washington and Idaho. The Gas System High Pressure Lines has 219 miles to clear. This is a significant amount of miles, and each of these miles requires vegetation management. Avista's VM program is almost entirely contracted out, with the primary contractor for this work being Asplundh Tree Experts.

As shown in Illustration 1 below, Washington's electric distribution vegetation management level of expenditure necessary in 2011 is approximately $4.5 million, or $2.2 million above that included in the 2009 test period. This $2.2 million of incremental cost (less offsetting savings included as described below of $188,000) has been included in the Company's electric revenue requirement request filed in this case as discussed further by Ms. Andrews.

Illustration 1, Distribution Pro Forma Increment

Year	WA Electric
2009 Actual	$ 2,284,497
2011 Planned	$ 4,521,679
Pro Forma Increment	$ 2,237,182

Q. What is the cause for the incremental increase in costs in distribution vegetation management over that included in the Company's 2009 test period?

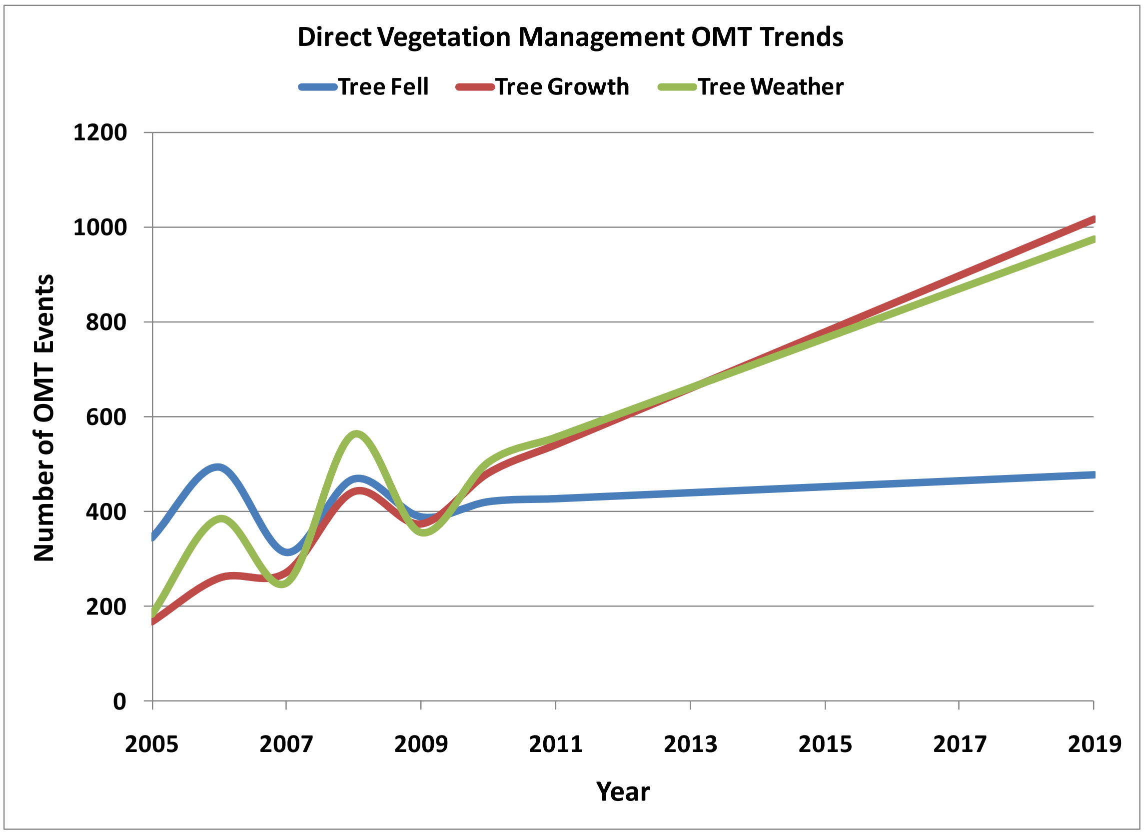
A. Over the past few years, Avista's vegetation management has experienced higher than anticipated rates of inflation, over 6%, due to labor, fuel costs and equipment costs. In addition, through the AM program analysis performed on the Company's vegetation management work plan, the Company has determined that a five year clearing cycle, requiring the Company to clear 1,550 miles per year, is necessary in order to minimize future increases in costs, reduce future failure rates and optimize system reliability. The Company's current level of spend in its Washington jurisdiction is based on a seven to eight year clearing cycle.

As the Company has analyzed the AM plan over time, outage data collected by the Company's Outage Management Tool (OMT)[1] has shown a dramatic increase in outages on circuit miles where trees are trimmed less frequently. As shown in Illustration 2 below, Avista continues to see an increase in the number of vegetation related outages. For example, while 2009's performance was better than 2008 in all areas, we see an overall increasing trend, now

[1] The data behind the failure rates used in the AM program models come from information gathered during past years' work and failures. Information was gathered for the number of trees removed, trees trimmed, and brush removed along with the failure documented in the Outage Management Tool (OMT) and were used to create the failure curves used by the models.

and in the future, in the number of events due to Tree Growth (i.e. trees growing into the power lines and causing an outage or other problems with the power line) and Tree Weather (i.e. tree related outages or events where the root cause is related to the weather). Avista has successfully maintained Tree Fell (i.e. events in OMT where a tree has fallen into a power line because it was dead and/or rotten) events to a relatively stable value, but Tree Growth and Tree Weather events continue to trend upwards.

<u>Illustration 2:</u>



The general OMT trends in Tree Growth and Tree Weather events remain a concern for VM with an increasing trend upwards as shown in the chart above. Action is required to address this trend before it becomes a larger problem, and based on our current analysis, a five year

Vegetation Management cycle (versus a 7-8 year cycle at present) will check the upward trend and level the annual number of associated events to match today's levels.

Delaying work, however, beyond 5 years increases the amount of work required and the expected cost as shown in Illustration 3.

Illustration 3:

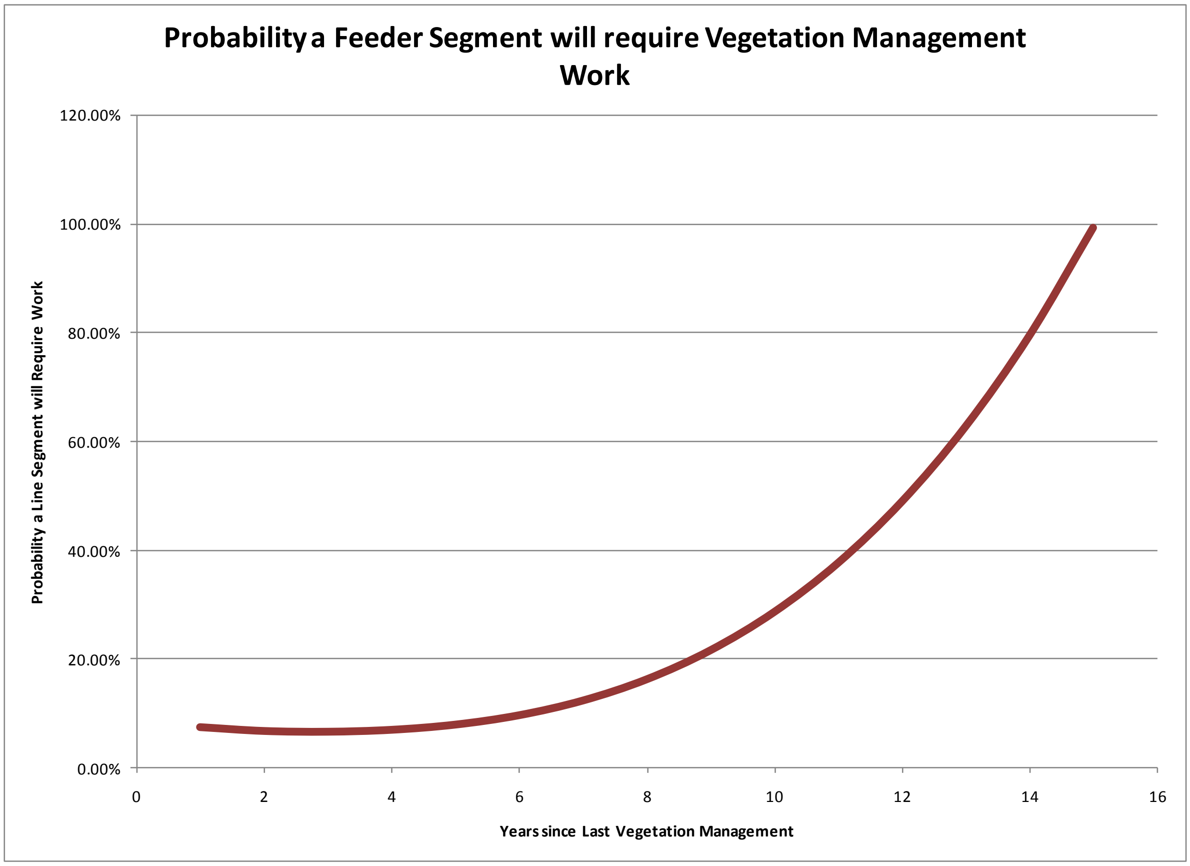
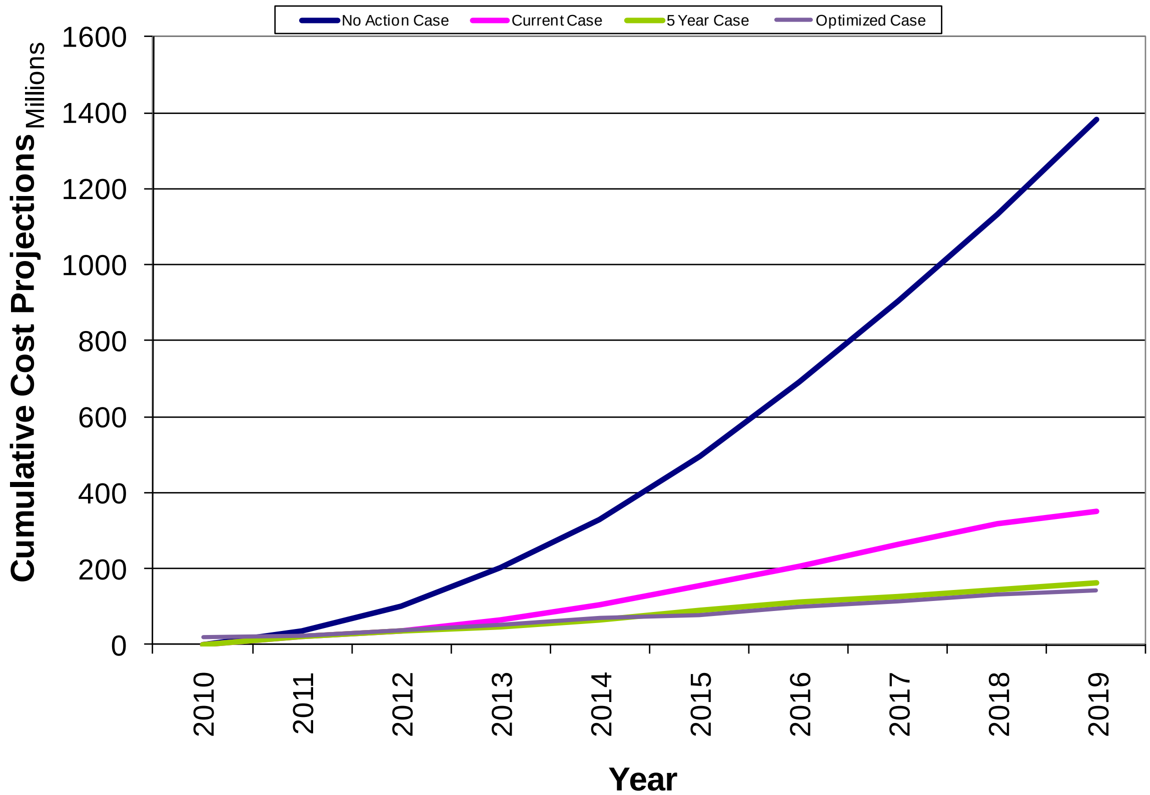


Illustration 4 below shows the cost projections of the Company's current case (or seven to eight year cycle) and the proposed case, or five-year cycle.

Illustration 4



To further support the rational for a five-year cycle, Illustration 5 below shows the estimated average number of OMT events over the next 10 years for the Company's current case (or seven to eight year cycle) and the proposed case, or five-year cycle. Based on the information shown in Illustration 5, we anticipate preventing over 670 events each year once all feeders are on a five-year cycle.

Illustration 5

OMT Events	Tree Fell	Tree Growth	Tree Weather	Combined OMT Totals
6 Year Average OMT Events-actual	403	304	349	1056
Projected 10 Year Average - Current Case	330	789	774	1892
Projected 10 Year Average - 5 Year Trim Cycle Case	238	406	576	1220
Projected Average Number of Avoided OMT Events changing to a 5 Year Trim Cycle	92	383	198	672

As can be seen from the illustrations above, for the distribution system, our analysis shows that a five year clearing cycle has definite advantages and savings over the longer current and previous line clearing cycles, and that a pro-active maintenance program is necessary to provide the best value, and level of reliability to our customers.

Q. How does the Company contract for vegetation management?

A. The company has used a "Time and Material" contract since the 1990's, and its primary contractor since 2005 has been Asplundh Tree Expert Co. These contracts are used to project the overall average cost per mile to accomplish a five-year plan requirement. With this information, the Company can determine the cost for this effort, and as stated above for the electric distribution vegetation management, equates to $4.5 million.

Q. Has the Company considered other options for contracting its current vegetation management work plan?

A. Yes. Avista explored combining all the vegetation management components into a "Request For Proposal" (RFP) using a "by project" quotation format to obtain firm pricing for future work. After reviewing the potential impacts of this method, it was determined Avista would continue with a Time and Material contract we currently utilize.

To begin with, there are a limited number of qualified contractors in this region who could fulfill all the needs of this type of proposal (or RFP), and each contractor would be facing similar challenges associated with a "project type" of contract. In addition, contractors are facing uncertain labor costs into the future due to pending labor negotiations later in 2010, uncertain fuel prices to operate equipment, and extensive research time to evaluate all of the feeders' current condition and project needs into the future. These unknowns represent an increased risk to contractors they would need to factor into any proposals submitted. Past studies have shown project type contracts cost more than the Time and Material contracts we use today. For these and other reasons, although a firm contract would have provided a more exact total cost for 2011, Avista chose to continue with our current contracting practices, utilizing Time and Material, and not execute project type agreements for our Vegetation Management work.

Q. Can the Company provide a guarantee to this Commission that the amount requested by the Company will be spent on the vegetation management program?

A. Yes. The Company is currently required, by Commission Order in Docket No. UE-050482, to spend approximately $2.8 million per year for electric and natural gas vegetation management (includes electric and gas distribution and transmission expenses). Avista reports this to the Commission annually within the Company's Commission Basis Report, and maintains a one-way balancing account to track any funds under-spent (below the $2.8 million). In the event any dollars for vegetation management are not spent in any given year, that unspent balance will be accounted for and spent in subsequent year(s) or credited back to customers.

To provide customers continued certainty that any increase in funds collected in rates on a pro forma basis will be dedicated to Avista's vegetation management program, the Company requests the Commission approve the additional pro formed amount included in this case, and increase the required spend level from the current $2.8 million to that requested in this case, to approximately $5.3 million (includes transmission and electric and gas distribution included in the test period of $3.1 million, plus the pro forma adjustment of $2.2 million.)

Q. What offsetting factors does the Company anticipate as a result of Avista's Asset Management plan, i.e. resulting from utilizing a five-year cycle?

A. For Avista's Asset Management plan, the offsetting factors represent avoided costs due to elimination of unplanned events associated with equipment failures. For vegetation management specifically, as discussed previously, a five year trim cycle is anticipated to prevent over 650 events each year once all feeders are on a five-year cycle (or approximately $1.4 million annually). The annual savings cannot be realized until after the specific feeders have been trimmed for a given year, and the savings would not be seen until the following year. Based on cost data from 2009, the annual savings anticipated in 2012, after the first year trim cycle is completed in 2011, is an estimated savings of $276,400 ($188,000 Washington share). However, to be conservative in this rate case, the Company has included this offset (reducing operating and maintenance expense) against the 2011 planned vegetation management expense pro formed into this case. Ms. Andrews discusses the pro forma vegetation management adjustment (including this offset) in her direct testimony.

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

A. Yes it does.