Exhibit No. ___(SJK-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-11________

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 educational 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 projects associated with 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, and Exhibit No. __(SJK-3C) is the Transmission Line Ratings Confirmation Plan (original dated January 18, 2011 and Revision B dated April 27, 2011) that was developed and filed with NERC to address the "NERC Alert" issued on October 7, 2010.

A table of contents for my testimony is as follows:

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 2010 to December 2010 test year to the 2012 pro forma rate period. The changes in expenses and a description of each is summarized in Table 1:

Table 1:

Transmission Expenses	
	***Pro Forma (System)**
Northwest Power Pool (NWPP)	$ 1,000
Colstrip O&M - 500kV Line	$ 117,000
ColumbiaGrid Development	$ (14,000)
ColumbiaGrid RTO	$ 56,000
ColumbiaGrid OASIS	$ 42,000
Grid West (WA Direct)	$ (158,000)
Elect Sched & Acctg Srv (OATI)	$ 4,000
NERC CIP	$ 3,000
OASIS Expenses	$ 1,000
BPA Power Factor Penalty	$ (7,000)
WECC Sys Secur & Admin- Net Oper Comm Sys	$ (21,000)
WECC - Loop Flow	$ 12,000
CNC Transmission Project	$ 255,000
Transmission Line Ratings Confirmation Plan (NERC Alert)	$ 2,145,000
Total Expense	**$ 2,436,000**

*Representing the change in expense above or below the 2010 test period level.

Northwest Power Pool (NWPP) ($1,000) – Avista pays its share of the NWPP operating costs. The NWPP serves the electric utilities in the Northwest by supporting regional transmission planning coordination, providing coordinated transmission operations including generation reserve sharing, and Columbia River water coordination. Actual 2010 transmission-related NWPP expenses were $42,000 and a $1,000 adjustment was made to the pro forma period to reflect the NWPP expenses allocated to the Company.

Colstrip Transmission ($117,000) – Avista is required to pay its portion of the O&M costs associated with its share of the Colstrip transmission system pursuant to the joint Colstrip contract. In accordance with NorthWestern Energy's (NWE) proposed Colstrip transmission plan provided to the Company, NWE will bill Avista $560,000 for Avista's share of the Colstrip

O&M expense during the pro forma period. This is an increase of $117,000 from the actual expense of $443,000 incurred during the 2010 test year.

ColumbiaGrid RTO (-$14,000) – 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 December 31, 2012. Avista's ColumbiaGrid general funding expenses for the 2010 test year were $194,000 while pro forma general funding expenses are $180,000, a reduction of $14,000.

ColumbiaGrid Transmission Planning ($56,000) – 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, Attachment K. Funding under the PEFA is on a two-year cycle with provisions to adjust for inflation. Actual PEFA expenses for the 2010 test year were $164,000. The Company's PEFA pro forma expenses are at the maximum total payment obligation of $220,000, reflecting ColumbiaGrid's final staffing levels to support the PEFA and the reallocation of a portion of ColumbiaGrid's administrative expenses (previously paid under the general funding agreement) to this functional agreement.

ColumbiaGrid Open Access Same-Time Information System (OASIS) ($42,000) – Avista entered into the ColumbiaGrid OASIS Functional Agreement in February 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 2010 test year expenses of $44,000 reflected initial developmental activities under this functional agreement. Avista's ColumbiaGrid OASIS pro forma expenses are $86,000, reflecting operational capability of the ColumbiaGrid OASIS and the reallocation of a portion of ColumbiaGrid's administrative expenses (previously paid under the general funding agreement) to this functional agreement.

Grid West (WA Direct) (-$158,000) – 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 was being amortized on a five-year basis from July 2006 through June 2011 with no interest or carrying costs. With amortization ending in June of 2011, the Company will not incur costs associated with ColumbiaGrid in the pro forma period. Avista did amortize $158,000 in the 2010 test year.

Electric Scheduling and Accounting Services ($4,000) – The $4,000 increase in the pro forma period compared to test year expense for electric scheduling and accounting services is a result of additional services provided by our third party vendor. These services are required to assist in meeting the requirements of the NERC mandatory reliability standards. The pro forma scheduling and accounting costs are $175,000.

<u>NERC Critical Infrastructure Protection</u> ($3,000) – 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's pro forma expenses increase $3,000 from the actual 2010 test year expense of $47,000 due to annual application cost increases.

<u>OASIS Expenses</u> ($1,000) – 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 $1,000 more than in the 2010 test year.

<u>Power Factor Penalty</u> (-$7,000) – 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 $138,000 of power factory penalty charges during the 2010 test year. The Company's pro forma 2012 expenses are set at $131,000 representing an average of the power factor penalty charges incurred in 2009 and 2010.

WECC – System Security Monitor and WECC Administration & Net Operating Committee Fees (-$21,000) – The Company's total WECC fees have begun to level off. The past increases have been driven primarily by increased compliance requirements associated 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 2010 test year WECC assessments were $167,000 for system security monitoring and $384,000 for dues and net Operating Committee fees, for a total 2010 WECC assessment of $551,000. The Company paid its 2011 WECC assessments in January 2011: $171,000 for system security monitoring and $359,000 for dues and net Operating Committee fees, for a total WECC assessment of $530,000. The Company's pro forma 2012 expenses have been set equal to these amounts paid in January 2011.

WECC - Loop Flow ($12,000) – 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. 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 2006 through 2010, pro forma Loop Flow expenses are $32,000. This is $12,000 more than actual 2010 test year charges of $20,000.

Q. Please now describe the proposed Canada to Northern California ("CNC") transmission project expense included in the Company's request.

A. The CNC transmission project was initially proposed with Pacific Gas and Electric Company ("PG&E") as its primary sponsor. As initially proposed, the CNC transmission project was an Extra High Voltage ("EHV") transmission project that, if developed, would include a 500 kV transmission line that would run between British Columbia, Canada and Northern California. With PG&E as the primary sponsor, Avista, British Columbia Transmission Corporation, PacifiCorp and Transmission Agency of Northern California were sponsors of the CNC transmission project.

Q. What was the purpose of the CNC transmission project?

A. The CNC transmission project was evaluated as a regional project intended to meet three primary objectives:

1. Enhance access to significant incremental renewable resources in Canada and the Pacific Northwest;
2. Improve regional transmission reliability; and
3. Provide market participants with beneficial opportunities to use the facilities.

Initially, the CNC transmission project offered three distinct alternatives for satisfying these objectives, which included:

1. An overland alternative from Southeast British Columbia to Northern California;
2. An overland alternative from Idaho to Northern California; and
3. An undersea alternative from Western British Columbia to Northern California.

Q. Why was Avista one of the sponsors of the CNC transmission project?

A. While there were several reasons why Avista was a sponsor of the CNC transmission project, Avista's sponsorship was based upon two primary objectives: (i) to obtain access to additional resources and additional import capacity to serve the needs of Avista's native load customers, and (ii) to maintain and enhance system reliability.

The State of Washington recently enacted a renewable portfolio standard with which Avista must comply. Renewable portfolio standards may also be established in other states in which Avista operates or may be federally adopted. The CNC transmission project offered an opportunity for Avista to access renewable resources that would help Avista meet its intermediate and long-term future renewable resource needs in order to satisfy its renewable portfolio standard requirements. In the context of integrating variable renewable resources, future access to regulation or shaping services from BC Hydro was also a consideration.

Additionally, to the extent Avista intends to consider any new resources, renewable or otherwise, that reside outside its service territory to meet the future needs of the Company's native load customers, the Company must maintain and develop additional import capacity on its transmission system to accommodate such resources. The vast majority of the Company's current transmission import capability flows through its interconnections with the Bonneville Power Administration. The CNC transmission project not only offered an opportunity to provide for future increase in import capability, but provided an opportunity to diversify that import capability.

The CNC transmission project also would serve to enhance system reliability both from a regional standpoint and specifically for Avista's system. The CNC transmission project would provide an EHV (extra-high voltage) source on the west side of Avista's service territory, increasing the overall reliability of Avista's transmission grid. Avista currently has only three 500 kV sources supporting its transmission system – the Company's Bell, Hatwai and Hot Springs interconnections which are all with the Bonneville Power Administration.

By participating as a sponsor of the CNC transmission project, Avista was able to affect certain determinations regarding the project, including the choice of the overland alternative from Southeast British Columbia to Northern California, and the planned interconnection with Avista's transmission system at Devils Gap.

Additionally, Avista was an affected party that needed to participate in review and analysis of the project as part of the Company's coordinated regional planning obligations under Attachment K to its Open Access Transmission Tariff.

Q. What is the current status of the CNC transmission project?

A. Currently, the CNC transmission project is undergoing a transformation. As originally conceived, the project sponsors planned to work cooperatively to develop a single transmission project from Canada to Northern California. That project has completed the Western Electricity Coordinating Council ("WECC") Regional Planning and Project Review process and Phase 1 Rating Study, and it is now in the WECC Phase II study process. As the project has evolved, however, the current sponsors BC Hydro, Avista, and PG&E have recognized that each sponsor now desires to focus its resources on potential transmission segments that are geographically closer to its own respective service area. PG&E continues to be interested in developing a transmission line from Northern California to Eastern Oregon. Similarly, BC Hydro is interested in developing a transmission line from Canada to Eastern Oregon. Accordingly, the CNC transmission project is being evaluated as two distinct projects—a northern project which will be a 500kV transmission line from Selkirk, BC to a transmission switching station in Northeast Oregon ("NEO"), and a southern project that will run from NEO to Northern California. To the extent that the northern and/or southern projects are developed, they will be developed as separate projects that will likely be sponsored primarily by BC Hydro and PG&E, respectively.

Q. Will Avista continue to participate as a sponsor of either the proposed northern or the proposed southern transmission lines?

A. Avista has not yet made a final determination regarding the scope of its participation, including sponsorship, in the northern transmission line. At this point in time, Avista has no plans to participate as a sponsor in the southern transmission line.

Q. Will Avista continue to participate in the development of either the proposed northern or the proposed southern transmission lines?

A. Yes. While Avista has not yet made a final determination regarding the scope of its participation, to the extent that BC Hydro continues to develop the northern transmission line, Avista will need to continue to participate in the regional planning process as an affected party under its Attachment K and as planning activities relate to the Company's development of its Devils Gap Interconnection. Avista does not anticipate the need to continue participation in the southern transmission line at this time.

Q. Have Avista's customers derived any benefit from Avista's initial participation in the CNC transmission project?

A. Yes. As explained previously in this testimony, there were initially three alternatives for developing the CNC transmission project. Through its participation as a sponsor of the CNC transmission project, Avista was instrumental in the selection of the first alternative (i.e., an overland route from Southeast British Columbia to Northern California) and the establishment of a transmission corridor for the project that would run through Avista's service territory. To the extent that the northern transmission line is developed, the current plans call for the use of portions of existing Avista transmission corridors. This is significant because Avista will be able to establish an interconnection to the northern transmission line at Devils Gap, which would meet the objectives sought by the Company, namely: (i) access to additional resources, shaping services and import capacity to meet the needs of native load customers, and (ii) enhanced system reliability, as described earlier in this testimony.

Q. Please explain the benefits of Avista's planned interconnection with the northern transmission line at Devils Gap.

A. Avista is planning the development of a 500/230 kV transmission interconnection project with the northern transmission line of the CNC transmission project at Devils Gap ("Devils Gap Interconnection"). Avista has completed the Western Electricity Coordinating Council ("WECC") Regional Planning and Project Review process and Phase 1 Rating Study for the Devils Gap Interconnection and is now in the WECC Phase II study process for this project. In conjunction with the northern portion of the CNC transmission project, the Devils Gap Interconnection would provide benefits to Avista's native load customers consistent with the Company's objectives previously outlined.

Q. What is the cost associated with Avista's participation in the CNC transmission project?

A. The cost accrued by Avista for its participation in the CNC transmission project is $886,000. Of this amount, $665,000 is the amount Avista paid for its initial sponsorship of the CNC transmission project pursuant to the Stage One Project Development Agreement, and $221,000 consists of the direct transmission planning expenses incurred by Avista. Avista anticipates receiving a refund from the CNC Development Agreement of $121,000 with the closure of the Stage One agreement by June of 2011. Therefore the Company's net expenditures are $765,000.

Q. How does Avista propose to recover the costs associated with its participation in the CNC transmission project?

A. Avista proposes to recover these expenses over a three-year period, resulting in an amortized expense of $255,000 ($166,000 Washington share) in each of the next three years. Ms. Andrews has reflected this amount in her revenue requirement calculations.

Q. Please describe the Transmission Line Ratings Confirmation Plan and the amounts for which the Company is requesting an increase in costs above its historical test period.

A. The Transmission Line Ratings Confirmation Plan was developed to address a "NERC Alert" issued on October 7, 2010. The North American Electric Reliability Corporation (NERC) issued a "Recommendation to Industry addressing Consideration of Actual Field Conditions in Determination of Facility Ratings" based on a vegetation contact conductor-to-ground fault by another Transmission Owner, which stated at p. 4:

> "NERC and the Regional Entities are concerned that Transmission Owners and Generator Owners have, in some instances, not considered existing field conditions when establishing facility ratings for transmission facilities, including transmission conductors. Transmission Owners should strive to achieve a heightened awareness of the actual operating conditions of their respective transmission conductors and take prompt corrective action as necessary."

Upon further review, the affected Transmission Owner subsequently discovered significant discrepancies between actual topography and the values used for design. Using a Light Detection and Ranging (LIDAR) technology, the Transmission Owner identified over one hundred (100) previously undetected conductor-to-ground issues. These discrepancies resulted in the Transmission Owner operating with higher facility ratings than actual conditions. This could lead to the Transmission Owner operating its system to higher levels than appropriate and, therefore, impacting the reliability of the interconnected transmission grid.

The NERC Alert was issued to provide the industry an opportunity to review actual field conditions and compare them to design values to ensure system reliability. Avista is required to meet NERC Standard FAC-008-1 – Facility Ratings Methodology. The purpose of the standard is "To ensure that facility ratings used in the reliable planning and operations of the Bulk Electric System (BES) are determined based on an established methodology or methodologies." Requirement R1.1 states that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. Therefore Avista must adhere to the NERC Alert in order to ensure compliance with FAC-008-1. If Avista doesn't comply with the Alert, then the Company will lack sufficient compliance evidence to provide auditors during its next on-site audit.

The Avista Transmission Line Ratings Confirmation Plan is a three year program designed to:

- Provide true-up between Plan and Profile drawings produced in the Transmission Line Design (TLD) Group and the SCADA Variable Limit (SVL) documents utilized by the System Operations Group, provided to NERC under FAC-008-1.
- Establish a field confirmation process for conductor sag clearances using a variety of techniques.
- Provide a means to annually identify changes to grade and other clearance impacts.

Unless otherwise exempted/confirmed due to construction inspection documentation or a substantial design clearance buffer, the Plan calls for performing LIDAR surveying of all Avista

230kV transmission lines and the five (5) 115kV transmission lines. These lines represent Avista's High Priority facilities (NERC assessment reporting date of December 31, 2011 as mentioned in the November 29, 2010 NERC update). It is expected this process will take two years to complete, depending upon availability of resources and weather conditions. LIDAR will allow for Avista to computer model (via TL-Pro) its most important transmission lines, and also support Transmission Vegetation Management efforts. The original plan was submitted to NERC on January 18, 2011. A revised plan was submitted on April 28, 2011 to show a modification to the overall cost estimate driven by changes in the number of miles to be inspected using LIDAR. The original NERC submission showed a cost of $1.8 million, and the new submission increases the miles inspected using LIDAR to 1,400 miles at a cost of $2.945 million. The details of the original and revised plans are provided in Exhibit No. __(SJK-3)

No similar work was performed in 2010, so all of the work represents new work. The overall cost of the three year plan is $2,945,000. The Pro Forma increment for 2012 is $1,397,700 for Washington and is shown in Table 2.

Table 2: Transmission Line Ratings Confirmation Plan Costs

Year	Combined	WA Electric
2010 Actual	$0	$0
2011 Planned	$350,000	$228,000
2012 Planned	$2,145,000	$1,397,700
Pro Forma Increment	$2,145,000	$1,397,700

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 2012 pro forma period as compared to the 2010 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, 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). Accordingly, adjustments have been made in the pro forma period to reflect the increases in transmission rates. Please see table 3 and descriptions below for further detail on the revenue pro forma amounts.

Table 3:

Transmission Revenues	
	***Pro Forma (System)**
Borderline Wheeling Trans and Low Volt	$ 7,000
OASIS nf & stf Whl (Other Whl)	$ 103,000
Seattle/Tacoma Main Canal	$ (4,000)
Seattle/ Tacoma Summer Falls	$ -
PP&L - Dry Gulch	$ 11,000
Spokane Waste to Energy Plant	$ (160,000)
Grand Coulee Project	$ -
First Wind Energy Marketing	$ 200,000
BPA Settlement	$ (1,177,000)
Total Revenue	**$ (1,020,000)**

*Represents the change in revenues above or below the 2010 test period level.

Borderline Wheeling Transmission and Low Voltage ($7,000)

- Borderline Wheeling – Total borderline wheeling revenues for the 2010 test year were $7,729,000. Total borderline wheeling revenue in the pro forma period has been set at $7,736,000, which reflects a slight increase over the test year due to transmission charge increases associated with a specific contract with the Spokane Indian Tribe. In the past the pro forma borderline revenue has been developed using a five-year rolling average of revenues from borderline wheeling service provided to Bonneville and other customers. However, with the new transmission rates that went into effect in 2010, use of the previous five-years of actual revenues would not properly reflect the new level of revenues, including the transmission rate increase. Therefore, pro forma transmission revenue has been set equal to 2010 actual revenue, with a slight known adjustment. Each of the specific borderline contracts are further described below.
- Borderline Wheeling – Bonneville Power Administration – Actual test year revenue from borderline wheeling service provided to Bonneville was $7,493,000. The Bonneville borderline wheeling contracts are divided into transmission and low voltage service. These were accounted for separately beginning in October of 2010 as a result of the new transmission rates. The new transmission rates apply to the transmission services, but not to the low voltage services. The current Bonneville Network contracts expire on September 30, 2011. However similar follow-on contracts are expected to be executed with the same billing provisions under the Avista Open Access Transmission Tariff. Therefore, the pro forma Bonneville borderline wheeling revenue is $7,493,000, which is equal to the 2010 test year revenue.
- 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 2010 test year revenue of $24,000.

- 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 2010 test year was $60,000. Pro forma revenue for the 2012 pro forma period is $60,000 per the restructured contract.
- Borderline Wheeling – Spokane Tribe of Indians – The Company provides borderline wheeling service over both transmission and low-voltage facilities to the Spokane Tribe of Indians. Total transmission and low-voltage wheeling revenue under this contract for the 2010 test year was $35,000. Revenue associated with the transmission component of this contract is adjusted annually per the contract. Accordingly, 2012 pro forma period revenue under this contract is set at $42,000.
- Borderline Wheeling – Consolidated Irrigation District - The Company provides borderline wheeling service over both transmission and low-voltage facilities to the Consolidated Irrigation District. Total transmission and low-voltage wheeling revenue under this contract for the 2010 test year was $118,000. The current contract with the Consolidated Irrigation District expires September 30, 2011, however a follow on contract is expected to be signed with similar billing requirements resulting in pro forma revenue of $118,000.

OASIS Non-Firm and Short-Term Firm Transmission Service ($103,000) – 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. The Company is calculating its pro forma 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 transmission outage situations in the region, forced or planned generation resource outage situations in the region, 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). In this filing, the Company is using the most recent three-year average. OASIS revenues for the 2010 test year were $2,887,000, and the most recent three-year average of OASIS revenues from 2008 through 2010 is $2,990,000.

<u>Seattle and Tacoma Revenues Associated with the Main Canal Project</u> (-$4,000) – 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 $292,000 during the 2010 test year. Pro forma revenues are $288,000 based on the ratchet demand of $35,960 per month set in September of 2010.

Seattle and Tacoma Revenues Associated with the 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 2010 test year and are expected to remain the same for the 2012 pro forma period.

PacifiCorp Dry Gulch ($11,000) – Revenue under the Dry Gulch use-of-facilities agreement has been adjusted to $229,000 for the pro forma period, which is an $11,000 increase from the 2010 test year actual revenue of $218,000. The Company is calculating its pro forma adjustments 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. A three-year average is also consistent with that used for the Company's OASIS revenue. 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 three-year average of revenue was calculated using years 2008 through 2010.

Spokane Waste to Energy Plant (-$160,000) – This revenue is the result of a long-term transmission service agreement with the City of Spokane that expires December 31, 2011. Currently it is unclear whether a follow-on contract with Spokane Waste-to-Energy will be signed, and the City of Spokane has not requested such a contract. Therefore, the Company is assuming no revenue for this contract beyond its termination date. Revenue from the Spokane Waste to Energy Plant contract was $160,000 in the 2010 test year, and is adjusted to $0 in the pro forma period.

Grand Coulee Project Hydroelectric Authority ($0) – The Company provides operations and maintenance services on the Stratford – Summer Falls 115kV Transmission Line to the Grand Coulee Project Hydroelectric authority under a contract signed in March 2006. These services are provided for a fixed annual fee. Annual charges under this contract totaled $8,100 in the 2010 test year and will remain the same for the 2012 pro forma period.

First Wind Energy ($200,000) – First Wind Energy has signed a transmission service contract with the Company. First Wind has a proposed start date of wind energy production of 01/01/12. However, they intend to delay the in-service date of their project by at least one year since they have not received required permits and have not started construction of their facilities. A pro forma amount of $200,000 in January 2012 is included in the rate case per the postponement language in the transmission reservation contract.

BPA Parallel Operation Agreement (-$1,177,000) – The Company signed a Parallel Operating Agreement with the Bonneville Power Administration regarding Bonneville's use of the Avista transmission system to support the integration of wind in south eastern Washington. The agreement included a one-time settlement charge of $1,177,000 received in December of

2010. The Company will not receive any additional revenue from the agreement so 2012 pro forma period revenue has been adjusted to zero.

IV. TRANSMISSION AND DISTRIBUTION CAPITAL PROJECTS

Q. Please describe the Company's capital transmission projects that will be completed in 2011?

A. Avista continuously needs to invest in its transmission system to maintain reliable customer service and meet mandatory reliability standards. The 2011 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 so that the loss of up to two facilities simultaneously will not 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 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 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 continue to have a need to develop these compliance related projects as system load grows, new generation is interconnected, and the system functionality and usage changes.

Avista capital transmission project requirements are developed through system planning studies, engineering analysis, or scheduled upgrades or replacements. The larger specific projects that are developed through the system planning study process typically go through a thorough internal review process that includes multiple stakeholder review to ensure all system needs are adequately addressed. For the smaller specific projects, Avista doesn't perform a traditional cost-benefit analysis. Projects are selected to meet specific system needs or equipment replacement. However, both project cost and system benefits are considered in the selection of the final projects.

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

A. Yes. The Company evaluated each project and determined that some of the 2011 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 facilities. For these projects, an analysis was performed to determine the savings. 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, which will continue over time as our equipment across our entire system continues to age.

Although one might think that the replacement of equipment may reduce the failure rate of equipment and reduce after-hours labor costs, a newly installed switch can fail just like an older switch. Significant system failures also occur during large weather related events caused by wind, lightning, and snow. Furthermore, each year as we replace old equipment with new, the remainder of our system gets another year older, which continues to generate a similar level of failures on our system.

Q. Please describe each of the transmission projects included in the Company's filing for 2011.

A. The major capital transmission costs (system) for projects to be completed in 2011 are approximately $18.756 million and are shown in table 4 and described below.

Table 4:

Transmission Capital – Compliance, Environmental and Replacement Projects		
	Pro Forma (System)	**O&M Offsets (System)**
Transmission Reliability Projects:		
Moscow 230kV Sub	$ 400,000	$ -
Spokane/CDA relay upgrade	$ 1,000,000	$ -
SCADA Replacement	$ 625,000	$ -
System Replace/Install Capacitor Bank	$ 400,000	$ -
West Plains Transmission Reinforcement	$ 2,300,000	$ (214,200)
Bronx-Cabinet 115kV rebuild/reconductor	$ 2,000,000	$ (142,200)
Power Transformers - Transmission	$ 3,250,000	$ -
Total Reliability Projects	**$ 9,975,000**	**$ (356,400)**
Environmental Regulation-Beacon Storage Yard	**$ 1,020,000**	**$ -**
Replacement Projects:		
Asset Management Replacement Programs	$ 1,887,000	
Noxon Rapids B Bank GSU Replacement*	$ 5,874,000	$ (125,000)
Total Replacement Projects	**$ 7,761,000**	**$ (125,000)**
Total Transmission Projects	**$ 18,756,000**	**$ (481,400)**

*Per FERC asset accounting rules, generation step-up transformers are deemed a transmission asset.

Reliability Compliance Projects ($9.975 million):

- **Moscow 230 kV Sub – Rebuild 230 kV Yard ($0.4 million)**: This project involves the rebuild of the existing Moscow 230 kV substation. The substation rebuild includes the replacement of the existing 125 MVA 230/115 kV autotransformer with a new 250 MVA autotransformer to meet compliance with NERC standards and ensure adequate load service. The existing 230/115 kV autotransformer overloads for an outage of another autotransformer in the area during peak load. The substation will be constructed as a double breaker double bus configuration to maximize reliability and operational flexibility. The substation will be constructed over a two-year period with complete energization occurring in 2012. Several transmission lines will be rerouted during 2011 to prepare for the new substation. The transmission line work will be completed and placed into service in the fall of 2011. This is the portion pro formed into the Company's case. 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. There are no offsets to apply to this project in 2012.

- **Spokane/Coeur d'Alene area relay upgrade ($1 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 to seven year project and is required to maintain compliance with mandatory reliability standards. This project is required to meet Reliability Compliance under NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Positive offsets in reduced maintenance costs associated with this replacement effort are negatively offset by increased NERC testing requirements per standard PRC-005-1.

- **SCADA Replacement ($0.625 million)**: The System Control and Data Acquisition (SCADA) system is used by the system operators to monitor and control the Avista transmission system. An upgrade to the SCADA system to a new version provided by our SCADA vendor was started in 2010 and will be completed in 2011. 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.

- **System Replace/Install Capacitor Bank ($0.4 million)**: This project includes the replacement of the 115 kV capacitor bank at the Pine Creek 115 kV substations 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 the end of 2011. There are no loss savings or other offsets associated with this new equipment installation.

- **West Plains Transmission Reinforcement; Garden Springs – Hallet and White 115 kV reconductor ($2.3 million)**: This work is necessary to upgrade the Garden Springs – Hallet and White 115 kV. Avista's System Planning West Plains Transmission Reinforcement Study (Rev. B, November 22, 2010) identifies the reconductoring/rebuilding with 795 kcmil conductor of the 10.6-mile South Fairchild 115kV Transmission Line between Garden Springs and Silver Lake Substation as needed to maximize the flexibility of the transmission system in this area. Phase 1 of the project (addressed here) consists of the six-mile Garden Springs to Hallet & White section. 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 2010 actual loads, the new conductor will reduce line losses by 2142 MWh on an annual basis, establishing a yearly offset savings of $214,200 (based on a $100/MWh avoided energy cost).

- **Bronx – Cabinet 115 kV rebuild/reconductor ($2 million)**: In 2010 Avista's System Operations identified a thermal constraint on the 32-mile Bronx-Cabinet 115kV Transmission Line. This constraint was confirmed by the System Planning Group, and documented in the Transmission Line Design (TLD) Design Scoping Document (DSD) created on January 4, 2011, and modified on January 7, 2011. The reconductoring/rebuilding of this line with 795 kcmil ACSS conductor will provide a present-day 143 MVA line rating to match the Cabinet Switchyard Transformer, and a future 200 MVA line rating to match the parallel path Bonneville Power Authority (BPA) system. Phase 1 of the project (addressed here) consists of the approximately eight-mile section between the Cabinet Switchyard and the Clark Fork Substation. 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 2010 actual loads, the new conductor will reduce line losses by 1422 MWh on an annual basis, establishing a yearly system offset savings of $142,200 (based on a $100/MWh avoided energy cost).

- **Power Transformers – Transmission ($3.25 million)**: As previously discussed, the Moscow 230 kV substation is being rebuilt in 2011 and 2012. The rebuild includes the addition of a new 250 MVA autotransformer. This autotransformer will arrive on-site in 2011 and will be capitalized upon delivery per the company's accounting practices. There are no offsets or savings associated with the purchase of this autotransformer.

Environmental Regulation Projects:

- **Beacon Storage Yard ($1.02 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 and 2010, the Company began construction of the Beacon

Substation Equipment Storage Yard. In 2011, 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 eliminate the potential of environmental contamination.

The Company will also spend approximately $7.761 million in transmission system equipment replacements associated with storm damage or aging/obsolete equipment. A brief description of the projects included in these replacement efforts are given below.

- **Asset Management Replacement Programs ($1.887 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 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, 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 a set schedule. The equipment is replaced when useful life has been exceeded.

- **Noxon Rapids B Bank GSU Replacement ($5.874 million)**: Replacement of the Generator Step up Transformers (GSU) were needed to accommodate the additional capacity from the turbine upgrades discussed in witness Lafferty's testimony. These transformers were 50 years old and were reaching the end of their useful life, without the additional capacity requirements. The new GSU's are approximately 50% more efficient than the replaced transformers. The Noxon Rapids A Bank GSU project was completed in 2010. The B Bank GSU Transformers will be replaced in 2011 at a cost $5.874 million. The more efficient transformers will provide loss savings of $125,000 in the pro forma period.

Q. Please describe each of the distribution projects included in the Company's filing for 2011.

A. The Company also will spend approximately $12.400 million (system) in Distribution equipment replacements and minor rebuilds associated with aging distribution equipment discovered through inspections or poor reliability performance. A brief description of the projects included in these replacement efforts is given below and shown in Table 5.

Table 5:

Distribution		
Capital -Distribution Projects		
	Pro Forma (System)	**O&M Offsets (System)**
Wood Pole Replacement Program and Feeder Repair	$ 8,900,000	$ -
Electric Underground Replacement	$ 3,500,000	$ 35,000
Total Distribution Projects.	**$ 12,400,000**	**$ 35,000**

- **Wood Pole Replacement Program and Capital Distribution Feeder Repair ($8.9 million):** The distribution wood pole management program evaluates wood pole strength of a certain percentage of the wood pole population each year such that the entire system is inspected every 20 years. Avista has over 240,000 distribution wood poles and 33,000 transmission wood poles in its electric system. Depending on the test results for a given pole, the pole is either considered satisfactory, needing to be reinforced with a steel stub, or needing to be replaced. 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. potentially leaking transformers, transformers older than 1981, failed arrestors, missing grounds, damaged cutouts, and dated high resistance conductor). Transformers older than 1981 have the potential to have oil that contains polychlorinated biphenyls (PCBs). These older transformers present increased risk because of the potential to leak oil that contains PCBs. Poles installed during the pre-World War II buildup have reached the end of their useful life. Avista's Wood Pole Management program was put into place to prevent the Pole-Rotten events and Crossarm – Rotten events from increasing. So far, the Wood Pole Management Program has helped keep Pole-Rotten and Crossarm-Rotten events in check. Comparing 2007 to 2010 data, Crossarm-Rotten Events went from 46 events to 25 events, however, Pole-Rotten events climbed from 25 events to 37 events in 2008 to 2010. Thus, no net offsets are anticipated from the Wood Pole Management program for the 2012 rate period. The Company spent $7.507 million on these efforts in 2010.

- **Electric Underground Replacement ($3.5 million):** This effort involves replacing the first generation of Underground Residential District (URD) cable. This project which has been ongoing for the past several years and will be completed in 2012. 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 $4.092 million in 2010. The incremental savings in Operation and Maintenance expenses seen in 2010 was $35,000 due to reduced number of URD Primary Cable fault reductions. In 2012, we anticipate that we will see the same incremental savings as 2010, which has been included as an offset for the Electric Underground Replacement project.

V. AVISTA'S ASSET MANAGEMENT PROGRAM

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

A. Entering the 21st Century, Avista like most utilities faced an aging infrastructure and needed to transition the electric distribution and transmission system into a new era. Planning to replace aging physical assets in the most cost effective and beneficial manner for customers has become a priority. Asset Management involves determining what equipment should be integrated into a comprehensive program, what are the optimum maintenance intervals for each asset, and when is the right time to replace these assets to reduce lifecycle costs.

Avista's Asset Management program has made an impact for our customers. The wildlife guard installation program on Distribution Transformers has cut the number of squirrel related events from a high of 902 in 2006 to 390 in 2010. Underground Residential Primary Cable faults were reduced from a high of 211 to 93. Combined, the number of Asset Management related events in our Outage Management Tool (OMT) has come down from a high of 3,742 events in 2008 to 3,191 in 2010. While there is still room for improvement, Asset Management has made a difference and is saving money by avoiding or reducing the number of future failures.

Asset Management uses a process which combines technology and information into an integrated analysis from a myriad of sources and creates a comprehensive plan for Avista's physical plant. Asset Management strives to maximize the lifecycle value of the Company's assets for its customers. By minimizing life cycle costs, Avista is able to maximize system reliability and value for our customers. Using the analytical models, Avista enhances the decision process to better ensure future success.

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

Based on the work of Asset Management, Avista's Vegetation Management program results in a pro forma adjustment to program costs planned for 2012 that are above that included in the Company's test period.

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. Vegetation Management is a key component of Avista's Asset Management Plan. 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 reduces customer outages caused by trees, weather, and, to a lesser extent, squirrel caused outages. Avista's electric distribution system includes 7,800 distribution overhead circuit miles of which 5,200 are in Washington and 2,600 are in Idaho. The Transmission System includes 1,675 circuit miles of 115 kV Transmission Lines and 984 circuit miles of 230 kV Transmission Lines mainly in Washington and Idaho. The Gas System High Pressure Lines include 291 miles. This is a significant amount of miles, and each mile 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 Table 5 below, Washington's electric distribution vegetation management level of expenditure necessary in 2012 is $6.07 million, almost $3 million above that included in the 2010 test period ($3.145 million). The approved 2011 spending level in Docket No. UE-100467 is $4.025 million, so the actual increase proposed in 2012 compared to the approved 2011 spend is $2.045 million[1]. The $2.770 million of incremental pro forma spend compared to 2010 actual spend (less offsetting savings included as described below of $154,800) has been included in the Company's electric revenue requirement request filed in this case as discussed further by Company witness, Ms. Andrews.

Table 6: Distribution Pro Forma Increment For Vegetation Management

Year	WA Electric
2010 Actual	$3,144,720
2011 Planned	$4,521,679
2011 Approved by UTC	$4,025,000
2012 Planned	$6,069,761
2012 Offset	-$154,800
Pro Forma Increment above 2010	$2,770,241

Q. What is the cause for the incremental increase in costs in distribution vegetation management over that included in the Company's 2010 test period?

A. Avista strives to improve its Asset Management programs as better information is available or conditions change. Over the last few years the Company has continued to evaluate its processes and plans and determined it can further optimize its Vegetation Management program. The most recent analysis performed on the Company's vegetation management work plan determined an optimized clearing cycle more customized to each feeder will provide more

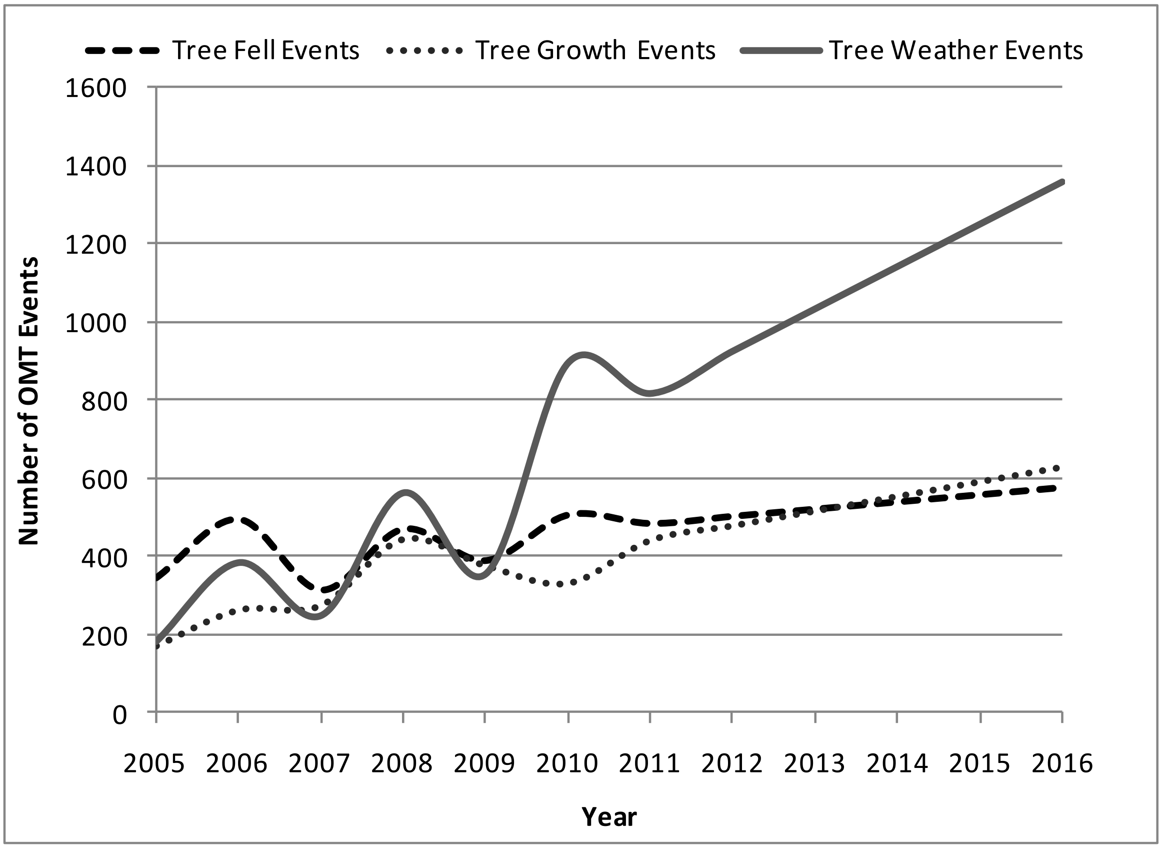
[1] WUTC Docket No. UE-100467 increased the company's required annual electric distribution and transmission vegetation management spending amount from $2.8 million to $4.025 million annually.

value to our customers. The Optimized Cycle has an average clearing cycle time of four years, but the actual cycle times will vary depending upon the circuits needs. This equates to clearing 1,950 miles per year in order to minimize future increases in costs, reduce future failure rates and optimize system reliability. The Company's 2009 level of spending in Washington equated to a seven to eight year clearing cycle, and in 2010 the spending level supported a six year clearing cycle time. The $4.025 million spending level approved in Docket UE-100467 provides funding for a 5.3 year clearing cycle program.

As the Company has analyzed the plan over time, outage data collected by the Company's Outage Management Tool (OMT)[2] has shown an increase in events on circuit miles where trees are trimmed less frequently. As shown in Illustration 1 below, Avista continues to see an increase in the number of vegetation related events. The general OMT trends in Tree Growth (i.e. trees growing into the power lines and causing an outage or other problems with the power line), Tree Fell (i.e. trees falling from outside and inside the easement into a distribution power line) and Tree Weather (i.e. tree related outages or events where the root cause is related to the weather) events remain a concern for VM with an increasing trend upwards. While weather conditions change each year and contribute to the number of events each year, the overall trend continues upward even with a few good years of weather in 2009 and 2010.

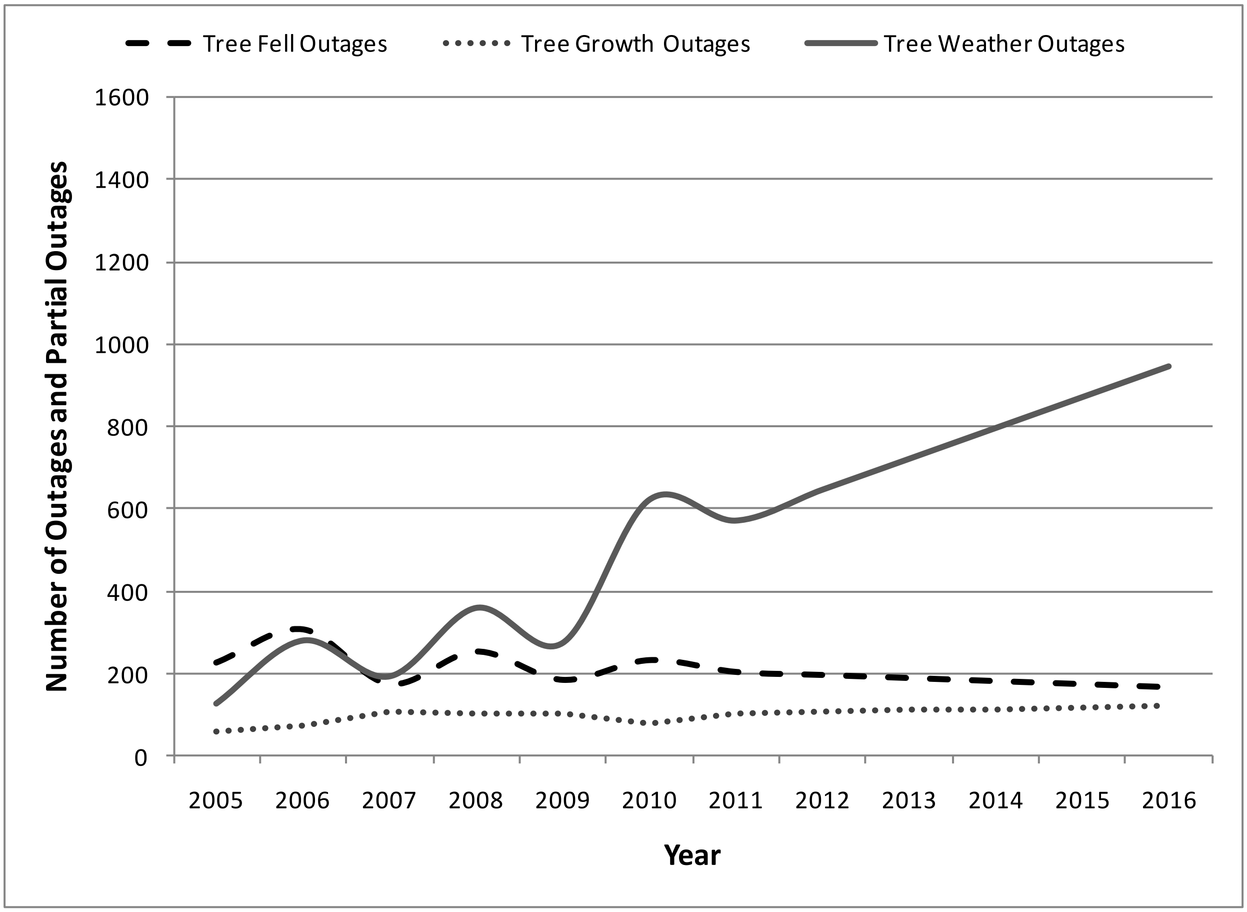
[2] The data behind the failure rates used in the program models come from information gathered during past years' work and failures. Information was gathered for the number of trees removed, trees trimmed, and brush removed along with the failure documented in the Outage Management Tool (OMT) and were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

Illustration 1:



However, a trend in the number of actual outages and partial outages associated with Tree Fell, Tree Growth, and Tree Weather shows promise and improvement as shown in Illustration 2 below. While the number of <u>events</u> continues upwards for Tree Fell (see Illustration 1), the actual number of <u>outages</u> is trending downwards and Tree Growth <u>outages</u> remain relatively flat (see Illustration 2). This suggests the current program is having a positive impact, but not enough to stop all of the rising trends.

Illustration 2:



Delaying work, increases the amount of work required and the associated cost. This is clearly shown in the exponential curve illustrated in Illustration 3 below. The probability that a line segment will require work begins to trend upwards when you exceed four years since the last vegetation work.

<u>Illustration 3:</u>

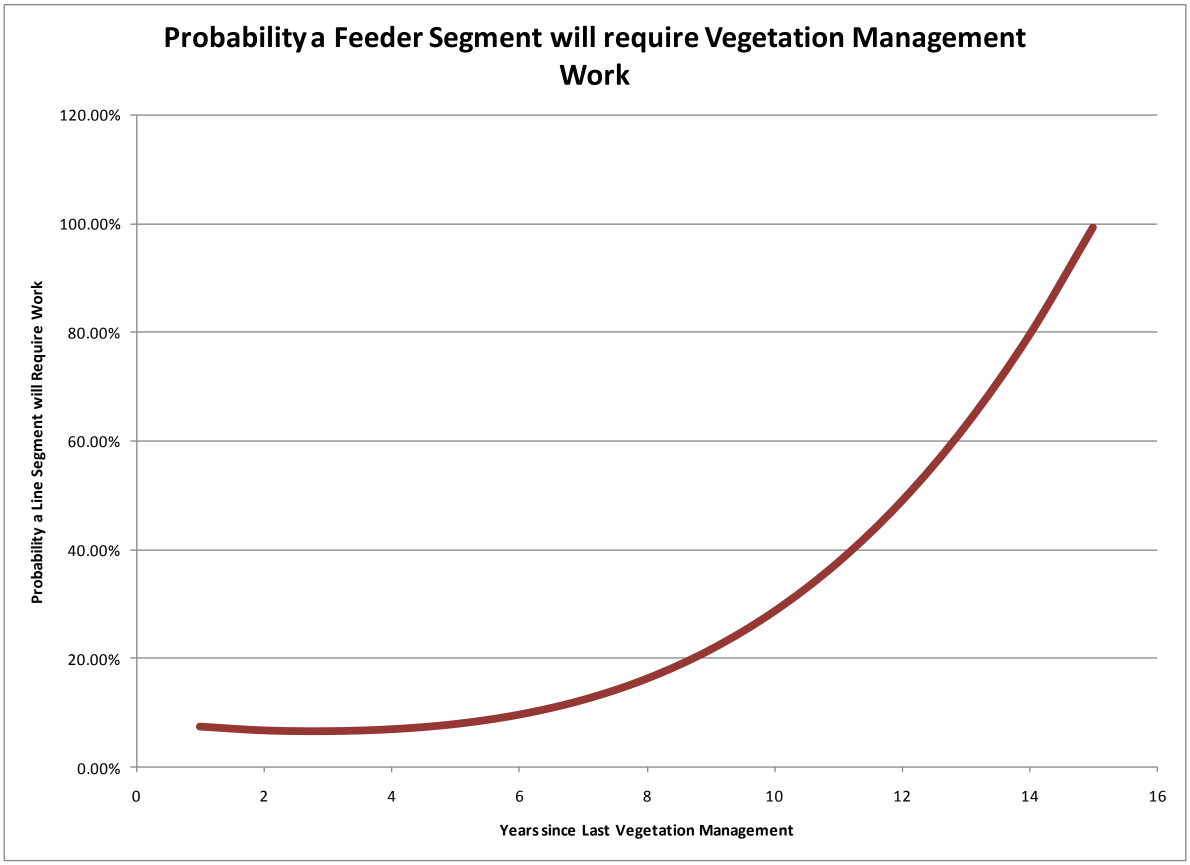
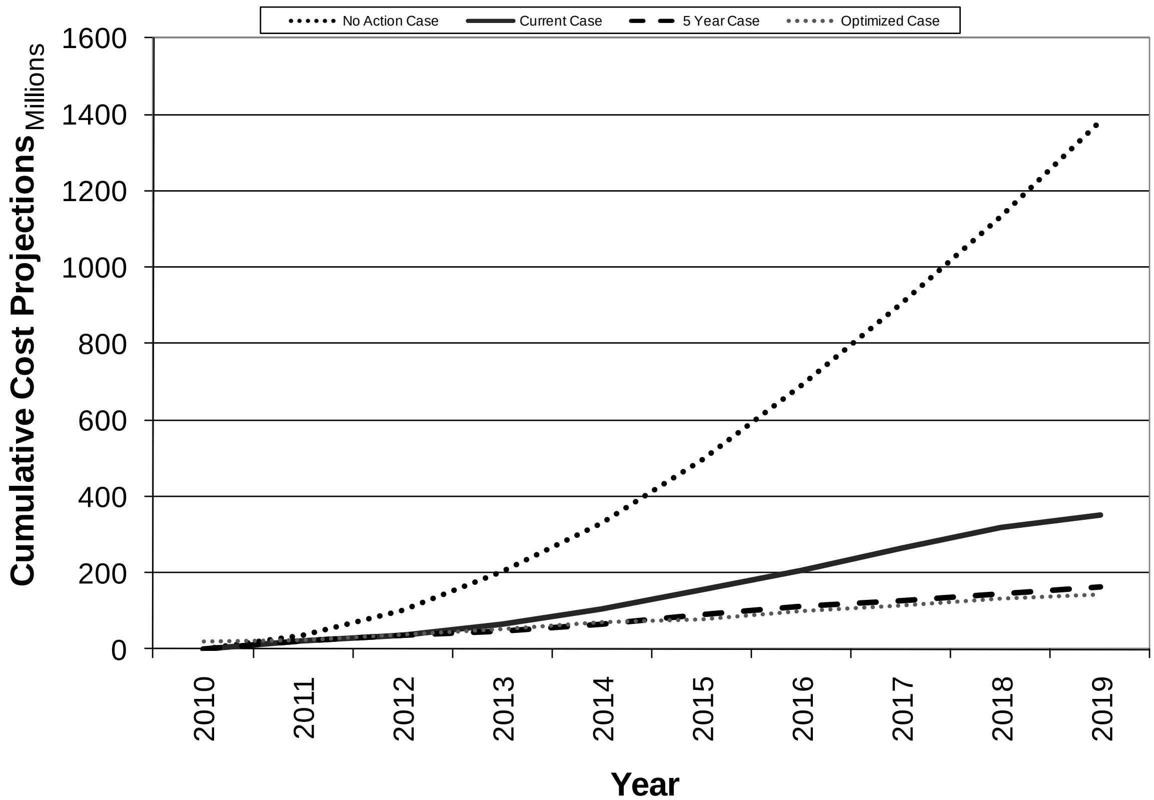


Illustration 4 below shows cost projections of the Company's current case and the Optimized Case (average of a four-year clearing cycle).

<u>Illustration 4</u>:



To further support the rational for the optimized cycle time (four-year cycle), Table 7 below shows the estimated average number of OMT events over the next 10 years for the Company's current case and the Optimized Case (four year cycle). Based on the information shown in Table 7, we anticipate preventing over 1,500 events each year once all feeders are on an optimized cycle.

Table 7:

OMT Events	Tree Fell	Tree Growth	Tree Weather	Combined OMT Totals
6 Year Average OMT Events	420	309	440	1,169
Projected 10 Year Average - Current Case	330	789	774	1,893
Projected 10 Year Average - Optimized Case	53	225	62	340
Difference between Current Case and Optimized Case	277	564	712	1,553

In response to a revised look at risks, Avista is also expanding the Risk Tree inspections to include more trees such as those with split tops, which have a higher risk of failing than a normal tree. This additional work is estimated to add over $300,000 in Washington to the current work and is included in the increased expense for the overall Vegetation Management program.

As can be seen from the illustrations and discussions above, for the distribution system, our analysis shows that an optimized 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. What offsetting factors does the Company anticipate as a result of Avista's vegetation management plan?

A. Under the current plan, an approximate five-year trim cycle is anticipated to reduce OMT events each year once all feeders are on a cycle, providing estimated savings of approximately $1.5 million annually. 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. In 2011, since the Company is on an approximate five-year trim cycle, the annual savings anticipated in 2012 (after the first year cycle is completed) is estimated at $234,400 ($154,800 Washington share). The Company has included this offset (reducing operating and maintenance expense) against the 2012 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.

For future years, after moving to a four year trim cycle in 2012 as proposed in this case, anticipated savings increases to approximately $342,000 ($222,800 Washington share) in 2013.

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. Effective for 2011, by Commission Order in Docket No. UE-100467, the Company is required to spend approximately $4.025 million per year for electric vegetation management (includes electric distribution and transmission expenses).[3] Avista reports its actual spend 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 required spend - $4.025 million for 2011). 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. Avista is on track to spend the full $4.025 million on vegetation management for 2011.

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

[3] Prior to Docket No. UE-100467, the Company's required spend was $2.8 annually per Docket No. UE-050482.

requests the Commission approve the additional pro formed amount included in this case, and increase the required spend level from the current $4.025 million to that requested in this case - $6.8 million.

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

A. Yes it does.