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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-11-01 DIRECT TESTIMONY OF SCOTT J. KINNEY

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

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 Idaho 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 9, Schedule 1 provides the transmission pro forma adjustments, and Schedule 2C 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 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 RTO Development	$(14,000)
ColumbiaGrid Planning	$56,000
ColumbiaGrid OASIS	$42,000
Grid West (ID Direct)	$(71,000)
Electric Scheduling & Acctg. Services (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	**$2,523,000**

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

<u>Northwest Power Pool (NWPP)</u> ($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 increase was made for the pro forma period to reflect the NWPP expenses allocated to the Company.

<u>Colstrip Transmission</u> ($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.

<u>ColumbiaGrid RTO Development</u> (-$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 allows 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 (ID Direct) (-$71,000) - Avista signed an initial funding agreement in 2000, as did all other Pacific Northwest investor-owned electric utilities, to provide funding for the start-up phase of Grid West (then named "RTO West"). Grid West had planned to repay the loans to Avista and other funding utilities through surcharges to customers once it became operational. With the dissolution of Grid West, this repayment did not occur. As a result, Avista filed an application with the Commission to defer these costs. The Commission approved, on October 24, 2006, in Order No. 30151, the Company's request for an order authorizing deferred accounting treatment for loan amounts made to Grid West. In its Order the IPUC found these costs to be "prudent and in the public interest" and required the Company to begin amortization of the Idaho share of the loan principal ($422,000) beginning January 2007, for five years. With the completion of the amortization in December 2011 the Company will not incur costs associated with Grid West in the pro forma period. Avista did amortize a total of $71,000 in the test year.

<u>Electric Scheduling and Accounting Services</u> ($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) Critical Infrastructure Protection standards. The Company's pro forma expenses increase $3,000 from the actual 2010 test year expense of $47,000 due to annual software 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.

<u>WECC - System Security Monitor and WECC Administration & Net Operating Committee Fees</u> (-$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 describe Avista's engagement in the Northern Tier Transmission Group?

A. Avista is currently a Member of the ColumbiaGrid Subregional Group. ColumbiaGrid currently coordinates regional transmission planning for its members, offers a single portal access to OASIS, and performs regional coordination and development of other operational improvement efforts including evaluating Balancing Authority consolidation of its members. Avista is a signatory to the Planning and Expansion Functional Agreement (PEFA) and has relied on the PEFA and ColumbiaGrid to meet its FERC Order 890 Attachment K Requirements. Avista initially joined ColumbiaGrid to leverage an independent organization's ability to direct BPA (only as bound by the PEFA) to construct needed facilities and leverage ColumbiaGrid's dispute resolution process and cost allocation methodologies to meet FERC's Attachment K requirements.

Avista is geographically located at the edge of both the ColumbiaGrid and NTTG footprints and is physically interconnected with several NTTG members; Idaho Power, NorthWestern Energy and PacifiCorp. Avista also participates in several current regional study efforts to expand the northwest transmission system that involve these same entities.

With its geographic location and physical interconnection to both ColumbiaGrid and NTTG members, Avista plans to join NTTG in 2011. Avista will engage NTTG to determine what level of membership makes sense. Avista hopes to join NTTG as a nominal funder and participant. Becoming an NTTG member will allow Avista to gain knowledge of NTTG processes, continue to enhance relationships with its interconnected utilities, and further facilitate the relationship between the two sub-regional groups. Avista intends to remain a full member of ColumbiaGrid and utilize ColumbiaGrid and the PEFA to meet its FERC Attachment K requirements. At this time, no additional costs have been included in the Company's case for its involvement in the group.

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 CNC transmission project offered an opportunity for Avista to access resources that would help Avista meet its intermediate and long-term future renewable resource needs in order to satisfy its renewable portfolio standard requirements, as well as, other resources to meet future native load. In the context of integrating variable renewable resources, future access to regulation or shaping services from BC Hydro was also a consideration.

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 in the third quarter 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 ($89,000 Idaho 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 total cost of $2.495 million. The details of the original and revised plans are provided in confidential Schedule 2C of Exhibit No. 9.

No similar work was performed in 2010, so all of the work represents new work. The overall cost of the two year plan is $2,145,000. The Pro Forma increment for 2012 is $747,300 for Idaho and is shown in Table 2.

Table 2: Transmission Line Ratings Confirmation Plan Costs

Year	System	ID Electric
2010 Actual	$0	$0
2011 Planned	$350,000	$122,000
2012 Planned	$2,145,000	$747,300
Pro Forma Increment	$2,145,000	$747,300

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 <u>system</u> level and is included in Schedule 1 of Exhibit No. 9. Please see Table 3 and descriptions below for further detail on the revenue pro forma amounts.

<u>Table 3</u>

Transmission Revenues	
	***Pro Forma(System)**
Boarderline 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	$0
PP&L - Dry Gulch	$11,000
Spokane Waste to Energy Plant	($160,000)
Grand Coulee Project	$0
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.

<u>Borderline Wheeling Transmission and Low Voltage ($7,000)</u>

- <u>Borderline Wheeling</u> - 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 January 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.

- <u>Borderline Wheeling - Bonneville Power Administration</u> - 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.
- <u>Borderline Wheeling - Grant County PUD</u> - 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.

<u>OASIS Non-Firm and Short-Term Firm Transmission Service</u> ($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.

<u>Seattle and Tacoma Revenues Associated with the Summer Falls Project</u> ($0) - Effective March 1, 2008, the Company entered into long-term use-of-facilities arrangements with the City of Seattle and the City of Tacoma to transfer

output from the Summer Falls hydroelectric project across the Company's Stratford Switching Station facilities to the Company's Stratford interconnection with Grant County PUD. Charges under this use-of-facilities arrangement are based upon the Company's investment in its Stratford Switching Station and are not impacted by the Company's transmission service rates under its Open Access Transmission Tariff. Revenues under these two contracts totaled $74,000 in the 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 had originally proposed a start date of wind energy production of January 1, 2012. However, due to various project delays they intend to postpone the in-service date of their project by at least one year. A pro forma amount of $200,000 for one month of revenue in 2012 is included in the rate case per the postponement terms in the Company's FERC transmission tariff.

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 and 2012?

A. Avista continuously needs to invest in its transmission system to maintain reliable customer service and meet mandatory reliability standards. The 2011 and 2012 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 and 2012 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 or replacing older transformers. For these projects, an analysis was performed to determine the savings. Actual savings were calculated assuming an avoided cost of $53.01 per MWh, which is the current calculated average energy production cost.

However not all projects will result in loss savings or other offsets. Although one might think that the replacement of equipment may reduce the failure rate of equipment and reduce after-hours labor costs, there are several reasons that this may not occur. Significant system failures occur during large weather related events caused by wind, lightning, and snow. These weather related failures can impact both new and older equipment. Furthermore, each year as older equipment is replaced with new equipment, the remainder of the system gets another year older, which continues to generate a similar level of failures on our system. Until the average age of equipment is significantly reduced, failure rates are expected to remain the same.

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 $26.959 million and are shown in Table 4 and described below.

TABLE 4

Transmission		
2011 Capital - Compliance, Environmental and Replacement Projects		
	Pro Forma (System)	**O&M Offsets (System)**
Reliabiltiy Compliance		
Moscow 230 kV 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	$113,500
Bronx-Cabinet 115 kV Rebuild/Reconductor	$2,000,000	$75,400
Power Transformers - Transmission	$3,250,000	
Total Reliability Compliance	**$9,975,000**	**$188,900**
Environmental Regulations		
Beacon Storage Yard	**$1,020,000**	
Contractual Requirements		
Colstrip Transmission	$533,000	
Tribal Permits	$325,000	
Total Contractual Requirements	**$858,000**	
Reliabiltiy Improvements		
Idaho Road Substation	$1,750,000	$5,300
Hatwai-N Lewistion 230kV Re-insulate	$250,000	
East Farms and Prarie View Upgrades	$265,000	
Total Reliabiltiy Improvements	**$2,265,000**	**$5,300**
Reliability Replacement		
Transmission Minor Rebuilds	$2,750,000	
Power Circuit Breakers	$1,600,000	
Otis Orchards 115 kV Breaker and Relay Replacements	$730,000	
* Noxon Rapids B Bank GSU Replacement	$5,874,000	$66,300
Asset Management Replacement	$1,887,000	
Total Reliablity Replacement	**$12,841,000**	**$66,300**
Total Transmission Projects	**$26,959,000**	**$260,500**

*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 three-year period with energization of the 230 kV portion 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. Offsets for this project will not occur until the Moscow 230 kV Substation is complete in 2012, and therefore have been included in the 2012 project described later in my testimony.

- **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 due to equipment age. 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 and rebuilding 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 an offset of $113,500 in the pro forma period (based on a $53.01/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 and 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 an offset savings of $75,400 in the pro forma period (based on a $53.01/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. Offsets for this project will not occur until the Moscow 230 kV Substation is complete in 2012, and therefore have been included in the 2012 project described later in my testimony.

<u>ENVIRONMENTAL REGULATION PROJECTS ($1.020 MILLION)</u>:

- **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.

<u>CONTRACTUAL REQUIRED PROJECTS ($0.858 MILLION)</u>:

- **Colstrip Transmission ($0.533 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 joint owned facilities.

- **Tribal Permits ($0.325 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.

<u>RELIABILITY IMPROVEMENT PROJECTS ($2.265 MILLION)</u>:

- **Idaho Road Substation ($1.750 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. The new conductor will reduce line losses by 100 MWh on an annual basis, establishing an offset savings of $5,300 in the proforma period (based on a $53.01/MWh avoided energy cost).

- **Hatwai-N Lewiston 230 kV Re-insulate ($0.250 million):** Re-Insulate existing 230kV polymer insulators on seven (7) mile Hatwai-North Lewiston 230kV Transmission Line with a toughened glass type insulator in response to documented corona induced shed cutting. Shed cutting has resulted in catastrophic failure of polymer insulators. Toughened glass insulators are impervious to this phenomenon. This project will complete in 2011.

- **East Farms and Prairie View 115 kV Upgrade ($0.265 million):** This is a transmission and distribution project slated for completion in 2011 to connect and upgrade 13.2 kV primary feeder ties between Pleasant View (Idaho) and East Farms (WA) substations. This project is located near Post Falls, Idaho and Liberty Lake, WA. This project is part of an overall transmission and distribution effort to connect these primary feeders in compliance with Avista's 500A Distribution Feeder Plan. This project is currently under construction and the costs shown here are associated with transmission upgrades.

The Company will also spend approximately $12.841 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.

- **Transmission Minor Rebuilds ($2.750 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. The specific projects aren't known at this time but the facilities will need to be replaced when damaged in order to maintain customer load service. In 2010 the Company spent $3.053 million on these minor rebuild projects as a result of damage caused by weather or the public.

- **Power Circuit Breakers ($1.600 million):** The Company transfers all circuit breakers to plant upon receiving them. The breakers purchased in 2011 are planned for installation at Moscow and Lind substations.

- **Otis Orchards – 115 kV Breaker and Line Relay Replacements ($0.730 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.

- **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 Company 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 of $5.874 million. The more efficient transformers will provide loss savings of $66,300 in the pro forma period (based on a $53.01/MWh avoided energy cost).

- **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.

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

A. The Company also will spend approximately $65.727 million in Distribution projects at a system level, with $17.861 million specific to Idaho. A summary of the projects is shown in Table 5 and a brief description of each project is given below.

TABLE 5

Distribution			
2011 Capital - Distribution Projects			
	Pro Forma (System)	**Pro Forma (Idaho)**	**O&M Offsets**
Idaho Distribution Projects			
Power Transformers - Distribution	$350,000	$350,000	
Appleway Sub Rebuild	$4,200,000	$4,200,000	
System Wood Sub Rebuild - Deary	$1,615,000	$1,615,000	$12,200
System Dist Reliability Improve Worst Feeders	$925,000	$925,000	
East Farms and Prarie View Upgrades	$360,000	$360,000	
Distribution CDA East & North	$675,000	$675,000	
Distribution Pullman & Lewiston	$350,000	$350,000	
Total Idaho Distribution Projects	**$8,475,000**	**$8,475,000**	**$12,200**
Distribution Replacement Projects			
Elect Distribution Minor Blanket	$8,000,000	$2,787,000	
Wood Pole Replacement and Capital Dist Feeder Repair	$8,900,000	$3,101,000	
Electric Underground Replacement	$3,500,000	$1,219,000	$35,000
Distribution Line Relocation	$1,700,000	$592,000	
Failed Electric Plant	$2,000,000	$697,000	
Replace High Resistance Conductor	$2,491,000	$615,000	
PCB Related Dist Rebuilds	$2,500,000	$375,000	
Total Distribution Replacement Projects	**$29,091,000**	**$9,386,000**	**$35,000**
Washington Distribution Projects (Not included in this case)			
Distribution Projects in Washington	$9,700,000	$0	
Washington Smart Grid Projects	$18,461,000	$0	
Total Washington Distribution Projects	**$28,161,000**	$0	
Total Distribution Projects	**$65,727,000**	**$17,861,000**	**$47,200**

Distribution Projects specific to Idaho (including transformation) for 2011 total $8.475 million. These projects are necessary to meet capacity needs of the system, improve reliability, and rebuild aging distribution substations and feeders. The following projects make up the $8.475 million.

- **Power Transformer Distribution ($0.350 million):** Transformers are transferred to plant upon receiving them. These transformers are being purchased to replace existing spares that will be installed in 2011 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. There are no offsets associated with these transformers until they are placed into service.

- **Appleway Substation ($4.200 million):** Appleway 115-13 kV Substation is a wood substation serving most of the City of Coeur d'Alene. The station has reached the end of its useful life and additional capacity is required. The new station will include 2-30 MVA transformers and six 13 kV feeders. The project started in late 2009 and will be transferred to plant in 2011. Loss calculations on the new transformer banks indicate that the losses are equivalent to the existing banks so there are no offsets associated with this project.

- **Deary Substation ($1.615 million):** Deary 115-24 kV Substation is a wood substation scheduled to be rebuilt as a steel substation in 2010 and 2011. Avista plans to rebuild at least one old wood substation every year based on age. Loss savings calculations indicate that the new transformer installation will result in an offset of $12,200 in the pro forma period (based on a $53.01/MWh avoided energy cost).

- **System - Dist Reliability - Improve Worst Feeders ($0.925 million):** Based on a combination of reliability statistics, including CAIDI, SAIFI, and CEMI (Customers Experiencing Multiple Interruptions), feeders have been selected for reliability improvement work. This work is expected to improve the reliability of these electric primary feeders. This is a annually recurring program initiated in 2008 to address underperforming feeders on the electric distribution system. Most of the feeder circuits are rural in nature and many experience 10 to 20 sustained outages per year discounting major events. The treatment of feeder projects varies from conversion of overhead to URD facilities, installing additional mid-line protective devices, to hardening of existing facilities. In Idaho, projects stretch from Sandpoint, Kellogg, St. Maries, Moscow, and Grangeville.

- **East Farms and Prairie View Feeder Upgrade ($0.360 million):** This is a transmission and distribution project slated for completion in 2011 to connect and upgrade 13.2 kV primary feeder ties between Pleasant View (Idaho) and East Farms (WA) substations. This project is located near Post Falls, Idaho and Liberty Lake, WA. This project is part of an overall transmission and distribution effort to connect these primary feeders in compliance with Avista's 500A Distribution Feeder Plan. The project will allow load to be served from either substation to improve reliability and load service. This project is currently under construction and the cost shown here are associated with distribution upgrades in Idaho.

- **Distribution - Cda East & North ($0.675 million):** These are all Idaho distribution projects. This project represents (4) discrete feeder reconductor projects as determined by SynerGEE modeling by Avista's distribution planning engineers and divisional area Engineers. These projects are characterized as "segment reconductor" projects and represent portions of main feeder trunk lines that are thermally constrained. The projects tend to be urban in nature.

- **Distribution Pullman & Lewiston ($0.350 million):** As above, this project includes the segment reconductor of two (2) primary feeder trunk lines in the Lewiston and Orofino areas. Both have been identified as "thermally constrained" via SynerGEE load flow modeling and analysis.

The Company also will spend approximately $29.091 million (system) in equipment replacements and minor rebuilds associated with aging distribution equipment discovered through inspections, feeders with poor reliability performance, replacements from storm damage, relocation of feeder sections resulting from road moves, or safety improvements. A brief description of the projects included in these replacement efforts is given below.

- **Electric Distribution Minor Blanket Projects ($8.000 million):** This effort includes the replacement of poles and cross-arms on distribution lines in 2011 as required, due to storm damage, wind, fires, or obsolescence. The Company spent $9.177 million in 2010 for these projects.

- **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 2011, 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.

- **Distribution Line Relocation ($1.700 million):** The relocation of transmission and distribution lines as required due to road moves requested by State, County or City governments. The Company spent $1.559 million in 2010 on line relocations associated with road moves.

- **Failed Electric Plant ($2.000 million):** Replacement of distribution equipment throughout the year as required due to equipment failure. The Company spent $2.665 million in 2010.

- **Replace High Resistance Conductor ($2.491 million system / $0.615 million Idaho):** Avista operates approximately 18,500 miles of primary distribution main trunk and service lateral circuits. Nearly 1,000 miles of our system has been identified as "high resistance" at 10 ohms per mile or greater. These high resistance conductors are generally small wire copper, iron, or steel conductors and most have been in service greater than 50 years. In 2011, Avista has initiated an annually recurring program to systematically replace these conductors with modern aluminum wire. Several projects have been identified in the Idaho service territory and are targeted for replacement. High resistance wire impairs the ability of protective devices, such as circuit reclosers and fuses, to operate as designed resulting in a safety issue. The high resistance wire that is being replaced under this program is very lightly loaded so there isn't measurable loss savings.

- **PCB Related Distribution Rebuilds ($2.500 million system / $0.375 million Idaho):** Avista has begun a systematic replacement of PCB containing distribution line transformers. 2011 represents year one of a six year effort to replace these "pre-1981" distribution transformers. The program is focused on replacing units that are located near waterways such as the Spokane river watershed. The $375,000 slated for Idaho represents the replacement of approximately 250 transformers.

Q. Please describe each of the transmission projects included in the Company's filing for 2012.

A. The major capital transmission costs (system) for projects to be completed in 2012 are approximately $22.407 million and are shown in Table 6 and described below.

TABLE 6

Transmission		
2012 Capital - Compliance, Environmental and Replacement Projects		
	Pro Forma (System)	**O&M Offsets (System)**
Reliabiltiy Compliance		
Moscow 230 kV Sub	$3,870,000	$6,400
Spokane/CDA Relay Upgrade	$1,250,000	
SCADA Replacement	$450,000	
System Replace/Install Capacitor Bank	$1,200,000	
Irvin Integration, Irvin - Millwood 115 kV Line	$1,150,000	
Thornton 230 kV Substation	$4,900,000	
Bronx-Cabinet 115 kV Rebuild/Reconductor	$1,500,000	$3,900
Power Transformers - Transmission	$2,665,000	
Total Reliability Compliance	**$16,985,000**	**$10,300**
Contractual Requirements		
Colstrip Transmission	$195,000	
Tribal Permits	$325,000	
Total Contractual Requirements	**$520,000**	
Reliability Replacement		
Transmission Minor Rebuilds	$1,500,000	
Power Circuit Breakers	$1,200,000	
Asset Management Replacement	$2,202,000	
Total Reliablity Replacement	**$4,902,000**	
Total Transmission Projects	**$22,407,000**	**$10,300**

RELIABILITY COMPLIANCE PROJECTS ($16.985 MILLION):

- **Moscow 230 kV Sub - Rebuild 230 kV Yard ($3.870 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 three-year period with energization of the 230 kV portion of the substation occurring in November of 2012. This is the portion pro formed into the Company's case. The completion of the 115 kV portion of the substation will occur in 2013. 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. Loss savings calculations indicate that the new transformer installation will result in an offset of $6400 in the pro forma period (based on a $53.01/MWh avoided energy cost and an energization date of November, 2011).

- **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 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 ($0.450 million):** The System Control and Data Acquisition (SCADA) system is used by the system operators to monitor and control the Avista transmission system. Upgrades to the SCADA system occur on an annual basis and include such items as replacing servers, increasing security, and expanding functionality. 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 due to age. 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 ($1.200 million):** This project includes the addition of 115 kV capacitor banks at Lind 115 kV substation and Odessa 115 kV substation 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 projects are scheduled to be completed by the end of 2012. There are no loss savings or other offsets associated with this new equipment installation.

- **Irvin Integration, Irvin - Millwood 115 kV line ($1.150 million):** A new 115 kV Switching Station will be constructed in the Spokane Valley to reinforce the transmission system. The Irvin 115kV Switching Station is the initial project in a series of projects intended to improve reliability of the 115kV transmission system and accompanying load service in the Spokane Valley. In 2012 $1,150,000 is scheduled to be spent for the construction of a new transmission line from the future Irvin station site to the existing Millwood Substation. Work will also be performed to relocate existing structures in and around the Irvin site to accommodate its integration.

- **Thornton 230 kV Substation ($4.900 million):** The Thornton 230kV Substation Project interconnects a Third party Wind Farm Generation Project to Avista's Benewah - Shawnee 230kV Transmission Line. The 2011 Transmission portion of this project consists of preparing the transmission line to accept the Customer's shoo-fly (a temporary routing and tap allowing for the Substation work are to be electrically isolated from the transmission line while allowing generation from the customer's wind farm) transmission line, tapping the Benewah - Shawnee directly to the Customer Generation Collection Station and beginning the construction of the 230 kV switching station. 2012 work consists of installing 230kV drop structures for the Thornton Substation, removing the shoo-fly taps, and finalizing the construction of the 230 kV switching station. The station is required to maintain Avista's 230 kV transmission service with or without the wind generation so Avista's customers are not affected by any outages as a result of the interconnection. One third of the substation costs will be paid by the customer as direct assigned facilities according to FERC Open Access requirements.

- **Bronx - Cabinet 115 kV rebuild/reconductor ($1.5 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 and 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 completed in 2011 included the rebuild and reconductor of the eight-mile section between the

Clark Fork Substation and Cabinet Gorge Hydro-Generation Station Switchyard. Phase 2 (2012) of the project will look to complete an additional approximate eight-mile section (specific location(s) to be determined) section of line. 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. The new conductor will reduce line losses by 889 MWh on an annual basis, establishing a system offset savings of $3,900 in the pro forma period (based on a $53.01/MWh avoided energy cost and energization of the project in December 2012).

- **Power Transformers - Transmission ($2.665 million):** The Company will be rebuilding several 230 kV substations over the next 5 years. One of these stations is Westside in western Spokane and involves the replacement of two 230/115 kV autotransformers. One of the autotransformer will arrive on-site in 2012 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 until it is put into service.

<u>CONTRACTUAL REQUIRED PROJECTS ($0.520 MILLION)</u>:

- **Colstrip Transmission ($0.195 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 joint owned facilities.

- **Tribal Permits ($0.325 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.

The Company will also spend approximately $4.902 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.

- **Transmission Minor Rebuilds ($1.550 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. The specific projects aren't known at this time but the facilities will need to be replaced when damaged in order to maintain customer load service. In 2010 the Company spent $3.053 million on these minor rebuild projects as a result of damage caused by weather or the public.

- **Power Circuit Breakers ($1.200 million):** The Company transfers all circuit breakers to plant upon receiving them. The breakers purchased in 2012 are planned for installation at Odessa 115 kV substation as part of the new capacitor bank installation and the new Irvin 115 kV switching station in Spokane planned for energization in 2013 or 2014.

- **Asset Management Replacement Programs ($2.202 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.

Q. Please describe each of the Idaho distribution projects included in the Company's filing for 2012.

A. The Company also will spend approximately $58.003 million in Distribution projects at a system level, with $16.630 million specific to Idaho. A summary of the projects is shown in Table 7 and a brief description of each project is given below.

TABLE 7

Distribution			
2012 Capital - Distribution Projects			
	Pro Forma (System)	**Pro Forma (Idaho)**	**O&M Offsets**
Idaho Distribution Projects			
Power Transformers - Distribution	$350,000	$350,000	
System Wood Sub Rebuild - Big Creek	$1,515,000	$1,515,000	$6,600
System Dist Reliability Improve Worst Feeders	$1,075,000	$1,075,000	
Distribution CDA East & North	$1,325,000	$1,325,000	
Distribution Pullman & Lewiston	$600,000	$600,000	
10th & Stewart Dist Int	$250,000	$250,000	
Blue Creek 115 kV Substation Rebuild	$1,500,000	$1,500,000	
Total Idaho Distribution Projects	**$6,615,000**	**$6,615,000**	**$6,600**
Distribution Replacement Projects			
Elect Distribution Minor Blanket	$8,000,000	$2,787,000	
Wood Pole Replacement and Capital Dist Feeder Repair	$9,468,000	$3,299,000	
Electric Underground Replacement	$3,675,000	$1,280,000	$35,000
Distribution Line Relocation	$1,700,000	$592,000	
Failed Electric Plant	$2,100,000	$732,000	
Replace High Resistance Conductor	$3,017,000	$905,000	
PCB Related Dist Rebuilds	$2,820,000	$420,000	
Total Distribution Replacement Projects	**$30,780,000**	**$10,015,000**	**$35,000**
Washington Distribution Projects (Not included in this case)			
Distribution Projects in Washington	$12,204,000	$0	
Washington Smart Grid Projects	$8,404,000	$0	
Total Washington Distribution Projects	**$20,608,000**	$0	
Total Distribution Projects	**$58,003,000**	**$16,630,000**	**$41,600**

Distribution Projects specific to Idaho (including transformation) for 2012 total $6.615 million. These projects are necessary to meet capacity needs of the system, improve reliability, and rebuild aging distribution substations and feeders. The following projects make up the $6.615 million.

- **Power Transformer Distribution ($0.350 million):** Transformers are transferred to plant upon receiving them. These transformers are being purchased to replace existing spares that will be installed in 2012 as either replacements or new installations. The purchased transformers will either remain as system spares or placed into service as part of proposed 2012 projects. There are no offsets associated with these transformers until they are placed into service.

- **System Wood Substation Rebuild - Big Creek 115 kV ($1.515 million):** The Big Creek 115 kV Substation near Kellogg, ID, will be rebuilt with steel structures and new equipment. The station was originally constructed in 1956 and needs to be rebuilt to today's design and construction standards. Loss savings calculations indicate that the new transformer installation will result in an offset of $6,600 in the pro forma period (based on a $53.01/MWh avoided energy cost and an energization date of October, 2012).

- **System - Dist Reliability - Improve Worst Feeders ($1.075 million):** Based on a combination of reliability statistics, including CAIDI, SAIFI, and CEMI (Customers Experiencing Multiple Interruptions), feeders have been selected for reliability improvement work. This work is expected to improve the reliability of these electric primary feeders. This is an annually recurring program initiated in 2008 to address underperforming feeders on the electric distribution system. Most of the feeder circuits are rural in nature and many experience 10 to 20 sustained outages per year discounting major events. The treatment of feeder projects varies from conversion of overhead to URD facilities, installing additional mid-line protective devices, to hardening of existing facilities. In Idaho, projects stretch from Sandpoint, Kellogg, St. Maries, Moscow, and Grangeville.

- **Distribution – CdA East & North ($1.325 million):** This program represents several distribution capacity upgrade projects as determined by SynerGEE modeling by Avista's distribution planning engineers and divisional area Engineers. These projects are characterized as "segment reconductor" projects and represent portions of main feeder trunk lines that are thermally constrained. The projects tend to be urban in nature.

- **Distribution Pullman & Lewiston ($0.600 million):** As above, this project includes the segment reconductor of primary feeder trunk lines in Lewiston, Idaho. Both have been identified as "thermally constrained" via SynerGEE load flow modeling and analysis.

- **10th & Stewart Distribution Integration ($0.250 million):** Load growth in the Lewiston "Orchards" requires a substation capacity increase from a 20MVA to 30MVA 115/13.2 kV unit. An associated third distribution feeder will be added to the substation. This $250,000 dollar project represents the cost to reconfigure the distribution system beyond the substation boundary fence line.

- **Blue Creek 115 kV Substation Rebuild ($1.500 million):** The Blue Creek 115 kV Substation just east of Coeur d'Alene needs to be rebuilt adjacent to the existing substation to accommodate new equipment, including a new panelhouse, as a result of the need to replace the substation transformer. An additional feeder will also be added for distribution system reliability and operational flexibility as well as future load service capability.

The Company also will spend approximately $30.780 million (system) in equipment replacements and minor rebuilds associated with aging distribution equipment discovered through inspections, feeders with poor reliability performance, replacements from storm damage, relocation of feeder sections resulting from road moves, or safety improvements. A brief description of the projects included in these replacement efforts is given below.

- **Electric Distribution Minor Blanket Projects ($8.000 million):** This effort includes the replacement of poles and cross-arms on distribution lines in 2011 as required, due to storm damage, wind, fires, or obsolescence. The Company spent $9.177 million in 2010 for these projects.

- **Wood Pole Replacement Program and Capital Distribution Feeder Repair ($9.468 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 ($3.675 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, 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.

- **Distribution Line Relocation ($1.700 million):** The relocation of transmission and distribution lines as required due to road moves requested by State, County or City governments. The Company spent $1.559 million in 2010 on line relocations associated with road moves.

- **Failed Electric Plant ($2.100 million):** Replacement of distribution equipment throughout the year as required due to equipment failure. The Company spent $2.665 million in 2010.

- **Replace High Resistance Conductor ($3.017 million system / $0.905 million Idaho):** Avista operates approximately 18,500 miles of primary distribution main trunk and service lateral circuits. Nearly 1,000 miles of our system has been identified as 'high resistance" at 10 ohms per mile or greater. These high resistance conductors are generally small wire copper, iron, or steel conductors and most have been in service greater than 50 years. 2012 represents year-2 of an annually recurring program to systematically replace these conductors with modern aluminum wire. Several projects have been identified in the Idaho service territory and are targeted for replacement. High resistance wire impairs the ability of protective devices, such as circuit reclosers and fuses, to operate as designed resulting in a safety issue. The high resistance wire that is being replaced under this program is very lightly loaded so there isn't measurable loss savings.

- **PCB Related Distribution Rebuilds ($2.820 million system / $0.420 million Idaho):** In 2011, Avista initiated a systematic replacement of PCB containing distribution line transformers. 2012 represents year-two of a six year effort to replace these "pre-1981" distribution transformers. In 2012, the program is expected to replace approximately 280 line transformers in Idaho.

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, 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 8 below, Idaho's electric distribution vegetation management level of expenditure necessary in 2012 is $3.237 million, which is approximately $1.3 million above that included in the 2010 test period ($1.874 million). The $1.284 million of incremental pro forma spend compared to 2010 actual spend (less offsetting savings included as described below of $80,000) has been included in the Company's electric revenue requirement request filed in this case as discussed further by Ms. Andrews.

Table 8: Distribution Pro Forma

Increment for Vegetation Management

Year	ID Electric
2010 Actual	$1,873,707
2012 Planned	$3,237,477
2012 Offset	-$80,000
Pro Forma Increment	$1,283,770

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 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.

As the Company has analyzed the plan over time, outage data collected by the Company's Outage Management Tool (OMT)[1] 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 a trend upwards. While weather conditions change each year and contribute to the number of

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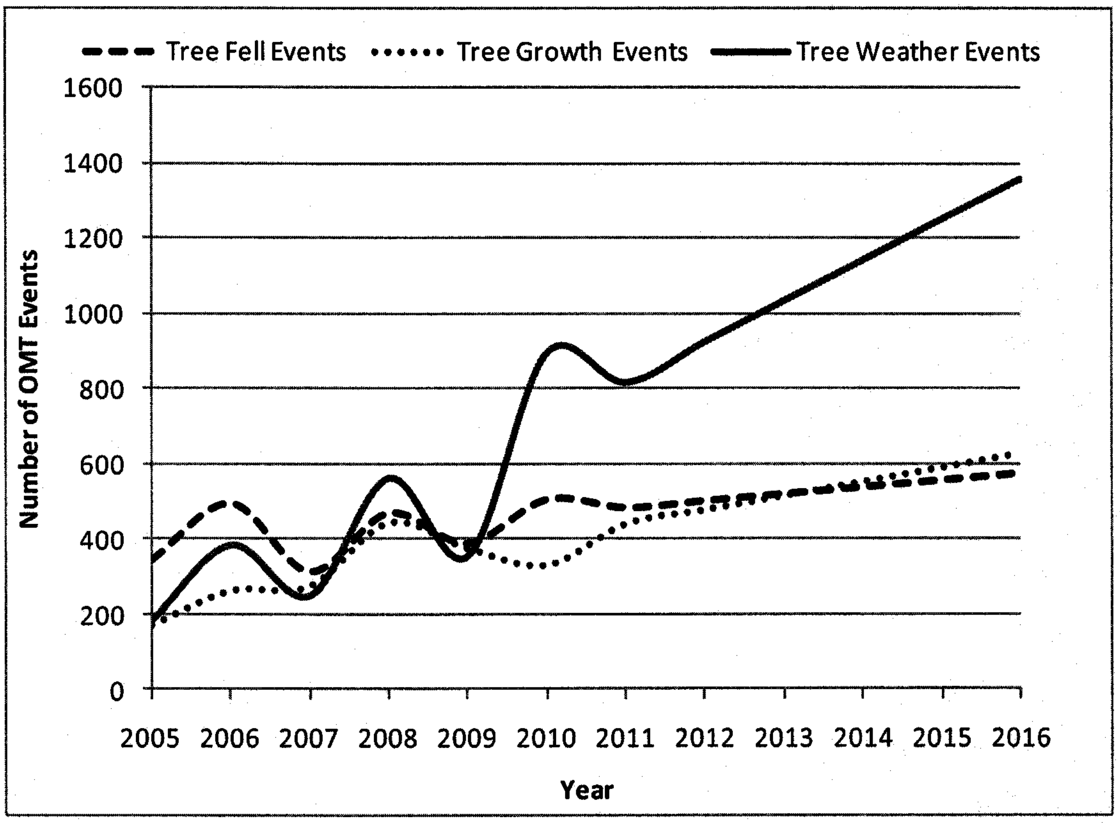
[1] The data behind the failure rates used in the program models come from information gathered during past years' work and failures. Information was gathered for the number of trees removed, trees trimmed, and brush removed along with the failure documented in the Outage Management Tool (OMT) and were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

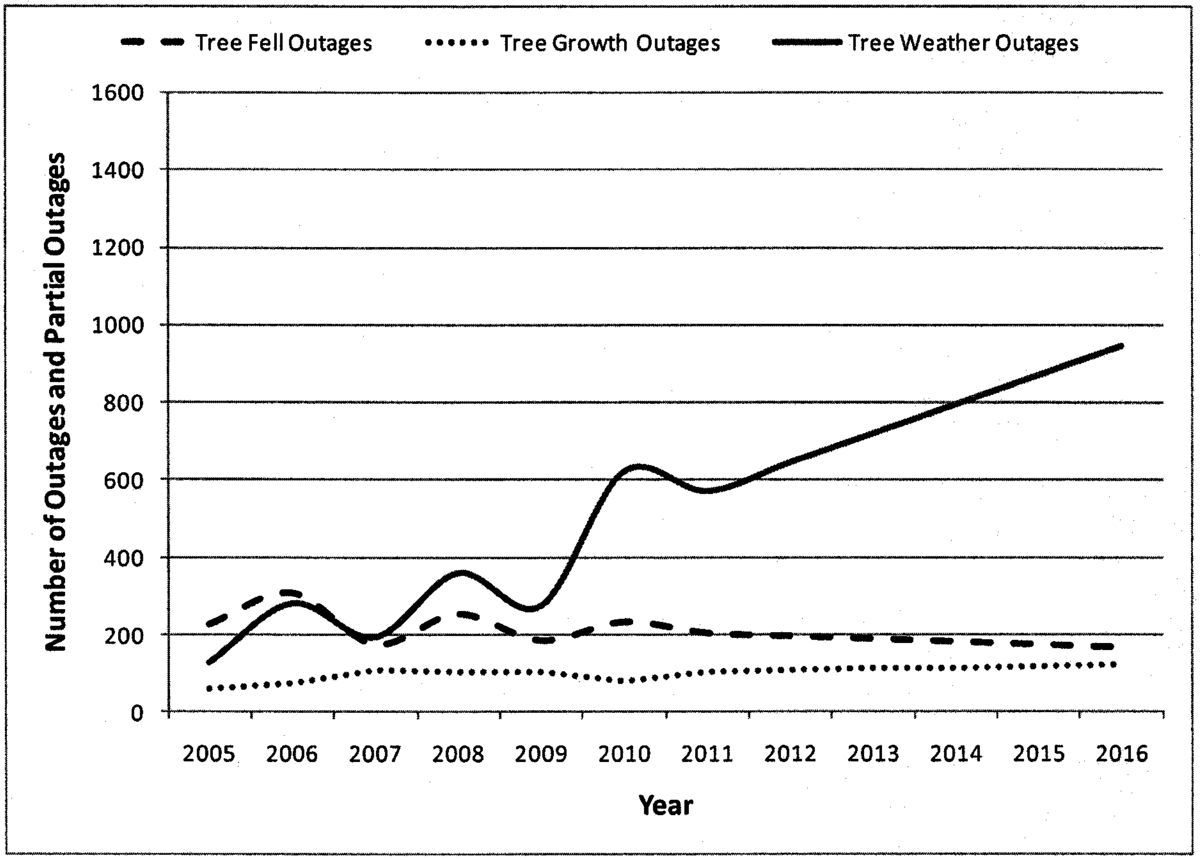
events each year, the overall trend continues upward even with a few good years of weather in 2009 and 2010.

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 events continues upwards for Tree Fell (see Illustration 1), the actual number of outages is trending downwards and Tree Growth outages 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.

Illustration 3

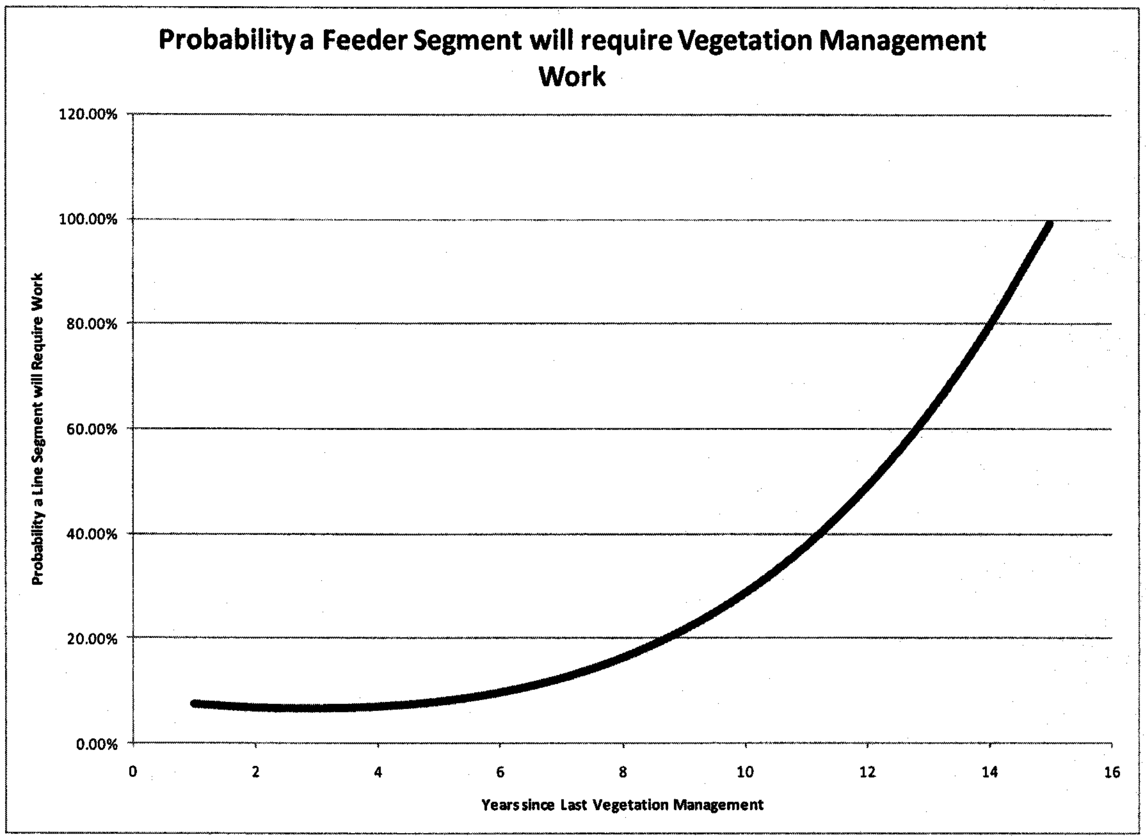
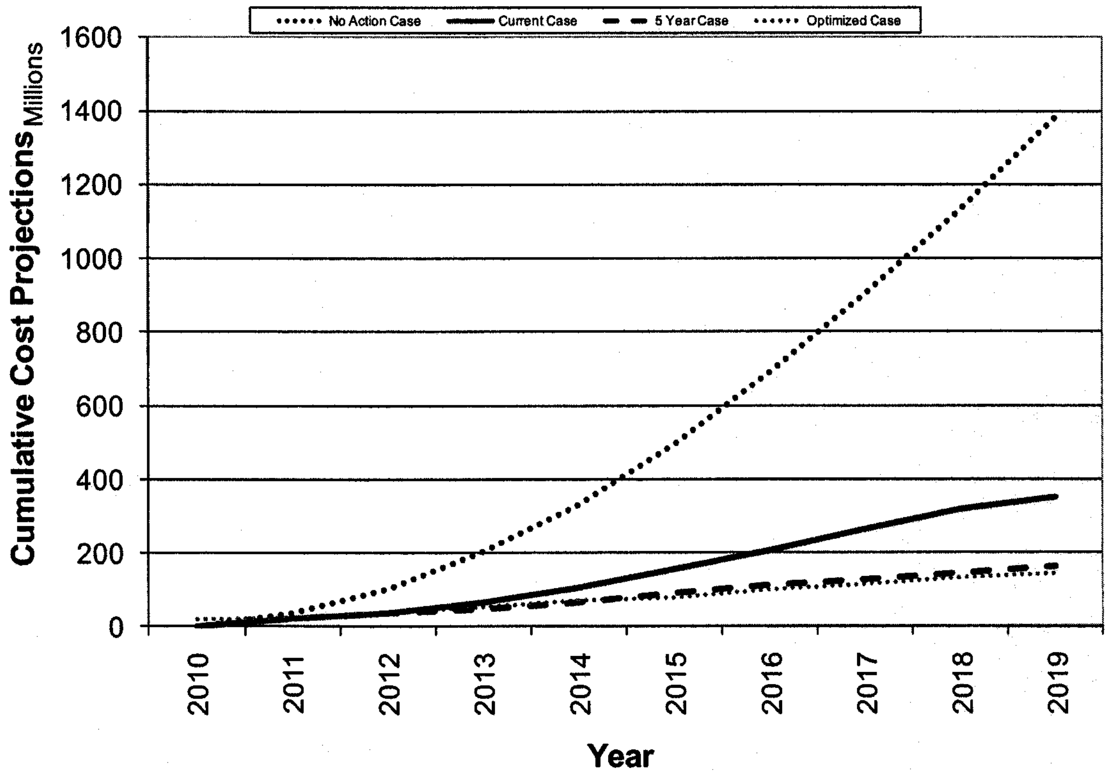


Illustration 4 below shows cost projections of the Company's current case and the Optimized Case (average of a four-year clearing cycle).

Illustration 4



To further support the rational for the optimized cycle time (four-year cycle), Table 9 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 9, we anticipate preventing over 1,500 events each year once all feeders are on an optimized cycle.

Table 9

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 $100,000 in Idaho 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 ($80,000 Idaho 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 includes the pro forma vegetation management adjustment (including this offset) in her adjustments.

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 ($119,200 Idaho share) in 2013.

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

A. Yes it does.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-11-01
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 9
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	SCOTT J. KINNEY
	)	

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

Avista Corporation
- Energy Delivery -
Pro Forma Transmission Revenue/Expenses
($000s)

Line No.			2010 Actual	Adjusted	2012 Pro Forma Period
		556 OTHER POWER SUPPLY EXPENSES			
1		NWPP	42	1	43
		560-71.4, 935.3-.4 TRANSMISSION O&M EXPENSE			
2		Colstrip O&M - 500kV Line	443	117	560
3		ColumbiaGrid Development	194	-14	180
4		ColumbiaGrid Planning	164	56	220
5		ColumbiaGrid OASIS	44	42	86
6		Canada to N.Cal (CNC) Project	0	255	255
7		Transmission Line Ratings Confirmation Plan	0	2,145	2,145
8	*	Grid West (ID)	71	-71	0
9		Total Account 560-71.4, 935.3-.4	916	2,530	3,446
		561 TRANSMISSION EXP-LOAD DISPATCHING			
10		Elect Sched & Acctg Srv (OATI)	171	4	175
		566 TRANSMISSION EXP-OPRN-MISCELLANEOUS			
11		NERC CIP	47	3	50
12		OASIS Expenses	8	1	9
13		BPA Power Factor Penalty	138	-7	131
14		WECC - Sys. Security Monitor	167	4	171
15		WECC Admin & Net Oper Comm Sys	384	-25	359
16		WECC - Loop Flow	20	12	32
17		Total Account 556	764	-12	752
18		**TOTAL EXPENSE**	1,893	2,523	4,416
		456 OTHER ELECTRIC REVENUE			
19		Borderline Wheeling Transmission	7,365	-706	6,659
		Borderline Wheeling Low Voltage	364	713	1,077
20		Seattle/Tacoma Main Canal	292	-4	288
21		Seattle/ Tacoma Summer Falls	74	0	74
22		OASIS nf & stf Whl (Other Whl)	2,887	103	2,990
23		PP&L - Dry Gulch	218	11	229
24		Spokane Waste to Energy Plant	160	-160	0
25		Grand Coulee Project	8	0	8
26		First Wind Energy Marketing	0	200	200
27	**	BPA Settlement	1,177	-1,177	0
28		Total Account 456	12,545	-1,020	11,525
29		**TOTAL REVENUE**	12,545	-1,020	11,525
30		**TOTAL NET EXPENSE**	-10,652	3,543	-7,109

* Grid West/RTO Deposit Amortization for Idaho ends December 2011.
** One time event.

CONFIDENTIAL

Transmission Line Ratings Confirmation Plan

Pages 1 through 32

THESE PAGES ALLEGEDLY CONTAIN TRADE SECRETS OR CONFIDENTIAL MATERIALS AND ARE SEPARATELY FILED.