Exhibit No. ___(SJK-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-12________

DIRECT TESTIMONY OF

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

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

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

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

Q. What is the scope of your testimony?

A. My testimony describes Avista's pro forma period transmission revenues and expenses. I also discuss the Transmission and Distribution expenditures that are part of the capital additions testimony provided by Company witness Mr. DeFelice, as well as projects associated with the Company's Asset Management Program. Company witness Ms. Andrews incorporates the Washington share of the net transmission expenses.

Q. Are you sponsoring any exhibits?

A. Yes. Exhibit No. __(SJK-2) provides the transmission pro forma adjustments.

A table of contents for my testimony is as follows:

II. PRO FORMA TRANSMISSION EXPENSES

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

A. Adjustments were made in this filing to incorporate updated information for any changes in transmission expenses from the January 2011 to December 2011 test year to the 2013 pro forma rate period. The changes in expenses and a description of each is summarized in Table 1:

Table 1:

Transmission Expense Adjustments		
	***Pro Forma (System)**	
Northwest Power Pool (NWPP)	$	(3,000)
Colstrip Transmission	$	(69,000)
ColumbiaGrid RTO	$	18,000
ColumbiaGrid Transmission Planning	$	53,000
ColumbiaGrid OASIS	$	13,000
Grid West (WA Direct)	$	(79,000)
Elect Sched & Acctg Srv (OATI)	$	3,000
NERC CIP	$	3,000
OASIS Expenses	$	8,000
BPA Power Factor Penalty	$	(12,000)
WECC Total Dues - WECC Sys Secur & Admin- Net Oper Comm Sys	$	3,000
WECC - Loop Flow	$	14,000
CNC Transmission Project	$	253,000
Transmission Line Ratings Confirmation Plan (NERC Alert)	$	982,000
Total Expense	**$**	**1,187,000**

*Representing the change in expense above or below the 2011 test period level.

Northwest Power Pool (NWPP) (-$3,000) – 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 contingency generation reserve sharing, and Columbia River water coordination. Actual 2011 transmission related NWPP expenses were $48,000 and a negative $3,000 adjustment is being made to the pro forma period to reflect the NWPP expenses allocated to the Company.

Colstrip Transmission (-$69,000) – 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 $387,000 for Avista's share of the Colstrip O&M expense during the pro forma period. This is a decrease of $69,000 from the actual expense of $456,000 incurred during the 2011 test year.

ColumbiaGrid RTO ($18,000) – 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, however a follow-on contract will be developed to replace the expiring contract. Avista's ColumbiaGrid general funding expenses for the 2011 test year were $131,000 while pro forma general funding expenses are $149,000, an increase of $18,000.

ColumbiaGrid Transmission Planning ($53,000) – The ColumbiaGrid Planning and Expansion Functional Agreement (PEFA) was accepted by the Federal Energy Regulatory Commission (FERC) on April 3, 2007 and Avista entered into the PEFA on April 4, 2007. Coordinated transmission planning activities under the PEFA allow the Company to meet the coordinated regional transmission planning requirements set forth in FERC's Order 890 issued in February, 2007, and outlined in the Company's Open Access Transmission Tariff, Attachment K. Funding under the PEFA is on a two-year cycle with provisions to adjust for inflation. Actual PEFA expenses for the 2011 test year were $171,000. The Company's PEFA pro forma expenses are at the maximum total payment obligation of $224,000, 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.

<u>ColumbiaGrid Open Access Same-Time Information System (OASIS)</u> ($13,000) – 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 2011 test year expenses of $26,000 reflected initial developmental activities under this functional agreement. Avista's ColumbiaGrid OASIS pro forma expenses are $39,000, 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.

<u>Grid West (WA Direct)</u> (-$79,000) – Avista's total deferred Grid West expense was approximately $1.2 million including interest through March 31, 2006 (a $796,000 Washington share). This amount was being amortized on a five-year basis from July 2006 through June 2011 with no interest or carrying costs. With amortization ending in June of 2011, the Company will not incur costs associated with Grid West in the pro forma period. Avista is removing the $79,000 of amortization expense included in the 2011 test year.

Electric Scheduling and Accounting Services ($3,000) – The $3,000 increase in the pro forma period compared to test year expense for electric scheduling and accounting services is a result of annual increases and additional services provided by our third party vendor. These services are required to assist in meeting the requirements of the NERC mandatory reliability standards. The pro forma scheduling and accounting costs are $172,000.

NERC Critical Infrastructure Protection ($3,000) – The Company has purchased two software products to assist in protecting critical transmission system data from intrusion and to meet applicable North American Electric Reliability Corporation (NERC) standards. The Company's pro forma expenses increase $3,000 from the actual 2011 test year expense of $55,000 due to annual application cost increases.

OASIS Expenses ($8,000) – 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, regional criterion development, and FERC OASIS requirements. The costs associated with OASIS expenses in the pro forma period are $9,000 compared to only $1000 of actual expenses in the 2011 test year. In 2011 the employees associated with the OAIS function didn't travel or attend training due to increased workload associated with several new projects.

Power Factor Penalty (-$12,000) – 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 $162,000 of power factory penalty charges during the 2011 test year. The Company's pro forma 2012 expenses are expected to be $150,000 representing an average of the power factor penalty charges incurred in 2010 and 2011.

<u>WECC – System Security Monitor and WECC Administration & Net Operating Committee Fees</u> ($3,000) – 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 2011 test year WECC assessments were $171,000 for system security monitoring and $359,000 for dues and net Operating Committee fees, for a total 2011 WECC assessment of $530,000. The Company paid its 2012 WECC assessments in January 2012: $205,000 for system security monitoring and $328,000 for dues and net Operating Committee fees, for a total WECC assessment of $533,000. The Company's pro forma 2013 expenses have been set equal to these amounts paid in January 2012.

<u>WECC - Loop Flow</u> ($14,000) – 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 average WECC Loop Flow charges incurred by the Company during the five-year period from 2007 through 2011, pro forma Loop Flow expenses are $30,000. This is $14,000 more than actual 2011 test year charges of $16,000.

<u>Canada to Northern California (CNC) Transmission Project</u> ($253,000) – 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 the original sponsors of the CNC transmission project. The cost accrued by Avista for its participation in the CNC regional transmission project was $758,000. Of this amount, $537,000 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 is amortizing these expenses over a three-year period, resulting in an amortized expense of $253,000 ($164,000 Washington share) beginning in 2012.

<u>Transmission Line Ratings Confirmation Plan (NERC Alert)</u> ($982,000) – The Transmission Line Ratings Confirmation Plan was developed to address a "NERC Alert" issued on October 7, 2010. The North American Electric Reliability Corporation (NERC) issued a "Recommendation to Industry addressing Consideration of Actual Field Conditions in Determination of Facility Ratings" based on a vegetation contact conductor-to-ground fault by another Transmission Owner. The NERC Alert was issued to provide the industry

an opportunity to review actual field conditions and compare them to design values to ensure system reliability. Avista initiated a three year program to perform Light Detection and Ranging (LIDAR) surveying of all Avista 230kV transmission lines and five (5) 115kV transmission lines. A total of 1400 miles of transmission lines will be evaluated at a total system cost of $2.945 million. The total Washington share of this project is $1.914 million. Per Order No. 06, Docket UE-11086 and UE-11087 the Company will amortize these costs over a three-year period beginning in 2012. Therefore the pro forma expenses associated with this project are $982,000 ($638,000 Washington share). There were no expenses associated with this project in the 2011 test year.

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 2013 pro forma period as compared to the 2011 test year. Each revenue item described below is at a <u>system</u> level and is included in Exhibit No.__ (SJK-2). Please see Table 2 and descriptions below for further detail on the revenue pro forma amounts.

Table 2:

Transmission Revenue Adjustments	
	***Pro Forma (System)**
Borderline Wheeling Transmission & Low Voltage	$ (231,000)
Seattle/Tacoma Main Canal	$ (10,000)
OASIS, non-firm, & short-term firm (Other Wheeling)	$ (118,000)
Seattle/Tacoma Summer Falls	$ 0
Pacificorp– Dry Gulch	$ (10,000)
Spokane Waste to Energy Plant	$ (132,000)
Grand Coulee Project	$ 0
Palouse Wind	$ 200,000
Stimson Lumber	$ 8,000
Hydro Tech Systems – Meyers Falls	$ 6,000
BPA Parallel Operating Agreement Settlement	$ 392,000
BPA Parallel Capacity Support	$ (200,000)
Total Expense	**$ (95,000)**

*Representing the change in revenue above or below the 2011 test period level.

Borderline Wheeling Transmission and Low Voltage (-$231,000)

Total borderline wheeling revenues for the 2011 test year were $8,179,000. Total borderline wheeling revenue in the pro forma period has been set at $7,948,000, which reflects a slight decrease over the test year. 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 since a large portion of the revenue is dependent upon usage. However, with billing adjustments implemented in 2009 and the new transmission rates that went into effect in 2010, use of the previous five-years of actual revenues would not properly reflect the new level of revenues. Therefore, pro forma transmission revenue has been set equal to the average of 2010 and 2011 actual revenue or per the set charges in each specific contract. Each of the specific borderline contracts is further described below.

- Borderline Wheeling – Bonneville Power Administration – (-$232,000) Actual test year revenue from borderline wheeling service provided to Bonneville was $7,931,000. 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 pro forma Bonneville borderline wheeling revenue is $7,699,000, which is the average of the 2010 and 2011 actual revenues.

- Borderline Wheeling – Grant County PUD – (-$2000) The Company provides borderline wheeling service to two Grant County PUD substations under a Power Transfer Agreement executed in 1980. Charges under this agreement are not impacted by the Company's transmission service rates under Avista's Open Access Transmission Tariff so a 5-year average is used to determine the pro forma revenue of $27,000. The 2011 test year revenue was $29,000.
- Borderline Wheeling – East Greenacres Irrigation District – ($0) 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 2011 test year was $60,000. Revenue for the 2013 pro forma period is $60,000 per the restructured contract.
- Borderline Wheeling – Spokane Tribe of Indians – ($2,000) 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 2011 test year was $41,000. Revenue associated with the transmission component of this contract is adjusted annually per the contract. Accordingly, 2013 pro forma period revenue under this contract is set at $43,000.
- Borderline Wheeling – Consolidated Irrigation District – ($1,000) 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

2011 test year was $118,000. A new contract signed with the Consolidated Irrigation District in October of 2011, resulted in a shift of charges between transmission and low-voltage services. Per the new contract, the total Consolidated Irrigation District revenue for the pro forma period is $119,000.

OASIS Non-Firm and Short-Term Firm Transmission Service (-$118,000) – 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 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). However, if there are known events or factors that occurred during the period that would cause the average to not be representative of future expectations, then adjustments may be made to the three-year average methodology. In this filing, the Company is using the most recent three-year average with some adjustments associated with 2011 revenues due to additional revenue received from Puget Sound Energy as a result of an outage on BPA's transmission system. The outage resulted in additional revenue of $1.6 million. The adjusted OASIS revenue for the 2011 test year used in the three-year average calculation is $3.101 million and results in pro forma revenue of $2.983 million.

<u>Seattle and Tacoma Revenues Associated with the Main Canal Project</u> (-$10,000) – 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 $288,000 during the 2011 test year. Pro forma revenues are $278,000 based on a reduction in the ratchet demand.

<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 2011 test year and are expected to remain the same for the 2013 pro forma period.

<u>PacifiCorp Dry Gulch</u> (-$10,000) – Revenue under the Dry Gulch use-of-facilities agreement has been adjusted to $218,000 for the pro forma period, which is a $10,000 decrease from the 2011 test year actual revenue of $228,000. 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 2009 through 2011.

<u>Spokane Waste to Energy Plant</u> (-$132,000) – This revenue has historically been associated with a long-term transmission service agreement with the City of Spokane that expired December 31, 2011. Avista decided to purchase the energy from the Spokane Waste to Energy facility beginning January 1, 2012 after the old contract expired with Puget Sound Energy (PSE). With the new contract, the Spokane Waste to Energy no longer pays for transmission service to move the energy to PSE and instead pays a use of facility charge for the interconnection to Avista's transmission system. The pro forma revenue associated

with the use of facility charge is $28,000. The 2011 test year revenue from the transmission service contract was $160,000.

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 2011 test year and will remain the same for the 2013 pro forma period.

Palouse Wind ($200,000) – Palouse Wind signed a transmission service contract with the Company based on its initial intent to sell the output from a wind facility to an entity other than Avista. Since then Avista signed a power purchase agreement with Palouse Wind, which voided the need for transmission service. Palouse Wind intends to delay use of the 100 MW of reserved transmission service for up to five years unless they are able to re-market the capacity. However, according to Avista's Open Access Transmission Tariff and the contract signed with Avista, Palouse wind must still pay one month's worth of service as a penalty for the delay. A pro forma amount of $200,000 is included in the rate case per the postponement language in the transmission reservation contract. There was $0 in revenue collected from this contract in 2011.

Stimson Lumber Agreement ($8,000) – The Company has identified a revenue stream associated with sole-use, or directly assigned, low-voltage facilities related to the integration of small generation resources. The Company will receive annual use-of-facilities revenue of $9,000, or approximately $790 per month, from Stimson Lumber for the dedicated use of low-voltage facilities in the Company's Plummer Substation. The test year revenue was $1000.

Hydro Tech Systems Agreement ($6,000) – Low-voltage facilities in the Company's Greenwood Substation are dedicated for use by the Meyers Falls generation project resulting in annual use-of-facilities revenue of $6,000, or $510 per month. The pro forma revenue from this agreement is $6,000. There was $0 in revenue collected during the 2011 test year.

BPA Parallel Operation Agreement ($392,000) – 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. Per the final WUTC 2010 general rate case order the Company will amortize these costs over a three-year period beginning in 2012. The pro forma revenue associated with the three-year amortization is $392,000 ($256,000 Washington share). There was no revenue collected in the test year associated with this agreement.

BPA Parallel Capacity Support (-$200,000) – Avista provided interim parallel capacity support to BPA during the months of March-June, 2011. BPA needed this support prior to commencing work to upgrade its transmission system, pursuant to the "Parallel Operation and Construction Agreement between Avista and BPA." This four-month stream of payments from BPA was part of this settlement contract, but not a part of the lump-sum settlement payment from BPA which covered the historical period prior to January, 2011. Since this was an interim support agreement, there will be no revenue associated with this item in the pro forma period.

IV. TRANSMISSION AND DISTRIBUTION CAPITAL PROJECTS

Q. Please describe the Company's capital transmission projects that will be completed in 2012?

A. Avista continuously needs to invest in its transmission system to maintain reliable customer service and meet mandatory reliability standards. The 2012 and 2013 capital transmission projects are being planned and constructed to meet either compliance requirements, improve system reliability, fix broken equipment, or replace aging equipment that is anticipated to fail.

Included in the compliance requirements are the North American Electric Reliability Corporation (NERC) standards, which are national standards that utilities must meet to ensure interconnected system reliability. Beginning June 2007, compliance with these standards was made mandatory and failure to meet the requirements could result in monetary penalties of up to $1 million per day per infraction. The majority of the reliability standards pertain to transmission planning, operation, and equipment maintenance. The standards require utilities to plan and operate their transmission systems in such a way as to avoid the loss of customers or impact to neighboring utility systems due to the loss of transmission facilities. The transmission system must be designed so that the loss of up to two facilities simultaneously will not impact the interconnected transmission system. These requirements drive the need for Avista to continually invest in its transmission system. Avista is required to perform system planning studies in both the near term (1-5 years) and long term (5-10 years). If a potential violation is observed in the future years, then Avista must develop a project plan to ensure that the violation is fixed prior to it becoming a real-time operating issue. Avista plans for the future projects and 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 2012 and 2013 capital transmission projects will result in efficiency gains and potential offsets or savings, and the Company has included those where applicable. The primary offsets result in loss savings from reconductoring heavily-loaded transmission or distribution facilities. For these projects, an analysis was performed to determine the savings. The assumed avoided energy cost to determine the savings was $77 MWh, which is the 20 year life cycle cost calculated in Avista's 2011 Integrated Resource Plan. However, not all projects will result in loss savings or other offsets. Avista has maintenance schedules for certain equipment. These maintenance cycles range from 5-15 years depending on the equipment. Unless the replacement of equipment occurs in the same year as the scheduled maintenance, there will not be any savings.

Although one might think that the replacement of equipment may reduce the failure rate of equipment and reduce after-hours labor costs, newly-installed equipment can get out of alignment, or require other adjustments. Significant system failures also occur during large weather-related events caused by wind, lightning, and snow. Furthermore, each year as we replace old equipment with new, the remainder of our system gets another year older, which continues to generate a similar level of failures on our system. At the current funding levels, the Company's Asset Management program is designed to keep failure rates at current levels.

Q. Please describe each of the transmission projects planned for in 2012.

A. The major capital transmission costs (system) for projects to be completed in 2012 are $25.974 million and are shown in Table 3 and described below.

TABLE 3		
Transmission		
2012 Capital - Compliance, Contractual, and Replacement Projects		
	Pro Forma (System)	**O&M Offsets (System)**
Reliability Compliance		
Spokane/CDA Relay Upgrade	$900,000	
SCADA Replacement	$1,262,000	
System Replace/Install Capacitor Bank	$1,627,000	
Bronx-Cabinet 115 kV Rebuild/Reconductor	$2,500,000	$7,800
Power Transformers - Transmission	$600,000	
Total Reliability Compliance	**$6,889,000**	**$7,800**
Contractual Requirements		
Thornton 230 kV Switching Station	$4,350,000	
Colstrip Transmission	$410,000	
Tribal Permits	$325,000	
Total Contractual Requirements	**$5,085,000**	**$0**
Reliability Improvements		
Moscow City-N Lewiston 115 kV Reconductor	$2,500,000	
Burke-Thompson A&B 115 kV Reconductor	$2,500,000	
Millwood 115 kV Substation Rebuild	$690,000	
Noxon-Hot Springs 230 kV Line Re-Route	$500,000	
Pullman (Turner) Substation Rebuild	$151,000	
Total Reliability Improvements	**$6,341,000**	**$0**
Reliability Replacement		
Transmission Minor Rebuilds	$2,370,000	
Power Circuit Breakers	$1,200,000	
Hatwai 230 kV Breaker Replacement	$610,000	
Asset Management Replacement	$3,479,000	
Total Reliability Replacement	**$7,659,000**	**$0**
Total Transmission Projects	**$25,974,000**	**$7,800**

Reliability Compliance Projects ($6.889 million):

- **Spokane/Coeur d'Alene area relay upgrade ($0.900 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 ($1.262 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 will be completed in the first quarter of 2012. 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 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 ($1.627 million)**: This effort includes two projects. The first project is the replacement of the 115 kV capacitor bank at the Pine Creek 115 kV substations to support local area voltages during system outages. The second project is the addition of new shunt capacitors at Lind 115 kV substation to support system voltages during summer irrigation load conditions and system outages. These projects are 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 Lind project is scheduled to be completed by June 2012 and the Pine Creek project is scheduled to be completed in the fall of 2012. There are no loss savings or other offsets associated with these projects. The projects improve voltage support but don't reduce loss savings.

- **Bronx – Cabinet 115 kV rebuild/reconductor ($2.500 million)**: In 2010 Avista's System Operations identified a thermal constraint on the 32-mile Bronx-Cabinet 115kV Transmission Line. This constraint was confirmed by the System Planning Group, and documented in the Transmission Line Design (TLD) Design Scoping Document (DSD) created on January 4, 2011, and modified on January 7, 2011. The reconductoring/rebuilding of this line with 795 kcmil ACSS conductor will provide a present-day 143 MVA line rating to match the Cabinet Switchyard Transformer, and a future 200 MVA line rating to match the parallel path Bonneville Power Authority (BPA) system. The 32 miles of line will be reconductored over a four year period, which began in 2011. Phase 2 of the project (addressed here) consists of the approximately 10-mile stretch between Hope, ID and Clarkfork Sub. The line upgrade will ensure compliance with requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Using 2010 actual loads, since the line was operated open in over half of 2011 for the first phase of the project, the new conductor will reduce line losses by 1220 MWh on an annual basis.

This project will not be completed until December so offset savings of $7,800 will be observed in 2012 (based on a $77/MWh avoided energy cost).

- **Power Transformers – Transmission ($0.600 million)**: The Moscow 230kV substation is currently being rebuilt. Construction started in 2011 and will continue through 2013. The rebuild includes the addition of a new 250 MVA 230/115 kV autotransformer. This autotransformer arrived on-site in late 2011 and was capitalized upon delivery per the company's accounting practices. The transformer was paid for in several installments. This $600,000 was the final installment (paid in 2012), which was paid after receiving warranty approval from the manufacturer to energize the autotransformer. This project is required to meet Reliability Compliance under NERC Planning and Operations 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 2013, and therefore have been included in the 2013 project described later in my testimony.

<u>Contractual Requirements ($5.085 million):</u>

- **Thornton 230 kV switching Station ($4.350 million):** The Thornton 230kV Substation Project interconnects a Third Party Wind Farm Generation Project owned and operated by Palouse Wind to Avista's Benewah - Shawnee 230kV Transmission Line. The project includes the construction of the switching station and associated line work to connect the new station to Avista's existing 230 kV line. Palouse Wind will construct and pay for facilities to connect its Generation Collection Station to Thornton. Thornton 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 (not included here) will be paid for upfront by Palouse Wind as direct assigned facilities according to FERC Open Access Transmission Tariff requirements. There are no offsets with the construction of the new substation.

- **Colstrip Transmission ($0.410 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 Improvements ($6.341 million):</u>

- **Moscow City-North Lewiston 115 kV Transmission Rebuild ($2.500 million):** This project includes the reconductor/rebuild of the 22-mile line between Moscow

City substation and North Lewiston due to the poor condition of the existing line. The project will be completed in three phases. The first phase in 2012 includes reconductoring the first seven miles out of Moscow City towards Leon Junction. The Moscow City-North Lewiston 115 kV line is normally operated in a radial configuration open at Moscow City to avoid the line being overloaded for area outages. If the line section between North Lewiston and Leon Junction is lost (normal source), then the breaker is closed at Moscow City to pick up load at Leon Junction. Since the 7 mile line section being rebuilt is normally not carrying load, there are no offsets associated with this project.

- **Burke-Thompson A&B 115 kV Transmission Rebuild ($2.500 million):** The Burke-Thompson falls 115 kV lines are jointly owned by Avista and Northwestern Energy. Avista owns and operates the 4-mile line section from Burke to the Montana border on both the A&B lines. These lines are part of the Montana to Northwest transmission path that moves generation from Montana to load centers in both Eastern and Western Washington and also serves mining load and residential customers in the Silver Valley area of Idaho. The current lines are in poor condition and are a significant safety concern. In the winter, the snow levels get high enough to reduce conductor clearance so the lines have to be removed from service to ensure safety. This project will rebuild both the A&B lines to improve reliability and eliminate the need to open the lines during the winter. The projects will reuse the existing conductor so there will be no loss savings or offsets associated with the rebuild.

- **Millwood Sub Rebuild ($0.690 million):** In 2012 the Company will begin to rebuild the existing 115 kV Millwood substation. Millwood serves local area Avista customers and Inland Empire Paper Company one of Avista's largest industrial customers. The current substation is old, approaching full capacity, and contains a significant amount of PCBs that are an environmental concern. Most of this project is considered a distribution effort, but the 115 kV lines that feed the substation need to be reconfigured to support the substation rebuild effort. The costs included here are associated with the 115 kV line reconfigurations. The existing conductor will be reused so there are no offsets associated with this project.

- **Noxon-Hot Springs #2 230 kV reroute ($0.500 million):** The Noxon-Hot Springs project is being driven by environmental issues that are impacting the reliability of the lines. Several h-frame structures are being undercut due to the meandering of Beaver Creek. The Company had hoped to reroute the line by moving all impacted structures away from the creek. However, the property owners didn't support the new line route, so instead existing structures are being replaced with hybrid poles (concrete bottoms and steel tops) to eliminate the creeks impact on the poles. The new poles are being buried up to 25 feet to accommodate scouring. The project will reuse existing conductor so there are no offsets.

- **Pullman (Turner) Substation Rebuild ($0.151 million):** The old Pullman substation was rebuilt in 2011 due to equipment age and to support the installation of new equipment associated with the Smart Grid Demonstration Project approved and supported by the Department of Energy. The substation was rebuilt on its existing site but required expansion resulting in the need to build a temporary substation. The rebuild was completed and placed into service in December of 2011. In 2012 the temporary substation will be decommissioned and the cost associated with this effort is shown later in my testimony under distribution projects. Two spans of transmission conductor will be upgraded to match the rating of the rest of the line at a cost of $151,000.

<u>Reliability Replacements ($7.659 million)</u>

- **Transmission Minor Rebuilds ($2.370 million):** These projects include minor transmission rebuilds as a result of age or damage caused by storms, wind, fire, and the public. These 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 2011 the Company spent $2.465 million on these minor rebuild projects as a result of damage caused by weather or the public. Since the actual projects are not known offsets can't be determined.

- **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 Moscow 230 and Lind 115 kV substations.

- **Hatwai Breaker and switch replacement ($0.610 million):** Avista currently owns the breaker terminal at BPA's Hatwai substation associated with the Hatwai-North Lewiston 230 kV line. The Breaker and switches need to be replaced due to age. Avista has contracted with BPA to replace the breaker and three air switches in 2012 since BPA owns and operates the Hatwai substation.

- **Asset Management Replacement Programs ($3.479 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 is replaced when useful life has been exceeded. The equipment under these replacement programs are usually not maintained on a set schedule so there aren't any associated offsets.

Q. Please describe each of the distribution projects planned for in 2012.

A. The Company will spend approximately $64.431 million in Distribution projects at a system level, with $48.542 million specific to Washington in 2012. A summary of the projects is shown in Table 4 and a brief description of each project impacting Washington are given below.

TABLE 4

Distribution			
2012 Capital - Distribution Projects			
	Pro Forma (System)	**Pro Forma (Washington)**	**O&M Offsets Washington**
Distribution Projects			
Wood Pole Management	$13,025,000	$9,449,000	$14,400
System Efficiency Feeder Rebuilds	$7,371,000	$7,371,000	$31,000
PCB Related Distribution Rebuilds	$3,812,000	$1,755,000	$60,000
Distribution Spokane North and West	$1,910,000	$1,910,000	$1,300
System Dist Reliability Improve Worst Feeders	$1,950,000	$1,228,000	
Millwood Sub Rebuild	$1,000,000	$1,000,000	
Power Transformers - Distribution	$1,450,000	$958,000	
Pullman (Turner) Substation Rebuild	$609,000	$609,000	
Metro Feeder Upgrade	$502,000	$502,000	
Wood Substation Rebuild – Orin	$300,000	$300,000	
Total Distribution Projects	**$31,929,000**	**$25,082,000**	**$106,700**
Distribution Replacement Projects			
Elect Distribution Minor Blanket	$8,300,000	$5,065,000	
Failed Electric Plant	$2,200,000	$1,186,000	
Distribution Line Relocation	$1,900,000	$1,208,000	
Electric Underground Replacement	$1,792,000	$1,351,000	$57,000
Spokane Electric Network Increase Capacity	$1,650,000	$1,650,000	
Total Distribution Replacement Projects	**$15,842,000**	**$10,460,000**	**$57,000**
Smart Grid Projects			
Spokane Smart Circuit *	$5,400,000	$5,400,000	
Pullman Smart Grid Demonstration Project *	$6,300,000	$6,300,000	
Smart Grid Workforce Program *	$1,300,000	$1,300,000	
Total Smart Grid Projects	**$13,000,000**	**$13,000,000**	**$0**
Idaho Distribution Projects (not included in case)			
Blue Creek 115 kV Rebuild - ID	$1,905,000		
Distribution - Pullman & Lewis Clark - ID	$650,000		
Distribution - Cda East & North - ID	$855,000		
10 & Stewart Dx Int - ID	$250,000		
Total Idaho Distribution Projects	**$3,660,000**	**$0**	**$0**
Total Distribution Projects	**$64,431,000**	**$48,542,000**	**$163,700**
* These projects are described in detail by Company witness, Mr. Kopczynski, Exhibit No.__(DFK-1T).			

Distribution specific projects in Washington (including transformation) for 2012 total $25.082 million ($31.929 million system). 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 $25.082 million.

- **Wood Pole Management ($13.025 million system / $9.449 million Washington):** The distribution wood pole management program evaluates wood pole strength of a certain percentage of the wood pole population each year such that the entire system is inspected every 20 years. Avista has over 240,000 distribution wood poles and 33,000 transmission wood poles in its electric system. Depending on the test results for a given pole, the pole is either considered satisfactory, needing to be reinforced with a steel stub, or needing to be replaced. 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 containing more than or equal to 1 ppm polychlorinated biphenyls (PCBs), 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. The company expects to achieve $14,400 in savings resulting from reduced call outs to fix problems during 2012. The Company spent $15.961million (system) on these efforts in 2011.

- **System Efficiency Feeder Rebuild ($7.371 million Washington):** Beginning in 2012, Avista will begin a program to rebuild distribution feeders to reduce energy losses, improve operation of the feeders and increase long-term reliability. The program will replace poles, transformers, conductor and other equipment on a rural feeder and two urban feeders in 2012. The work associated with this effort will be completed between June and December. The energy savings from reduced losses calculated using an average of three months of savings is 400 MWh. This equates to an offset of $31,000 using an avoided cost of $77/MWh.

- **PCB Related Distribution Rebuilds ($3.812 million system / $1.755 million Washington):** In 2011, Avista initiated a systematic replacement of distribution line transformers because their oil contains PCBs. In addition, replacement of the "pre-1981" transformers has benefits of improving the energy efficiency and long-term reliability of the distribution system. 2012 represents year-two of a six year effort to replace these distribution transformers. In 2012, the program is expected to replace approximately 1500 line transformers in Washington. The replacement work is scheduled to be completed throughout the entire year. The energy savings from reduced losses calculated using a six months average is 1200 MWh system and 780 MWh in Washington. This equates to an offset of $60,000 assuming an avoided cost of $77/MWh.

- **Distribution – Spokane North & West ($1.910 million Washington)**: Distribution feeder upgrade/reconductor projects were identified by Distribution Planning as being thermally constrained. In order to maintain system reliability and service of customer load, these feeders will be reconductored during 2012. The reconductor efforts will result in some loss savings due to the installation of a larger conductor. The effort will result in annual loss savings of 32.9 MWh. The projects won't be completed until after June. Assuming avoided cost of $77/MWh, the total anticipated 2012 savings is $1,300.

- **System Distribution Reliability Improve Worst Feeders ($1.950 million system / $1.228 million Washington):** 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. This work will improve the reliability of these feeders and overall service to customers in these areas. The projects were selected based on poor reliability performance not on cost savings. The treatment of feeder projects varies from conversion of overhead to underground facilities, installing additional mid-line protective devices, to hardening of existing facilities.

- **Millwood Sub Rebuild ($1.000 million Washington):** In 2012 the Company will begin to rebuild the existing 115 kV Millwood substation. The complete rebuild will take three years. In 2012 a new panel-house, fencing, grading, and bus reconfiguration will be completed and put into service. Millwood serves local area Avista customers and Inland Empire Paper Company one of Avista's largest industrial customers. The current substation is old, approaching full capacity, and contains a significant amount of PCBs that are an environmental concern.

- **Power Transformer Distribution ($1.450 million system / $0.958 million Washington)**: 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 the proposed 2013 projects. There are no offsets associated with these transformers until they are placed into service.

- **Pullman (Turner) Substation Rebuild ($0.609 million Washington):** The old Pullman substation was rebuilt in 2011 due to equipment age and to support the installation of new equipment associated with the Smart Grid Demonstration Project approved and supported by the Department of Energy. The substation was rebuilt on its existing site but required expansion resulting in the need to build a temporary substation. The new substation was completed and placed into service in December of 2011. In 2012 the temporary substation will be decommissioned.

- **Metro feeder upgrade ($0.502 million Washington):** This is part of a multi-year program to systematically replace paper insulated, lead jacketed cable (PILC) in the Spokane Network Underground System. This program was identified in the 2009 Asset Management Plan as a priority for the Spokane Network. This replacement is being driven by environmental concerns. We have not experienced measurable outages on the cable so there are no calculated offsets.

- **Wood Substation Rebuild – Orin ($0.300 million Washington):** The 115 kV portion of Orin Substation will be rebuilt by replacing the existing wood structures with Avista's standard steel structures. The station was originally constructed in 1956 and needs to be rebuilt to today's design and construction standards.

The Company also will spend approximately $15.842 million (system) or $10.460 million (Washington share) in Distribution equipment replacements and minor rebuilds associated with aging distribution equipment, underground cable with poor reliability performance, replacements from storm damage, or relocation of feeder sections resulting from road moves. The exact location of these rebuild projects aren't known until testing is completed or equipment failures occur. A brief description of the projects included in these replacement efforts is given below.

- **Electric Distribution Minor Blanket Projects ($8.300 million system / $5.065 million Washington):** This effort includes the replacement of poles and cross-arms on distribution lines in 2012 as required, due to storm damage, wind, fires, or obsolescence. The Company spent $8.270 million in 2011 for these projects. Since the location of these replacements is not known and they still require crew call outs to perform, there aren't any associated offsets.

- **Failed Electric Plant ($2.200 million system / $1.186 million Washington):** Replacement of distribution equipment throughout the year as required due to equipment failure. The Company spent $1.384 million in 2011. There are no offsets or savings that can be determined for these projects because the age and status of the equipment being replaced are not known. The Company must replace the equipment to maintain customer load service.

- **Distribution Line Relocation ($1.900 million system / $1.208 million Washington):** The relocation of distribution lines as required due to road moves requested by State, County or City governments. The Company spent $2.061 million in 2011 on line relocations associated with road moves. There are no offsets or savings determined for these projects because the age and status of the equipment being moved are not known.

- **Electric Underground Replacement ($1.792 million system / $1.351 million Washington):** This effort involves replacing the first generation of Underground Residential District (URD) cable. This project 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 $3.887 million in 2011. The company anticipates that it will see approximately $82,000 (system) or $57,000 (in Washington) in incremental savings as a result of reduced cable failures. This is being included as an offset for the Electric Underground Replacement project.

- **Spokane Electric Network Increase Capacity ($1.650 million Washington):** These projects are associated with the Downtown Spokane electric network. The projects involve the installation of vaults, cables, network transformers and protectors, as required, to maintain reliable service to customers by replacing overloaded and deteriorated equipment.

Q. Please describe the Company's capital transmission projects that will be completed in 2013?

A. The major capital transmission costs (system) for projects to be completed in 2013 are approximately $33.604 million and are shown in Table 5 and described below.

TABLE 5		
Transmission		
2013 Capital - Compliance, Contractual, and Replacement Projects		
	Pro Forma (System)	**O&M Offsets (System)**
Reliability Compliance		
Spokane/CDA Relay Upgrade	$1,450,000	
SCADA Replacement	$450,000	
System Replace/Install Capacitor Bank	$1,050,000	
Moscow 230 kV Substation Rebuild	$7,619,000	$9,200
Bronx-Cabinet 115 kV Rebuild/Reconductor	$2,500,000	$4,800
Power Transformers - Transmission	$2,065,000	
Irvin 115kV Switching Station	$1,150,000	
Opportunity 115 kV Switching Station	$1,550,000	
Opportunity 12F2	$400,000	
Total Reliability Compliance	**$18,234,000**	**$14,000**
Contractual Requirements		
Lancaster 230 kV Interconnection	$3,700,000	
Colstrip Transmission	$463,000	
Tribal Permits	$332,000	
Total Contractual Requirements	**$4,495,000**	**$0**
Reliability Improvements		
Moscow City-N Lewiston 115 kV Reconductor	$2,450,000	
Burke-Thompson A&B 115 kV Reconductor	$2,500,000	$1,600
Total Reliability Improvements	**$4,950,000**	**$1,600**
Reliability Replacement		
Transmission Minor Rebuilds	$2,200,000	
Power Circuit Breakers	$1,200,000	
Hatwai 230 kV Breaker Replacement	$215,000	
Asset Management Replacement	$2,310,000	
Total Reliability Replacement	**$5,925,000**	**$0**
Total Transmission Projects	**$33,604,000**	**$15,600**

<u>Reliability Compliance Projects ($18.234 million):</u>

- **Spokane/Coeur d'Alene area relay upgrade ($1.450 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. The SCADA system requires annual enhancements to improve performance, replace computer systems and networks, and integrate vendor provided improvements. 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 ($1.050 million)**: This effort includes the replacement of the 115 kV capacitor bank at the Odessa 115 kV substations to support local area voltages during system outages and summer irrigation load conditions. This 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 Odessa project is scheduled to be completed by June 2013. There are no loss savings or other offsets associated with these projects. The project improves voltage support but doesn't reduce loss savings.

- **Moscow 230 kV Sub - Rebuild 230 kV Yard ($7.619 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. Currently the existing 230/115 kV autotransformer overloads for an outage of another autotransformer in the area during peak load conditions. The 230 kV portion of 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 substation occurring in November of 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 $9,200 in the pro forma period (based on a $77/MWh avoided energy cost and an energization date of November, 2013).

- **Bronx – Cabinet 115 kV rebuild/reconductor ($2.500 million)**: In 2010 Avista's System Operations identified a thermal constraint on the 32-mile Bronx-Cabinet 115kV Transmission Line. This constraint was confirmed by the System Planning Group, and documented in the Transmission Line Design (TLD) Design Scoping

Document (DSD) created on January 4, 2011, and modified on January 7, 2011. The reconductoring/rebuilding of this line with 795 kcmil ACSS conductor will provide a present-day 143 MVA line rating to match the Cabinet Switchyard Transformer, and a future 200 MVA line rating to match the parallel path Bonneville Power Authority (BPA) system. The 32 miles of line will be reconductored over a four year period, which began in 2011. Phase 3 of the project (addressed here) consists of reconductoring an 8-mile section of the line. The line upgrade will ensure compliance with requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Using 2010 actual loads, since the line was operated open in over half of 2011 for construction of the first phase of the project, the new conductor will reduce line losses by 755 MWh on an annual basis. This project will not be completed until December 2012 so offset savings of $4,800 will be observed in 2012 (based on a $77/MWh avoided energy cost).

- **Power Transformers – Transmission ($2.065 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. The autotransformer purchased in 2013 may be part of the Westside project or included as a system spare. The transformer will be capitalized upon delivery per the Company's accounting practices. The Westside project is required to meet Reliability Compliance under NERC Planning and Operations 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 autotransformer is actually placed into service.

- **Irvin 115 kV Switching Station ($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 2013, $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. Since this is a new transmission line, no offsets will be observed.

- **Opportunity 115 kV Switching Station ($1.550 million):** This project involves adding three 115 kV breakers to the existing Opportunity substation. The project is part of a group of projects to support the reliability of the 115kV transmission system and accompanying load service in the Spokane Valley. The completion of the Opportunity switching station will allow for the connection of a 115 kV line from the new Irvin Substation as well as future construction of the Greenacres substation in 2014. This upgrade will ensure compliance with requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3.

- **Opportunity 12F2 ($0.400 million):** In order to support the reliability of the Spokane Valley, a 115 kV transmission line needs to be added from the new

Opportunity switching station to the new Irvin 115 kV switching substation. This project involves the under-build of a feeder on a 115 kV transmission line. The 115 kV line currently operates at Distribution voltage but will be reenergized at 115 kV with the completion of the feeder under-build. This will require the addition of a 115 kV line to the existing Opportunity 12F2 feeder poles. The transmission line upgrade will ensure compliance with requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3.

Contractual Requirements ($4.495 million):

- **Lancaster 230 kV Interconnection ($3.700 million):** Avista plans to interconnect to BPA's existing 230 kV Lancaster substation by looping in its Boulder-Rathdrum 230 kV line. The interconnection improves the load service and system reliability in the Coeur d'Alene and Rathdrum Prairie areas of Avista's service territory. The interconnection also reduces the loading on the heavily loaded Beacon-Bell transmission lines that serve the Spokane area. The interconnection will provide direct transmission access to output of the Lancaster natural gas combined cycle plant. Avista owns part of the plant and has a power purchase agreement for the remainder of the plant output. BPA will perform the upgrade work, including the addition of 2 new breakers, required at Lancaster substation for a cost of $3.2 million and Avista will perform the necessary transmission line work to loop in its Boulder Rathdrum line for a cost of $0.500 million.

- **Colstrip Transmission ($0.463 million):** As a joint owner of the Colstrip Transmission projects, Avista pays its ownership share of all capital improvements. Northwestern Energy either performs or contracts out the capital work associated with the jointly owned facilities.

- **Tribal Permits ($0.332 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.

Reliability Improvements ($4.950 million):

- **Moscow City-North Lewiston 115 kV Transmission Rebuild ($2.450 million):** This project includes the reconductor/rebuild of the 22-mile line between Moscow City substation and North Lewiston due to the poor condition of the existing line. The project will be completed in three phases. The first phase will be completed in 2012 and the second phase in 2013. The 2013 effort includes reconductoring/rebuilding seven miles of line, completing the line section between Moscow city and Leon Junction. Phase 3 in 2015 will complete the 8-mile line section between Leon Junction and North Lewiston. The Moscow City-North Lewiston 115 kV line is normally operated in a radial configuration open at Moscow City to avoid the line being overloaded for area outages. If the line section between

North Lewiston and Leon Junction is lost then the breaker is closed at Moscow City to pick up load at Leon Junction. Since the line section being rebuilt is normally not carrying load, there are no offsets associated with this project.

- **Burke-Thompson A&B 115 kV Transmission Rebuild ($2.500 million):** This project is the second phase of the Burke-Thompson A&B line rebuild effort that will begin in 2012. The 5-6 miles stretch on Burke-Pine Creek #4 115kV Line between Wallace and Burke Substation will be rebuilt. These lines are part of the Montana to Northwest transmission path that moves generation from Montana to load centers in both Eastern and Western Washington and also serves mining load and residential customers in the Silver Valley area of Idaho. The current lines are in poor condition. The projects will result in loss savings due to the replacement of the existing conductor with a larger conductor. The new conductor has less resistance resulting in savings of 251 MWh for an entire year. The project is scheduled to be energized in December 2013. Assuming an avoided cost of $77/MWh total 2013 savings is $1,600.

<u>Reliability Replacements ($5.925 million)</u>

- **Transmission Minor Rebuilds ($2.200 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 2011 the Company spent $2.465 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 2013 are planned for installation at Irvin and Odessa substations.

- **Hatwai Breaker and switch replacement ($0.215 million):** Avista currently owns the relays at BPA's Hatwai substation associated with the breaker terminal of Hatwai-North Lewiston 230 kV line. The relay and protection system needs to be upgraded along with the breaker and switches that are planned to be replaced in 2012. Avista has contracted with BPA to replace the relays and protection system since BPA owns and operates the Hatwai substation.

- **Asset Management Replacement Programs ($2.310 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 is replaced when useful life has been exceeded. The equipment under these replacement programs are usually not maintained on a set schedule so there aren't any associated offsets.

Q. Please describe each of the distribution projects planned for in 2013.

A. The Company will spend approximately $53.934 million in Distribution projects at a system level, with $32.779 million specific to Washington in 2013. A summary of the projects is shown in Table 6 and a brief description of each project impacting Washington are given below.

TABLE 6

Distribution			
2013 Capital - Distribution Projects			
	Pro Forma (System)	**Pro Forma (Washington)**	**O&M Offsets Washington**
Distribution Projects			
Wood Pole Management	$12,016,000	$8,133,000	$14,400
System Efficiency Feeder Rebuilds	$8,001,000	$4,838,000	$20,000
PCB Related Distribution Rebuilds	$2,925,000	$2,026,000	$64,000
Feeder Automation Upgrades	$2,501,000	$2,501,000	$564,000
Distribution Spokane North and West	$500,000	$500,000	$1,100
Millwood Sub Rebuild	$3,000,000	$3,000,000	$1,500
Power Transformers - Distribution	$2,100,000	$350,000	
Metro Feeder Upgrade	$498,000	$498,000	
Total Distribution Projects	**$31,541,000**	**$21,846,000**	**$665,000**
Distribution Replacement Projects			
Elect Distribution Minor Blanket	$8,300,000	$5,065,000	
Failed Electric Plant	$2,250,000	$1,213,000	
Distribution Line Relocation	$2,200,000	$1,397,000	
Spokane Electric Network Increase Capacity	$1,763,000	$1,763,000	
Total Distribution Replacement Projects	**$14,513,000**	**$9,438,000**	**$0**
Smart Grid Projects			
Pullman Smart Grid Demonstration Project *	$195,000	$195,000	
Smart Grid Workforce Program *	$1,300,000	$1,300,000	
Total Smart Grid Projects	**$1,495,000**	**$1,495,000**	**$0**
Idaho Distribution Projects (not included in case)			
Distribution - Cda East & North - ID	$500,000		
Distribution - Pullman & Lewis Clark	$500,000		
System Wood Substation Rebuild	$3,705,000		
N. Moscow Increase Capacity - ID	$1,680,000		
Total Idaho Distribution Projects	**$6,385,000**	**$0**	**$0**
Total Distribution Projects	**$53,934,000**	**$32,779,000**	**$665,000**

* These projects are described in detail by Company witness, Mr. Kopczynski, Exhibit No.__(DFK-1T).

Distribution specific projects in Washington (including transformers) for 2013 total $21.846 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 $21.846 million.

- **Wood Pole Management ($12.016 million system / $8.133 million Washington):** The distribution wood pole management program evaluates wood pole strength of a certain percentage of the wood pole population each year such that the entire system is inspected every 20 years. Avista has over 240,000 distribution wood poles and 33,000 transmission wood poles in its electric system. Depending on the test results for a given pole, the pole is either considered satisfactory, needing to be reinforced with a steel stub, or needing to be replaced. 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. The Company expects to achieve $14,400 in savings resulting from reduced call outs to fix problems during 2013. The Company spent a total $15.961 million (system) on these efforts in 2011.

- **System Efficiency Feeder Rebuild ($8.001 million system / $4.838 Washington):** Beginning in 2012, Avista will begin a program to rebuild distribution feeders to reduce energy losses, improve operation of the feeders and increase long-term reliability. The program will replace poles, transformers, conductor and other equipment on a rural feeder and two urban feeders in 2012. The work associated with this effort will be completed between June and December of 2013. The energy savings from reduced losses calculated using an average of three months of savings is 400 MWh. This equates to an offset of $31,000 system and $20,000 in Washington using an avoided cost of $77/MWh.

- **PCB Related Distribution Rebuilds ($2.925 million system / $2.026 million Washington):** In 2011, Avista initiated a systematic replacement of distribution line transformers because their oil contains PCBs. In addition, replacement of the "pre-1981" transformers has benefits of improving the energy efficiency and long-term reliability of the distribution system. 2013 represents year-three of a six year effort to replace these distribution transformers. In 2013, the program is expected to replace approximately 1600 line transformers in Washington. The replacement work is scheduled to be completed throughout the entire year. The energy savings from reduced losses calculated using a six months average is 1200 MWh system and 830 MWh in Washington. This equates to an offset of $64,000 assuming an avoided cost of $77/MWh.

- **Feeder Automation Upgrades ($2.501 million Washington):** In 2012 and 2013, Avista will continue the installation of feeder automation equipment in urban areas of the distribution system. The work in 2012 will continue the development of intelligent device standards and methods for feeder automation. In 2013 additional feeders in Spokane will be automated. As the utility upgrades the Millwood Substation, the Feeder Automation project will provide upgrades to the distribution feeders in that area. Feeders at Ninth & Central and Beacon will also be automated. The circuits that are upgraded with feeder automation equipment will allow the Distribution Management System to make real time system decisions and improve feeder reliability and reduce feeder losses. Anticipated loss savings for the 2013 feeder automation efforts will result in approximate reduction of 7230 MWh resulting in savings of $557,000. This assumes one of three the projects being completed in March, one in June, and one in August. The Company also plans to reduce Operating and Maintenance cost by $7,000 based on improvements to the crew dispatching process. Therefore the total offsets for the Feeder Automation Upgrades are $564,000 in 2013.

- **Distribution – Spokane North & West ($0.500 million Washington)**: Distribution feeder segment reconductor projects were identified by Distribution Planning as being thermally constrained. In order to maintain system reliability and service of customer load, these feeders will be reconductored during 2013. The reconductor efforts will result in some loss savings due to the installation of a larger conductor. The effort will result in annual loss savings of 28.5 MWh. The projects won't be completed until after June. Assuming avoided cost of $77/MWh, the total anticipated 2013 savings is $1,100.

- **Millwood Sub Rebuild ($3.000 million Washington):** In 2012 the Company will begin to rebuild the existing 115 kV Millwood substation. The complete rebuild will take three years. Millwood serves local area Avista customers and Inland Empire Paper Company one of Avista's largest industrial customers. The current substation is old, approaching full capacity, and contains a significant amount of PCBs that are an environmental concern. The work completed in 2013 will include the installation and energization of one of the two transformers in November. The new transformer will result in lower losses creating an offset. The transformer losses will be reduced by 115 MWh. This results in savings of $1,500 assuming an avoided cost of $77 MWh.

- **Power Transformer Distribution ($2.100 million system / $0.350 million Washington)**: Transformers are transferred to plant upon receiving them. These transformers are being purchased to replace existing spares that will be installed in 2013 as either replacements or new installations. The purchased transformers will either remain as system spares or placed into service as part of proposed 2014 projects. There are no offsets associated with these transformers until they are placed into service.

- **Metro Feeder Upgrade ($0.498 million Washington):** This is year two of a multi-year program to replace paper insulated lead jacketed cable throughout the Spokane Underground Network. Year one and two (2012-2013) concentrate reconstruction on feeder lines served via Metro Substation. This replacement is being driven by environmental concerns. We have not experienced measurable outages on the cable so there are no calculated offsets.

The Company also will spend approximately $14.513 million (system) or $9.438 million (Washington share) in Distribution equipment replacements and minor rebuilds associated with aging distribution equipment, underground cable with poor reliability performance, replacements from storm damage, or relocation of feeder sections resulting from road moves. The exact location of these rebuild projects aren't known until testing is completed or equipment failures occur. A brief description of the projects included in these replacement efforts is given below.

- **Electric Distribution Minor Blanket Projects ($8.300 million system / $5.065 million Washington):** This effort includes the replacement of poles and cross-arms on distribution lines in 2013 as required, due to storm damage, wind, fires, or obsolescence. The Company spent $8.270 million in 2011 for these projects. Since the location of these replacements is not known and they still require crew call outs to perform, there isn't any associated offsets.

- **Failed Electric Plant ($2.250 million system / $1.213 million Washington):** Replacement of distribution equipment throughout the year as required due to equipment failure. The Company spent $1.384 million in 2011. There are no offsets or savings that can be determined for these projects because the age and status of the equipment being replaced are not known. The Company must replace the equipment to maintain customer load service.

- **Distribution Line Relocation ($2.200 million system / $1.397 million Washington):** The relocation of distribution lines as required due to road moves requested by State, County or City governments. The Company spent $2.061 million in 2011 on line relocations associated with road moves. There are no offsets or savings determined for these projects because the age and status of the equipment being moved are not known.

- **Spokane Electric Network Increase Capacity ($1.763 million Washington):** These projects are associated with the Downtown Spokane electric network. The projects involve the installation of vaults, cables, network transformers and protectors, as required, to maintain reliable service to existing customers by replacing overloaded and deteriorated equipment.

V. Vegetation Management Program

Q. Please provide an update on the Company's vegetation management program?

A. "Avista's Vegetation Management Program" is still striving towards an average frequency of 4 years. Work performed as part of Avista's Performance Excellence Initiative suggested changes to the Company's contracting practices could provide increased efficiencies, allowing more work to be performed on an annual basis. For 2012, a new contract with provisions to transition from "time and material pricing" at the beginning of the year to a unit price structure by the end of the year was established. Avista will be measuring the results to quantify potential value and opportunities that would allow us to approach a four-year cycle within our current annual spending level for distribution feeders of $4.1 million. Accordingly, the Company has not made an adjustment for Vegetation Management.

The work performed over the past few years has made a positive impact to Avista's performance. While the number of "Tree Fell" events in our Outage Management Tool (OMT) shows a small trend upwards (Illustration 1), the number of "Tree Growth" events has declined over the past 4 years, except for a slight increase in 2011. The real improvement from Vegetation Management shows up in the number of outages (Illustration

2). The number of outages or partial outages due to “Tree Fell” and “Tree Growth” events has generally decreased.

Illustration 1 – Number of OMT Events

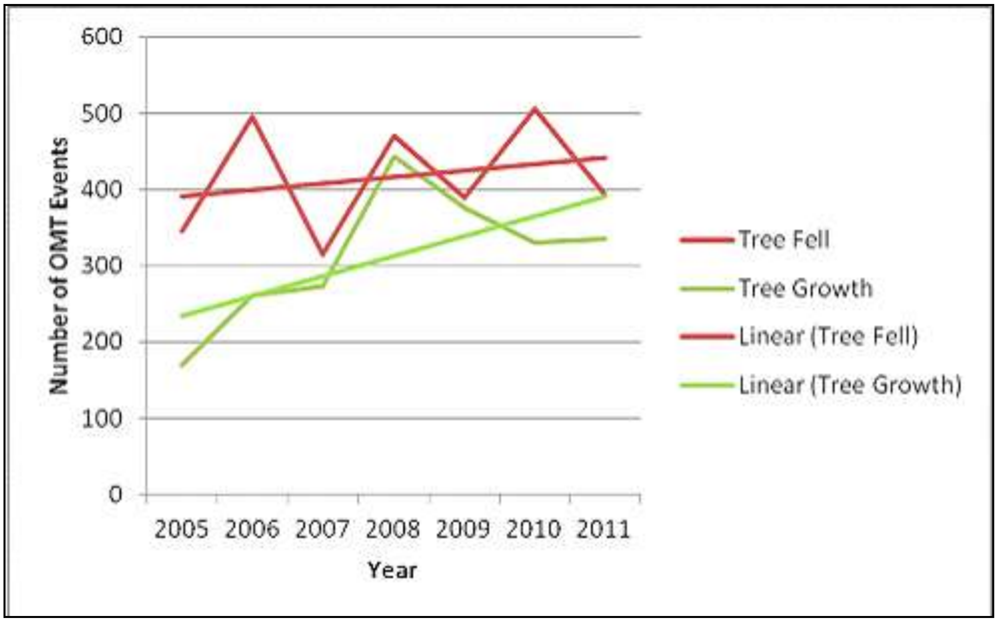
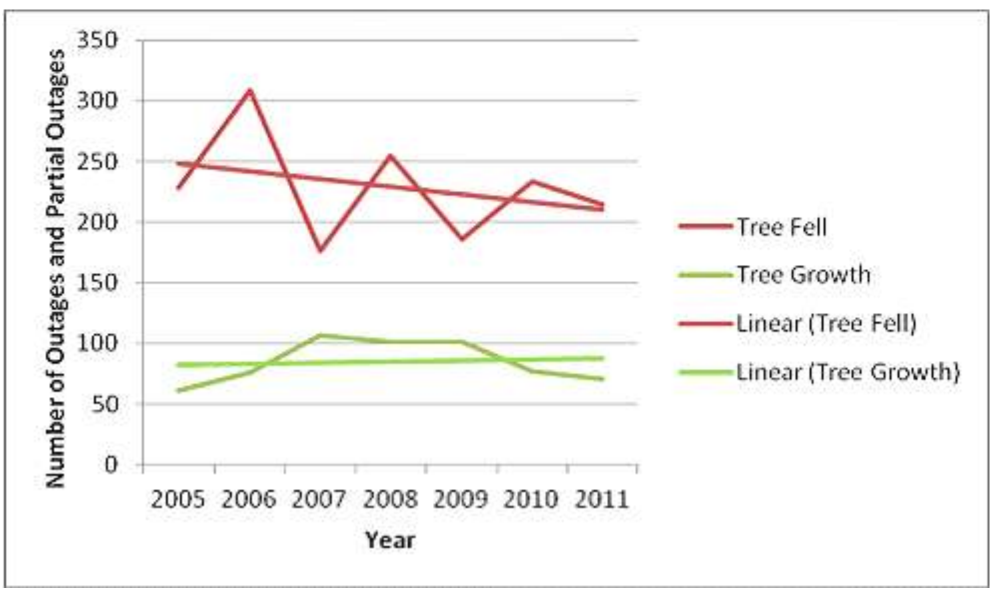


Illustration 2 – Number of Outages



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

A. Yes it does.