AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/23/2015
CASE NO:	UE-150204 &UG-150205	WITNESS:	Karen Schuh
REQUESTER:	ICNU	RESPONDER:	Karen Schuh
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	ICNU – 006	TELEPHONE:	(509) 495-2293
		EMAIL:	karen.schuh@avistacorp.com

REQUEST:

Please explain in detail the need for any significant capital expenditure (above $20 million) when Avista is experience no load growth.

RESPONSE:

The Company has the following projects over $20 million on a system basis:

- Transmission – Reconductors and rebuilds are listed in Company witness Schuh's, Exhibit No. __(KKS-4), totaling $21.161 million (System) in 2016. ICNU_DR__006 Attachment A, Electric Transmission 2014 Annual Update, in the Capital Replacement and Maintenance Investment section (pages 13 –19) describes the need for this spending in order to maintain the reliability of the system.

- The Customer Information System (Project Compass) is also listed in Exhibit No__(KKS-4), page 4 and totals $95.108 million (System) in 2015. Company witness Mr. Kensok discusses the Customer Information System in his testimony at Exhibit No. ___(JMK-1T).

- Nine Mile Rehab Project is also listed in Exhibit No.___(KKS-4), page 6 and totals $51.323 million (System) in 2015. Company witness Mr. Kinney discusses the Nine Mile Rehab Project in his direct testimony at Exhibit No. ___(SJK-1T).

- Washington Advanced Metering Infrastructure (AMI) is listed in Exhibit No.__(KKS-4) and totals $32.243 million (System) in 2016. Company witness Mr. Kopczynski discusses the Washington AMI Project in his direct testimony at Exhibit No. ___(DFK-1T).

In general, all of these projects are largely predicated on the advancing age and declining functionality of the plant being replaced. And in order to achieve optimum life-cycle cost/value for ratepayers, these categories of plant need to be replaced in a timely manner.

2014

Electric Transmission System 2014 Annual Update

For Internal Use Only

Rendall Farley, Tia Benjamin
Asset Management
Avista Corp.
03-31-2014

Front cover:

Inspector Javier Tamez testing the Walla Walla – Wanapum 230kV line
(December, 2013)

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Purpose

Annual updates are meant to serve a general audience from the perspective of long-term, balanced optimization of lifecycle costs, performance, and risk management. The intent is to help the reader become rapidly familiar with the system's physical assets, performance, risks, and replacement and maintenance programs. Consistent annual updates also provide the continuity required for useful historical information and continuous improvement of asset management practices.

In addition to this narrative report, two other elements of the annual update include a "Quick Facts" sheet highlighting key points, and a spreadsheet providing supporting data. Additional "Quick Facts" sheets describing various asset management programs and projects are also available. This annual update reflects the best available information as of December 31, 2013. For more details, please visit the Asset Management Sharepoint site at AM Annual Updates.

Executive Summary

In order to maintain reliability levels and provide the best value to customers, the bulk of Avista's aging transmission infrastructure requires replacement over the next 20 to 30 years. This totals over $600M in capital replacement investment, based on current material, labor and other project costs. Ramping up over the next two years, we are effectively doubling planned design and construction output from the former $12M to a sustained level of over $25M in annual projects. This represents a significant undertaking, requiring careful management and support. In order to be most effective, it also requires fact-based prioritization and targeting of available funds to the riskiest elements of the system. In this respect, although a long term capital replacement budget of over $20M per year is clearly needed, planned condition assessment of older lines in the next few years may well justify larger investments in the near term.

While outages and related unplanned/emergency spending on the 230kV system have remained at a relatively low level (less than $200k per year), they increased substantially for the 115kV system to over $1.5M in 2013. This continues a trend of rising 115kV emergency spending since 2011. However, if not for two separate storm events in Othello and northeast Washington, 115kV emergency spending would have seen a slight decrease from the $1.1M spent in 2012. While no statistically significant trends are evident, last year also saw an increase in outages caused by birds and other animals, primary conductor, and vehicles hitting poles. Pole fires and tree related issues continued to decrease, possibly due to the effectiveness of fire protective coatings and the transmission vegetation management programs.

Notable achievements in 2013 include continued compliance with clearance mitigation (LiDAR) work mandated by NERC . Nine LiDAR projects were completed last year, maintaining schedule for all lines complete in 2015. Major rebuilds of the Moscow City to North Lewiston 115kV line at $6.4M, and the Burke-Thompson A&B 115kV lines at $2.2M were also accomplished. Wood pole inspections surpassed goals last year, allowing for earlier condition assessment and future rebuild work on the Walla Walla – Wanapum and Hot Springs – Noxon #2 230kV lines. Although for a few more years many 115kV lines will not have had a ground inspection for 20 years, at the current pace we will reach the targeted 15-year inspection cycle for all transmission circuits by 2019. With a few exceptions, timely follow-up work remains on-track. Confirmation of 230kV data including the location of larch wood poles is now complete and progress is underway on the 115kV system. This is critical to making more accurate risk assessments and effectively targeting capital funding, given the shorter service life of larch compared to cedar wood species. The large backlog of job updates to drawings and electronic records was also completed, as well as a detailed air switch asset inventory, preparations for Maximo implementation, the development of new standards and methods integrating the use of new PLS-CADD design software, and a root cause analysis and implementation of preventive actions following the Othello storm.

Beyond execution of approved construction, below is a list of recommended initiatives to further improve the long-term performance and management of transmission assets.

<u>Top 10 Recommendations</u>

1. Confirm the location, quantity and age of larch, cedar and steel poles on all 115kV circuits.
2. Complete the Risk Index for all transmission circuits, use it to prioritize and schedule ground inspections, business case development, follow-up repairs and rebuilds.
3. Continue refinement, reporting and use of transmission system KPIs.
4. Complete simulation studies and business cases for rebuilds of Cabinet – Noxon, Benewah – Pine Creek, and Hot Springs – Noxon #2 230kV circuits in 2014.
5. Complete a system-wide simulation study to support optimal Transmission asset inspection intervals and long-term asset replacement policies/budgets.
6. Investigate industry best practices and develop agreement on a systematic air switch risk ranking method, replacement schedule, and inspection and maintenance program.

7. Reduce the lead time for as-built construction updates to AFM, Plan and Profile (P&P) drawings, and the engineering vault files to one month (currently 6 to 12 months).

8. Investigate industry best practices, develop and implement an inspection and planned maintenance program for steel transmission structures.

9. Determine the risks and appropriate mitigation work resulting from structural loads of distribution underbuild, across the entire transmission system.

10. Publish a major revision of transmission construction standards, accurately reflecting best practices in design and construction work. Engage the line crews and regional staff, commit to continuous improvement and prompt updates of these standards for the long term.

Assets

The tables and charts below provide a high-level summary of physical assets in the transmission system. Replacement values represent the cost to replace existing assets with equivalent new equipment in 2014 dollars, not including right-of-way purchases, capacity or ratings upgrades, mandated projects, and other work associated with growth-related installations.

	Average Replacement Cost/Mile			
Circuit Type	**Installation**	**Removal**	**Miles**	**Total Replacement Cost**
60kV Circuit	$250,000	$20,000	0.4	$72,049
115 Single Circuit	$400,000	$20,000	1452.2	$609,915,600
115 Underground Circuit	$3,600,000	$180,000	2.8	$10,584,000
115 Double Circuit	$525,000	$20,000	23.9	$13,014,600
230 Single Circuit	$700,000	$20,000	604.0	$434,851,200
115-230 Double Circuit	$850,000	$20,000	55.3	$48,145,800
230 Double Circuit	$900,000	$20,000	25.8	$23,736,000
			2164.3	**$1,140,319,249**
		Average Asset Lifecycle (Years)		70
Annual Levelized Replacement Spending over Lifecycle				**$16,290,275**

Table 1: Primary Assets of the Electric Transmission System – Circuits

	Quantity			
Asset Category	**230kV**	**115kV**	**Total**	**Expected Service Life (years)**
Structures	4990	16483	21473	70
Poles	9021	27401	36422	78
Air switches (not incl substations)	2	188	190	40
Conductor (miles)	2055	4602	6657	100
Compression sleeves	1370	3068	4438	50
Insulators (Ceramic/Poly/Glass)	22978	60202	83180	70

Table 2: Component Assets and Quantities

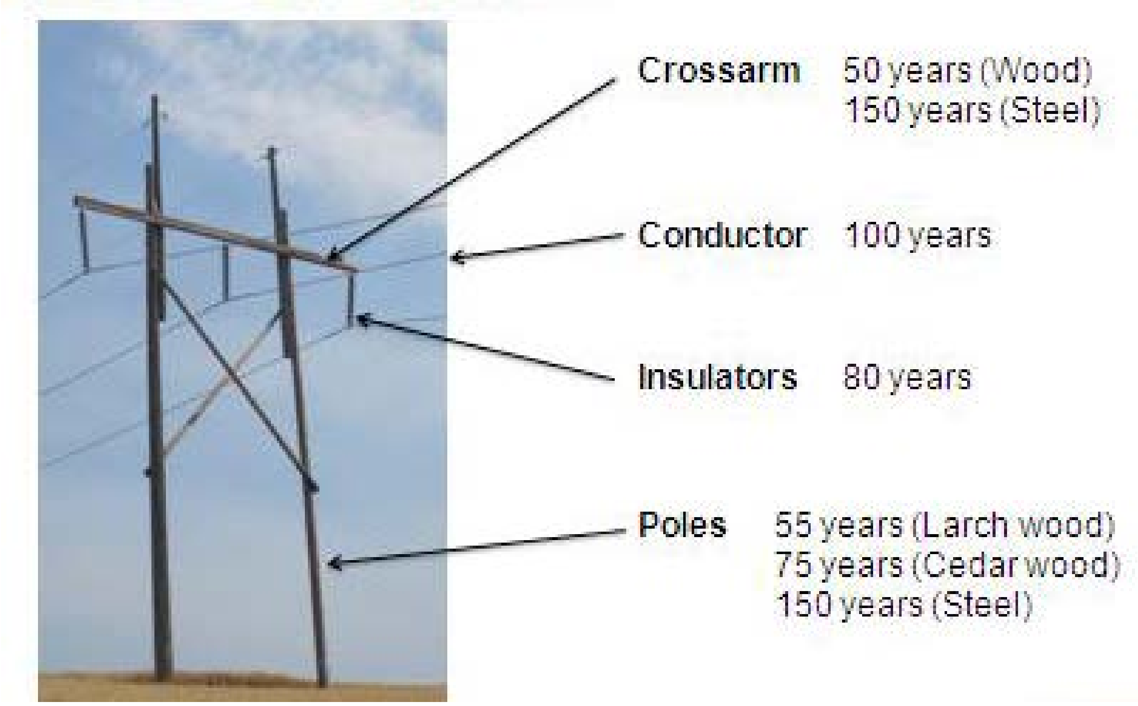
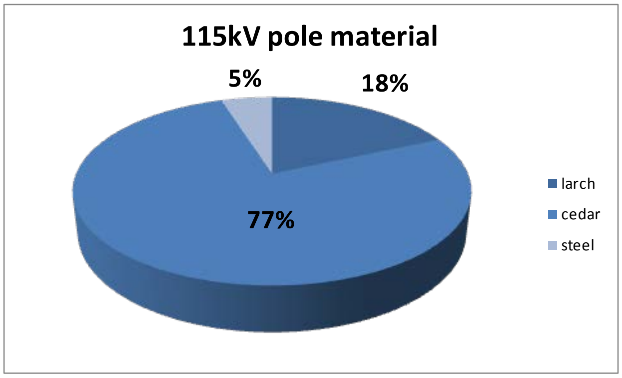
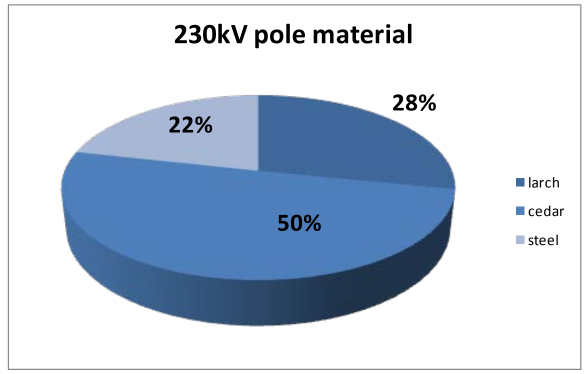


Figure 1: Example Transmission Asset Components and Expected Service Life

100	Steel Towers (galvanized steel)
50	Steel Pole/Tubular structures (galvanized or painted)
2585	Self-Weathering Steel Structures
18817	Wood Pole Structures
4	Hybrid Concrete/Steel structures
0	Concrete Structures
0	Aluminum Structures
40	Laminated Wood Structures
21596	Total Transmission Structures
9.7	average # structures/mile
3277	# self-weathering (cor-ten) steel poles
50	# tubular galvanized steel poles
8	# hybrid concrete/steel poles
7602	# larch poles
366	# fir poles
25079	# cedar poles
40	# laminated wood poles
36422	Total # Poles
6247	# beyond expected service life
17%	% beyond expected service life
80	# of structures with buried galvanized steel foundations
1014	# of structures with coated buried steel foundations
unknown	# of structures with caisson concrete foundations
2700	# of structures with anchors

Table 3: Transmission Structures and Poles





pole material	larch	cedar	steel	total
service life	55	75	150	78
# 115 poles	4989	20820	1341	27150
# 230 poles	2613	4665	1994	9272
total # poles	7602	25485	3335	36422

Table 4: 115kV vs 230kV Pole Materials

Key Performance Indicators (KPIs)

The table below shows overall KPI results for 2013, which are monitored and recorded on a monthly basis throughout the year. The first four are leading indicators over which we have direct operational control. The final two KPIs are lagging indicators of system performance, which should have a causal link to the leading indicators. In other words, if we consistently execute well as demonstrated by the leading indicators, over time we should see satisfactory outcomes as manifested by the lagging indicators, and vice versa. When this does not occur, deeper investigation and root-cause analysis is justified, as something other than the expected causal relationship is potentially at play.

Completed Ground Inspections	Goal	Actual	Normalized
# wood poles ground inspected	2,400	3,476	0.69

Completed Aerial Inspections	Goal	Actual	Normalized
% of 230kV system inspected	100	100	1.00
% of 115kV system inspected	70	70	1.00

Followup Repair Backlog	Goal	Actual	Normalized
# worksites overdue (> 1 year after inspection year)	10	10	1.00
# Category 4 or 5 items overdue (> 6 months since inspection, ground	1	1	1.00
oldest item in backlog (# months since inspection)	18	17	0.94

Aging Infrastructure Replacement	Goal	Actual	Normalized
# 115kV wood poles older than 60 years replaced with steel	500	296	1.86
# 230kV wood poles older than 50 years replaced with steel	175	15	23.33
# air switches > 40 yrs old replaced	4	5	0.80

Reliability Performance	Goal	Actual	Normalized
Extended Unplanned Outages due to Transmission (Customer-Hrs)	113,142	238,861	2.88
# of Customers with Unplanned Transmission Outages > 3 Hrs	10,182	17,135	3.17

Emergency Spending	Goal	Actual	Normalized
230kV Emergency Spending	$204,022	$118,329	0.58
115kV Emergency Spending	$1,116,997	$1,512,614	1.35
Total Emergency Spending	$1,321,019	$1,630,943	1.23

Unity Box Metric	Weighting	2013 Result
Completed Ground Inspections	20%	**0.7**
Completed Aerial Inspections	20%	**1.0**
Followup Repair Backlog	15%	**1.0**
Aging Infrastructure Replacement	15%	**6.1**
Reliability Performance	15%	**1.7**
Emergency Spending	15%	**1.2**
Sum of Weight * Value	100%	**1.8**

Results
1 = Planned/On-Track
< 1 = Better than Planned
> 1 = Worse than Planned

Table 5: Transmission KPIs and Unity Box Metrics

By these measures, performance was much better than planned for structural ground inspections, as the Walla-Walla – Wanapum 230kV line was inspected ahead of schedule to facilitate mandated clearance violation mitigation and other repair work in 2014. Aerial patrol inspections and system-wide followup repairs from ground and aerial patrol inspections remained on-track overall. Emergency spending was slightly worse than "planned" (the average since 2009), and reliability performance even more so – as detailed in the unplanned spending and outages sections of this report. Aging infrastructure replacement was much less than that required to maintain system reliability over the long term, as recently established with levelized replacement budgets recommended at $21M per year over a 30-year timeframe ($12M for aging 115kV, $9M for 230kV). As we ramp up replacement construction in the years ahead, we expect to meet or exceed these goals. We will continue to replace equipment primarily on the basis of recent inspection and condition assessments. However the age and respective service life of the system at a high-level provides a strong leading indicator of long-term system reliability.

Additional performance measures are tabulated below since 2009:

Performance Measure	Goal	2009	2010	2011	2012	2013	Remarks
Customer-Hours unplanned, extended outage due to transmission issues	113142	129,780	255,426	64,453	82,908	238,861	
# of customers of Tx related unplanned outages greater than 3 hrs	10182	12,197	16,478	6,644	5,409	17,135	
Tx emergency repair costs	$1,321,019	$1,401,539	$1,442,969	$1,029,597	$1,409,972	$1,630,943	
Avista crew safety: # recordable injuries from Transmission work	0	not avail	not avail	not avail	not avail	not avail	Unable to isolate to Transmission
Top 10 highest risk circuits	TBD	not avail	not avail	not avail	not avail	in progress	Critical to identify larch pole locations for 115kV
Top 10 worst performing components - by failures	NA	not avail	not avail	not avail	not avail	not avail	Not available from OMT data
Top 10 worst performing circuits by # of component failures	NA	not avail	not avail	not avail	not avail	not avail	Not available from OMT data

Table 6: Additional Performance Measures, 2009 - 2013

Note that important performance measures currently cannot be evaluated due to inadequate data availability. This includes safety incidents from transmission work, the total number of annual failures and respective failure modes for various asset components such as poles, air switches, crossarms, insulators, splice connections, and so forth. An ongoing, long-term effort is necessary to make this information available and assimilate into our set of KPIs and circuit risk rankings.

Capital Replacement and Maintenance Investment

Levelized replacement spending represents the annual spending required to replace the asset category in a perfectly level form over the asset's service life in 2014 dollars, not including inflation. Prior to adjusting for uneven service life profiles, this provides a simple, rough-cut measure to compare against actual replacement spending each year, i.e. the minimum needed to keep up with aging infrastructure replacement. This currently stands at $16.3 M per year for the transmission system.

Relative to other major areas of the transmission and distribution (T&D) system, transmission assets have a longer service life, and the total replacement value of $1.1B is on par with substation's $0.9B and about half of distribution's $2.0B. All together, levelized replacement spending is roughly $84 M per year in perpetuity for Avista's T&D system (2014 dollars). However, as shorter lived wood materials are replaced with steel in the decades ahead, we expect overall service life to increase from 70 years to over 100 years for the transmission system. Assuming all other factors being equal, this in turn would reduce the minimum levelized spending to under $12M/year, roughly 50 years from now.

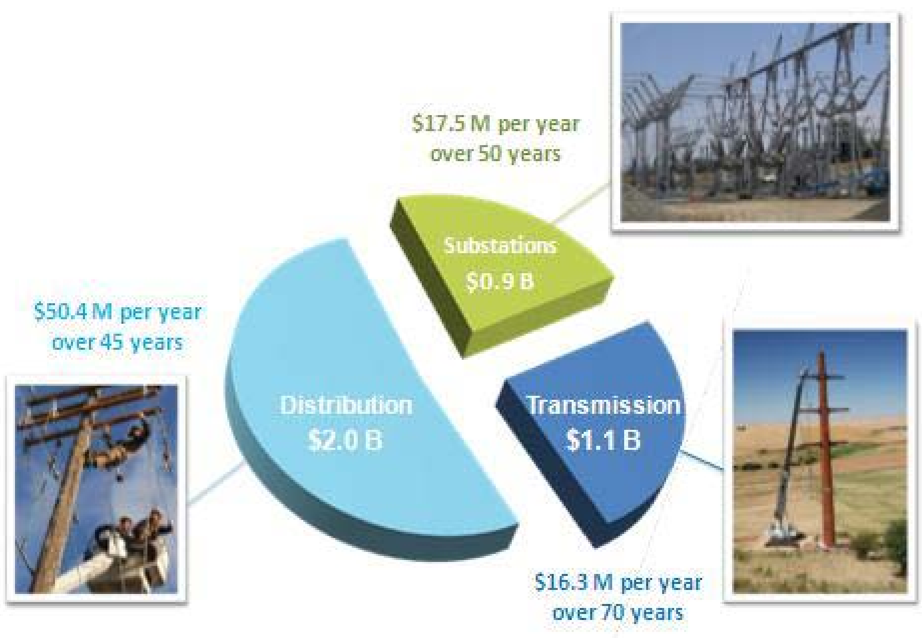


Figure 2: Transmission and Distribution System Replacement Values, Average Service Life, and Levelized Replacement Spending

The next step is to look more closely at the replacement cost of actual installed assets compared to remaining service life. This provides the basis for levelized replacement budgets given an uneven profile, as summarized in the following chart:

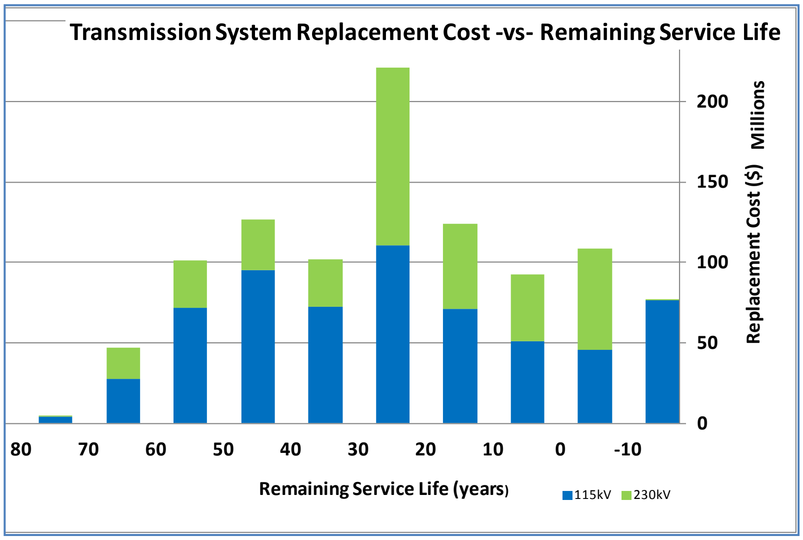


Figure 3: Replacement Cost vs. Remaining Service Life

Note that $185M of assets in the field, mostly 115kV, are currently beyond expected service life based on their age and statistical predictions of mean time to failure. This represents a significant risk to the continued reliability of the transmission system, particularly for those 115kV circuits with more than 10 years past normal service life.

To address this issue, several alternatives present themselves in terms of long-term replacement policies, as shown in the table below. The 30-year replacement period is recommended at $21M per year, split between $12M for 115kV and $9M for 230kV. This policy, when coupled with an ongoing, annual risk assessment and targeting of funds, over the long term will effectively reduce risks. This does not take into account further opportunities to reduce lifecycle costs, which in many cases present very real and substantial benefits. For example, lower costs of capital and capturing economies of scale by rebuilding larger sections of line could justify higher infrastructure replacement in the near term, in order to achieve optimal lifecycle costs and system performance for the long term. In fact, when we look at the older lines scheduled to be inspected in the next few years (see the Area Work Plans section at the end of this report), it is probable that we will discover such a large number of unacceptable conditions that major if not full rebuilds will provide the optimal business cases, dramatically increasing the recommended budgets as presented here. Accordingly, recommendations will be revised as inspections and subsequent analyses are completed in the years ahead.

In any case, the table below presents a simple levelization as a starting point, that addresses the aging infrastructure problem in a way that reduces the volatility and operational business risk of ramping up and down construction work from year to year, while responsibly maintaining system performance. Again, it should be emphasized that in order to be most effective, this level of replacement spending must be targeted at those assets that pose the greatest overall risk, as discussed in the Risk Prioritization section of this report.

		Cumulative Replacement Costs ($)			
Tx Capital Assets Service Life (yrs)	**Levelized Replacement Period (yrs)**	**115kV**	**230kV**	**Total**	**Annual Levelized Replacement Spending ($)**
0 or less	10	$121,818,337	$63,403,797	$185,222,134	$18,522,213
10 or less	10	$172,614,331	$104,840,104	$277,454,435	$27,745,443
20 or less	20	$243,757,791	$157,624,545	$401,382,336	$20,069,117
30 or less	30	$354,360,799	$268,451,050	$622,811,849	$20,760,395
40 or less	40	$426,666,970	$297,862,499	$724,529,469	$18,113,237
50 or less	50	$521,791,371	$329,200,008	$850,991,379	$17,019,828
60 or less	60	$593,613,079	$358,611,457	$952,224,536	$15,870,409
70 or less	70	$621,033,711	$378,184,386	$999,218,097	$14,274,544

Table 7: Levelized Replacement Spending Options

A variety of data uncertainties result in +/- 10% confidence in the stated figures. In terms of replacement costs, the most significant uncertainty from year to year involves the volatility of contract labor, which has risen 12% since last year. Extensive work was recently completed to confirm 230kV pole data, most importantly the identification of pole material. However, this work remains to be completed in 2014 for the 115kV system. When completed, we expect relatively small changes to high-level funding recommendations. However, it will significantly improve confidence in risk rankings and targeting of available replacement funds on a line-by-line basis.

The recommended $21M/year in levelized replacement spending over the next 30 years compares to $9.9M actual spending in 2013. Significant effort is underway to ramp up replacement construction within the next two years. Other project categories include growth/mandated, reimburseable, operations and maintenance (O&M), and unplanned/emergency. These figures are tabulated below for 2013. Spending associated with liability claims and the underground network are not included, due to data uncertainty. Please note that many construction projects involve a combination of replacement and growth/upgrade/mandated work, and are reflected accordingly as approximate values. Historically, upwards of 90% of transmission construction is through contractors. However, the rising costs of contract labor and greater availability of Avista crews has reduced this percentage recently.

$9,906,225	Replacement Capital Projects
$3,965,832	Growth/Mandated Capital Projects
$1,630,943	Unplanned/Emergency Work
$1,100,000	O&M - Vegetation Management
$500,000	O&M - Other
$1,136,787	Reimburseable Capital Completed
$18,239,787	Total Tx Planned and Unplanned Spending
$15,008,844	Total Planned Capital (including reimburseable)
$1,600,000	Total Planned O&M
$16,608,844	Total Planned Capital & O&M
$418,080	Colstrip capital Tx&Sub Avista portion
$378,000	Colstrip O&M Tx&Sub Avista portion
$796,080	Total Colstrip Tx&Sub Capital & O&M, Avista portion

Table 8: 2013 Transmission Spending

2013 Project Spend	Program/Project Description	Project Type
$6,445,399	Moscow City to North Lewiston 115kV Rebuild Proj	Replacement
$2,190,649	Burke-Thompson A&B 115kV Transmission Rebuld Proj	Replacement
$884,953	Irvin 115kV Switching Stn: Transmission Integration	Growth/Upgrade
$732,742	Moscow 230 Sub Rebuild: Transmission Integration	Growth/Upgrade
$623,136	Asset Mgmt Trans Minor Rebuilds WA	Replacement
$542,284	Lancaster Sub: 230kV Transm Interconnection Proj	Growth/Upgrade
$451,689	Benewah-Pine Creek 230kV Transmission Line: LiDAR	Growth/Upgrade
$369,289	Cabinet-Rathdrum 230kV Transmission Line: LiDAR	Growth/Upgrade
$346,900	Asset Mgmt Trans Minor Rebuilds ID	Replacement
$216,864	Hatwai-Moscow 230kV Trans Line: LiDAR	Growth/Upgrade
$199,482	Dry Creek-Lolo 230kV Trans Line: LiDAR	Growth/Upgrade
$159,110	Millwood Sub Rebuild: Transmission Integration	Growth/Upgrade
$150,556	Asset Mgmt Transmission Switch Upgrade	Replacement
$121,090	Clearwater 115 kV Transmission Line Upgrade	Growth/Upgrade
$110,389	Xsmn Asset Management	Replacement
$88,788	Noxon-Pine Creek 230kV Transmission Line LiDAR	Growth/Upgrade
$66,492	Hatwai-Lolo 230kV Trans Line: LiDAR	Growth/Upgrade
$32,340	Benewah-Boulder 230kV Trans Line: LiDAR Mitigation	Growth/Upgrade
$29,470	Blue Creek 115kV Sub Rebuild - Transmiss Integrate	Growth/Upgrade
$24,157	Greenacres 115 Sub New Cons:Transmission Integrate	Growth/Upgrade
$23,041	Devils Gap-Lind 115kV Transmission Rebuild Proj	Replacement
$18,426	Lolo-Oxbow 230kv Transmission Line LiDAR	Growth/Upgrade
$17,056	Benton-Othello 115 Recond	Growth/Upgrade
$15,207	Asset Mgmt Transmission Wood Sub Rebuild	Replacement
$4,532	Cabinet-Noxon 230kV Transmission Line: LiDAR	Growth/Upgrade
$4,200	Bronx-Cabinet 115kV Reconduct/Rebuild: Distr	Growth/Upgrade
$2,868	Coulee-Westside 230kV Transmission Line: R-O-W	Growth/Upgrade
$948	Noxon - Hot Springs #2 230kV Reroute	Replacement

Table 9: 2013 Planned Capital Projects (Non-Reimburseable)

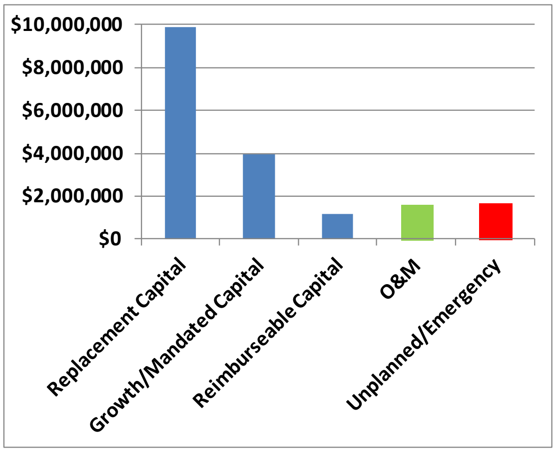


Figure 4: 2013 Transmission Spending Categories

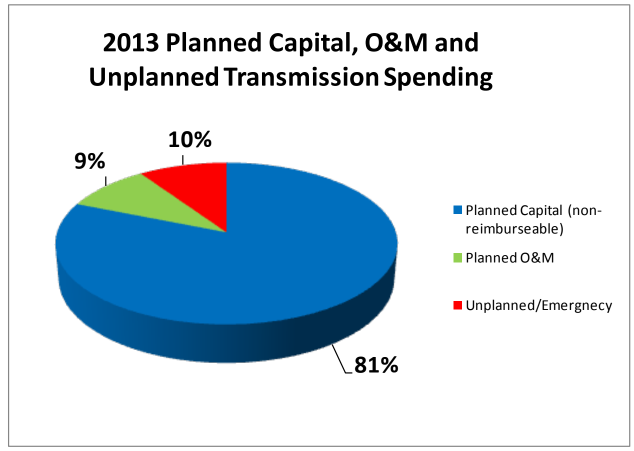
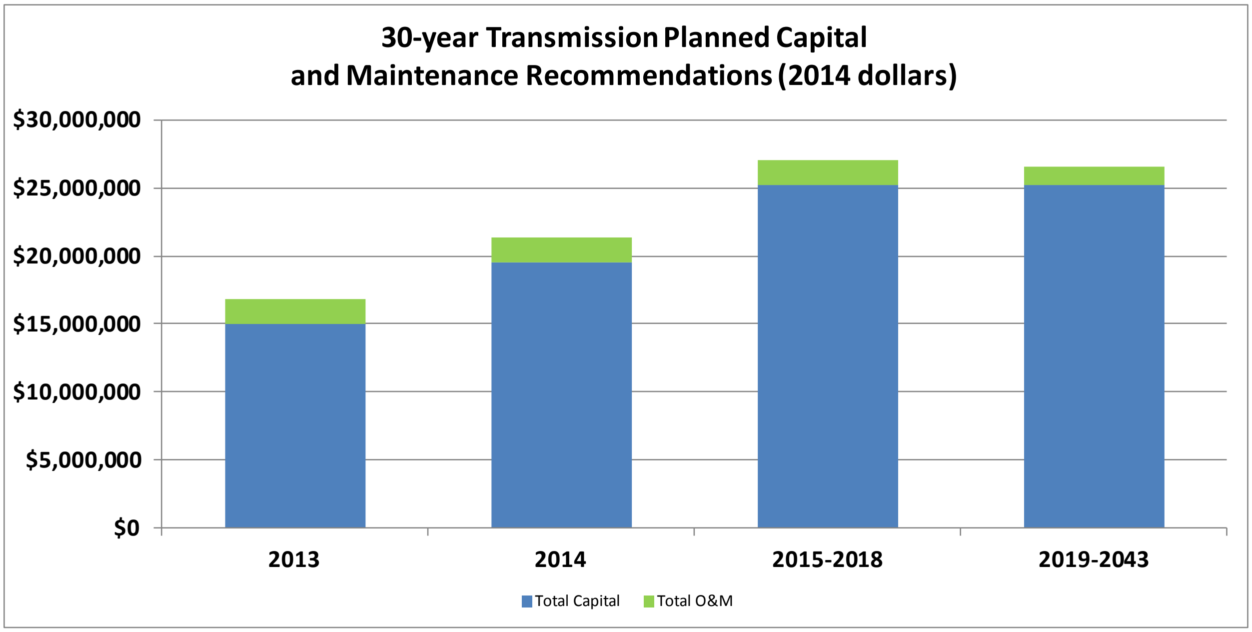


Figure 5: 2013 Planned Capital, O&M, and Emergency Spending

This shows that approximately 90% of spending is planned, vs. 10% unplanned. The percent of planned work should increase as planned replacements ramp up and unplanned/emergency spending is held constant or reduced. Mandated clearance mitigation work (a.k.a. LiDAR projects) accounted for $1.5M of the $4M in the growth/mandated category for 2013. Although the spending in this category is highly variable from year to year, a constant value of $3M is assumed for the future. Note that it is possible that a system plan for looped 230kV system around Spokane may become solidified, in which case spending in this category would increase substantially. A small increase of 2% per year is assumed for reimbursable projects such as road moves. O&M dollars may be reduced over the long-term, due to lower inspection costs of wood vs. steel poles, however this was not accounted for as it is somewhat uncertain and represents a relatively insignificant sum. Other figures represent recommendations for planned replacement and maintenance programs as specified in the Programs section of this report. As stated earlier, optimal planned spending may vary considerably after making adjustments for actual condition assessments as inspections are completed, capturing economies of scale opportunities when rebuilding larger sections of line, and taking into account cost of capital considerations from year to year. Notwithstanding these variables, the numbers below represents the minimum recommended for consistent, planned transmission work in the years ahead.



	Major Capital Replacement Projects	Growth/Mandated Capital Projects	Reimburseable Capital Projects	Air Switch Replacements	Minor Rebuilds & Repairs	Structural Ground Inspection	Structural Aerial Patrols	Vegetation Management	Fire Retardant Program	230kV Foundation Grouting				
O&M %	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%				
Capital %	100%	100%	100%	100%	100%	0%	0%	0%	0%	0%		**Total Capital**	**Total O&M**	**Total Planned**
2013	$8,785,633	$3,965,832	$1,136,787	$150,556	$970,036	$294,000	$94,595	$1,100,000	$200,000	$100,000		$15,008,844	$1,788,595	$16,797,439
2014	$14,110,816	$2,210,000	$1,159,523	$264,000	$1,300,000	$192,000	$100,000	$1,200,000	$242,000	$100,000		$19,044,339	$1,834,000	$20,878,339
2015	$19,436,000	$3,000,000	$1,182,713	$264,000	$1,300,000	$192,000	$100,000	$1,200,000	$242,000	$100,000		$25,182,713	$1,834,000	$27,016,713
2016	$19,436,000	$3,000,000	$1,206,367	$264,000	$1,300,000	$192,000	$100,000	$1,200,000	$242,000	$100,000		$25,206,367	$1,834,000	$27,040,367
2017	$19,436,000	$3,000,000	$1,230,495	$264,000	$1,300,000	$192,000	$100,000	$1,200,000	$242,000	$100,000		$25,230,495	$1,834,000	$27,064,495
2018	$19,436,000	$3,000,000	$1,255,105	$264,000	$1,300,000	$192,000	$100,000	$1,200,000	$242,000	$0		$25,255,105	$1,734,000	$26,989,105
2019-2043	$19,450,000	$3,000,000	$1,280,207	$250,000	$1,300,000	$175,000	$100,000	$1,000,000	$50,000	$0		$25,280,207	$1,325,000	$26,605,207

Table 10: 30-year Planned Capital and O&M Recommendations

In short, in order to minimize lifecycle costs and maintain system performance, the bulk of the transmission system needs to be rebuilt over the next three decades, if not sooner. This is no small endeavor, entailing significant financial and operational risk. Although construction and even design work may be contracted out, internal workloads will in all cases rise substantially in the years ahead for the Transmission Engineering group and supporting departments. A successful transition and sustained production of high quality design work and construction in the field – that will last well into the 22nd century – requires careful management and strong support across the company.

Risk Prioritization

According to Wikipedia, risk is defined as " . . . 1. The probability of something happening multiplied by the resulting cost or benefit if it does. (This concept is more properly known as the 'Expectation Value' and is used to compare levels of risk)"

- from http://en.wikipedia.org/wiki/Risk

In mathematical form, this is expressed as:

$$\text{Risk/Benefit} = \sum_{i=1}^{n} (\text{Event Probability})\, i \ * \ (\text{Event Consequence})\, i$$

Beginning this year, the transmission system's major circuits will be ranked by this formulation. The rankings will be used as a starting point for further deliberation among internal stakeholders, with the goal of allocating resources where they will have the most significant impact. The rankings may also be used to justify inspection and follow-up work earlier than normally scheduled (currently a 15-year inspection cycle on each line). At minimum, the rankings will be used to prioritize the commissioning of detailed studies, simulations and development of business cases for major line rebuild projects.

The first component of risk for our transmission lines is the probability of a failure event, which we will refer to as the asset's "**Health and Failure Probability Index**". This is a normalized score from 0 (low failure probability) to 100 (high failure probability). The factors and respective weighting for the Health and Failure Probability Index are as follows, derived from a combination of the line's condition, track record, and severity of operating environment. Each factor is scored from 1 (low) to 5 (high), based on a set of objective measures collaboratively developed by representatives in Asset Management, Transmission Design, System Planning, and System Operations groups.

% weight	criteria
25	Unplanned outages/spending
20	Remaining service life
20	Time since last minor rebuild, # items identified for replacement
20	# of miles
15	Severity of terrain & operating environment (soil conditions, weather intensity, vegetation, relative probability of vehicle/equip. impacts, etc)

Table 11: Health and Failure Probability Index Criteria

The second component of risk (event consequence), we will refer to as the asset's "**Criticality Index**". It is basically a measure of the severity of consequences should an unplanned failure event occur. This is also a normalized score from 0 (low severity = low event consequence) to 100 (high severity = high event consequence). The factors and respective weighting for the Criticality Index are as follows, derived from the relative importance of the line in terms of power flow, its effect on the system should it become unavailable, the relative time and cost to effect repairs, and potential secondary damage based safety and environmental issues and its proximity to other company and private property. These factors are also scored from 1 (low) to 5 (high), based on a set of objective measures.

% weight	criteria
40	power delivery
20	potential damages (company/private/environmental)
15	access
15	system stability, voltage control and thermal problems
10	voltage & configuration

Table 12: Criticality Index Criteria

Given the Health and Failure Probability Index and Criticality Index, we now have the ability to prioritize lines based on comparable risk levels, which we refer to as the line's "**Reliability Risk Index**" , where

Reliability Risk Index = (Health and Failure Probability Index) * (Criticality Index)

This is also normalized from a score of 0 (low risk) to 100 (high risk). In order to be worthwhile, it is essential that the risk index is ultimately useful to making practical business decisions. It must produce credible results to a wide variety of experts and decision makers, and it must be reliably reproduced each year without a great burden of effort. In this light, we expect some iteration as we obtain results from the formulation developed thus far and gain additional feedback from stakeholders and technical experts. Over time, improvement in our ability to collect and use data may also allow us to evaluate shorter segments of lines, rather than the entire circuit. This would facilitate a more detailed view of system risks and targeted mitigation efforts. The development and use of aids that help visualize results (e.g. color-coded system maps), may also be worthwhile.

Finally, once the Reliability Risk Index is fully vetted and found useful, we may consider including a simple, quantitative measure of other concerns from various groups such as system planning, operations, and communications. This is essentially a way to quantify subjective knowledge of different kinds of risks/benefits other than reliability. A **"Stakeholder Index"** could easily be produced, for example, by allocating a number of points to each representative, distributing these points to respective lines in the system based on their level of concerns and/or potential opportunities. This could then provide the basis for a final "**Capital Project Index**", where

Capital Project Index = Reliability Risk Index + Stakeholder Index

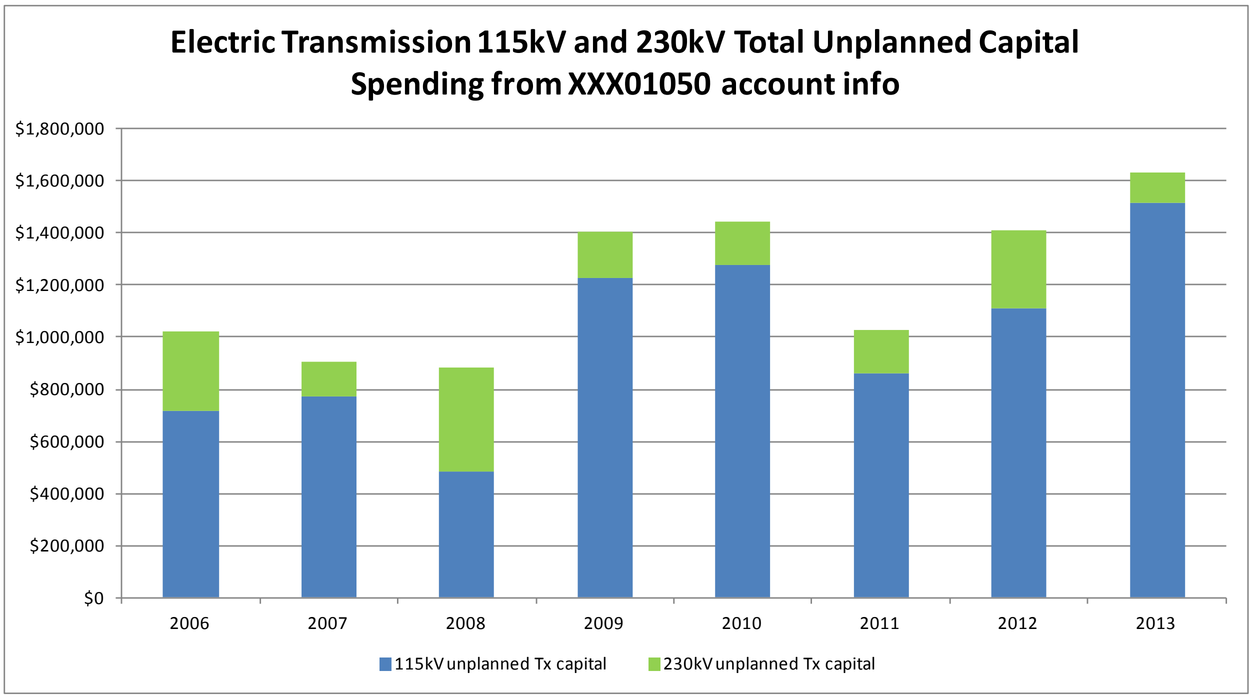
In reality, this is simply the summation of two different sets of risks/benefits that apply to the same set of assets, consistent with expected value methodology. A reasonable weighting factor for each set is advisable, e.g. 75% reliability weighting, 25% stakeholder weighting.

Ultimately, objective rankings must be truly useful, helping the organization arrive at the right business decisions with less effort. Asset management staff will continue to facilitate and support this collaborative undertaking, striving for improvement and strong results.

Unplanned Spending

Unplanned spending represents capital replacement of those transmission assets that have unexpectedly failed and require prompt attention, typically by Avista crews (e.g. storm response events). Despite the variability that is correlated with fluctuations in weather intensity, unplanned spending is an especially important lagging indicator of system performance, trends, and the effectiveness of asset management programs. In addition to cost premiums incurred from overtime labor, unplanned work typically presents greater safety risks to the public and on-site Avista employees, as well as other risks including property damage, environmental, general liability, planned work delays, and additional rework costs following the event. We have set annual goals at the average of unplanned spending from 2009 through 2012 as shown in the chart and table below, reflecting a desire to maintain system reliability. This results in targets of $1.1M for 115kV and $210k for 230kV, for a total of $1.3M per year. Note that we have consistently spent a much greater amount of total unplanned dollars on the 115kV system, at four times the proportional value of capital assets when compared to the 230kV system. Normalizing for respective system replacement values, each year we are spending an average of $0.0017 unplanned capital for every 115kV asset dollar in the field, compared to $0.0004 for 230kV.

This is consistent with the fact that 230kV assets are felt to pose a higher potential consequence should they fail, and therefore we maintain them accordingly – deliberately effecting a lower frequency of unplanned events on the 230kV system, relative to 115kV. While this may be the case, it remains that the optimal target of unplanned spending has not been quantitatively determined for either system. This is a desired output from a future system model and analysis, involving the quantification and simulation of all significant risks and costs associated with unplanned events and maintenance/replacement work. Note that zero emergency spending is actually sub-optimal unless there is zero tolerance for any risk – otherwise, it represents over-investment in the design configuration and actual condition of physical assets.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	Avg 2009-2012
115kV - WA	$127,835	$312,958	$609,438	$265,221	$874,996	$649,760	$585,250	$499,341	$1,123,122	
115kV - ID	$170,725	$406,111	$161,470	$221,343	$349,459	$626,503	$274,517	$608,163	$389,492	
115kV - all	$298,560	$719,070	$770,908	$486,564	$1,224,455	$1,276,263	$859,767	$1,107,505	**$1,512,614**	**$1,116,997**
230kV - WA	$79,136	$215,228	$97,946	$215,416	$57,721	$73,482	$156,491	$58,976	$89,984	
230kV - ID	$10,018	$74,783	$32,856	$120,056	$89,364	$79,950	$12,979	$228,681	-$134,091	
230kV - MT w/ Colstrip	$6,015	$0	$286,338	$257,879	$249,429	$368,855	$574,428	$298,059	$436,991	
230kV - MT w/o Colstrip	$6,015	$0	$1,590	$59,590	$27,525	$13,275	$0	$72	$18,910	
230kV - OR	$0	$12,273	$0	$0	$2,475	$0	$360	$14,738	$9,435	
230kV - all w/o Colstrip	$95,170	$302,285	$132,392	$395,062	$177,085	$166,706	$169,830	$302,467	**$118,329**	**$204,022**
115kV and 230kV (all)	$393,729	$1,021,354	$903,300	$881,625	$1,401,539	$1,442,969	$1,029,597	$1,409,972	**$1,630,943**	**$1,321,019**

Table 13: Unplanned/Emergency Spending, 2006 - 2013

Total unplanned spending increased in 2013 to just over $1.6M, above the average of $1.3M per year since 2009. This was largely due to over $500k in costs attributed to the Othello 115kV storm response in September. Unplanned spending for 115kV in Idaho actually decreased by over $200k in 2013 compared to 2012, as well as nearly $200k in reduced 230kV unplanned spending overall. 230kV unplanned spending was dominated by $72k on the Walla Walla – Wanapum line, and $24k on the Lolo – Oxbow line.

Unfortunately, the use of 115kV blanket accounts does not allow for ready analysis of unplanned spending on individual 115kV circuits. This is necessary to get a better understanding of risk and asset prioritization on a line-by-line basis. It is hoped that Maximo will help remedy this situation.

The figures above do not include spending on the 11% Avista ownership of the roughly 500 miles of 500kV Colstrip transmission and substation assets. Total planned and unplanned Colstrip transmission/substation spending under the project #42401050 account was $418k in capital and another $378k in O&M expenses in 2013. This work is performed by Northwestern Power. Further investigation would be required to determine what portion of this spending is planned vs. unplanned, and to segregate transmission and substation spending. 11% of 500 miles is 55 miles (plus our proportion of substation assets), for which we spent nearly $800k to replace and maintain last year. This works out to nearly $15k spent per mile of 500kV assets, compared to just over $7k per mile of 115kV and 230kV assets.

$15,472,057	Total Tx Planned Construction & O&M, Non-reimburseable
2,164	# miles Tx 115kV & 230kV
$7,149	Total spending per mile, 115kV & 230kV
$796,080	Total Colstrip Tx&Sub Capital & O&M spend
55	# equivalent miles 11% ownership of 500miles 500kV Tx
$14,474	Total Spending Tx&Sub per mile, 500kV

Table 14: 115kV, 230kV, and 500kV Unplanned Spending per Mile

Outages

The following information is taken from the number of sustained outages (longer than five minutes) for Transmission–type events per the annual Reliability Report created by Operations Management.

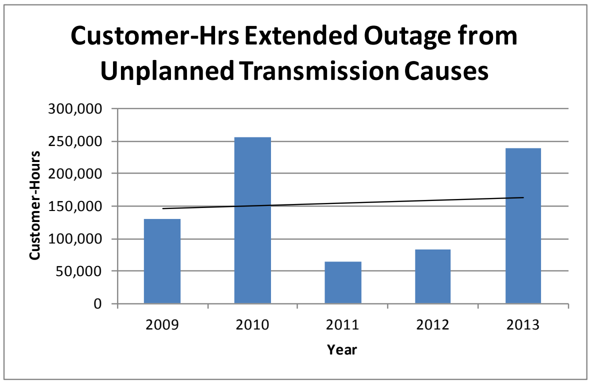
Outages are a strong lagging indicator of system reliability, highly correlated with unplanned/emergency spending.

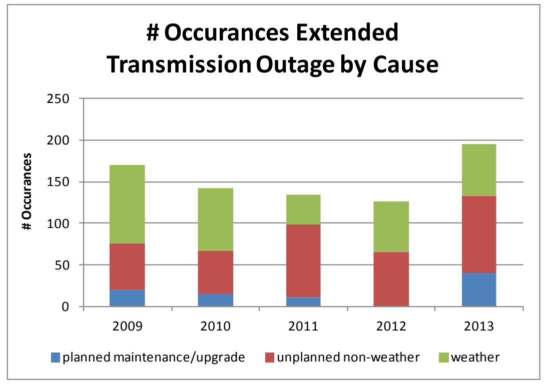
# Outage Occurances					
Subreason	**2009**	**2010**	**2011**	**2012**	**2013**
Bird			10		15
Other					1
Squirrel					2
Company - Other	4		1	4	6
Conductor - Pri		1			20
Connector - Pri		4			1
Crossarm-rotten		7	10		1
Insulator		2			1
Cutout/Fuse				1	
Highside Breaker					1
Relay Misoperation					1
Tranformer				4	2
Equipment - Other	1				
See Remarks					1
Planned - Forced Outage	3	4	1	1	8
Planned - Maint/Upgrade	17	11	10		32
Pole Fire	6	18	20	14	9
Car Hit Pole		15	3	5	13
Public - Tree				3	1
Tree Fell		1	1	11	
Undetermined	45	4	43	22	18
Weather - Lightning		13	9	19	32
Weather - Snow/Ice	83	17	12	8	7
Weather - Tree	5	5	3		
Weather - Wind	6	40	11	34	23
Grand Total	170	142	134	126	195

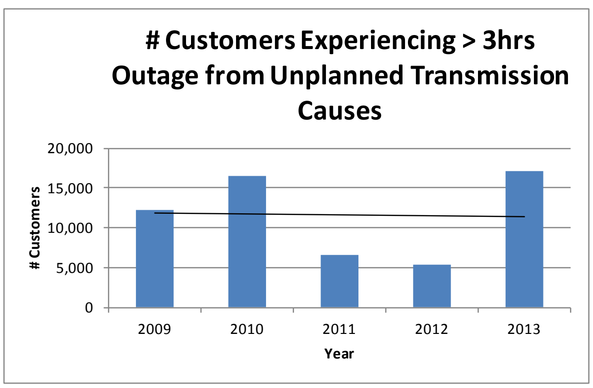
Table 15: Transmission Outage Causes, 2009 - 2013

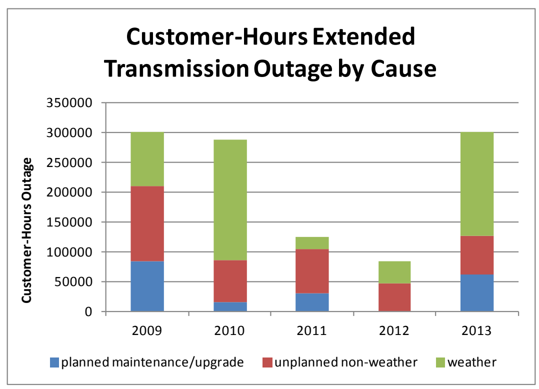
Notable changes include the large increase in planned outages and weather events, particularly from wind and lightning. Although the number of wind events went down from 34 to 23, the customer-hours outage went up considerably – from 2,748 to 100,450. The increase in weather related outages was mostly due to large storm events near Colville and Kettle Falls in August, and Othello in September. Lightning and wind make up 12 of the 13 largest outage events for the year, a primary conductor event in Springdale, WA in August the lone non-weather event to make this list. Pole fire outages continued their decline, and tree incidents also dramatically decreased – positive indicators for the effectiveness of the fire protective coating and vegetation management programs, respectively. However, two separate fire events occurred last year on the Walla Walla – Wanapum 230kV line despite the recent application of fire protective coating.

The large increase in bird incidents and car hit poles is not conclusive as they are on par with some previous years, but warrants close attention for sustained trends in future years. Closer scrutiny of those events resulting in a large number of customers experiencing an outage greater than three hours is advisable in the future, as recent surveys indicate this is the most important reliability factor driving customer satisfaction.









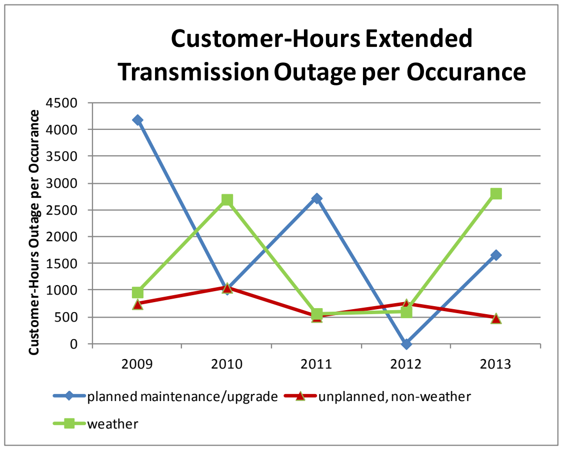


Figure 6: Outage Charts, 2009 - 2013

As far as weather-attributed causes, in fact the root cause could be a component which has fallen below its required specification parameters, waiting as a "hidden" failure until such time as a storm of sufficient force makes it evident through an extended outage. It might be possible to "normalize" the data to a reasonable measure of weather intensity, so that we might have some indication as to whether outages are being caused by weather conditions above and beyond design specifications, or by component degradation. This could help ascertain root causes, and if storm intensity trends are evident to justify changes to component specifications. Exactly how this might be accomplished is uncertain, however, and requires further evaluation.

The Reliability Report is derived from the Transmission Outage Report (TOR) and OMT data, providing excellent information on overall transmission related outages, but not directly on individual transmission lines. The TOR in turn is produced by System Operations, based on a custom logging tool with daily updates. This report includes any transmission event, not just actual customer outage events per the Reliability Report. Utilizing the TOR, System Operations compiles the Transmission Adequacy Database System (TADS), and associated NERC reports. The TADS provides information on individual 230kV lines, but not 115kV lines as it is not a NERC requirement.

In order to improve the reliability risk indices, it would be desirable to obtain event information on a line-by-line basis. With current information and systems, this would require approximately 250 work-hours annually. A cost/benefit analysis and business case could be considered to obtain this information with additional resources and/or improved data collection.

Programs

1. Major Rebuilds

Out of the $9.9M in planned capital replacement projects in 2013, $8.8M was spent on major rebuilds, $970k on minor rebuilds and $151k on switch replacements. The recommended level is a minimum of $19.4M, $1.3M and $264k, respectively, for a total of $21M replacement spending per year over 30 years. As stated previously, replacement projects do not include additional capital projects that are mandated, growth related, reimburseable, or otherwise do not address aging infrastructure. Furthermore, the recommended spending is the minimum levelized spending over the entire 30 year period, which in the shorter term may need to be increased to minimize lifecycle costs – given inspection results, risk analysis, cost of capital, and economies of scale opportunities.

The most significant major rebuild projects planned through 2017 are listed below, with rough estimates of budget dollars allocated for each year.

ER Description	BI Proj	BI Description	2014	2015	2016	2017	2014-2017
Benewah-Moscow 230kV	PT305	Reconductor/Rebuild	$25,000	$7,815,802	$8,060,576	$8,302,393	$24,203,771
CDA-Pine Creek 115kV Rebuild	CT300	Rebuild Transmission	$25,000	$0	$4,500,000	$5,750,000	$10,275,000
Devils Gap-Lind 115kV Rebuild	ST302	Rebuild Transmission	$2,346,742	$3,947,144	$4,050,558	$0	$10,344,444
Ben-Oth SS 115 - ReCond/ReBld	FT130	Ben-Oth SS 115 - ReCond/ReBld	$2,500,000	$3,600,000	$3,500,000	$0	$9,600,000
Sys - Rebuild Trans - Condition	AMT81	BRX-CAB & BRX-SCR Rebuild	$2,500,000	$2,500,000	$2,500,000	$2,000,000	$9,500,000
Pine Creek-Burke-Thompson Falls	CT101	Rebuild Transmission	$3,700,000	$3,500,000	$0	$0	$7,200,000
LP Line Ratings Mitigation Project	CT305	BEN-PIN 115kV Trans Line Mitigatic	$250,000	$500,000	$2,500,000	$2,500,000	$5,750,000
			$11,346,742	$21,862,946	$25,111,134	$18,552,393	$76,873,215

Table 16: Major Rebuild Projects, 2014 - 2017

2. Minor Rebuilds

The information collected by aerial patrols is used in conjunction with inspection reports to prioritize and budget minor rebuild capital projects, where a major rebuild is not justified. Our goal is to complete repairs and replacements for high-risk issues from 0 to 6 months after identification by aerial or ground inspection, and for all other moderate risk issues by the end of the year following the inspection year.

Planned inspections and follow-up work in the form of minor rebuilds is effective in maintaining service levels while minimizing capital and O&M costs. However, from a quantitative perspective it has not yet been established at what point it becomes suboptimal to “patch together” a line per the minor rebuild approach, when instead large sections if not the entire line should be rebuilt. Where warranted and on a line-by-line basis, detailed simulation modeling helps ascertain the optimal rebuild approach and support a business case to compete with others in the company’s capital projects selection and budgeting process. A system-wide simulation model is needed to help validate and provide adjustment recommendations to our inspection intervals, minor rebuild budgets, and fact-based policies on minor vs. sectional vs. full rebuild thresholds.

See the Area Work Plans section at the end of this report for a list of minor rebuild projects in 2014.

3. Air Switch Replacements

Transmission Air Switches (TAS) are used to sectionalize transmission lines during outages or when performing maintenance. The frequency of operation varies greatly depending on location. Some TAS may not be operated for years.

TAS may not operate properly when opened and flashover, possibly tripping the line out. This can be the result of a component failure (whips and vac-rupters) or the TAS may be out of adjustment. Although most TAS mis-operations could be avoided with regular inspection and maintenance, we currently have no planned inspection or maintenance program. Inspections could range from systematic visual inspection to infrared scanning and inspections for corona discharge. Maintenance could consist of exercising switches, lubrication, blade adjustment, replacement of live parts such as contacts and whips, and repair of ground mats/platforms.

Ground grids and platforms are installed at the base of each switch to provide equal potential between an operator's hands and feet in the event of a flashover of the air switch. The typical ground grid is buried copper wire attached to ground rods covered with fine gravel. Over time the ground grids may be damaged by machinery, cattle and erosion, or even theft. We are currently benchmarking other utility's practices and configurations regarding air switch grounding, in order to evaluate and implement changes that may minimize these issues. Preliminary indications are that most utilities perform much more inspection and maintenance of their air switch assets than Avista.

With radial switching of the 115kV transmission system, many TAS are operated remotely. In these instances, company personnel are not present to observe the opening of the switch and some problems therefore remain hidden. A small problem could progress to the point where a major failure occurs. A small amount of material is maintained in the warehouse and Beacon yard for emergency repairs, but many of the switches are old and parts are often difficult to locate.

Typically three to four TAS are replaced each year. A detailed inventory of 115kV TAS outside substations was completed in 2013, including determination of age where formerly 20% of the assets were unknown. TAS inventory includes 180 switches of various types and configurations, as shown below according to remaining service life. Based on this profile, levelized replacement should increase to five replacements per year (increase to $264M annual budget), prioritized according to a rational condition assessment and quantitative risk assessment, rather than ad-hoc requests from field personnel and anecdotal observation.

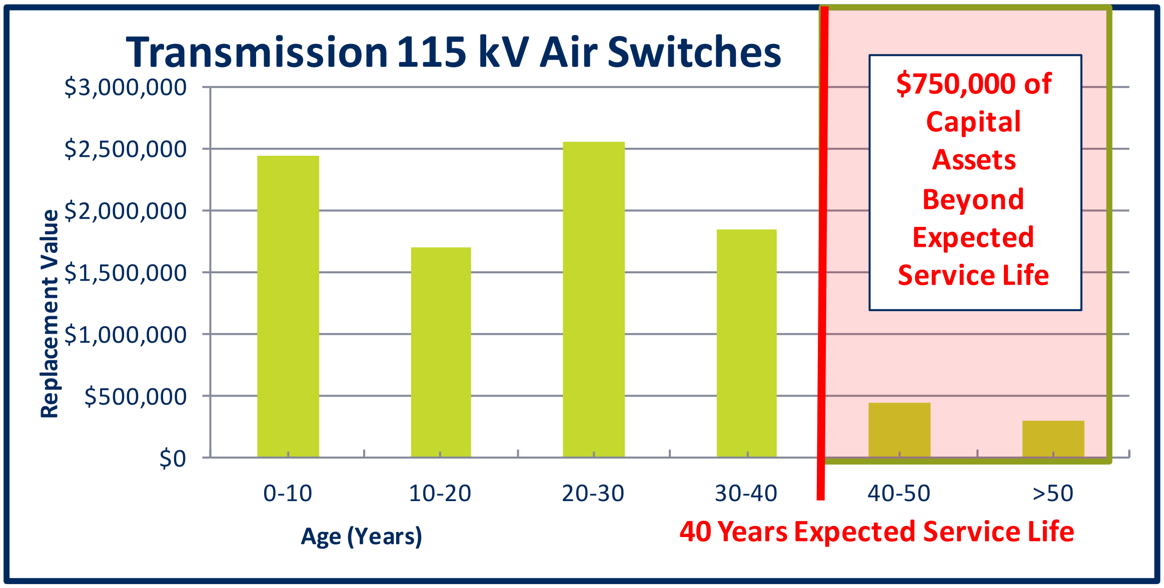


Figure 7: Air Switch Replacement Value vs. Remaining Service Life

In 2008, 80 TAS were fitted with grounding platforms for worker safety. During this process a new worm gear handle was installed and disconnecting whips were adjusted. Operating pivot joints of the switch mechanisms are not affected by this work. Thus, the 2008 work was safety related, not switch mechanism related. Remaining switches in the system requiring new platforms need to be confirmed and upgraded.

Investigation of industry best-practices regarding inspection and planned maintenance of air switches, with follow-up recommendations is currently in progress. At minimum, a reasonable condition assessment program is envisioned, such as visual inspection at least every two years, possibly annual inspection for those more critical switches, and annual performance evaluation based on System Operations input. Below is a prioritized list of switches due for repairs or replacement in the next few years, with those switches exhibiting operational problems listed first.

SW #	Problems	Age (yrs)	LINE/SUBSTATION
A-70	Problem Switch	84	Chelan-Stratford
A-336	Old KPF, Needs Replaced	49	Grangeville-Nez Perce #1: Cottonwood Tap
A-355	Old KPF on a broken pole	48	Jaype-Orofino
A-346	Wood in Switching Mech. Is bowed	47	Grangeville-Nez Perce #2
A-376	Old KPF, Needs Replaced	43	Grangeville-Nez Perce #2
A-298	Needs whips; Center 0 and North 0 gone, South Bent	38	115kv Boulder-Rathdrum
A-158	Doesn't work properly, drop load on both sides then use switch, mat ground straps need repair	31	Beacon-Francis & Cedar
A-345	Pole Needs Structure # Tag	30	Grangeville-Nez Perce #2
A-442	Broken Whip	26	Dworshak-Orofino
A-377	Scott paper tap; Engerized to Switch	21	Grangeville-Nez Perce #2 : Scott Paper Tap
A-176	Mat ground straps need repair	18	Bell-Northeast
A-679	Difficult to Close	15	Othello-Warden #2
A-680	Motor Operator is too slow - it arcs	15	Othello-Warden #2
A-358	Old KPF, Needs Replaced	10	Jaype-Orofino
A-407	Broken Crossarms ??	4	Grangeville-Nez Perce #1
A-421	Ground Cables and Strands cut, NEEDS REPAIR	4	Ramsey-Rathdrum #1
A-184		61	Shawnee-Sunset
A-19		59	Pine Street-Rathdrum: Oldtown Tap
A-26		59	Burke-Pine Creek # 3
A-220		57	Lolo-Nez Perce
A-221		57	Lolo-Nez Perce
A-173		47	Moscow 230-Orofino
A-58		46	Chelan-Stratford
A-295		46	Benewah-Pine Creek : St Maries Tap
A-49		44	Devils Gap-Stratford
A-126		40	8th & Fancher-Latah 115 kV
A-127		40	8th & Fancher-Latah 115 kV

Table 17: Airswitch Priority List for Repairs and Replacements

Finally, transmission outage cause tracking needs to be improved in order to ascertain failure trends for the air switch population. In reading through notes on the TOR, Asset Management was able to determine that there were 122 outages from 1975 through 2007. An average of 3.7 outages per year were caused by switches.

4. Structural Ground Inspections (Wood Pole Management)

Avista wood transmission structures are predominately butt-treated Western Red Cedar poles. Most of the service territory is in a semi-arid climate. The most common failure mode for wood poles is internal and external decay at or near the ground line. Transmission Wood Pole Management (WPM) measures this decay and determines which poles must be reinforced or replaced. Details describing inspection techniques are in the company's "Specification for Inspection and Treatment of Wood Poles, S-622". This specification was revised in 2013 to include protocols for prompt reporting and remediation of severely degraded poles.

The testing program is valuable in identification of poles needing replacement or reinforcement. Compared to the pre-1987 method of solely visual inspections for pole integrity, the testing program replaces about 15% as many poles.

The wood transmission poles are on a 15-year inspection cycle. We are currently targeting inspection of 2400 wood transmission poles annually out of 36,422 wood poles installed. At this pace, by 2019 we will reach the 15-year cycle for all transmission lines. See the Area Work Plans section of this report for a list of future planned inspections.

In recent years, prioritization and scheduling of ground inspections has been based on the time since the last ground inspection. Results of these inspections provide the basis for case-by-case analysis and the scope of subsequent minor and major rebuild projects on each line. While it is important that we maintain a maximum 15-year ground inspection cycle, it is recommended that future inspection scheduling includes the risk index, which may justify earlier inspection. As a general rule, critical assets that exhibit age-related failures should be inspected to verify condition and justify service extension or removal near the end of their expected service lives. We currently have many 115kV lines with assets 10 or more years past expected service life, that have not been inspected for nearly 20 years. This poses a significant unknown risk.

If actual condition assessment warrants service extension, shorter inspection intervals are prudent when the time to failure characteristics worsen with age – as is the case with much of our transmission wood infrastructure. Approximately 17% of the system is beyond its expected life, with a large portion of those assets over 15 years since the last ground inspection. The scattered age profile on many lines that results over many decades from periodic minor rebuilds and one-off replacements, makes this situation difficult to remedy – one must choose between the pros and cons of a somewhat spotty and expensive replacement policy, larger line section replacements and full rebuilds, or detailed analysis and business case development tailored to each individual line. Regardless, for those lines that have significant sections or quantities of older assets that demonstrate higher relative risks, out-of-cycle inspection and a shorter inspection interval may be warranted (e.g. 10 years instead of 15).

5. Structural Aerial Patrols

The Avista transmission system covers a large geographical area that has all types of terrain. Some parts of the system are so remote and difficult to access that they only get inspected when company personnel are in the area due to a failure or a major reconstruction project. Transmission Aerial Patrols (TAP) have been utilized to provide a quick above-ground inspection to identify significant problems that require immediate attention, such as lightning damage, cracked or sagging crossarms, fire damage, bird nests and danger trees.

In addition, aerial patrols can identify improper uses of the transmission Right-of-Way (R/W), such as dwellings, grain bins, and other types of clearance problems that must be addressed. Typically, the patrol will be performed in the spring. Identified repairs, depending on severity, are scheduled to be performed within 6 months.

TAP inspects 100% of 230kV lines and 70% of 115kV lines annually. The remaining 30% of 115kV lines are located in urban areas that are frequently viewed by line personnel for potential problems. The Transmission Design group schedules patrols for each service territory. The TAP areas are: Spokane (includes Othello, Davenport and Colville), CD'A (includes Kellogg and St. Maries), Pullman, and Lewiston/Clarkston (includes Grangeville and Orofino).

Aerial patrols are performed by qualified personnel from Transmission Design, often accompanied by local office personnel. Inspection forms have been developed that contain a weighting system to identify the severity of defects. This information can then be utilized to make recommendations for necessary repairs.

6. Vegetation Aerial Patrols and Follow-up Work

The Transmission Vegetation Management (TVM) program maintains the transmission system clear of trees and other vegetation, in order to provide safe clearance from trees and reduce outages caused by trees, weather, snow/ice, and wind.

The entire 230kV system is annually inspected with a combination of aerial and ground patrols by the System Forester, who solely manages the overall program. Select 115kV lines are also patrolled according to criticality. In addition, vegetation issues noted during structural aerial patrols on the 115kV system, as well as fielding of transmission line projects by Transmission Engineering are relayed to the System Forester. Based on this information, follow-up work plans are adjusted and executed with contract crews over the course of the year.

An increase from the current budget of $1.1 M to $1.2 M is recommended to allow for optimal completion of major re-clearing work and a transition to mostly herbicide applications over the next ten years. At this point overall costs should come back to the $1 M/yr level.

See the Transmission Vegetation Management Program reference for more details on the program.

7. Fire Retardant Coatings

After several fires and a 2008 study to initiate systematic remediation, fire retardant coating has been applied to the base of wood transmission poles. At this point the entire 230kV system has been deemed adequately protected and the 115kV system is approximately 22% complete. Targeted areas include those subject to grassland fires and in close proximity to railroads. Protective coating is not applied to heavily forested areas as it is deemed inadequate in these areas to merit the cost of application.

It is estimated that approximately 5182 poles remain to be coated in the 115kV system. Following the current plan to coat 792 poles in 2014, it recommended to coat 1000 poles per year for the following five years to complete the work by 2020. At a total labor and materials cost of $242/pole, this equates to $242,000/year. Beyond this, regular maintenance and upkeep will only be required, at an unknown amount depending on the longevity of the coatings. Until better information is obtained, estimate $50k/year for ongoing coating maintenance. Performance metrics should be established to monitor performance of this program, possibly in terms of % of the system protected, maintenance spending and actual fire damage costs. As noted in the Outages section, pole fire incidents have come down dramatically of late, however at least two pole fire events occurred on lines with recent application of fire retardant coating.

See Whicker (2013) for more details and history of this program, which is now administered by the Transmission Design group.

8. 230kV Foundation Grouting

The Noxon-Pine Creek and Cabinet – Rathdrum 230kV circuits have unique steel structures where the interface between the steel sleeve in the foundation and above-ground structure requires re-grouting after approximately 30 years, to avoid destructive corrosion. This work has been completed on the Noxon-Pine Creek 230kV line. Approximately $100k out of $500k worth of additional work remaining on Cabinet – Rathdrum 230kV was completed in 2013, with another $100k/year planned for 2014 through project completion in 2017.

9. Polymer Insulators

Transmission Line Polymer Insulators (TPI) provide insulation at the connection points for transmission lines to the supporting structure. Other types of insulators include toughened glass and older porcelain types. Although no significant problems have been noted on 115kV lines, there were numerous faults on 230kV lines from 1998 to 2008 attributable to poly insulators causing line outages, and five mechanical failures that caused the line to fall.

In 2008 a plan was initiated to replace TPIs and install corona rings on dead-end TPI insulators on various 230kV lines (without corona rings, TPIs are expected to fail in the 10 – 15 year timeframe, with corona rings the expected service life is extended to an unknown age).

Work was completed primarily in 2009 on N. Lewiston - Shawnee 230kV and Dry Creek – N. Lewiston 230kV, and in 2011 all suspension and dead-end TPIs on the Hatwai - N. Lewiston 230kV were replaced with toughened glass insulators.

This work appears to have been effective. From 2009 to 2012, only 2 sustained outage occurances involving insulators are recorded. However, the degree to which TPIs exist on the remainder of the system, and the prediction of current and future risk is unknown.

For this reason, it is recommended that at least on 230kV lines, future ground inspections include information gathering on the insulator type, so that an analysis of risk and optimal mitigation actions may be made in a short time period should that become necessary.

Current transmission engineering standards use toughened glass insulators for 230kV, and either toughened glass or poly insulators for 115kV. Due to the lighter weight of polymer insulators, they are generally preferred by Avista crews. However, given the problems experienced on 230kV lines and anecdotal evidence of high scrap rates for TPIs on 115kV projects, their use on 115kV lines poses some unknown risks and a systematic monitoring program may be advisable.

10. Conductor & Compression Sleeves

Credible condition and failure characteristics of conductor and compression sleeves, and the location and age of thousands of compression sleeves in the system are currently unknown. Provided proper installation, protection, and service conditions, most conductor will last over 100 years, if not indefinitely. The compression sleeves, however, are expected to last between 40 and 50 years, posing a more immediate reliability risk.

Between 2008 and 2010, an effective risk mitigation program was carried out for compression sleeves on 230kV AAC lines, following several years of one to two failures per year. Since then, no known compression sleeve failures have occurred. However, at some point we should expect failures to resurface. Until that time, an effort to determine sleeve locations and confirmation of reliable reporting of conductor and sleeve failures system-wide is advisable. Proactive reinforcement of sleeves may also be justified, pending more detailed study.

See Whicker (2009) for more details on the 230kV sleeve mitigation project.

Benchmarking

As stated previously, investigation of air switch maintenance practices of various utilities is in progress, with preliminary results indicating that most utilities perform a much greater degree of maintenance than Avista.

In terms of broader maintenance benchmarking, a study through a CEATI report (excerpts below) show that Avista is among the majority of peers conducting aerial patrols once per year, but that of all 15 utilities responding, we have the longest ground inspection interval at 15 years, as compared to the most common interval of 10 years.

This does not necessarily mean that our inspection interval needs to be shortened. However, it does at least indicate where we stand relative to other utilities participating in the survey, and at minimum would tend to discourage extending our inspection interval any further.

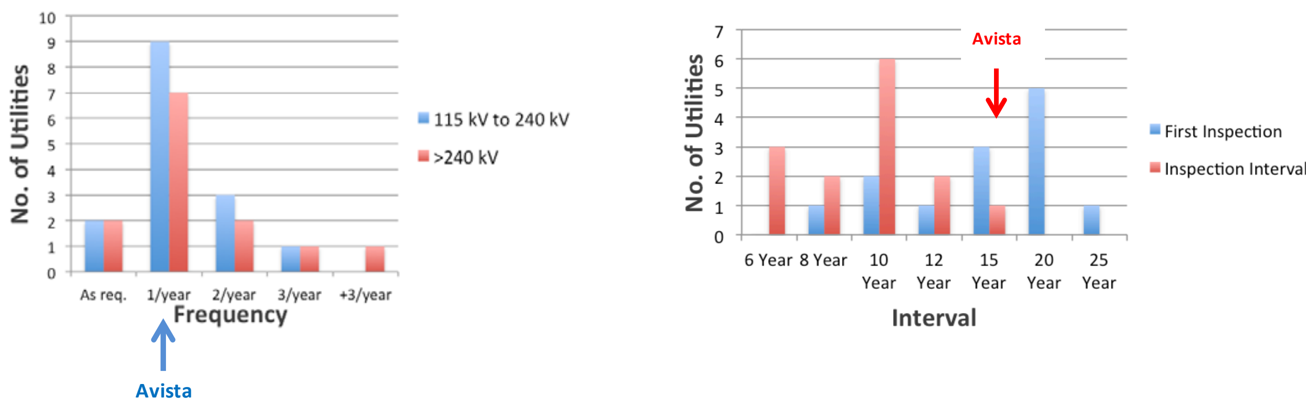


Figure 8: Maintenance Benchmarking: Aerial Patrols (left) and Pole Inspections (right)

Idaho Power, which did not participate in the CEATI survey, is a very good benchmark utility for Avista in terms of size, operating environment and electric transmission component/system similarities. In discussions with their staff, thorough transmission structure ground inspections are conducted every 10 years, with quick visual inspections (drive-bys) every 2 years. It is also clear that in general, Idaho Power spends considerably more time and effort on O&M maintenance activities relative to Avista, at least in areas of transmission and substation systems.

Idaho Power is also projecting a significant rise in capital replacement of aging infrastructure in the next several decades, as shown below. Over just the next 10 years, this indicates a total capital spend for Idaho Power of $211 M for replacement of wood poles alone, or $21 M per year levelized. This is similar in magnitude to the recommended replacement of aging wood infrastructure at Avista over the next several decades.

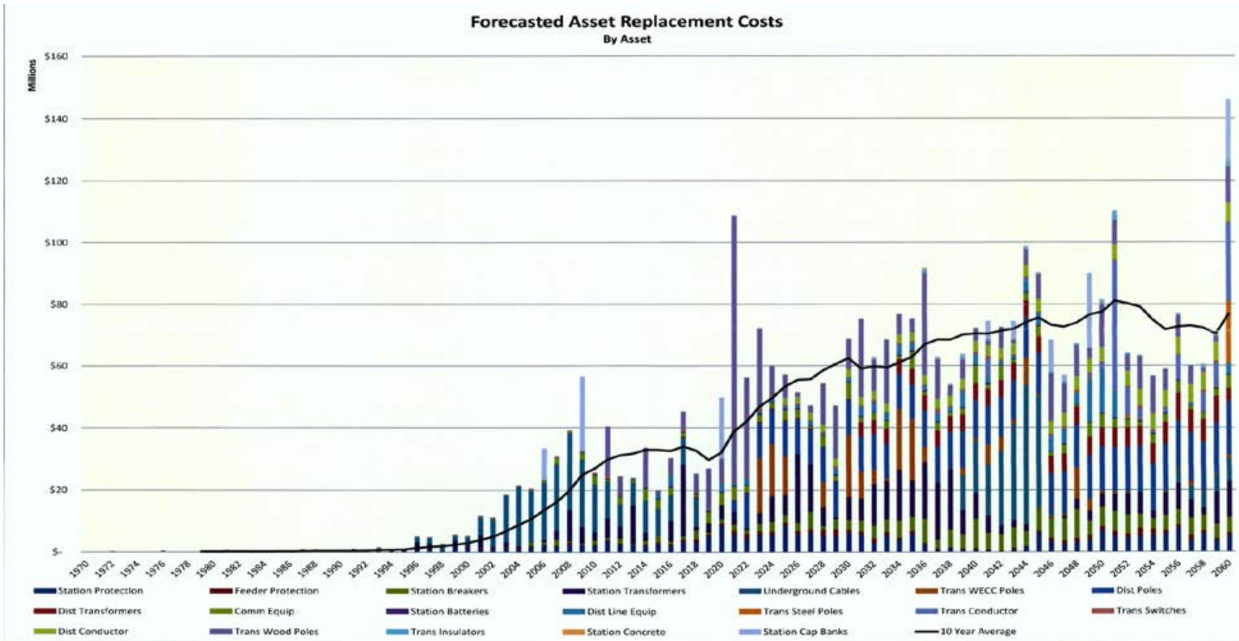


Figure 9: Idaho Power Long-term Replacement Costs

Data Integrity

The following table lists the various sources of information used for Asset Management purposes. Data gathering from non-electronic sources, mining and cleaning of available information makes up a disproportionately large amount of current work for Asset Management staff, on the order of 80% of total work. Long term, in order to provide the most value to Avista this needs to be reversed with 80% applied to analyzing data and 20% to gathering and cleaning data.

Status	Data Source	Notes/Comments
	AFM	wood species info missing for 115kV; potentially large # of stubs entered as pole installs, major job backlog updates pending from 1992
	Line History Binder	great historical info but hasn't been updated for 15 years
	Safety information	unable to isolate to Transmission work
	Plan & Profile (P&P drawings)	major job backlog updates pending from 1992 to present; long term migration to digital (PLS-CADD) format
	WPM database	pole information is not updated to reflect followup work or other projects, just at time of inspection; handnotes need to be consolidated and alphebetized, line naming conventions need to be synced up; wood species in hand notes and electronic files needs to be uploaded to AFM
	Maximo	in design phase for Tx, summer 2014 implementation; may not capture component failure mode data as designed
	Transmission Engineering Guidelines	partially complete, need more participation to complete
	Engineering files vault	engineers need to submit as-built updates more promptly, "archived" files need to be refiled in their proper line section
	Discoverer	unwieldly to summarize costing across different Tx projects, difficult to isolate costs/activities to Tx
	AWB simulations	building on progress/standards/methods
	PLS-CADD and design/construction standards	progress continues, plan to publish new standards in 2014
	Air Switch Master Inventory Spreadsheet	updated inventory and detailed info complete
	OMT data	mostly reliable info but some categories are mixed with substations, for example PMs that really are transmission related are placed in subs
	Tx Projects & Capital Budget Spreadsheets	
	System Data Book	verified long term viability of data-base, closely maintained

Table 18: Transmission Asset Data Integrity

Transmission system records in particular are outdated and/or insufficient in many cases to perform effective asset management analyses, e.g. outdated Plan & Profile drawings, unreliable AFM data, missing larch pole information, conflicting line names between data sources due to line name changes, lack of component failure data, etc. It is hoped that with Maximo implementation, much of this problem will be resolved over time.

We are 100% complete processing updates to a backlog of 459 transmission jobs dated from 1992 to the present in our GIS/AFM database and on plan and profile (P&P) drawings. However, prompt updates from construction as-builts continue to be problematic, as most of the transmission jobs completed in 2013 have yet to be updated in system records.

Material Usage

According to Supply Chain staff, a definitive list of parts, quantities and funds spent on transmission work is currently unavailable. The following list of materials was tabulated from a query of the Oracle database for those projects listed as Transmission from October 2010 to October 2012. This should not be taken as complete costing information, but may be reasonably considered accurate for the relative use of material categories.

Category	Total Amount	%
steel poles	$1,770,582	44%
other	$466,378	12%
fire retardant coating	$445,514	11%
crossarms	$349,709	9%
air switches	$293,131	7%
conductor	$259,622	6%
insulators	$228,702	6%
crossbraces	$96,212	2%
vibration dampers	$78,916	2%
wood poles	$52,927	1%
total	$4,050,929	100%

Table 19: Relative Material Purchases, 10/2010 – 10/2012

Root Cause Analysis (RCA)

Following the Othello storm in September 2013, a team was formed to study the causes of the event and develop effective solutions to prevent recurrence, as appropriate. Representatives from Transmission Design, Asset Management, Distribution Engineering, Construction Services, and Spokane Electric participated. In addition to technical forensics, a rigorous methodology was followed known as the "Apollo Root Cause Analysis method™ ", requiring evidence and team consensus to develop effective solutions. Not only the root causes, but also the significance of the event and the more severe consequences that were narrowly avoided were unexpectedly discovered through the team's deliberations. A summary report was generated and a number of significant action items initiated to prevent or mitigate similar events in the future.

Unexpected events such as the Othello storm, while undesirable, in many cases offer rare opportunities to learn and improve. No single formula or approach is generically applicable to all problems. However, the Apollo RCA method or close variant is applicable to many, and it is hoped that it may be used to greater effect in the future. Lessons learned from this effort will inform the next RCA effort if/when it arises.

Business Cases

This section highlights specific business cases developed on the basis of optimized asset management, supported by detailed simulation studies. The list below provides a summary of current and anticipated work in this area, based on planned ground inspections.

Line	Business Case Submission	Anticipated Construction	Status
Devil's Gap – Lind 115kV	2012	2014 - 2016	Approved
Benewah – Moscow 230kV	2013	2015 – 2016	Approved
Cabinet – Noxon 230kV	2014	2016 – 2018	In progress
Benewah – Pine Creek 230kV	2014	2016 – 2018	In progress
Hot Springs – Noxon #2 230kV	2014	2016 – 2019	In progress
Walla-Walla – Wanapum 230kV	2015	2017 – 2020	Pends analysis
Moscow230 – Orofino 115kV	2015	2017 – 2020	Pends inspection
Devil's Gap - Stratford 115kV	2015	2017 – 2020	Pends inspection

Table 20: Simulation-Supported Business Cases, 2012 - 2015

In addition to the above list, a system-wide simulation study is desired to help support policy decisions for levelized, long-term inspection and replacement schedules. This is a stretch-goal for 2014.

Acceptable simulation studies require a recent inspection (within five years of the study), in order to provide valid results and recommendations. For this reason it is critical that the reliability risk index is completed and used to schedule future inspections, prioritize rebuild studies and follow-up work.

It should be noted that not all rebuild projects warrant the time and expense of conducting a simulation study. This is the case, for example, where the right business decision is obvious or may be sufficiently justified by easier and/or faster means.

System Planning Projects

The following table lists substation and transmission projects at various stages from study through construction, as provided by system planning on Sharepoint. This list is a snapshot of current plans and is subject to frequent change. In particular, projects to create a looped 230kV system around Spokane is in development and not included here. See the Area Work Plans section of this report for more detail on transmission specific projects and inspection plans.

Project List by Area

		Construction	Committed	Planned	Concept
End	(Multiple Items)				

	Cost Estimate	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TBD
Big Bend	$78,019,444	0	0	0	0	0	0	0	0	0	0	5
49 Degrees Station	$6,000,000											
Addy - Devils Gap 115 kV Transmission Line Reconductor	$2,025,000											
Benton - Othello SS 115 kV Transmission Line Rebuild	$9,600,000											
Bruce Siding Station												
Chelan - Stratford 115 kV Transmission Line Rebuild	$13,000,000											
Devils Gap - Lind 115 kV Transmission Line Rebuild	$10,344,444											
Ford Station Rebuild	$1,275,000											
Gifford Station Rebuild	$900,000											
Harrington Station Rebuild	$3,000,000											
Lee and Reynolds Transformation												
Lind – Warden 115 kV Transmission Line Rebuild	$9,000,000											
Little Falls Station Rebuild	$4,775,000											
Odessa Capacitor Bank	$500,000											
Saddle Mountain Integration	$16,400,000											
Stratford 115 kV Station Rebuild	$1,200,000											
Coeur d'Alene	$82,632,550	0	0	0	0	0	0	0	0	0	0	7
Beck Road Station	$182,550											
Big Creek Station Rebuild	$1,425,000											
Blue Creek Station Rebuild	$650,000											
Bronx Station	$1,500,000											
Burke - Pine Creek #3 & #4 115 kV Transmission Line Rebuild	$7,200,000											
Cabinet – Bronx – Sand Creek 115 kV Transmission Line Rebuild	$9,500,000											
Cabinet Gorge Switching Station	$12,000,000											
Carlin Bay Station	$10,000,000											
Coeur d' Alene – Pine Creek 115 kV Transmission Line Rebuild	$12,775,000											
Noxon - Pine Creek #2 230 kV Transmision Line												
Noxon Construction Station Rebuild	$650,000											
Noxon Rapids 230 kV Switchyard Rebuild	$26,750,000											
Pine Creek Transformer Replacement												
Priest River Station												
Sandpoint, Sagle, and Oden Grid Modernization												
St. Maries SCADA Upgrade/Add Feeder												
Lewiston/Clarkston	$28,305,000	0	0	0	0	0	0	0	0	0	0	2
10th & Stewart Station Rebuild	$1,000,000											
230 kV Voltage Control	$5,500,000											
Clearwater Station Upgrade	$3,000,000											
Grangeville Station Rebuild	$2,025,000											
Hatwai - Lolo #2 230 KV Transmission Line	$8,025,000											
Kamiah Wood Station Rebuild	$1,485,000											
Kooskia Transformer Replacement												
Lewiston Mill Road Station	$1,950,000											
Pound Land Station Rebuild	$1,300,000											
South Lewiston Station Rebuild	$1,520,000											
Wheatland Station	$2,500,000											

Figure 10: System Planning Projects (Big Bend, CDA & Lewiston/Clarkston)

Project List by Area

End: (Multiple Items)

Construction | Committed | Planned | Concept

	Cost Estimate	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TBD
Palouse	$50,008,771	0	0	0	0	0	0	0	0	0	0	5
Benewah - Moscow 230 kV Transmission Line Rebuild	$24,203,771											
Deary - Potlatch 115 kV Transmission Line	$20,000,000											
Diamond Station Minor Rebuild												
Moscow 230 Station Rebuild	$2,650,000											
Moscow City 115 SCADA/Minor Rebuild												
North Moscow Transformation	$2,280,000											
Potlatch Transformer Replacement												
Tamarack Station	$875,000											
Tekoa SCADA Upgrade/Minor Rebuild												
Spokane	$117,890,000	0	0	0	0	0	0	0	0	0	0	10
Beacon - Bell - Francis & Cedar - Waikiki Reconfiguration	$2,000,000											
Beacon Substation Rebuild	$15,000,000											
Bell Second Tranformer	$1,000,000											
Chester Station Rebuild	$1,460,000											
College and Walnut Consolidation/Rebuild												
Deer Park Partial Rebuild												
Downtown East Station	$2,000,000											
Downtown West Station	$2,000,000											
Garden Springs Substation Integration	$20,000,000											
Greenacres/Otis Orchards Stations	$2,590,000											
Hallett & White - Silver Lake 115 kV Transmission Line Rebuild	$2,025,000											
Hallett & White Capacitor Bank	$500,000											
Hawthorne Station	$3,000,000											
Hillyard Station	$3,275,000											
Irvin Distribution	$1,225,000											
Metro Station Rebuild	$11,150,000											
Nine Mile - Westside Protection Upgrade	$200,000											
Ninth & Central - Sunset 115 kV Transmisison Line Rebuild	$925,000											
Ninth & Central 230 kV Integration	$15,000,000											
Ninth & Central Station Upgrade	$2,775,000											
Northwest Station Rebuild	$1,675,000											
Spokane Valley Transmission Reinforcement	$8,840,000											
Sunset Station Rebuild	$5,325,000											
Westside Transformer Replacement	$15,925,000											
System	$134,907,000	0	0	0	0	0	0	0	0	0	0	
230 kV Capacitor Automatic Switching	$20,000											
Distribution Programs												
Line Ratings Mitigation	$12,637,000											
New Distribution Stations	$7,500,000											
RAS Update	$1,000,000											
Spokane - Coeur d'Alene 115 kV Relay Upgrades	$3,250,000											
Substation Asset Management	$41,000,000											
Substation Capital Spares	$51,000,000											
Substation Rebuilds	$4,500,000											
Transmission Asset Management	$14,000,000											
Grand Total	$491,762,765											30

Figure 11: System Planning Projects (Palouse, Spokane and System)

Area Work Plans

The following transmission projects are scheduled for work based on a variety of factors including changing system and operational requirements, remaining service life, asset condition and performance. This list is provided for planning and reference purposes only. It represents current plans and is subject to frequent change. See the Transmission Engineering Manager for the latest revision. Those items with no marks for any year represent tentative projects under consideration.

See the end of the list for the current minor rebuild and ground inspection schedule, which typically drives follow-up repairs and minor rebuilds the following year (when a major rebuild is not justified based on condition assessment).

Projects

EFA = Reimburseable or Growth
HPRM = High Priority Line Ratings Mitigation Program Business Case
IAA = Other
LPRM = Low Priority Line Ratings Mitigation Program Business Case
MPRM = Medium Priority Line Ratings Mitigation Program Business Case
NG = New Growth
NT = New Transmission Program Business Case
PS = Project Specific Business Case
SDSR = Substation - Distribution Station Rebuild Program Business Case
SNDS = Substation - New Distribution Stations Program Business Case
SVTR = Spokane Valley Transmission Reinforcement Program Business Case
TAM = Transmission Asset Management Program Business Case
TRR = Transmission Rebuild/Reconductor Program Business Case

Major Rebuilds and Other Projects

Business Case	Area	ER Description	2014	2015	2016	2017	2018
MPRM	Big Bend	Walla Walla-Wanapum 230kV Mitigation	X				
NT	Big Bend	Coulee - Westside 230 - Construct (Acquire ROW)					
PS	Big Bend	Harrington 115-4kV - Integration	X				
PS	Big Bend	Odessa Substation - Re-integration	X				
SDSR	Big Bend	Stratford 115kV Sub - Rebuild - Integration	X				
SDSR	Big Bend	Ford 115-13kV Sub - Integration				X	X
SDSR	Big Bend	Little Falls 115kV Sub - Integration		X	X	X	
SNDS	Big Bend	Bruce Siding 115 Sub - New - Tap to Sub					
SNDS	Big Bend	49 Deg North 115-21 Feeder - Integration					
TRR	Big Bend	Devils Gap-Lind 115kV Rebuild Transmission	X	X	X		
TRR	Big Bend	Ben-Oth SS 115 - ReCond/ReBld	X	X	X		
TRR	Big Bend	Addy-Devils Gap 115kV - Recon/Rbld near Ford sub				X	X
TRR	Big Bend	Chelan-Stratford 115kV - Rbld Columbia River Xing	X				

Business Case	Area	ER Description	2014	2015	2016	2017	2018
BLKT	CDA	15th Street Road Widening (CDA) - Reimburseable	X				
EFA	CDA	Prairie Avenue Road Widening - Reimbursable	X				
EFA	CDA	KEC Beck Rd Sub - Trans Integration- Reimbursable	X				
HPRM	CDA	Benewah-Pine Creek 230kV Trans Mitigation	X				
IIA	CDA	Colstrip Trans Capital Add's	X	X			
LPRM	CDA	BEN-PIN 115kV Trans Line Mitigation	X	X	X	X	
NT	CDA	Carlin Bay 115-13 Sub - New					
PS	CDA	Noxon 230kV SS - Rebuild - Integration	X	X	X	X	X
PS	CDA	Cabinet Gorge 230kV Switchyard - Integration					
SDSR	CDA	Blue Creek 115kV Sub - Rebuild - Integration	X				
SDSR	CDA	Bronx 115-21 Sub - Construct - Integration					
TRR	CDA	CDA-Pine Creek 115kV Rebuild Transmission	X		X	X	X
TRR	CDA	Pine Creek-Burke-Thompson Falls - Rebld Transmission	X	X			
EFA	Lewis-Clark	Hatwai - Lolo Casino - Reimbursable	X	X			
MPRM	Lewis-Clark	Dry Creek-Talbot 230kV Mitigation	X				
NG	Lewis-Clark	Lewiston-Mill Road Sub Integration	X				
NT	Lewis-Clark	Hatwai-Lolo #2 230kV - New			X	X	X
PS	Lewis-Clark	Clearwater Substation - Re-Integration	X				
SDSR	Lewis-Clark	Grangeville 115-13-34.5kV - Integration			X	X	
SNDS	Lewis-Clark	Wheatland 115 Sub - Construct - Tap to Sub					
MPRM	Palouse	North Lewiston-Shawnee 230kV Mitigation	X				
PS	Palouse	Moscow 230kV Sub - Rebuild - Integration	X				
SDSR	Palouse	N. Moscow Add Transformer - Integration				X	X
SDSR	Palouse	N. Moscow - Airport Rd - Add Transformer Upgrade for U				X	X
SNDS	Palouse	Tamarack 115 Sub - Construct - Integration		X	X		
SNDS	Palouse	Bovill 115kV Substation - New - Integration					
TRR	Palouse	Benewah-Moscow 230kV - Reconductor/Rebuild		X	X	X	

Business Case	Area	ER Description	2014	2015	2016	2017	2018
BLKT	Spokane	MLK New Road Relocation - Reimbursable	X				
EFA	Spokane	Hawthorne 115 Sub - Construct - Integration					
MPRM	Spokane	Beacon-F&C 115kV Mitigation	X				
MPRM	Spokane	Northwest-Westside 115kV Mitigation	X				
MPRM	Spokane	Beacon-Bell #5 230kV Mitigation	X				
MPRM	Spokane	Beacon-Boulder #2 115kV Mitigation	X				
MPRM	Spokane	Ninth & Central-Otis 115kV Mitigation	X				
MPRM	Spokane	Beacon-Bell #4 230kV Mitigation	X				
NT	Spokane	Westside/Garden Springs 230/115 - New					
PS	Spokane	Westside 230kV Sub - Rebuild - Integration					
PS	Spokane	Beacon 230kV Sub - 115kV Rebuild - Integration					
PS	Spokane	Garden Springs 230-115-13 Sub - Integration			X	X	X
PS	Spokane	9CE Sub - New 230kV Transformation - Integration					
SDSR	Spokane	Sunset 115kV Sub - Rebuild - Integration			X	X	
SDSR	Spokane	9CE 115 Sub - Rebuild/Expand	X	X			
SDSR	Spokane	Northwest 115-13kV Sub - Integration		X	X		
SDSR	Spokane	Chester 115-13kV Sub - Integration		X	X		
SDSR	Spokane	Beacon 230 - 2 X 2 - Integration					
SDSR	Spokane	Metro 115-13kV Sub - Integration			X	X	X
SNDS	Spokane	Hillyard 115-13 Sub - Construct - Integration				X	X
SNDS	Spokane	Greenacres 115 Sub - Construct - Integration	X				
SNDS	Spokane	Downtown West 115 Sub- New - Tap to Sub					X
SNDS	Spokane	Downtown East 115 Sub- New - Tap to Sub					
SVTR	Spokane	BEA-BLD #2 115 - Upgrd 140MVA		X	X		
SVTR	Spokane	Irvin SS 115 - Construct - Integration	X	X			
SVTR	Spokane	Opportunity Sub 115-13kV - Integration	X				
TRR	Spokane	Garden Springs - Silver Lake 115kV - Recon/Rbld				X	X
TRR	Spokane	BEA-BEL-F&C-WAI 115kV - reconfig @ Bell and Waikiki			X	X	
TRR	Spokane	9CE-Sunset 115kV Transmission - Recon/Rbld		X	X		
TRR	Spokane	Garden Springs - Sunset - West Plains Trans Reinforcem		X	X		

Business Case	Area	ER Description	2014	2015	2016	2017	2018
SDSR	All	Sys - Wood Sub Rebuilds - STR Design	X	X	X	X	X
TAM	All	Transmission Minor Rebuilds - WA	X	X	X	X	X
TAM	All	Transmission Minor Rebuilds - ID	X	X	X	X	X
TAM	All	Sys - Trans Air Switch Upgrade	X	X	X	X	X
TAM	All	Trans Air Switch Platform Grd Mat					

Minor Rebuilds

2014 Minor Rebuilds (following previous ground inspections)		
Area	**Transmission Line**	
Big Bend	Addy - Devil's Gap	115kV
Big Bend	Othello - Warden #2	115kV
Big Bend	Walla Walla - Wanapum	230kV
CDA	Noxon - Hot Springs #2	230kV
Lewis-Clark	Grangeville - Nez Perce #1	115kV
Lewis-Clark	Jaype - Orofino	115kV
Lewis-Clark	Moscow 230 - Orofino	115kV
Palouse	Benewah-Pine Creek	230kV
Spokane	Beacon - Bell #4	230kV
Spokane	Ninth & Central - Otis	115kV
Spokane	Post St. - Third & Hatch	115kV
Spokane	Ross Park - Third & Hatch	115kV
Spokane/Palouse	Shawnee - Sunset Phase 2	115kV

Ground Inspections

2014-2018 Structural Ground Inspections				
Area	**Transmission Line**		**# wood poles**	
Big Bend	Walla Walla - Wanapum	230kV	175	
Big Bend	Moscow230-Orofino*	115kV	1101	
Big Bend	Devil's Gap - Stratford**	115kV	1173	
			2274	Year 2014 total
* includes Deary Tap				
** partial inspection, from DG to Odessa only				
Palouse	Latah-Moscow	115kV	706	
Big Bend	Addy - Gifford	115kV	275	
Lewis-Clark	Grangeville-Nez Perce #2	115kV	507	
Lewis-Clark	Lolo - Oxbow	230kV	716	
Spokane	Benewah - Boulder	230kV	438	
			2642	Year 2015 total
Spokane	Boulder - Otis Orchards #1	115kV	55	
Spokane	Post Falls-Ramsey	115kV	161	
Lewis-Clark	Jaype-Orofino	115kV	540	
Big Bend	Chelan - Stratford	115kV	1197	
Lewis-Clark	Clearwater-North Lewiston	115kV	50	
Palouse	Shawnee-South Pullman	115kV	191	
Spokane	Francis & Cedar-Ross Park	115kV	85	
Spokane	Airway Hts - Sunset	115kV	129	
Spokane	College & Walnut-Post Street	115kV	3	
			2411	Year 2016 total
Spokane	College & Walnut-Westside	115kV	135	
Spokane	Francis & Cedar-Northwest	115kV	52	
Spokane	Ninth & Central-Sunset	115kV	184	
Spokane	Beacon - Bell #1	115kV	158	
Big Bend	Lind-Warden	115kV	498	
Big Bend	Lind-Washtucna	115kV	362	
CDA	Bronx - Cabinet	115kV	319	
Lewis-Clark	Lolo-Nez Perce	115kV	692	
			2400	Year 2017 total
Spokane	Metro - Sunset	115kV	53	
Spokane	Beacon - Ninth & Central #2	115kV	70	
Lewis-Clark	Lolo-Pound Lane	115kV	242	
Spokane	Beacon - Boulder #2	115kV	303	
Spokane	Boulder - Otis Orchards #2	115kV	44	
Spokane	Boulder - Rathdrum 115 kV	115kV	TBD	
Lewis-Clark	Hatwai - Lolo	230kV	146	
Palouse	Moscow - Terra View	115kV	TBD	
Palouse	Shawnee - Terra View	115kV	TBD	
Big Bend	Devil's Gap - Stratford*	115kV	621	
TBD	TBD	115kV	TBD	
			TBD	Year 2018 total
* partial inspection Odessa to Stratford only				

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