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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-16-03
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC SERVICE	)	EXHIBIT NO. 7
TO ELECTRIC CUSTOMERS IN THE	)	
STATE OF IDAHO	)	HEATHER L. ROSENTRATER
	)	

FOR AVISTA CORPORATION

(ELECTRIC)

Customer Usage
State of Idaho - Electric
As of December 31, 2015

Electric Schedule	No. of Customers	kwh (000s)	% of Total kwh
Residential Sch. 1	104,621	1,124,033	37%
General Sch. 11&12	21,154	366,126	12%
Lge. General Sch. 21&22	1,157	706,267	23%
Ex. Lge. General Sch. 25	8	316,352	10%
Ex. Lge. General Sch. 25P	1	450,717	15%
Pumping Sch. 31&32	1,437	66,287	2%
Street & Area Lights	148	14,189	0%
	128,526	3,043,971	100%

2016

Electric Transmission System 2016 Asset Management Plan

Mary Jensen, Rubal Gill
Asset Management
Avista Corp.
02-01-2016

Exhibit No. 7
Case No. AVU-E-16-03
H. Rosentrater, Avista
Schedule 2, Page 1 of 61

Prepared by: Mary C. Jensen

Mary Jensen, Asset Management Engineer

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Ken Sweigart, Transmission Engineering Manager

Approved by:

Scott Waples, Director of Planning and Asset Management

Front cover:

Steel Structures on the Benewah – Boulder 230kV Line (November, 2015)
1959 Original Construction
2015 Phase 1 Structure Replacement Project

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Purpose

System asset management plans 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, operational plans, and primary replacement and maintenance programs. Consistent annual updates of this plan provide the continuity required for useful historical information and continuous improvement of asset management practices.

For easy reference, a "Quick Facts" sheet is used to highlight key information and recommendations of this system-level asset management plan. At the individual program and project level, additional "Quick Facts" sheets may also be available. For more details, please visit the Asset Management Sharepoint site at Asset Management Plans. This update reflects the best available information as of December 31, 2015.

Executive Summary

Consistent with last year's assessment, the primary message of this asset management plan is that the company must commit itself to sustainably replace the bulk of the aging transmission system over the next three decades. This is essential to achieve the company's strategic objectives of maintaining reliability levels while minimizing total lifecycle costs, requiring over $624 million in capital replacement investment. As this represents a significant increase in capital investment as well as internal and external workloads from recent years, success demands strong company support and management. In order to be most effective and beneficial to customers and the company, it also requires fact-based prioritization and targeting of available funds to the riskiest elements of the system.

Key performance indicators (Table 5) for the transmission system showed results lower than targeted for 2015. Completed ground inspections were lower than planned and aerial inspections were on-track. Aging 115kV pole replacements were 80% below target, while aging 230kV pole replacements were 37% above target. Customer outages were 97% higher than targeted, while emergency spending was 50% higher than targeted. Finally, the follow-up repair backlog increased, ending the year with five category 4 items overdue and the oldest item in the backlog at 35 months. Much of this may be due to improved identification and tracking methods that were recently implemented.

Replacement budget recommendations remain relatively unchanged at $12 million for 115kV and $9 million for 230kV. Planned budgets for 2016 and 2017 are relatively close to this recommendation. Additional mandated, growth and reimbursable capital projects, as well as O&M work puts the total planned budget for

Transmission Engineering at approximately $25 million for 2016, and is expected to remain at this level or increase for many years. This output level is nearly triple that of just a few years ago, while dedicated staff have only increased from five to six in the transmission engineering group. In order to reduce operational risks, it is strongly recommended that management consider assigning additional dedicated staff members, as well as proper equipment for safe and effective fieldwork.

Outages and unplanned spending was $2 million in 2015 , mostly as the result of a severe winter wind storm that raised overall unplanned spending on the 230 kV and 115kV systems by $700k.

Notable achievements in 2015 include:

1. Design and project management of an expanded number of mandated and system planning projects including LiDAR mitigation, at $16.4 million in 2015 compared to $7.5 million in 2014.
2. Completion of minor rebuild and LiDAR mitigation on Moscow - Orofino 230kV, Devil's Gap – Stratford 115 kV, and Noxon – Hot Springs 230 kV
3. Total rebuild on Bronx – Cabinet 230 kV, tie line to the new Noxon reactor, and structure replacement projects on Benewah-Moscow 230 kV and Devils Gap-Lind 115 kV.
4. Approved 2015 budget closely matching the recommended replacement budget of $12 million for 115kV and $9 million for 230kV.
5. Effective transition of administrative maintenance work from departing staff, as well as hiring and productive output of new engineering staff.
6. Published a comprehensive set of construction standards for transmission engineering and effectively integrated the use of PLS-CADD software. Consistently using both as a baseline for continuous improvement, as a collaborative team effort.
7. Confirmation of system pole data including material and location, allowing for detailed expected service life information on each transmission line.
8. Began simulation studies for Lolo – Oxbow 230kV and Noxon – Pine Creek 230kV circuits.
9. In cooperation with other utilities, continued a major project to determine best design, construction, inspection and maintenance of self-weathering steel structures.

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

1. Provide additional dedicated staff as appropriate, to handle long-term increased workloads in the Transmission Engineering group and support processes.

2. Engage asset stakeholders within each major region of the transmission system in order to develop a comprehensive, prioritized capital project plan for the next 20 years.

3. Continue improving the transmission construction standards to reflect best practices in design and construction work. Engage line crews and regional staff.

4. Monitor the lead time for as-built construction updates to AFM, Plan and Profile (P&P) drawings, and the engineering vault files, with a target of six months. Carry out periodic quality audits of construction in the field and recorded data.

5. Develop a comprehensive inspection and planned maintenance program for steel transmission structures.

6. Develop a systematic air switch risk ranking method, replacement schedule, and inspection and maintenance program.

7. Complete rebuild simulation studies and business cases for Lolo – Oxbow 230kV and Noxon – Pine Creek 230kV circuits.

8. Determine the risks and appropriate mitigation work resulting from structural loads of distribution underbuild.

9. Complete a system-wide simulation study to support optimal Transmission asset inspection intervals as well as planned and unplanned replacement budget targets, including annual minor vs. major rebuild budgets.

10. Implement transmission outage software which will allow for accurate and efficient analysis of outages and causes on each transmission line and aerial patrol inspection software for follow up tracking.

Assets

The tables and charts below provide a high-level summary of physical assets in the transmission system, replacement values, and expected service lives. Replacement values represent the cost to replace existing assets with equivalent new equipment in 2015 dollars, not including right-of-way purchases, capacity or ratings upgrades, mandated projects, and other work associated with growth-related installations.

Circuit Type	Installation Cost/Mile	Removal Cost/Mile	Miles	Total Replacement Cost
69kV Circuit	$250,000	$20,000	0.4	$113,400
115 Single Circuit	$400,000	$20,000	1457.1	$611,986,200
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	604.3	$435,081,600
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
			2169.6	**$1,142,661,600**
		Average Asset Lifecycle (Years)		70
	Annual Levelized Replacement Spending over Lifecycle			**$16,323,737**

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

Asset Category	Quantity 230kV	Quantity 115kV	Quantity Total	Expected Service Life (years)
Structures	4990	16483	21473	65
Poles	9021	27401	36422	70
Air switches	2	188	190	40
Conductor (miles)	2055	4602	6657	100
Compression sleeves	1370	3068	4438	50
Insulators	22978	60202	83180	70

Table 2: Component Assets and Quantities

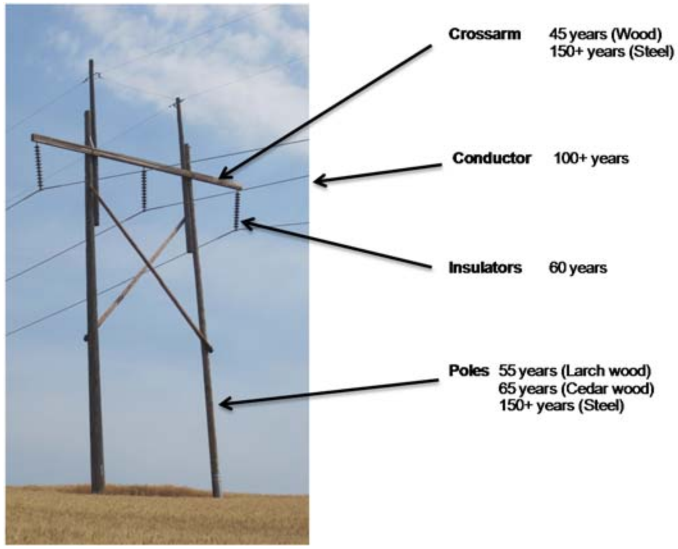
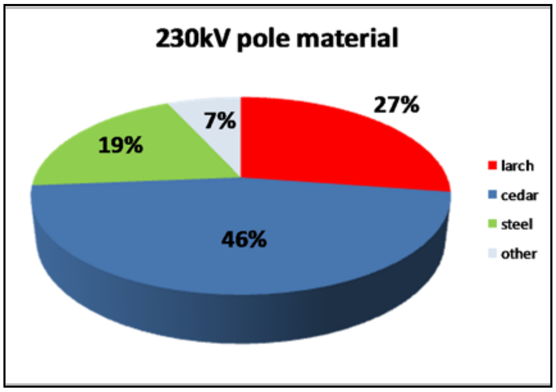
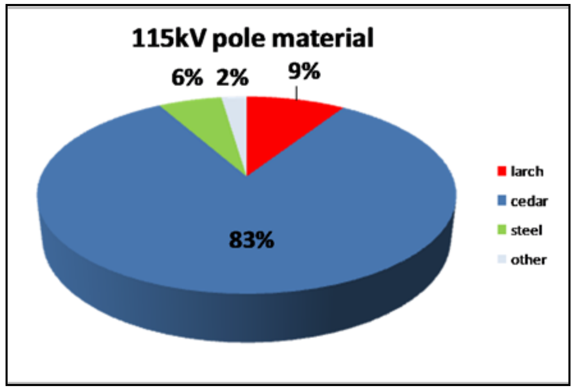


Figure 1: Example Transmission Asset Components and Expected Service Life

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
5660	# beyond expected service life
16%	% 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	other	total
service life	55	65	150	70	69
# 115 poles	2347	21198	1506	597	25648
# 230 poles	2545	4312	1813	635	9305
total # poles	4892	25510	3319	1232	34953

Table 4: 115kV vs 230kV Pole Materials

Key Performance Indicators (KPIs)

The table below shows overall KPI results for 2015, 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.

By these measures, performance was lower than targeted for structural ground inspections. Aerial patrol inspections remained on-track overall. System-wide follow-up repairs from ground and aerial patrol inspections were higher than planned for category 4 and 5 items. This may be primarily due to improved tracking methods. Aging infrastructure replacement was less than the levelized investment required to maintain system reliability over the long term for 115kV, as roughly indicated by the number of older poles replaced. Reliability performance and emergency spending were higher than targeted.

Completed Structural Ground Inspections	Projected	Actual	Normalized
# wood poles ground inspected	2400	2145	0.89
Completed Structural Aerial Inspections	Projected	Actual	Normalized
% of 230kV system inspected	100	100	1.00
% of 115kV system inspected	70	70	1.00
Followup Repair Backlog	Projected	Actual	Normalized
# worksites overdue (> 1 year after inspection year)	10	8	0.80
# Category 4 or 5 items overdue (> 6 months since inspection, ground + aerial)	1	5	5.00
oldest item in backlog (# months since inspection)	18	35	1.94
Aging Infrastructure Replacement	Projected	Actual	Normalized
# 115kV wood poles older than 60 years replaced with steel	500	98	0.20
# 230kV wood poles older than 50 years replaced with steel	175	240	1.37
# air switches > 40 yrs old replaced	4	1	0.25
Reliability Performance	Projected	Actual	Normalized
Extended Unplanned Outages due to Transmission (Customer-Hrs)	133,142	262,949	1.97
# of Customers with Unplanned Transmission Outages > 3 Hrs	10,182	24,927	2.45
Emergency Spending	Projected	Actual	Normalized
230kV Emergency Spending	$204,022	$ 388,272	1.83
115kV Emergency Spending	$ 1,116,997	$ 1,792,649	1.44
total Emergency Spending	$ 1,321,019	$ 2,180,921	1.50

Unity Box Metrics - Monthly	Weighting	2015 Result
Completed Structural Ground Inspections	20.00%	0.89
Completed Structural Aerial Inspections	20.00%	1.00
Followup Repair Backlog	15.00%	3.19
Aging Infrastructure Replacement	15.00%	0.73
Reliability Performance	15.00%	2.31
Emergency Spending	15.00%	1.50
Sum of Weight * Value	100.00%	1.54

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

Table 5: Transmission KPIs and Unity Box Metrics

It is strongly recommended that $21 million per year over a 30-year timeframe is allocated for worn-out infrastructure replacements – $12 million for 115kV, and $9 million 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 2010:

Performance Measure	Goal	2010	2011	2012	2013	2014	2015	Remarks
Customer-Hours unplanned, extended outage due to transmission issues	113,142	255,426	64,453	82,908	238,861	200,977	262,949	
# of customers of Tx related unplanned outages greater than 3 hrs	10,182	16,478	6,644	5,409	17,135	17,609	24,927	
Tx emergency repair costs	$1,321,019	$1,442,969	$1,029,597	$1,409,972	$1,630,943	$3,040,313	$2,180,921	
Avista crew safety: # recordable injuries from Transmission work	0	not avail	not avail	not avail	not avail	not avail	not avail	Unable to isolate to Transmission
Top 10 worst performing components - by failures	NA	not avail	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 avail	Not available from OMT data

Table 6: Additional Performance Measures, 2010-2015

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 transmission lines and system-wide 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. It is also essential to taking the next steps in evaluating the benefit and value of asset management programs and projects for continuous improvement.

Capital Replacement and Maintenance Investment

Levelized replacement spending is the annual spending required to replace the asset category in a perfectly level form over the asset's service life in 2015 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 that places reliability at risk. This currently stands at $16.3 million 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 $1.1 billion is on par with substation's $0.9 billion and about half of distribution's $2.0 billion. All together, levelized replacement spending is roughly $84 million 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 $12 million/year, roughly 50 years from now.

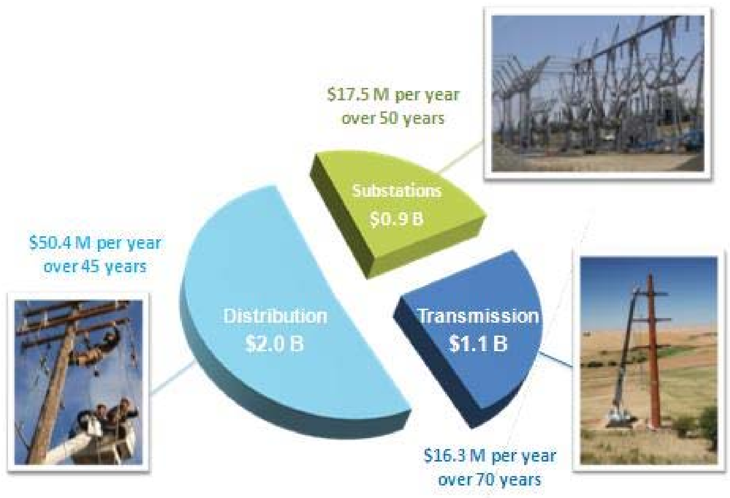


Figure 2: Transmission and Distribution System Replacement Values, Average Service Life, and Levelized Replacement Spending

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 actual remaining service life profiles, as summarized in the following chart.

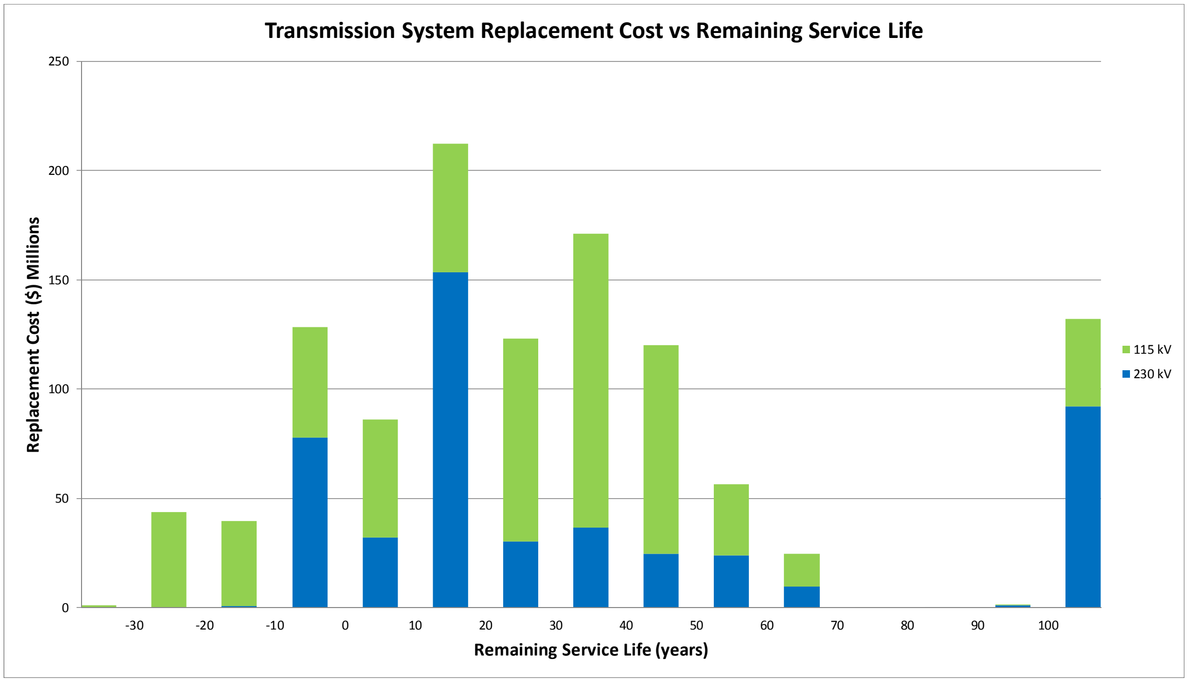


Figure 3: Replacement Cost vs. Remaining Service Life

Note that field assets costing $234 million to replace are currently beyond expected service life, based on their age and statistical predictions of mean time to failure (everything to the left of 0 years in Figure 3 above). The oldest and greatest quantities of these assets are 115kV transmission lines. 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 $21.1 million per year, split between $11.3 million for 115kV and $9.8 million for 230kV. This policy, when coupled with an ongoing, annual risk assessment and targeting of funds, over the long term will effectively reduce risks and minimize total lifecycle costs.

The table below presents a simple levelization 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 ($)			
Tx Capital Assets Service Life (yrs)	Levelized Replacement Period (yrs)	115kV	230kV	Total	Annual Levelized Replacement Spending ($)
-10 or less					
0 or less	10	$134,307,405	$78,477,092	$212,784,497	$21,278,450
10 or less	10	$188,044,730	$110,751,445	$298,796,176	$29,879,618
20 or less	20	$246,950,622	$264,119,590	$511,070,211	$25,553,511
30 or less	30	$339,538,157	$294,522,966	$634,061,123	$21,135,371
40 or less	40	$473,944,191	$331,318,848	$805,263,038	$20,131,576
50 or less	50	$569,441,268	$356,005,350	$925,446,618	$18,508,932
60 or less	60	$602,081,970	$379,756,364	$981,838,334	$16,363,972
70 or less	70	$617,172,136	$389,475,050	$1,006,647,186	$14,380,674

Table 7: Levelized Replacement Spending Options

A variety of data uncertainties result in +/- 5% confidence in the stated figures. In terms of replacement costs, the most significant uncertainty from year to year involves the volatility of contract labor. Extensive work was recently completed to confirm 115kV and 230kV pole data, most importantly the identification of pole material and respective expected service life, which has greatly improved confidence levels.

The recommended $21.1 million per year in levelized replacement spending over the next 30 years is higher than the $19.1 million actual replacement spending in 2015. Significant effort is underway to ramp up replacement construction in 2016 and sustain it over ensuing years. Other project categories include growth, mandated, and reimbursable capital projects, operations and maintenance (O&M) programs, and unplanned/emergency work. These figures are tabulated below for 2015. 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, growth, and mandated work, therefore these figures are rough approximations. Historically, upwards of 90% of transmission construction is through contractors.

$	19,074,307	Replacement
$	6,301,988	Growth/Upgrade
$	2,180,921	Unplanned/Emergency
$	936,843	O&M - Veg Management
$	327,319	O&M - Other
$	25,000	Reimburseable work completed
$	28,846,378	Total
$	26,640,457	Total Planned non-reimburseable
$	26,665,457	Total Planned Capital (including reimburseable)
$	1,264,162	Total Planned O&M
$	2,180,921	Total Unplanned/Emergency Capital
unknown		Total Unplanned O&M

Table 8: 2015 Transmission Spending

2015 Tx Project Spend		Program/Project Description	ER	BI	Type
$	5,344,333	Devils Gap-Lind 115kV Transmission Rebuild Proj	2564	ST302	Replacement
$	5,316,486	Benewah-Moscow 230kV - Structure Replacement	2577	PT305	Replacement
$	3,426,340	LiDAR Mitigation Projects, Med Priority	2560	CT203, various	Mandated Replacement
$	3,419,420	Xsmn Asset Management	2423	AMT81	Growth/Replacement
$	2,475,619	Benton-Othello 115 Recond	2457	FT130	Growth/Replacement
$	2,053,414	Asset Mgmt Trans Minor Rebuilds WA	2057	AMT12	Replacement
$	692,288	Noxon 230 kV Stn Rebuild:Transmission Integration	2532	AT300	Growth/Mandated
$	627,195	Asset Mgmt Trans Minor Rebuilds ID	2057	AMT13	Replacement
$	529,411	Transmission Line Road Move	2056	56L08	Replacement
$	443,619	Asset Mgmt Transmission Switch Upgrade	2254	AMT10	Replacement
$	411,600	Chelan-Stratford 115kV - Rbld Columbia River Xing	2574	BT304	Growth/Mandated
$	249,540	Lewiston Mill Rd. 115 kV Substation Integration	1107	LT403	Growth/Mandated
$	198,319	9CE-Sunset 115kV Transmission Line Rebuild	2557	ST503	Growth/Replacement
$	85,599	Opportunity Sub 115kV Breaker Add - Tx Integration	2552	ST307	Growth/Mandated
$	84,903	Irvin 115kV Switching Stn: Transmission Integration	2446	ST102	Growth/Mandated
$	18,209	Greenacres 115 Sub New Cons:Transmission Integrate	2443	ST203	Growth/Mandated
$	-	Burke-Thompson A&B 115kV Transmission Rebuld Proj	2550	CT101	Replacement
$	-	LiDAR Mitigation Projects, Low Priority	2579	CT304, various	Growth/Mandated
$	-	Asset Mgmt Transmission Wood Sub Rebuild	2204	AMT08	Replacement

Table 9: 2015 Planned Capital Projects (Non-Reimburseable)

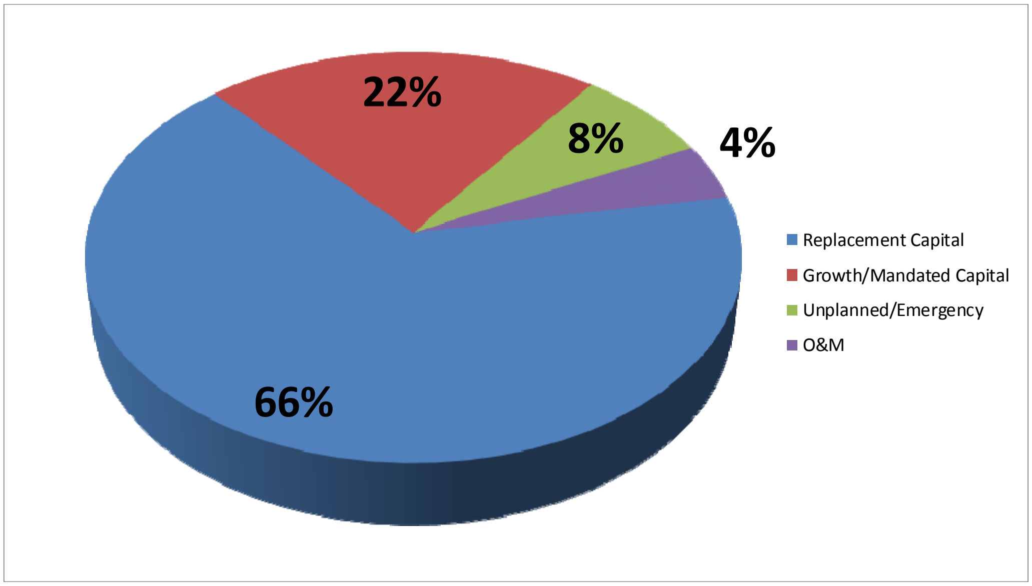


Figure 4: 2014 Planned Capital, O&M, and Emergency Spending

This shows that approximately 92% of spending was planned, vs. 8% unplanned in 2015. The percent of planned work should increase as planned replacements ramp up and unplanned/emergency spending is held constant or reduced. Growth and mandated projects (e.g. LiDAR projects) of $6.3 million resulted in 22% of total Transmission spending in 2015. Although the spending in this category is highly variable from year to year, a constant value of $3 million is assumed for the future. 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 expected lower inspection costs of steel poles as they are used to replace existing wood 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. 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 represent the minimum recommended investment for consistent, planned transmission work in the years ahead.

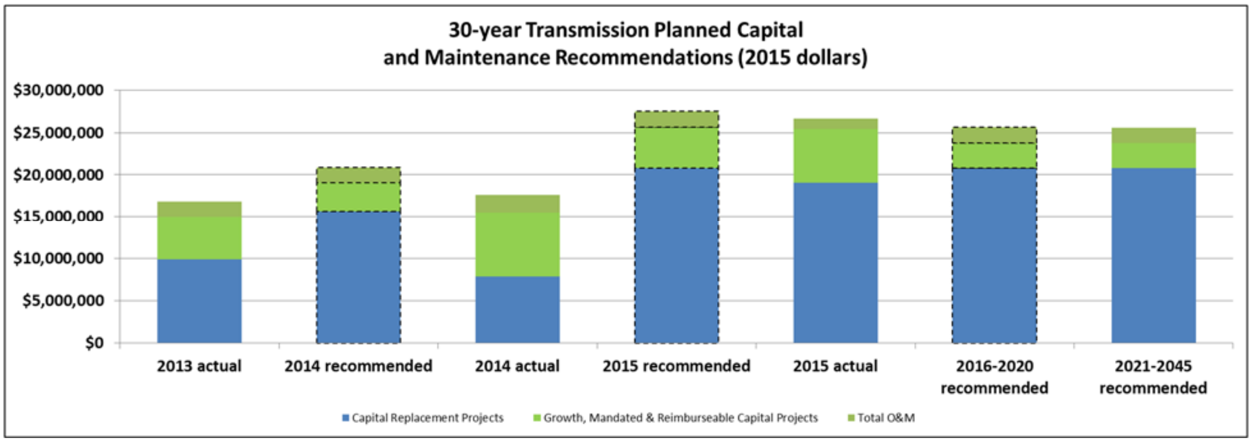


Figure 5: 30-year Transmission Planned Capital and Maintenance Recommendations

	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	Capital Replacement Projects	Growth, Mandated & Reimburseable Capital Projects	Total O&M	Total Planned
O&M %	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%				
Capital %	100%	100%	100%	100%	100%	0%	0%	0%	0%	0%				
2013 actual	$8,785,633	$3,965,832	$1,136,787	$150,556	$970,036	$294,000	$94,595	$1,100,000	$200,000	$100,000	$9,906,225	$5,102,619	$1,788,595	$16,797,439
2014 recommended	$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	$15,674,816	$3,369,523	$1,834,000	$20,878,339
2014 actual	$3,638,255	$7,499,457	$150,000	$135,493	$4,103,971	$317,790	$103,154	$1,300,000	$188,111	$181,405	$7,877,719	$7,649,457	$2,090,460	$17,617,636
2015 recommended	$18,667,888	$3,000,000	$1,870,600	$392,507	$1,700,000	$216,000	$100,000	$1,200,000	$242,000	$100,000	$20,760,395	$4,870,600	$1,858,000	$27,488,995
2015 actual	$15,420,668	$6,301,988	$25,000	$443,619	$3,210,020	$68,142	$135,318	$936,843	$19,322	$104,537	$19,074,307	$6,326,988	$1,264,162	$26,665,457
2016-2020 recommended	$18,496,395	$3,000,000	$25,500	$264,000	$2,000,000	$216,000	$103,154	$1,200,000	$242,000	$100,000	$20,760,395	$3,025,500	$1,861,154	$25,647,049
2021-2045 recommended	$18,496,395	$3,000,000	$26,010	$264,000	$2,000,000	$216,000	$103,154	$1,200,000	$242,000	$0	$20,760,395	$3,026,010	$1,761,154	$25,547,559

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.

Process Capability

As of 2010, total planned design, project management, and construction capital and O&M work for the Transmission system originating from the Transmission Engineering group was less than $10 million per year. At that time, Transmission Engineering had a dedicated staff of five members – one manager, three engineers, and one technician – equivalent to roughly $2.0 million per staff member. In 2015, total planned work amounts to $26,665,457 with a dedicated staff of six members – one manager and five engineers – equivalent to $4.4 million per staff member. This represents an output productivity increase of 120% in only a few years time. Hidden workloads such as mandated reporting and analysis from regulatory bodies such as NERC are also on the rise. In order to remedy operational risks and achieve management objectives, the need for additional staff, equipment, and improved support processes should be considered a very high priority, seriously investigated, and remedied as appropriate.

Other opportunities for improved process capability include reducing overall project lead times, particularly from the time of internal project initiation to the beginning of construction, which has increased substantially. Construction timelines and total costs may also be reduced, for example by completing line projects in one or two years instead of three to five.

Continued engagement and integration with internal and contracted line crews to communicate and improve construction standards is also recommended as a way to improve overall process capability.

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:

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

The transmission system's major circuits were 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 risk reduction. 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 "**Probability Index**". This is a normalized relative score from 1 (low unplanned event probability) to 100 (high unplanned event probability). The factors and respective weighting for the 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. In the future, improved data and analysis may allow for actual probability estimates rather than relative scoring methods.

% 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: Probability Index Criteria and Weightings

The second component of risk (event consequence), we will refer to as the asset's "**Consequence Index**". It is a measure of the severity of consequences should an unplanned failure event occur. This is also a normalized relative score from 1 (low severity = low event consequence) to 5 (high severity = high event consequence). The factors and respective weighting for the Consequence 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 on safety, environmental issues and its proximity to other company and private property. In the future, improved data and analysis may allow consequences to be financially quantified, rather than relative scoring methods.

% 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: Consequence Index Criteria

With these indices in hand, we 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 = (Probability Index) * (Consequence Index)

This is also normalized from a score of 1 (low risk) to 100 (high risk). In order to be worthwhile, it is essential that the risk index is 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. Over time, improvement in our ability to collect and use data may allow us to evaluate shorter segments of lines with greater ease, providing a refined view of system risk at the line segment or even structure level. This would facilitate a more detailed view of system risks and optimized mitigation efforts. The development and use of aids that help visualize results (e.g. color-coded system maps), may also be worthwhile.

The top 20 highest risk transmission lines are shown in the table below, and the complete list is included as Appendix A. This iteration only includes transmission lines and taps that are longer than one mile. An additional 37 short lines and taps not included in the risk index account for 14.3 additional miles, representing less than 0.7% of total Transmission system mileage.

Transmission Line Name	Voltage (kV)	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
Lolo - Oxbow	230	63.41	$45,655,200	85.4	100.0	100.0
Noxon - Pine Creek	230	43.51	$31,327,200	80.5	87.8	82.8
Benewah - Pine Creek	230	42.77	$30,794,400	68.3	87.8	70.3
Walla Walla - Wanapum	230	77.78	$56,001,600	68.4	83.7	67.1
Benewah - Boulder	230	26.15	$18,828,000	67.1	72.9	57.3
Hot Springs - Noxon #2	230	70.05	$50,436,000	66.0	68.8	53.2
Dry Creek - Talbot	230	28.27	$20,354,400	51.4	78.3	47.1
Latah - Moscow	115	51.41	$21,592,200	96.0	41.7	47.0
Devils Gap - Stratford	115	86.19	$36,199,800	100.0	39.0	45.6
Post Street - 3rd & Hatch	115	1.76	$3,696,000	70	100	43
Benewah - Moscow	230	44.28	$31,881,600	61.1	59.3	42.5
Cabinet - Rathdrum	230	52.3	$37,656,000	41.7	86.4	42.3
Bronx - Cabinet	115	32.38	$13,599,600	59.4	55.2	38.4
Metro - Post Street	115	0.5	$1,890,000	60	100	38
Ninth & Central - Sunset	115	8.63	$3,624,600	39.0	75.6	34.7
Burke - Pine Creek #3	115	23.79	$9,991,800	67.0	44.4	34.6
Shawnee - Sunset	115	61.51	$25,834,200	79.0	36.3	33.4
Sunset - Westside	115	10.03	$4,212,600	53.0	53.9	33.2
Hatwai - Lolo	230	8.27	$5,954,400	28.9	93.2	31.6

Table 13: Top 20 Most at Risk Circuits according to the Reliability Risk Index

Note that the two underground 115kV circuits, Post Street – 3rd & Hatch, and Metro – Post Street both have a 100 consequence rating and probability ratings of 70 and 60, respectively. The consequence of unplanned outages on these lines is arguably much larger than those of any other line on the system as they serve the high density core of downtown Spokane. In other words, the risks listed above may be understated for these two lines. A strong recommendation for full replacement of both lines is advised in the near future – realistically within 5 to 10 years.

It is important to recognize that the risk index does not yet provide an absolute priority order for replacement and maintenance decisions – option costs to reduce risks must first be factored in. Specifically, cost option analyses must be performed to determine which project options result in the highest reduction of risk per dollar spent. According to best practice asset management principles, this analyses results in a system "**Criticality Index**" for each line in priority order, where each line would be ranked according to:

Criticality Index = (Original Risk – Residual Risk) / (Option Cost)

Finally, other opportunities and benefits are factored in, also known as "bundling" in asset management parlance, to arrive at a final priority order for replacement and maintenance projects. These opportunities and benefits may come from various areas such as system planning for capacity and growth requirements, system operations, regulatory compliance, protection engineering and communications, operations, and power supply. After factoring in these priorities, a comprehensive replacement and maintenance plan for 20 years may be developed, sequenced according to system operations restrictions and with higher levels of detail for projects within the 10 year timeframe. A good start in this direction may be accomplished through the concept of area mitigation plans which involve and integrate stakeholders within each major transmission area of the system (e.g. Big Bend, Spokane, Lewis-Clark, etc).

Ultimately, objective rankings must be useful and effective, helping the organization to 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, reflecting a desire to maintain system reliability. This results in "targets" of $1.1 million for 115kV and $210k for 230kV, for a total of $1.3 million per year. Note that in past years we have consistently spent a much greater amount of total unplanned dollars on the 115kV system, at roughly four times the proportional value of capital assets when compared to the 230kV system. 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, maintenance and 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.

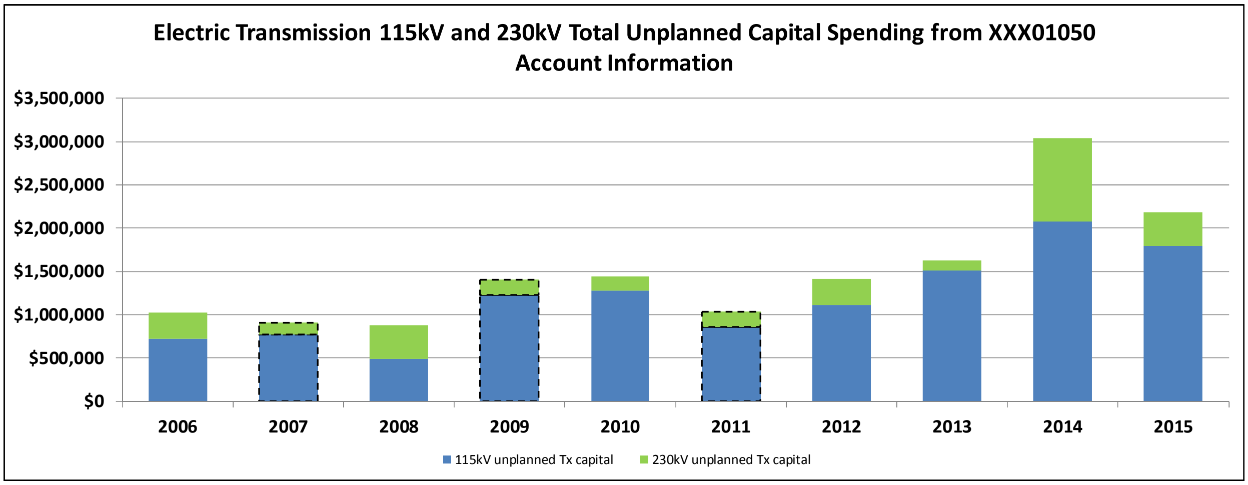


Figure 6: 115kV and 230kV Total Unplanned Capital Spending

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
115kV - WA	115kV - WA	$312,958	$609,438	$265,221	$874,996	$649,760	$585,250	$499,341	$1,123,122	$1,640,237	$1,087,223
115kV - ID	115kV - ID	$406,111	$161,470	$221,343	$349,459	$626,503	$274,517	$608,163	$389,492	$437,978	$705,426
115kV - all	115kV - all	$719,070	$770,908	$486,564	$1,224,455	$1,276,263	$859,767	$1,107,505	$1,512,614	$2,078,216	**$1,792,649**
230kV - WA	230kV - WA	$215,228	$97,946	$215,416	$57,721	$73,482	$156,491	$58,976	$89,984	$13,286	$116,311
230kV - ID	230kV - ID	$74,783	$32,856	$120,056	$89,364	$79,950	$12,979	$228,681	-$134,091	$945,631	$259,884
230kV - MT w/ Colstrip	230kV - MT w/ Colstrip	$0	$286,338	$257,879	$249,429	$368,855	$574,428	$298,059	$436,991	$249,307	$402,324
230kV - MT w/o Colstrip	230kV - MT w/o Colstrip	$0	$1,590	$59,590	$27,525	$13,275	$0	$72	$18,910	$0	$12,077
230kV - OR	230kV - OR	$12,273	$0	$0	$2,475	$0	$360	$14,738	$9,435	$3,181	$0
230kV - all	230kV - all w/o Colstrip	$302,285	$132,392	$395,062	$177,085	$166,706	$169,830	$302,467	$118,329	$962,097	**$388,272**
115kV and 230kV (all)	115kV and 230kV (all)	$1,021,354	$903,300	$881,625	$1,401,539	$1,442,969	$1,029,597	$1,409,972	$1,630,943	$3,040,313	**$2,180,921**

Table 14: Transmission Unplanned and Emergency Spending, 2006 - 2015

Total unplanned spending in 2015 was $2.18 million, significantly higher than any year recorded since 2006 except for 2014, and well above the target of $1.3 million per year. This was due to a major wind storm in November 2015, totaling $700k.

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. New software is in the process of implementation by System Operations. This should be complete by 2016 with annual data available for analysis starting in 2017.

The figures above do not include spending on the 11% Avista ownership of the roughly 500 miles of 500kV Colstrip transmission and substation assets.

Outages

Outages are a strong lagging indicator of system reliability and are highly correlated with unplanned and emergency spending. It is also the principle source of emerging trends and problem root cause analysis that is critical to maintaining system reliability over the long term. A full list of outage information for 2015 on a line-by-line basis is provided in Appendix B. Below are highlights of this information.

Primary data was obtained from both the annual Reliability Reports created by Operations Management and the Transmission Outage Reports (TOR) created by System Operations. The Reliability Report includes data on sustained outages (longer than five minutes) for Transmission related events that affect customers – it does not include any outages that do not affect customers. The TOR on the other hand, includes any transmission event (sustained or momentary), but it does not contain information about customer outages. Utilizing the TOR, System Operations compiles the Transmission Adequacy Database System (TADS), and associated mandated NERC reports for 230kV lines, but not for 115kV lines. It is important to analyze both the Reliability and TOR reports because they each contain different but important information regarding outages on the transmission system. This is currently a laborious process, as neither the Reliability nor TOR reports consistently list transmission lines that apply to each event. The Reliability Reports indicate substations and feeders associated with customer outages related to a transmission line outage, but not which transmission line that applies. Breaker identification is provided on the TOR and must be used to cross reference other information, in some cases multiple sources, to identify the applicable transmission line. New software is being implemented that will help identify outage events on each transmission line, greatly improving analysis capability. This data is expected to be available for analysis by 2017.

Based on the TOR data, there were 477 transmission line outages recorded in 2015, 182 of which were planned, 165 that were trip and recloses that lasted less than a minute, and 130 unplanned outages over one minute. Of these outages, only 35 caused an actual customer outage. The Transmission lines with the most sustained, unplanned outage occurrences are as follows (regardless if a line outage caused a customer outage):

Ranking	Transmission Line Name2	#Unplanned Outages
1	Lind - Shawnee 115 kV	19
2	Moscow 230 - Orofino 115 kV	17
3	Bronx - Cabinet 115 kV	16
4	Benewah - Pine Creek 115 kV	15
5	Devils Gap - Stratford 115 kV	13
6	Hot Springs - Noxon #1 2230 kV	9
7	CdA 15th St - Pine Creek 115 kV	8
8	Cabinet - Rathdrum 230 kV	8
9	Walla Walla - Wanapum 230 kV	8
10	Boulder - Rathdrum 115 kV	8

Table 15: Transmission lines with the most unplanned outages in 2014

Based on the Reliability Report, over 281,000 hours of unplanned customer outages were recorded in 2015. The transmission lines with the most unplanned customer-hours outage are as follows:

Ranking	Transmission Line Name2	Customer Hours
1	Devil's Gap - Lind 115 kV	74696:25
2	Addy - Kettle Falls 115 kV	51848:52
3	Beacon - Ross Park 115 kV	30852:35
4	Devils Gap - Stratford 115 kV	15388:45
5	Ninth & Central - Otis Orchards 115 kV	13257:14
6	Moscow 230 - Orofino 115 kV	8838:57
7	JAYPE-OROFINO 115 kV	6351:55
8	Clearwater - Lolo #2 115 kV	6093:56
9	Lolo - Nez Perce 115 kV	6002:19
10	Ninth & Central - Otis Orchards 115 kV	5971:43

Table 16: Transmission lines that caused the most customer hours lost in 2015

Over 27,000 customers experienced an outage that lasted longer than three hours, representing a slight increase from last year. The Transmission lines with the highest number of customers experiencing outages greater than 3 hours are as follows:

Ranking	Transmission Line Name2	# Customers experiencing Outages >3 hrs
1	Addy - Kettle Falls 115 kV	**13210**
2	Devils Gap - Stratford 115 kV	**2944**
3	Ninth & Central - Otis Orchards 115 kV	**2077**
4	Grangeville - Nez Perce #2 115 kV	**1271**
5	JAYPE-OROFINO 115 kV	**1122**
6	Moscow 230 - Orofino 115 kV	**797**
7	Clearwater - Lolo #2 115 kV	**652**
8	Devil's Gap - Lind 115 kV	**563**
9	Jaype - Orofino 115 kV	**288**
10	Lind - Washtucna 115 kV	**244**

Table 17: Transmission Lines causing the most customer outages greater than 3 hours in 2015

Overall, the data shows that the 115 kV system is significantly less reliable than the 230 kV system in terms of total outages and customers directly affected.

The causes for customer outages lasting longer than three hours increased for rotten crossarms, insulators, switch/disconnect, pole fires, cars hitting poles, and snow/ice events. These types of outages should be monitored closely as surveys indicate that outages lasting longer than three hours are the most important reliability factor driving customer satisfaction. Appropriate steps should be taken to prevent these outages in the future and to reduce repair time should an outage occur. Weather related outages caused the most customer-hours lost per occurrence.

It should be noted that two lines appear on all three of the 'worst transmission line' lists described above:

1. Moscow 230 - Orofino 115 kV
2. Devils Gap-Stratford 115 kV

Extending the above lists to include the worst 20 lines, four other lines would appear on all three indices:

3. Ninth & Central – Otis Orchards 115 kV
4. Devil's Gap - Lind 115 kV

Based on this information, closer monitoring for these lines is warranted. Moscow 230 – Orofino 115kV is scheduled for a minor rebuild in 2016. Devils Gap-Stratford 115kV is scheduled for a LiDAR/minor rebuild in 2016 and is being considered for full rebuild. In 2015, breakers were installed at Opportunity to help sectionalize Ninth & Central – Otis Orchards 115kV and by 2017 the Irvin Switching Station should be in service which will add an emergency tie to Opportunity to improve performance. Devils's Gap – Lind 115kV is scheduled for a major rebuild in 2017 – 2018.

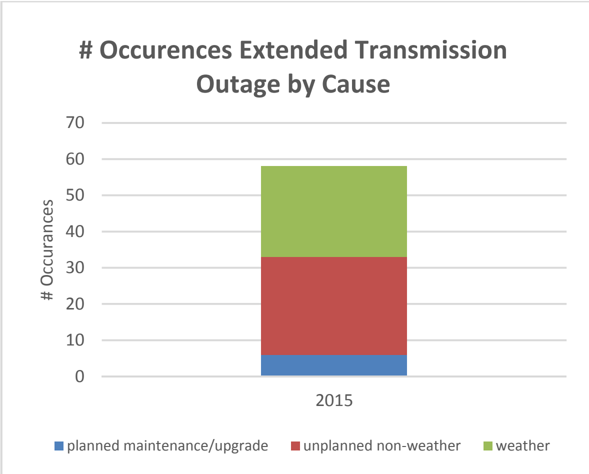
In 2015 there were 162 feeder outages, but only 58 unique transmission events that caused those outages. The 2015 data was analyzed to indicate only the number of unique transmission outages for each subreason.

Reason	Sub Reason	# Outage Occurances
ANIMAL	Squirrel	2
EQUIPMENT OH	Capacitor	5
EQUIPMENT OH	Crossarm-rotten	1
EQUIPMENT OH	Regulator	1
EQUIPMENT OH	Switch/Disconnect	1
PLANNED	Maint/Upgrade	6
POLE FIRE	Pole Fire	15
PUBLIC	Car Hit Pole	1
PUBLIC	Fire	13
TREE	Weather	1
UNDETERMINED	Undetermined	1
WEATHER	Wind	11
		58

Table 18: Transmission Outage Causes, 2009-2015

Pole fire related outages continue to dominate both in terms of number of occurrences and customer-hour outages. At over 50,000 hours, pole fires had the highest number of customer-hour outages. This number is higher than last year (29,000 customer-hours) and highlights the need to continue the fire retardant program and to replace wood poles with steel poles.

As can be seen from Figure 5 below, unplanned, non-weather and weather events dominate both the number of occurances and customer-hours outages for the transmission lines.



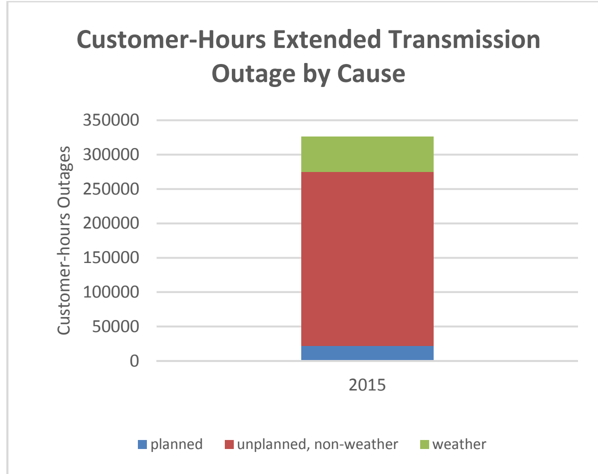


Figure 7: Transmission outage causes affecting customers in 2015

Programs

1. Major Rebuilds

Out of the $26,640,457 million in planned capital replacement projects in 2015, $15,420,668 was spent on major rebuilds, $3,210,020 on minor rebuilds and $443,619 on switch replacements, for a total of $19,074,307. The recommended level is a minimum of $18.5 million for major rebuilds, $2.0 million for minor rebuilds and $264k for switch replacements, for a total of $21 million replacement spending per year for 30 years. As stated previously, replacement projects do not include additional capital projects that are mandated, growth related, reimbursable, 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 and reconductor projects currently planned through 2020 are listed below, with rough estimates of budget dollars allocated for each year. Please note that these plans are subject to change and projects for 2019 and 2020 in particular are only partially complete.

Description	BI	Description2	2016	2017	2018	2019	2020
West Plains Trans Reinforcement	ST305	Garden Springs - Sunset	$ 450,000	$ 600,000	$ -	$ -	$ -
Pine Creek - Burke - Thompson Falls	CT101	Rebuild Transmission	$ 25,000	$ 3,500,000	$ -	$ -	$ -
9CE-Sunset 115kV Transmission	ST503	Reconductor/Rebuild	$ 2,250,000	$ -	$ -	$ -	$ -
High Resistance Conductor Replacement	xTxxx	Reconductor/Rebuild	$ -	$ -	$ -	$ -	$ -
Cabinet-Noxon 230kV Rebuild	AT700	CAB-NOX Rebuild w/Reconductor	$ -	$ -	$ 7,500,000	$ 7,500,000	$ -
Noxon-Pine Creek 230kV Rebuild	KT901	NOX-PCR Rebuild w/Reconductor	$ -	$ -	$ -	$ -	$ 7,500,000
Lolo-Oxbow 230kV Rebuild	LT900	LOL_OXB Rebuild w/Reconductor	$ -	$ -	$ -	$ -	$ 7,500,000
Benewah-Pine Creek 230 kV Rebuild	CT908	BEN-PIN Rebuild w/Reconductor	$ -	$ -	$ -	$ -	$ -
Sys-Rebuild Trans-Condition	AMT81	BRX-CAB & BRX-SCR Rebuild	$ 3,600,000	$ 1,500,000	$ 4,500,000	$ 2,500,000	$ 2,500,000
Ben-Oth SS 115 - ReCond/Rebld	FT130	Ben-Oth SS 115 - ReCond/Rebld	$ 3,000,000	$ 1,500,000	$ -	$ -	$ -
CDA-Pine Creek 115kV Rebuild	CT300	Rebuild Transmission	$ 25,000	$ 4,000,000	$ 6,000,000	$ 5,000,000	$ -
Devils Gap-Lind 115kV Rebuild	ST302	Rebuild Transmission	$ 1,002,134	$ 2,900,000	$ -	$ -	$ -
Chelan-Stratford 115kV Rebuild	BT304	Rebuild Columbia River Crossing	$ -	$ -	$ -	$ -	$ -
Addy-Devils Gap 115kV Reconductor	ST306	Recon/Rebld near Ford Substation	$ -	$ 25,000	$ 2,000,000	$ -	$ -
Recon/Rebld GDN-SLK 115kV Line	ST304	Recon/Rebld South Fairchild Tap	$ -	$ -	$ -	$ -	$ -
Beacon-Bell-F&C-Waikiki Reconfiguration	ST318	Reconfiguration into Bell and Waikiki	$ -	$ 25,000	$ 2,000,000	$ -	$ -
BEN-MOS Rebuild w/o Reconductor	PT305	BEN-MOS Rebuild w/o Reconductor	$ 8,684,000	$ 6,802,393	$ -	$ -	$ -

Table 19: Major Rebuild Projects, 2016 – 2020

Effort will continue to be applied to prioritize replacement spending according to risk and criticality rankings, using detailed analysis where appropriate and engaging various stakeholders to arrive at optimized business decisions. In the last several years, detailed simulation studies have repeatedly shown major rebuilds as the optimal rebuild option for those lines with older assets and relatively higher risk rankings, rather than sectional or partial rebuilds, or minor rebuild options. Due to the infrequency of conductor failures, unless system planning determines a need or benefit for increased capacity, these studies indicate rebuilding structures and re-using the existing conductor as optimal. Calculated Customer Internal Rate of Return (CIRR) are typically at 8% or higher, with strong business risk reduction and final assessment scores of 90 or more, placing them in the top 25% of competing capital project business cases across the company. Accordingly, similar simulation studies in the future are expected to generate comparable results, i.e. analysis of old, high risk lines will continue to show major rebuilds as the optimal rebuild decision from the standpoint of lowest lifecycle costs, including reduced business risk and lowest consequence costs for the customer.

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 near-term capital and O&M costs. 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 or other method is needed to help validate and/or provide adjustment recommendations to our inspection intervals, minor rebuild target budgets, and fact-based policies on minor vs. sectional vs. full rebuild thresholds. Current policy is to conduct detailed ground inspections every 15 years, following up with minor or major rebuilds as condition assessments justify. Current budget plans for minor rebuilds and air switch replacements are listed below, subject to changes. Given the large number of old lines due for inspection, the age profile of air switches and an expected life of 40 years for each air switch, it is recommended to increase the minor rebuild budget to $2.0 million per year and air switch replacements at $264,000 per year.

Description	BI	Description2	2016	2017	2018	2019	2020
Tx Minor Rebuilds	AMT12	Tx Minor Rebuild - WA	$775,000	$775,000	$800,000	$825,000	$850,000
Tx Minor Rebuilds	AMT13	Tx Minor Rebuild - ID	$772,262	$780,249	$813,420	$848,117	$885,022
Sys-Trans Air Sw Upgrade	AMT10	Asset Man Trans Sw Upgrade	$225,000	$225,000	$230,000	$230,000	$235,000

Table 20: Minor Rebuild and Switch Upgrade Budget, 2016 – 2020

See the Area Work Plans section at the end of this report for a detailed list of minor rebuild projects in 2015.

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. Most TAS mis-operations could be avoided with regular inspection and maintenance, however 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 and 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. 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. It is estimated that close to 100 switches require new platforms.

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, requiring an increase to $264,000 from the current $225,000 annual budget. Annual budgets should be prioritized according to a rational condition assessment and quantitative risk assessment, rather than ad-hoc requests from field personnel and anecdotal observation which is the current method.

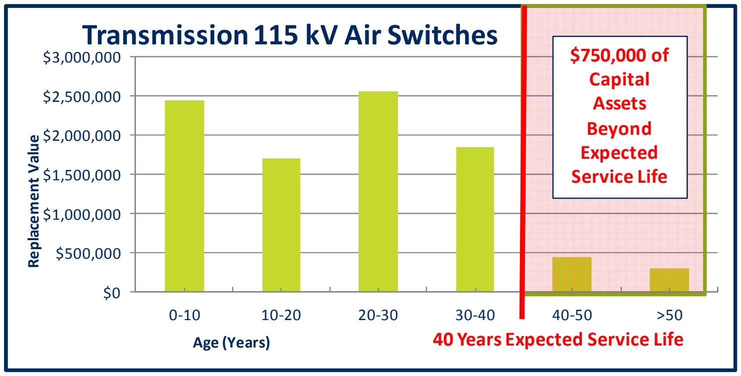


Figure 8: Air Switch Replacement Value vs. Remaining Service Life

Thorough investigation of industry best-practices regarding inspection and planned maintenance of air switches, with follow-up recommendations is recommended. 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; Scheduled 2016	84	Chelan-Stratford
A-336	Old KPF, Needs Replaced; Scheduled 2016	49	Grangeville-Nez Perce #1: Cottonwood Tap
A-355	Old KPF on a broken pole; Scheduled 2016	48	Jaype-Orofino
A-346	Wood in Switching Mech. Is bowed; Scheduled 2016	47	Grangeville-Nez Perce #2
A-376	Old KPF, Needs Replaced; Scheduled 2016	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	Repaired in 2015	26	Dworshak-Orofino
A-377	Scott paper tap; Engerized to Switch; Scheduled 2016	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	Replaced in 2015	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	Replaced in 2015	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	Replaced in 2015	47	Moscow 230-Orofino
A-58	Replaced in 2015	46	Chelan-Stratford
A-295	Replaced in 2015	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 21: Air Switch 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 and to justify long-term replacement policy, e.g. improved data for line outage durations and affected customers that result from failed air switch operations. In reading through notes on the TOR, Asset Management was able to determine that there were 122 outages from 1975 through 2007, resulting in an average of 3.7 outages per year caused by switches. The durations and quantified consequences of these outages however are unknown and difficult to model.

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".

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

Wood transmission poles are on a 15-year inspection cycle. We are currently targeting inspection of 2,400 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 consideration of 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 (non-Western Electricity Coordinating Council pathways) 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 spotty replacements when failure occurs on one end of the spectrum, to larger line section replacements and full rebuilds on the other. 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. 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), Coeur d'Alene (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.

Over the next ten years, annual budgets of $1.2 million are recommended to allow for optimal completion of major re-clearing work and a transition to Integrated Vegetation Management. It is expected that annual budgets will be evaluated and fine tuned to fit workloads as appropriate.

See the Transmission Vegetation Management Program reference (Avista Utilities, 2012) 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 system-wide. At this point the entire 230kV system has been deemed adequately protected and the 115kV system is approximately 37% complete. Given the fire event of last year, the Lolo-Oxbow 230kV line is planned for early recoating in 2016 to reduce risk (coatings are expected to remain effective for 12 years, Lolo-Oxbow was coated in 2007). 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 4,210 poles remain to be coated in the 115kV system. Following the current plan to coat 179 poles in 2015 (179 115 kV poles and 535 230 kV poles repainting the Lolo – Oxbow line was cut from the 2015 scope of work due to budget), it is 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, $50k/year for ongoing coating maintenance is estimated. Performance metrics could be considered 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 increased, reinforcing the necessity of monitoring and adjustment of this program.

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 $350k out of $500k of foundation grouting work on Cabinet – Rathdrum 230kV was completed through 2015. Another $100k/year is planned 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 occurrences 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 (dead ends), and the location and age of thousands of compression dead ends 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 dead ends, 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 in-line compression dead ends on 230kV AAC lines, following several years of one to two failures per year. Since then, no known in-line compression dead end failures have occurred. See Whicker (2009) for more details on the 230kV in-line sleeve mitigation project.

In 2015, Noxon-Pine Creek 230 kV was inspected and all failed compression dead ends were replaced. Compression dead ends that could fail in the future were identified. This data was gathered and sent back to the compression dead end manufacturer, AFL. The manufacturer ran a failure analysis on all the compression dead ends that failed and determined that the ones that failed didn't have the joint compound (oxide inhibitor) in the compression dead end. Avista's transmission department looked into this and determined that the specifications didn't call for the inhibitor. More than likely the inhibitor was not applied by the crew/contractor and that is why the compression dead ends failed. The transmission design department has now added the inhibitor to the specifications and they will make sure the crew/contractor puts the inhibitor inside the compression dead end.

Program Ranking Criteria

Programs implemented in the Transmission Department are chosen based on ranking criteria which consist of the customer internal rate of return, risk reduction ratio, revised risk score, and health index. The health index currently is not identified for each transmission program; however, each program is based upon the customer internal rate of return (CIRR) and revised risk score. The lower the revised risk score, the higher the rank for that program. The revised risk score is based upon the financial impact risks (consequential costs/revenues); legal, regulatory, and external business affairs risks; customer service and reliability risks; and the likelihood of each risk occurring per year. Table 22 details current Transmission Department programs and their ranking criteria.

Program	Customer Internal Rate of Return	Risk Reduction Factor	Revised Risk Score	Health Index
Transmission - NERC High Priority Mitigation	5% ≤ CIRR < 9%	0.011	1	N/A
Transmission - NERC Medium Priority Mitigation	Cirr = 9%	0.003	1	N/A
Transmission - NERC Low Priority Mitigation	Cirr = 9%	0.003	1	N/A
Transmission - New Construction	Cirr = 8%	0.003	1	N/A
Transmission - Reconductors and Rebuilds	Cirr = 10%	0.011	1	N/A
Transmission - Asset Management	Cirr = 10%	0.042	12	N/A

Table 22: Program Ranking Criteria

The NERC High, Medium, and Low Mitigation programs reconfigure insulator attachments, and/or rebuilds existing transmission line structures, or removes earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2012, North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "*Consideration of Actual Field Conditions in Determination of Facility Ratings*". Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have been adopted into the State of Washington's Administrative Code (WAC).

The NERC High Priority Mitigation Capital Program (ER2560) covers mitigation work on Avista's "High Priority" 230kV transmission lines, including: Benewah-Pine Creek (BI CT203), Cabinet-Noxon (BI AT203), Cabinet-Rathdrum (BI CT202), Hatwai-North Lewiston (BI LT205), Lolo-Oxbow (BI LT202), and Noxon-Pine Creek (BI AT202).

The NERC Medium Priority Mitigation Capital Program (ER25xx) covers mitigation work on Avista's "Medium Priority" 230kV and 115kV transmission lines, including North Lewiston-Shawnee 230kV, Beacon-Bell #4 230kV, Beacon-Bell #5 230kV, Noxon-Hot Springs #2 230kV, Beacon-Boulder #2 115kV, Beacon-Francis & Cedar 115kV, 9th & Central-Otis 115kV, Northwest-Westside 115kV, Dry Creek-Talbot 230kV, Walla Walla-Wanapum 230kV, Benewah-Moscow 230kV, Devils Gap-Stratford 115kV.

The NERC Low Priority Mitigation Capital Program (ER25xx) covers mitigation work on Avista's "Low Priority" 230kV and 115kV transmission lines.

The Transmission New Construction Program supports addition of new switching stations and substations to the system in order to serve new and growing load as well as for increased system reliability and operational flexibility. Projects include ER2578: HAT-LOL #2 230kV and 25xx: Westside-Garden Springs 230kV.

The Transmission Reconductors and Rebuilds Program reconductors and/or rebuilds existing transmission lines as they reach the end of their useful lives, require increased capacity, or present a risk management issue. Projects include: ER 2310 - West Plains Transmission Reinforcement, ER 2550 - Pine Creek-Burke-Thompson, ER 2557 9CE-Sunset Rebuild, ER 2423 - System Condition Rebuild, ER 2457 Benton-Othello Rebuild, ER2556 CDA-Pine Creek Rebuild, ER 2564 Devils Gap-Lind Major Rebuild, ER 2574 - Chelan-Stratford River Crossing Rebuild, ER 2576a Addy-Devils Gap Reconductor, ER 2575 Garden Springs-Silver Lake Rebuild, ER 2582 BEA-BEL-F&C-WAI Reconfiguration, ER 2577 BEN-M23 Rebuild, ER 25xa - Out-Year Transmission Rebuild. The Transmission Asset Management Program covers the follow-up work to the Wood Pole Inspection in ER 2057 and Air Switch Replacements in ER 2254.

Benchmarking

Asset replacement spending relative to other utilities is one area of particular interest. A 2008 study performed by First Quartile Consulting gathered data from 17 utilities of various sizes and geographic service territories in the U.S. and Canada, providing the 3-year average transmission line replacement capital spending per asset as shown in the figure below.

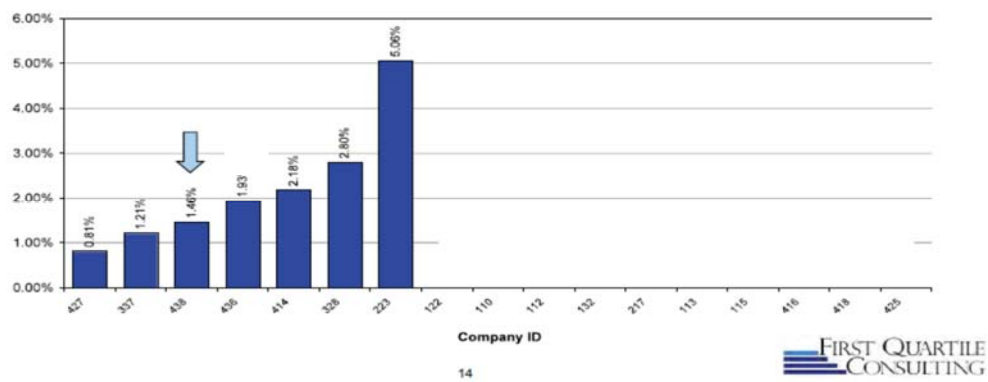


Figure 9: 3-year Transmission Lines Replacement Capital Spending per Asset (First Quartile Consulting, 2008)

This shows that out of seven companies providing data, the median was 1.93% and the mean was 2.41% over a three year period. Avista's comparable replacement spending over the last two years and the recommended annual replacement spending over a 30-year period are shown in the table below.

$ 7,877,719	2014 planned replacement spending
$ 3,040,313	2014 unplanned/emergency replacement spending
$ 10,918,032	2014 total replacement capital spending
$ 1,140,319,249	Transmission asset replacement value
0.96%	2014 replacement spending capital per asset
$ 19,074,307	2015 planned replacement spending
$ 2,180,921	2015 unplanned/emergency replacement spending
$ 21,255,228	2015 total replacement capital spening
$ 1,140,319,249	Transmission asset replacement value
1.86%	2015 replacement spending capital per asset
$ 21,135,371	Recommended planned annual replacement spending (30 year plan)
$ 1,321,019	Targeted unplanned/emergency replacement spending
$ 22,456,390	Targeted total replacement capital spending (30 year plan)
$ 1,140,319,249	Transmission asset replacement value
1.97%	Recommended replacement spending capital per asset

Table 23: Avista Transmission Lines Replacement Capital Spending per Asset

This shows that Avista's capital replacement spending over the last two years is lower than the study's average, close to the lowest of the seven reported utilities. Comparably, the recommended capital replacement spending as part of a levelized 30-year plan of $21.1 million (planned work) plus an assumed $1.3 million unplanned emergency work results in 1.97%, very near the study's median and less than the average.

Idaho Power is a very good benchmark utility for Avista in terms of size, operating environment and electric transmission component and 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 million for replacement of wood poles alone, or $21 million per year levelized. This is similar in magnitude to the recommended replacement of aging wood infrastructure at Avista over the next several decades.

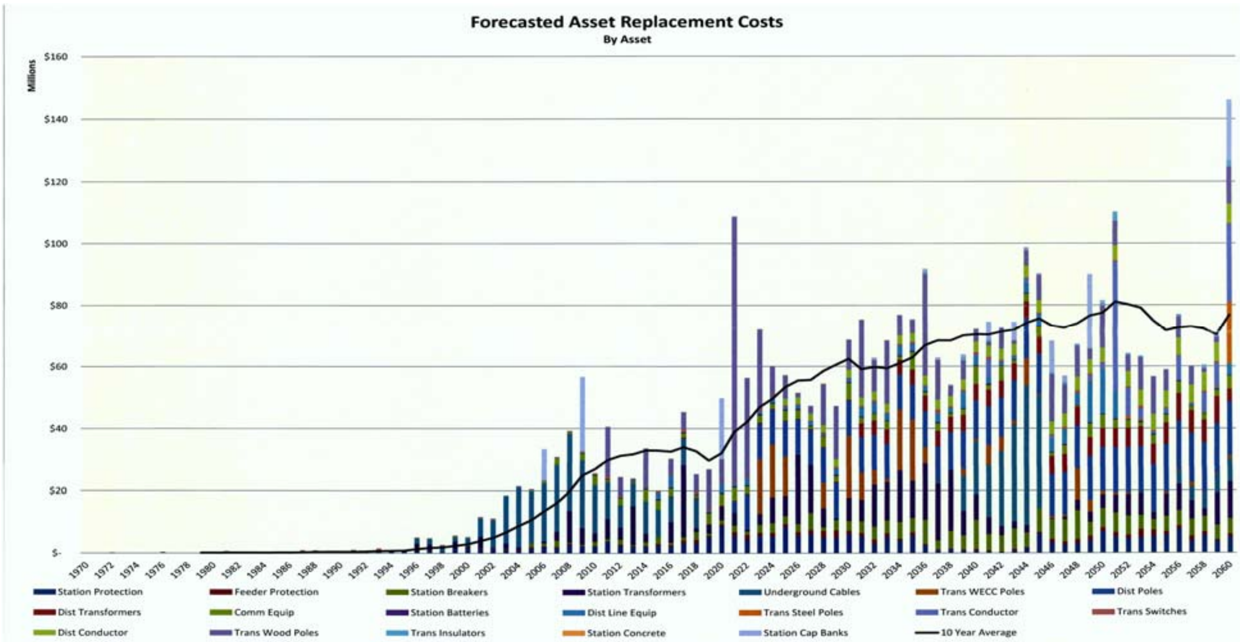


Figure 10: Idaho Power Long-term Replacement Costs

As stated previously, investigation of air switch maintenance practices of various utilities indicates 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.

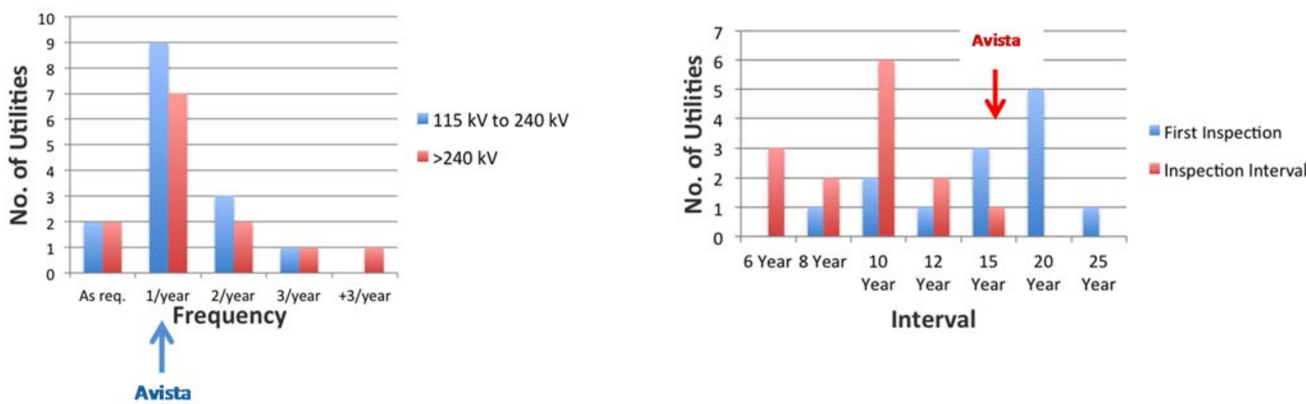


Figure 11: Maintenance Benchmarking: Aerial Patrols (left) and Pole Inspections (right)

Data Integrity

The following table lists the various sources of information used for Asset Management purposes. Data gathering from non-electronic sources, as well as 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.

Data Integrity - Electric Transmission System

Status	Data Source	Notes/Comments
Red	AFM	Wood species info missing for 115kV; potentially large # of stubs entered as pole installs, major job backlog updates pending from 1992
Red	Line History Binder	Great historical info but hasn't been updated for 15 years
Red	Safety information	Unable to isolate to Transmission work
Yellow	Plan & Profile (P&P drawings)	Major job backlog updates pending from 1992 to present; long term migration to digital (PLS-CADD) format
Yellow	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
Yellow	Maximo	Does not always capture component failure mode data as designed
Yellow	Transmission Engineering Guidelines	Partially complete, need more participation to complete
Yellow	Engineering files vault	Engineers need to submit as-built updates more promptly, "archived" files need to be refiled in their proper line section
Yellow	Discoverer	Unwieldly to summarize costing across different Tx projects, difficult to isolate costs/activities to Tx
Green	AWB simulations	Building on progress/standards/methods
Green	PLS-CADD and design/construction standards	Progress continues, published new standards in 2014
Green	Air Switch Master Inventory Spreadsheet	Updated inventory and detailed info complete
Green	OMT data	Mostly reliable info but some categories are mixed with substations, for example PMs that really are transmission related are placed in subs

Table 24: Transmission Asset Data Integrity

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. WPM inspection records in handnote form have been entered electronically. Pole material type, location and installation dates have been synchronized with updated AFM information. However, this clean dataset now exists in spreadsheet form and needs to be uploaded to AFM. Line history binders are in the process of being updated and converted to electronic files. Engineers are following the construction as-built recording process, however prompt updates continue to be problematic. A realistic goal of 6-months from the completion of construction to records updating complete and project close-out has been established. Maximo implementation is in progress. It appears that many years will be needed to obtain quality data that may be effectively used for asset management purposes. The new transmission construction standards are a major accomplishment and are being used as a baseline for improvement on a regular basis.

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 25: 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.

System Planning Projects

The tables below list substation and transmission projects at various stages from study through construction. This list is a snapshot of current plans and is subject to frequent change. For more details, see the System Planning Assessment (Avista, 2015). The first two tables below list projects classified as corrective action plans in order to mitigate performance issues. The last two tables contain projects that are not categorized as corrective action plans.

Overall, customer and load growth is low at about 1%, and is expected to remain stagnant for many years. Customer loads may even decrease over the next few years, due to continued conservation and efficiency trends such as the conversion to LED lighting. One exception to this is in the West Plains area, which is forecasted to grow at a higher rate in both the residential and business sectors for several years. Major system planning needs include adding transformer capacity, and improved redundancy around the Spokane area. This will most likely be best accomplished by the addition of new, looped 230kV transmission lines around Spokane.

Clear, objective ranking and decision criteria and its consistent use in the company's capital project selection and budgeting process is recommended, in order to reduce the time and effort required to develop, review, approve, prioritize, and execute construction projects.

	Starts	Start	End	y	Estimate
Big Bend	**2033**	**2017**	**2018**	**77.25**	**$82,125,000**
1-Completed					
Chelan - Stratford 115 kV Transmission Line River Crossing				0.01	
Stratford 115 kV Station Rebuild				0.01	
2-Planned					
Addy - Devils Gap 115 kV Transmission Line Reconductor	Present	2017	2018	4.16	$2,025,000
Benton - Othello SS 115 kV Transmission Line Rebuild	Present	2015	2016	77.25	$7,100,000
3-Needs Further Analysis					
Addy - Kettle Falls Protection Scheme	Present			45.00	$1,000,000
Chelan - Stratford 115 kV Transmission Line Rebuild	Present			2.48	$13,000,000
Lind – Warden 115 kV Transmission Line Rebuild	2033			0.14	$9,000,000
Saddle Mountain Integration	Present			23.18	$16,400,000
4-Conceptual					
Devils Gap - Stratford 115 kV Transmission Line Rebuild	2019			1.40	$30,100,000
Devils Gap Station Reconfiguration	Present			16.00	$3,000,000
Kettle Falls Capacitor Bank	2024			0.02	$500,000
Coeur d'Alene	**2034**	**2016**	**2018**	**90.30**	**$46,300,000**
1-Completed					
Lancaster Interconnection				0.01	
2-Planned					
Cabinet – Bronx – Sand Creek 115 kV Transmission Line Rebuild	Present	2015	2017	76.88	$7,500,000
Coeur d'Alene – Pine Creek 115 kV Transmission Line Rebuild	Present	2016	2018	90.30	$12,750,000
Pine Creek Transformer Replacement	2034			0.01	$500,000
3-Needs Further Analysis					
St. Maries Cap Bank	Present			3.13	$500,000
4-Conceptual					
Cabinet 230/115 kV Transformer Automatic LTC	2019			0.21	$50,000
Rathdrum 115 kV Bus Reconfiguration	2034			1.29	$5,000,000
Sandpoint Reinforcement	Present			16.31	$20,000,000
Lewiston/Clarkston	**2030**	**2017**	**2019**	**150.00**	**$15,325,000**
2-Planned					
Lolo Transformer Replacement	Present			0.13	$1,000,000
North Lewiston Reactors	Present	2015	2016	150.00	$4,900,000
4-Conceptual					
Hatwai - Lolo #2 230 KV Transmission Line	Present	2017	2019	7.97	$8,025,000
South Lewiston Station Rebuild	2030	2015	2016	0.06	$1,400,000

Table 26: Corrective System Planning Projects (Big Bend, CDA & Lewiston/Clarkston)

	Year Issue Starts	Construction Start	Construction End	Priority	Cost Estimate
Palouse	**Present**			**107.25**	**$2,500,000**
1-Completed					
Moscow 230 Station Rebuild				0.01	
4-Conceptual					
Shawnee #2 230/115 kV Transformer	Present			107.25	$2,500,000
Spokane	**2034**	**2017**	**2019**	**157.50**	**$147,715,000**
2-Planned					
Garden Springs 115 kV Station Integration	Present	2017	2019	12.50	$8,200,000
Ninth & Central - Sunset 115 kV Transmission Line Rebuild	2023	2015	2016	0.05	$925,000
Spokane Valley Transmission Reinforcement	Present	2015	2016	157.50	$8,890,000
Westside Transformer Replacement	Present	2015	2016	1.38	$2,500,000
3-Needs Further Analysis					
Bell - Beacon Protection Scheme	Present			128.25	$0
Garden Springs 230 kV Station Integration	2032			0.14	$15,000,000
Nine Mile - Westside Protection Upgrade	Present			26.00	$200,000
4-Conceptual					
Beacon - Francis & Cedar 115 kV Transmission Line Reconductor	2032			0.01	$1,500,000
Beacon 230 kV Capacitor	Present			25.00	$1,500,000
Garden Springs - Ninth & Central 230 kV Transmission Line	2034			1.25	$30,000,000
Garden Springs - Thornton 230 kV Transmission Line	Present			5.63	$30,000,000
Ninth & Central 230 kV Integration	Present			56.25	$15,000,000
Rathdrum - Westside 230 kV Transmission Line	2034			0.09	$30,000,000
Silver Lake Switching Station	2032			0.01	$4,000,000
System	**Present**			**600.00**	**$220,000**
3-Needs Further Analysis					
230 kV Capacitor Automatic Switching	Present			25.00	$20,000
RAS Update	Present			600.00	$200,000
Grand Total					**$294,185,000**

Table 27: Corrective System Planning Projects (Palouse, Spokane and System)

	Construction Start	Construction End	Cost Estimate
Big Bend	**2019**	**2019**	**$18,747,700**
1-Completed			
Odessa Cap Bank			
2-Planned			
Devils Gap - Lind 115 kV Transmission Line Rebuild	2015	2016	$7,997,700
Ford Station Rebuild	2018	2019	$1,275,000
Gifford Station Rebuild	2015	2015	$1,200,000
Harrington Station Rebuild	2015	2016	$3,000,000
Little Falls Station Rebuild	2015	2017	$4,275,000
Valley Station Rebuild	2019	2019	$1,000,000
3-Needs Further Analysis			
49 Degrees Station			
Bruce Siding Station			
Lee and Reynolds Transformation			
Coeur d'Alene	**2019**	**2019**	**$44,625,000**
1-Completed			
Blue Creek Station Rebuild			
Julia Street			
Noxon Construction Station			
2-Planned			
Beck Road Station	2015	2014	
Benewah - Pine Creek 230 kV Transmission Line Rebuild	2018	2019	$15,000,000
Big Creek Station Rebuild	2016	2017	$1,300,000
Burke - Pine Creek #3 & #4 115 kV Transmission Line Rebuild	2015	2015	$3,500,000
Cabinet - Noxon 230 kV Transmission Line Rebuild	2017	2018	$1,500,000
Noxon Rapids 230 kV Switchyard Rebuild	2015	2019	$21,075,000
Priest River Station			
Sandpoint, Sagle, and Oden Grid Modernization			
St. Maries SCADA Upgrade/Add Feeder	2018	2018	$750,000
3-Needs Further Analysis			
Bronx Station	2019	2019	$1,500,000
Cabinet Gorge Switching Station			
Carlin Bay Station			
Noxon - Pine Creek #2 230 kV Transmission Line			
Lewiston/Clarkston	**2018**	**2019**	**$5,625,000**
1-Completed			
10th & Stewart Station Rebuild			
Lewiston Mill Road Station			
North Lewiston Distribution Station Relocation			
2-Planned			
Clearwater Station Upgrade	2015	2016	$1,000,000
Grangeville Station Rebuild	2018	2019	$2,025,000
Kamiah Wood Station Rebuild	2017	2018	$1,300,000
Kooskia Transformer Replacement			
Pound Land Station Rebuild	2017	2018	$1,300,000
3-Needs Further Analysis			
Wheatland Station			$0

Table 28: Non-Corrective System Planning Projects (Big Bend, CDA & Lewiston/Clarkston)

Palouse	**2018**	**2019**	**$29,053,800**
2-Planned			
Benewah - Moscow 230 kV Transmission Line Rebuild	2015	2017	$24,178,800
Diamond Station Minor Rebuild			
Moscow City 115 SCADA/Minor Rebuild			
North Moscow Transformation	2018	2019	$1,800,000
Potlatch Transformer Replacement			
Tekoa SCADA Upgrade/Minor Rebuild			
3-Needs Further Analysis			
Deary - Potlatch 115 kV Transmission Line			
Tamarack Station	2018	2019	$3,075,000
Spokane	**2017**	**2019**	**$39,785,000**
2-Planned			
Chester Station Rebuild	2017	2018	$1,460,000
Deer Park Partial Rebuild	2015	2015	$750,000
Downtown West Station	2016	2018	$2,275,000
Greenacres/Otis Orchards Stations	2015	2015	$1,375,000
Hallett & White - Silver Lake 115 kV Transmission Line Rebuild	2017	2018	$2,025,000
Irvin Distribution	2016	2017	$1,875,000
Metro Station Rebuild	2016	2019	$13,150,000
Ninth & Central Station Upgrade	2015	2017	$2,950,000
Northwest Station Rebuild	2016	2017	$1,675,000
Ross Park Station Rebuild	2015	2017	$6,000,000
Southeast Capacity Increase	2016	2016	$450,000
Sunset Station Rebuild	2017	2019	$3,775,000
3-Needs Further Analysis			
Beacon - Bell - Francis & Cedar - Waikiki Reconfiguration	2016	2017	$2,025,000
Beacon Station Rebuild			
College and Walnut Consolidation/Rebuild			
Downtown East Station			
Hallett & White Capacitor Bank			
Hawthorne Station			
Hillyard Station			
Westside Station Rebuild			
System	**2015**	**2017**	**$9,794,000**
2-Planned			
Line Ratings Mitigation	2015	2017	$8,794,000
Spokane - Coeur d'Alene 115 kV Relay Upgrades	2015	2015	$1,000,000
Grand Total			**$147,630,500**

Table 29: Non-Corrective 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).

TRR = Transmission Rebuild/Reconductor Program Business Case
NT = New Transmission Program Business Case
PS = Project Specific Business Case
TAM = Transmission Asset Management Program 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
HPRM = High Priority Line Ratings Mitigation Program Business Case
MPRM = Medium Priority Line Ratings Mitigation Program Business Case
LPRM = Low Priority Line Ratings Mitigation Program Business Case
NG = New Growth

Table 30: Project Type Key

Business Case	Area	ER Description	2016	2017	2018	2019
TRR	All	Sys - Rebuild Trans - Condition			X	X
	All	Trans Air Switch Platform Grd Mat	X			
LPRM	All	LP Line Ratings Mitigation Project		X		
LPRM	All	LP Line Ratings Mitigation Project	X			
PS	Big Bend	Harrington 115-4kV	X			
SNDS	Big Bend	Bruce Siding 115 Sub - New			X	X
TRR	Big Bend	Ben-Oth SS 115 - ReCond/ReBld			X	X
TR	Big Bend	Devils Gap-Lind 115kV Rebuild	X	X	X	X
SDSR	Big Bend	Ford 115-13kV Sub		X	X	X
SDSR	Big Bend	Little Falls 115kV Sub	X	X	X	X
TR	Big Bend	Chelan-Stratford 115kV	X			
SDSR	CDA	Bronx 115-21 Sub - Construct	X	X		
TR	CDA	CDA-Pine Creek 115kV Rebuild	X	X		
TR	CDA	Cabinet-Noxon 230kV	X			
TR	CDA	Benewah-Pine Creek 230kV	X			
PS	CDA	Cabinet Gorge 230kV Switchyard	X			
SNDS	Lewis-Clark	Wheatland 115 Sub - Construct		X	X	
NT	Lewis-Clark	Hatwai-Lolo #2 230kV		X	X	X
TR	Lewis-Clark	Lolo-Oxbow 230kV	X			
SNDS	Palouse	Bovill 115kV Substation - New	X	X		
TR	Palouse	Benewah-Moscow 230kV	X	X		
SDSR	Spokane	Sunset 115kV Sub - Rebuild		X	X	
TR	Spokane	West Plains Trans Reinforcement			X	X
SNDS	Spokane	Downtown East 115 Sub- New				X
SDSR	Spokane	9CE 115 Sub - Rebuild/Expand		X	X	
SNDS	Spokane	Greenacres 115 Sub - Construct		X	X	
SVTR	Spokane	Irvin SS 115 - Construct	X	X	X	X
PS	Spokane	Westside 230kV Sub - Rebuild	X	X		
PS	Spokane	Garden Springs 230-115-13 Sub	X	X	X	X
SVTR	Spokane	Opportunity Sub 115-13kV	X			
SDSR	Spokane	Northwest 115-13kV Sub	X	X		
TR	Spokane	Garden Springs - Silver Lake 115kV	X	X		
TR	Spokane	BEA-BEL-F&C-WAI 115kV	X			
PS	Spokane	9CE Sub - New 230kV Transformation	X			
NT	Spokane	Westside/Garden Springs 230/115	X			

Table 31: Area Work Plans – Major Projects

2016 Minor Rebuilds (following previous ground inspections)		
Area	**Transmission Line**	**kV**
Spokane	Beacon - Boulder #2	115kV
CDA	Benewah - Boulder	230kV
CDA	Benewah - Pine Creek - 115kV	115kV
CDA	Benewah - Pine Creek - 115kV: St Maries Tap	115kV
Lewis-Clark	Dry Creek - N. Lewiston - 230kV	230kV
Lewis-Clark	Dry Creek - Pound Lane	115kV
CDA	Hot Springs - Noxon #2	230kV
Lewis-Clark	Moscow 230 - Orofino	115kV
Lewis-Clark	Nez Perce - Orofino	115kV
Spokane	Ninth & Central - Sunset	115kV
Big Bend	Othello Sw. Sta - Warden #1	115kV
CDA	Benewah - Pine Creek - 115kV: St Maries Tap	115kV

Table 32: Minor Rebuilds

Area	Transmission Line	kV	#Wood Poles	
OTHELLO	LIND - WARDEN	115KV	491	
CLARKSTON	JAYPE - OROFINO	115KV	395	
CLARKSTON	GRANGEVILLE - NEZ PERCE (GRANGEVILLE TAP)	115KV	9	
CLARKSTON	GRANGEVILLE - NEZ PERCE #2	115KV	487	
DAVENPORT	CHELAN - STRATFORD	115KV	1197	
SPOKANE	BEACON - BOULDER #5	230KV	6	
			2585	Year 2016 Total

Table 33: Ground Inspection Plan

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Appendix A –Transmission Probability, Consequence & Risk Index

Transmission Line Name	Voltage (kV)	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
Lolo - Oxbow	230	63.41	$45,655,200	85.4	100.0	100.0
Noxon - Pine Creek	230	43.51	$31,327,200	80.5	87.8	82.8
Benewah - Pine Creek	230	42.77	$30,794,400	68.3	87.8	70.3
Walla Walla - Wanapum	230	77.78	$56,001,600	68.4	83.7	67.1
Benewah - Boulder	230	26.15	$18,828,000	67.1	72.9	57.3
Hot Springs - Noxon #2	230	70.05	$50,436,000	66.0	68.8	53.2
Dry Creek - Talbot	230	28.27	$20,354,400	51.4	78.3	47.1
Latah - Moscow	115	51.41	$21,592,200	96.0	41.7	47.0
Devils Gap - Stratford	115	86.19	$36,199,800	100.0	39.0	45.6
Post Street - 3rd & Hatch	115	1.76	$3,696,000	70	100	43
Benewah - Moscow	230	44.28	$31,881,600	61.1	59.3	42.5
Cabinet - Rathdrum	230	52.3	$37,656,000	41.7	86.4	42.3
Bronx - Cabinet	115	32.38	$13,599,600	59.4	55.2	38.4
Metro - Post Street	115	0.5	$1,890,000	60	100	38
Ninth & Central - Sunset	115	8.63	$3,624,600	39.0	75.6	34.7
Burke - Pine Creek #3	115	23.79	$9,991,800	67.0	44.4	34.6
Shawnee - Sunset	115	61.51	$25,834,200	79.0	36.3	33.4
Sunset - Westside	115	10.03	$4,212,600	53.0	53.9	33.2
Hatwai - Lolo	230	8.27	$5,954,400	28.9	93.2	31.6
Burke - Pine Creek #4	115	23.13	$9,714,600	69.0	37.6	30.4
Beacon - Boulder #2	115	13.73	$5,766,600	38.7	66.1	29.9
Addy - Devil's Gap	115	43.31	$18,190,200	58.0	43.0	29.3
Othello Sw. Sta - Warden #2	115	16.56	$6,955,200	53.7	45.8	28.8
Pine Street - Rathdrum	115	33.24	$13,960,800	47.0	51.2	28.3
Benton - Othello Switch Station	115	26.07	$10,949,400	64.0	37.6	28.3
CdA 15th St - Pine Creek	115	29.75	$12,495,000	83.0	28.1	27.3
Cabinet - Noxon	230	18.51	$13,327,200	31.3	71.5	26.3
Chelan - Stratford	115	49.44	$20,764,800	66.6	32.2	25.1
Moscow 230 - Orofino	115	41.59	$17,467,800	84.0	25.4	25.0
Boulder - Rathdrum	115	19.07	$8,009,400	58.6	36.3	24.9
Benewah - Pine Creek	115	45.02	$18,908,400	67.0	29.5	23.2
Jaype - Orofino	115	34.64	$14,548,800	66.6	29.5	23.0
Clearwater - N. Lewiston	115	3.21	$1,348,200	30.7	63.4	22.8
Ninth & Central - Otis Orchards	115	16.31	$6,850,200	28.9	66.1	22.4
N. Lewiston - Shawnee	230	34.28	$24,681,600	33.2	56.6	22.0
Burke - Thompson Falls A	115	3.96	$1,663,200	34.4	53.9	21.7
College & Walnut - Post Street	115	0.54	$2,041,200	2.8	100	21
Beacon - Bell #4	230	6.3	$4,536,000	22.8	78.3	20.9

Transmission Line Name	Voltage (kV)	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
Devil's Gap - Lind	115	73.74	$30,970,800	95.1	18.6	20.8
Dry Creek - Lolo	230	11.23	$8,085,600	29.5	59.3	20.5
Eighth & Fancher - Latah	115	26.27	$11,033,400	55.6	30.8	20.1
Coulee - Westside	230	1.99	$1,432,800	27.1	62.0	19.7
Benewah - Thornton	230	32.2	$23,184,000	27.1	60.7	19.3
Shawnee - Thornton	230	27.83	$20,037,600	27.1	60.7	19.3
Hatwai - Moscow	230	18.05	$12,996,000	27.7	59.3	19.2
Grangeville - Nez Perce #2	115	37.17	$15,611,400	53.0	29.5	18.4
Bell - Northeast	115	1.53	$642,600	42.2	48.5	18.1
Addy - Kettle Falls	115	27.11	$11,386,200	27.7	55.2	17.9
Burke - Thompson Falls B	115	3.97	$1,667,400	28.3	53.9	17.9
Bell - Northeast	115	2.83	$1,188,600	31.9	34.9	17.3
Francis & Cedar - Northwest	115	2.12	$890,400	30.7	47.1	16.9
Grangeville - Nez Perce #1	115	26.9	$11,298,000	48.0	29.5	16.7
Lolo - Nez Perce	115	41.2	$17,304,000	55.7	25.4	16.6
Lolo - Pound Lane	115	10.25	$4,305,000	40.0	34.9	16.5
Beacon - Bell #5	230	6.04	$4,348,800	18.0	78.3	16.5
Dworshak - Orofino	115	3.62	$1,520,400	21.6	64.7	16.4
Airway Heights - Devils Gap	115	20.6	$8,652,000	22.8	60.7	16.2
Beacon - Ross Park	115	2.06	$865,200	20.4	67.5	16.1
Lind - Warden	115	21.71	$9,118,200	44.5	30.8	16.1
Hatwai - N. Lewiston	230	6.99	$5,032,800	18.0	75.6	15.9
Metro - Sunset	115	2.87	$1,205,400	24.6	52.5	15.1
Devils Gap - Ninemile	115	18.78	$7,887,600	28.9	44.4	15.0
Beacon - Boulder #1	115	13.07	$5,489,400	38.7	32.2	14.6
Moscow 230- Terre View	115	11.94	$5,014,800	40.4	30.8	14.6
Bronx - Sand Creek	115	6.62	$2,780,400	30.7	40.3	14.5
Beacon - Ninth & Central #2	115	3.5	$1,470,000	22.8	53.9	14.4
Beacon - Bell #1	115	6.86	$2,881,200	29.5	41.7	14.4
Lind - Shawnee	115	75.81	$31,840,200	83.6	14.6	14.3
Moscow 230 - Orofino	115	21.33	$8,958,600	50.0	24.1	14.1
College & Walnut - Westside	115	8.79	$3,691,800	24.0	49.8	14.0
Northwest - Westside	115	1.95	$819,000	24.0	49.8	14.0
Ross Park - Third & Hatch	115	2.19	$919,800	19.2	60.7	13.6
Beacon - Northeast	115	5.25	$2,205,000	30.7	41.7	13.5
Ninemile - Westside	115	6.8	$2,856,000	22.8	49.8	13.3
Nez Perce - Orofino	115	17.28	$7,257,600	27.7	40.3	13.1
Post Falls - Ramsey	115	9.01	$3,784,200	28.9	36.3	12.3
Addy - Gifford	115	20.68	$8,685,600	51.9	20.0	12.2
Ramsey - Rathdrum #1	115	8.42	$3,536,400	24.0	41.7	11.7
Beacon - Boulder	230	11.95	$8,604,000	17.4	56.6	11.5

Transmission Line Name	Voltage (kV)	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
Beacon - Ninth & Central #1	115	3.73	$1,566,600	18.0	53.9	11.3
Stratford - Summer Falls	115	6.3	$2,646,000	18.0	53.9	11.3
Beacon - Francis & Cedar	115	11.56	$4,855,200	34.3	28.1	11.3
Appleway - Rathdrum	115	11.77	$4,943,400	20.4	47.1	11.2
Shawnee - Terre View	115	10.05	$4,221,000	30.1	30.8	10.9
Dry Creek - N. Lewiston	230	8.06	$5,803,200	13.1	70.2	10.7
CdA 15th St - Rathdrum	115	12.67	$5,321,400	19.2	47.1	10.6
Milan Tap	115	8.22	$3,452,400	30.1	29.5	10.4
Shawnee - South Pullman	115	12.7	$5,334,000	35.0	25.4	10.4
Beacon - Rathdrum	230	25.36	$18,259,200	16.2	53.9	10.2
Airway Heights - Silver Lake	115	10.77	$4,523,400	24.0	36.3	10.2
Boulder - Lancaster	230	13.29	$9,568,800	11.3	76.9	10.2
Libby - Noxon	230	0.79	$568,800	12.5	68.8	10.1
Moscow 230 - South Pullman	115	12.07	$5,069,400	23.0	36.3	9.7
Colbert Tap	115	3.19	$1,339,800	34.3	24.1	9.7
Clearwater - Lolo #2	115	8.56	$3,595,200	24.0	33.5	9.4
Otis Orchards - Post Falls	115	7.62	$3,200,400	24.0	30.8	8.7
Ninth & Central - Third & Hatch	115	4.34	$1,822,800	24.0	29.5	8.3
Lind - Washtucna	115	28.78	$12,087,600	30.1	22.7	8.0
Benewah - Pine Creek	115	7.06	$2,965,200	27.0	24.1	7.6
Burke - Pine Creek #3	115	4.58	$1,923,600	23.0	28.1	7.5
Shawnee - Sunset	115	7.12	$2,990,400	37.0	15.9	6.8
Devils Gap - Long Lake #2	115	1.03	$432,600	13.1	41.7	6.4
Albeni Falls - Pine Street	115	2.27	$953,400	13.1	40.3	6.2
Francis & Cedar - Ross Park	115	5.16	$2,167,200	14.3	36.3	6.1
Clearwater - Lolo #1	115	8.63	$3,624,600	24.0	20.0	5.6
Dry Creek - Pound Lane	115	3.89	$1,633,800	12.5	36.3	5.3
Airway Heights - Sunset	115	9.52	$3,998,400	18.0	25.4	5.3
Sunset - Westside	115	11.97	$5,027,400	22.0	21.3	5.2
Latah - Moscow	115	10.37	$4,355,400	17.0	25.4	5.0
Dry Creek - N. Lewiston	115	8.17	$3,431,400	13.1	30.8	4.7
Devils Gap - Little Falls #2	115	3.9	$1,638,000	24.0	15.9	4.5
Othello Sw. Sta - Warden #1	115	8.28	$3,477,600	36.1	10.5	4.4
CdA 15th St - Ramsey	115	3.17	$1,331,400	9.4	36.3	4.0
Moscow City - N. Lewiston	115	22.19	$9,319,800	16.2	21.3	4.0
Devils Gap - Little Falls #1	115	3.42	$1,436,400	19.2	14.6	3.3
Critchfield - Dry Creek	115	1.58	$663,600	13.1	20.0	3.1
Benewah - Latah	115	6.68	$2,805,600	5.9	40.3	3.0
Lolo - Pound Lane	115	2.94	$1,234,800	12.0	20.0	2.8
Bell - Westside	230	1.99	$1,432,800	2.8	72.9	2.4

Transmission Line Name	Voltage (kV)	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
Lancaster - Rathdrum	230	2.93	$2,109,600	2.8	63.4	2.1
Wilbur Tap	115	5.35	$2,247,000	14.3	11.8	2.0
Benton - Othello Switch Station	115	3.79	$1,591,800	8.0	20.0	1.9
Dower - Post Falls	115	2.16	$907,200	9.4	17.3	1.9
Boulder - Otis Orchards #1	115	3.45	$1,449,000	2.8	39.0	1.3
Boulder - Otis Orchards #2	115	2.73	$1,146,600	2.8	34.9	1.1
Grangeville - Nez Perce #1	115	6.34	$2,662,800	8.0	11.8	1.1

Appendix B – Transmission System Outage Data

Transmission Line Name	Voltage (kV)	# Line Outages	#Planned Outages	#Unplanned Outages	Transmission Line Name	Voltage (kV)	# Line Outages	#Planned Outages	#Unplanned Outages	Transmission Line Name	Voltage (kV)	# Line Outages	#Planned Outages	#Unplanned Outages
AVISTA DOES NOT OWN		22	3	19	Shawnee - Terre View	115	3	0	3	Otis Orchards - Post Falls	115	1	1	0
Lind - Shawnee	115	21	2	19	Lolo - Pound Lane	115	3	0	3	Beacon-Bell #4	230	1	1	0
Moscow 230 - Orofino	115	17	0	17	College & Walnut - Westside	115	3	0	3	Noxon Construction Tap	230	0	0	0
Bronx - Cabinet	115	16	0	16	Cabinet - Noxon	230	3	0	3	Airway Heights - Sunset	115	2	2	0
Benewah - Pine Creek	115	18	3	15	Benewah - Pine Creek	230	5	3	2	Albeni Falls - Pine Street	115	0	0	0
Devils Gap - Stratford	115	13	0	13	Libby - Noxon	230	3	1	2	Beacon - Ninth & Central #1	115	0	0	0
Hot Springs - Noxon #1	230	9	0	9	Beacon - Boulder #2	115	2	0	2	Beacon - Ninth & Central #2	115	0	0	0
CdA 15th St - Pine Creek	115	11	3	8	Moscow 230- Terre View	115	2	0	2	Boulder - Boulder Park	115	0	0	0
Cabinet - Rathdrum	230	10	2	8	Othello Sw. Sta - Warden #2	115	5	3	2	Boulder - Otis Orchards #1	115	0	0	0
Walla Walla - Wanapum	230	11	3	8	Hatwai - Moscow	230	3	1	2	Boulder - Otis Orchards #2	115	0	0	0
Boulder - Rathdrum	115	9	1	8	Addy - Kettle Falls	115	2	0	2	Bronx Tap	115	0	0	0
Ninth & Central - Otis Orchards	115	10	2	8	Airway Heights - Devils Gap	115	4	2	2	CdA 15th St - Ramsey	115	0	0	0
Ross Park - Third & Hatch	115	8	0	8	Beacon - Francis & Cedar	115	3	1	2	College & Walnut - Post Street	115	1	1	0
Shawnee - Sunset	115	10	3	7	Benewah - Latah	115	2	0	2	Critchfield - Dry Creek	115	0	0	0
Noxon - Pine Creek	230	9	2	7	Lind - Warden	115	2	0	2	Devils Gap - Long Lake #1	115	0	0	0
Chelan - Stratford	115	7	0	7	Post Street - 3rd & Hatch	115	2	0	2	Devils Gap - Long Lake #2	115	0	0	0
Benton - Othello Switch Station	115	8	2	6	Latah - Moscow	115	3	2	1	Dower - Post Falls	115	0	0	0
Lolo - Nez Perce	115	10	4	6	Sunset - Westside	115	6	5	1	Dry Creek - N. Lewiston	115	0	0	0
Hot Springs - Noxon #2	230	6	0	6	Burke - Thompson Falls B	115	5	4	1	LOON LAKE TAP	115	0	0	0
Ramsey - Rathdrum #1	115	7	1	6	Beacon - Boulder	230	1	0	1	Metro - Sunset	115	0	0	0
Devil's Gap - Lind	115	6	1	5	Hatwai - Lolo	230	2	1	1	NE-NE Turbine Generator	115	0	0	0
Shawnee - South Pullman	115	6	1	5	Airway Heights - Silver Lake	115	2	1	1	Nez Perce - Orofino	115	0	0	0
Benewah - Moscow	230	5	0	5	Lind - Washtucna	115	2	1	1	Rathdrum C.T. - Rathdrum #2	115	0	0	0
Burke - Pine Creek #4	115	6	1	5	Post Falls - Ramsey	115	2	1	1	Sagle Tap	115	0	0	0
Appleway - Rathdrum	115	6	1	5	Clearwater - Lolo #1	115	4	3	1	Stratford - Summer Falls	115	0	0	0
Benewah - Boulder	230	5	0	5	Devils Gap - Little Falls #1	115	2	1	1	Wilbur Tap	115	0	0	0
Clearwater - Lolo #2	115	7	2	5	Ninth & Central - Sunset	115	6	5	1	Milan Tap	115	0	0	0
CdA 15th St - Rathdrum	115	5	0	5	Beacon-Bell #5	230	2	1	1	Millwood - Paper Mill	60	0	0	0
Burke - Thompson Falls A	115	12	8	4	Bell - Westside	230	1	0	1	Colbert Tap	115	0	0	0
Dry Creek - Talbot	230	4	0	4	Dry Creek - Lolo	230	4	3	1	Francis & Cedar - Northwest	115	0	0	0
Lolo - Oxbow	230	5	1	4	Appleway - Ramsey	115	1	0	1	Kettle Falls Tap	115	0	0	0
Burke - Pine Creek #3	115	4	0	4	Dworshak - Orofino	115	1	0	1	Boulder - Lancaster	230	0	0	0
Ninth & Central - Third & Hatch	115	6	2	4	Mead Tap	115	1	0	1	Hatwai - N. Lewiston	230	0	0	0
Beacon - Ross Park	115	5	1	4	Metro - Post Street	115	1	0	1	Eighth & Fancher - Latah	115	0	0	0
Dry Creek - Pound Lane	115	4	0	4	Addy - Devil's Gap	115	5	5	0	Shawnee - Thornton	230	0	0	0
Northwest - Westside	115	4	0	4	Jaype - Orofino	115	0	0	0	Devils Gap - Little Falls #2	115	0	0	0
Beacon - Bell #1	115	4	0	4	N. Lewiston - Shawnee	230	3	3	0	Pine Street - Rathdrum	115	0	0	0
Francis & Cedar - Ross Park	115	4	0	4	Devils Gap - Ninemile	115	3	3	0	Addy - Gifford	115	0	0	0
Moscow 230 - South Pullman	115	4	0	4	Beacon - Boulder #1	115	0	0	0	Lancaster - Rathdrum	230	0	0	0
Ninemile - Westside	115	4	0	4	Beacon - Northeast	115	2	2	0	Kettle Falls - KF Generator	115	0	0	0
Coulee - Westside	230	4	1	3	Grangeville - Nez Perce #1	115	1	1	0	Priest River Tap	115	0	0	0
Grangeville - Nez Perce #2	115	5	2	3	North Lewiston - Walla Walla	115	2	2	0	Bell - Northeast	115	0	0	0

2016

Substation System Review Asset Management

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February 12, 2016

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Purpose

This report provides summary information relating to the annual review of Avista's electric substations operating in its Washington and Idaho service territory. The intent is to present a comprehensive overview of the substation capital assets, performance, risks, ongoing asset management programs, current and planned projects, and summary recommendations. Asset Management Plans are intended to serve a general audience from the perspective of long-term, balanced optimization of lifecycle costs, system performance, and risk management. A consistent sequence of asset management plans will provide the continuity required for continuous improvement of capital asset management, as well as historical information useful for rate case submissions.

With Avista's implementation of IBM's Maximo as its Asset Information System in 2014, a distinct reference point for asset data has been established. The Maximo implementation provides a comprehensive informational and historical repository for all asset data, applications, locations, inspection history, maintenance activity, and life cycle status. As such, the reportable data included in this report centers around activities in 2014 and 2015 in order to leverage the reference data within Maximo and to provide consistent and repeatable data from a single source for this and future reports.

Avista Utilities currently operates 162 substations consisting of:

- 21 transmission substations
- 30 transmission substations with distribution
- 109 distribution substations
- 2 foreign-owned substations.

In addition, there are 14 locations associated with generation.

Equipment Portfolio

From a perspective of key equipment as reference, the average age of the 162 substations is just over 31 years. Figure 1 shows the age distribution of the substation population.

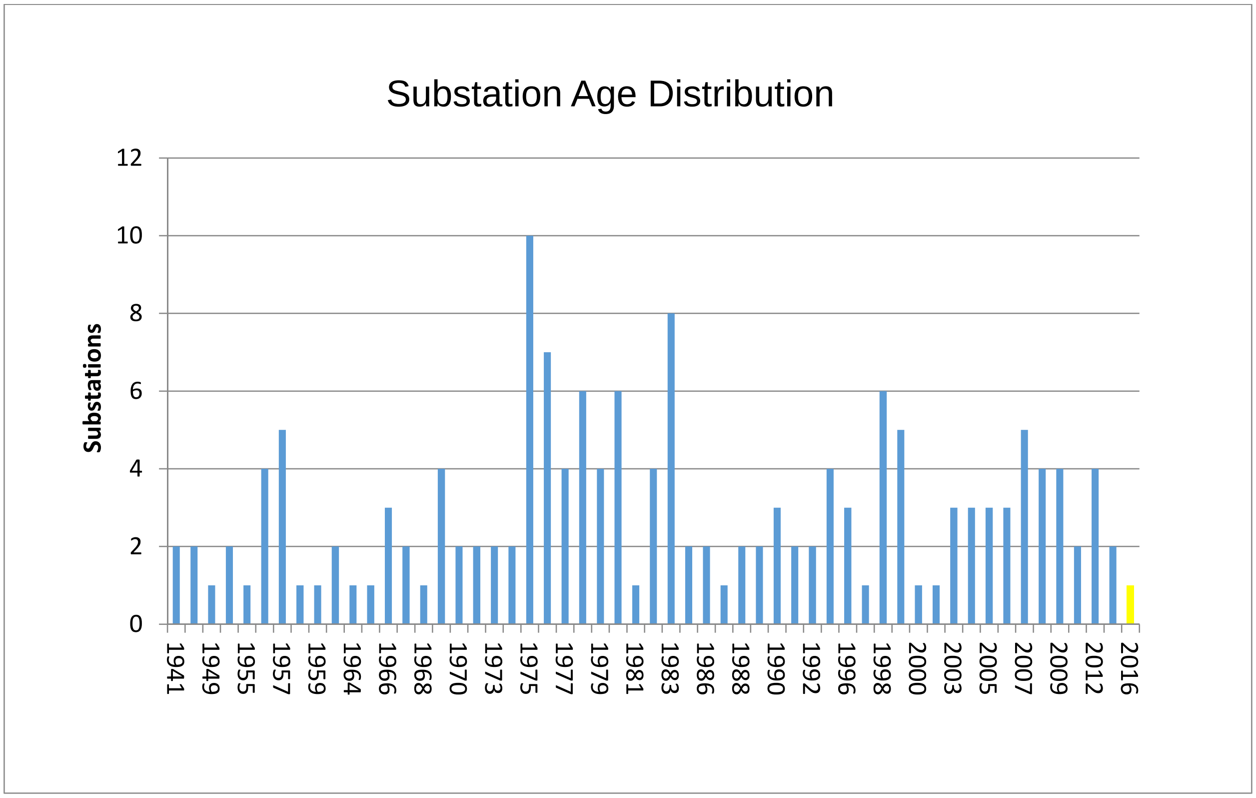


Figure 1: Substation Age Distribution

Substations are typically classified by voltage and function. The number of sites in each of these categories is included in Figure 2. In addition to the standard population of 230kV and 115kV substations, Avista continues to operate six substations at lower system voltages. These include the Kooskia substation at 34kV, the St. John substation at 24kV, and four substations at 13kV including Coeur d'Alene Shaft Mine, Sunshine Mine, and two at the Washington State University campus in Pullman.

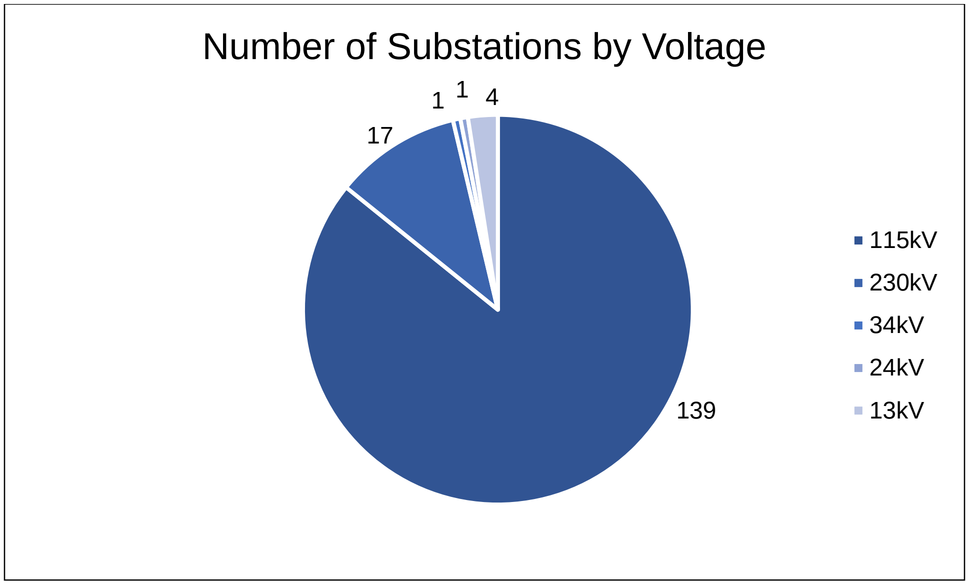


Figure 2: Substations by classification

Included in the totals above are 13 switching stations, 11 in the 115kV group and two at 230kV, that do not incorporate voltage transformers or regulation. Standard interconnect and protection services are provided at these locations, supporting their inclusion in the general substation reporting.

Each substation is comprised of major assets that coordinate to serve the principal regulation, switching, and protection activities of each site. Each asset class has unique maintenance, lifecycle, and operational considerations. Within the greater population of substations, the quantity of each asset is shown in Table 1.

Capital Asset	Quantity
Air Switch	1,175
Disconnect Switch	1,171
Bushings	1,890
Circuit Switcher	120
High Voltage Circuit Breakers	318
Low Voltage Circuit Breakers	353
Reclosers	309
Switchgear	95
Autotransformers	17
Power Transformers	211
Voltage Regulators	1,341

Table 1: Substation asset quantities

Within the current implementation of the Maximo asset database, fields that provide the manufactured date, in-service date, and last-installed date continue to be updated and populated with the data available from the database integration. As such, succinct reports providing age profiles for these substation asset families are not included at this time.

Capital Replacement and Maintenance

Projects with current approved Business Case proposals are included in this Capital Replacement and Maintenance section, including a brief description of the project's scope and purpose. In summary, specific project evaluation metrics are included in Table 2.

	Internal Rate of Return	Benefit/Cost Ratio	Risk Reduction Factor
Asset Management Capital	5% to 9%	N/A	0.027302
Capital Spares	5% to 9%	N/A	0.015362
Distribution Station Rebuilds	9% to 12%	N/A	0.010633
Garden Springs	5% to 9%	N/A	0.004268
New Distribution Stations	5% to 9%	N/A	0.009185
Noxon Switchyard	5% to 9%	N/A	0.004268
South Region Voltage Control	7%	N/A	0.000798
Westside Rebuild	7%	N/A	0.017570

Table 2: Capital Project Metrics

Substation Asset Management Capital Maintenance

The Substation Asset Management Capital Maintenance program installs, replaces, or upgrades substation apparatus based on Asset Management planning or emergency replacement determinations. All obsolete, end-of-life, or failed apparatus, based on the Asset Management analysis, are included under this program. Apparatus includes panel houses, high voltage breakers, relays, metering, surge arresters, insulating rock, fence work, low voltage breakers and reclosers, circuit switchers, SCADA systems, batteries and chargers, power transformers, high voltage fuses, air switches, capacitor banks, autotransformer diagnostic equipment, step voltage regulators, and instrument transformers.

Substation Capital Spares

The Substation Capital Spares program maintains Avista's inventory of power transformers and high voltage circuit breakers in order to manage the long lead time of the procurement cycle for these system-critical items. These components are capitalized at receipt and placed in service in response to both planned and emergency installations. The program expenditures may vary significantly year to year due to the specific equipment purchased and deployed in any given year.

Distribution Substation Rebuilds

The Distribution Substation Rebuild program supports either the complete replacement or rebuild of existing substation infrastructure as the site nears the end of its useful life, a need to support increased capacity requirements, or to implement modifications necessary to accommodate equipment upgrades. Included in the program are Wood Substation rebuilds as well as upgrades to substations to comply with current design and construction standards. Some substation rebuilds are necessitated by external requirements, including obligation to serve, customer or load growth, or technology improvement projects such as Smart Grid. Substation rebuilds currently planned to be completed under this program in the next five years include Big Creek, Kamiah, and South Lewiston (Wood Substations), 9th & Central, Ford, Sprague, Davenport, and Northwest (Lifecycle), Deer Park, Gifford, Lee & Reynolds, Huetter, Dalton, and Southeast (Equipment Additions), and Hallett & White (Growth).

Garden Springs Substation Integration

The Garden Spring Substation Integration project will construct a new 230kV/115kV substation at the existing Garden Springs property that will terminate the existing Airway Heights-Sunset, Sunset-Westside, and South Fairchild Tap 115kV transmission lines. Options being considered to energize the 230kV bus include the possibility of a new interconnection with the BPA Bell-Coulee #5 230kV transmission line and a new 230kV feed from the Westside Substation following the completion of the Westside Substation Rebuild Project. Both of the newly designated Garden Springs-Sunset 115kV transmission lines will require upgrades to 150MVA capacity conductors.

New Distribution Substations

The New Distribution Substation program provides for new distribution substations in the system in order to serve new and growing load, increased system reliability, and operational flexibility. New substations under this program will require planning and operational studies, justification, and approved Project Diagrams prior to funding. Current plans for new substation projects include Tamarack in northeast Moscow, Greenacres in the Spokane Valley, and Hillyard and Downtown West in Spokane. Design and construction phases will be coordinated to achieve one new substation per year depending on need and justification.

Noxon Switchyard Rebuild

The existing Noxon Rapids 230kV Switchyard requires reconstruction due to the age and condition of the equipment within the station. The existing bus, constructed as a strain bus with a number of recent failures, is configured as a single bus with a tie breaker separating the East and West bus segments. This station is the interconnection point of the Noxon Rapids Hydroelectric generation as well as a principal interconnect point between Avista and BPA. As such, this is a crucial asset for the reliable operation of the Western Montana Hydro Complex. Equipment outages within the station, either planned or unplanned, can cause significant curtailments of the local generation output. Due to the key role of the station, a complete rebuild will require coordination with Avista's Energy Resources Department and affected utilities, including BPA. The Noxon Switchyard Rebuild Project is a greenfield design incorporating a double bus-double breaker 230kV switching station as a complete replacement of the existing Noxon Switchyard.

South Region Voltage Control

Avista's 230kV transmission system in the southern area of its service territory, generally located around the cities of Lewiston and Clarkston, experiences excessive high voltage during periods of low power loading. Voltage levels exceed equipment ratings over approximately 35% of the time. Continued operation of equipment outside its specifications and ratings exposes Avista to potentially significant legal and regulatory risks. This is in addition to increasing the probability of large-scale outages due to equipment failure. The installation of 230kV Reactors at North Lewiston substation will eliminate existing overvoltage conditions in Avista's southern region, which includes the 230kV buses at Dry Creek, Lolo, North Lewiston, Moscow, and Shawnee substations.

Westside Substation Rebuild-Phase One

Phase One of the Westside Substation Rebuild will extend the existing Westside Substation and the 115kV and 230kV buses and will support design and installation options in consideration of a new 250MVA autotransformer and other substation equipment. This installation will eliminate overload potentials for certain bus outages and tie breaker failure contingencies in the Spokane area. Following the completion of Phase One, the second phase will replace a second autotransformer with a new 250MVA unit. The final phase would extend the 230kV yard to a double breaker-double bus configuration. In addition, alternatives for the 115kV configuration would be considered to achieve either a breaker-and-and-half or a full double breaker-double bus implementation.

Capital Spending

For 2015, the major capital expenditures associated with substation construction or equipment activities are included in Table 3. As most capital projects extend over multiple calendar years, the summary expenditures listed may represent only a portion of the overall project's expenses. In total, these projects represent $24.4 million in capital spending during 2015.

ER	Project	Capital Expenditure	Status
2532	Noxon 230kV Substation Rebuild	$10,162,871	Partial in 2016
2000	Substation - Capital Spares	$3,267,594	Ongoing
2589	Mobile Substation - Purchase New Mobile Substations	$2,539,571	2015
2443	Greenacres 115kV/13kV Substation New Construction	$1,661,927	2016
2215	Substation Asset Management Capital Maintenance	$915,677	Ongoing
2001	System - High Voltage Circuit Breaker Replacements	$580,324	Ongoing
2278	Replace Obsolete Reclosers	$530,128	Ongoing
2484	Moscow 230kV Substation Rebuild Switchyard	$527,614	Complete
2275	Rock and Fence Restoration	$450,226	Ongoing
2449	System - Substation Air Switches Replacements	$447,733	Ongoing
1006	System - Distribution Power Transformers	$394,856	Ongoing
1107	Lewiston Mill Road - 115kV substation construction	$369,980	2015
2493	Replace/Upgrade Voltage Regulators	$343,358	Ongoing
2446	Irvin Substation- New Construction	$296,734	Ongoing
2590	Deer Park 115kV Substation - Minor Rebuild	$247,956	2016
1108	Hallett & White Substation Expansion	$142,621	Ongoing
2294	System - Batteries	$140,538	Ongoing
2546	Blue Creek 115kV Rebuild	$104,669	Complete
2592	Sprague 115kV Substation Minor Rebuild	$96,304	2016
2204	Wood Substation Rebuilds	$89,274	Ongoing
2571	Clearwater 115kV Substation Upgrades	$85,695	Complete
2573	Little Falls 115kV Substation Rebuild	$66,485	Ongoing
2341	Ninth & Central Substation - Increase Capacity and Rebuild	$54,960	In progress
2569	Gifford 115kV - Rebuild Substation	$28,251	Ongoing
2538	College & Walnut Substation Yard Expansion	$27,473	2016
2425	System - High Voltage Fuse Upgrades	$25,135	Ongoing
2112	Beacon 230kV Substation Bus Conversion	$14,286	Ongoing
2505	System-Replace Current and Potential Devices	$13,262	Ongoing
2531	Westside 230kV Substation Rebuild	$12,598	In progress
2274	New Substations	$11,088	Ongoing
2561	Lewiston Mill Road 115kV Substation	$8,912	2016
2343	System - Replace/Install Substation Structures	$8,702	Ongoing
2336	System - Replace Distribution Power Transformers	$7,939	Ongoing
2572	Noxon Construction Substation - Minor Rebuild	$2,471	Complete
2591	Davenport 115kV Substation - Minor Rebuild	$2,275	Ongoing

Table 3: Substation Capital Expenditures – 2015

Maintenance and Operations (M&O) Spending

During 2015, a total of nearly $4.7 million supported Maintenance and Operations activities relating to existing substations. As shown in Figure 3, approximately 85.1% of the maintenance and operation expenses were associated with planned services, while the remaining 14.9% was in response to unplanned or reactive activities. Figure 4 shows the total substation maintenance and operations spending by calendar month throughout 2015.

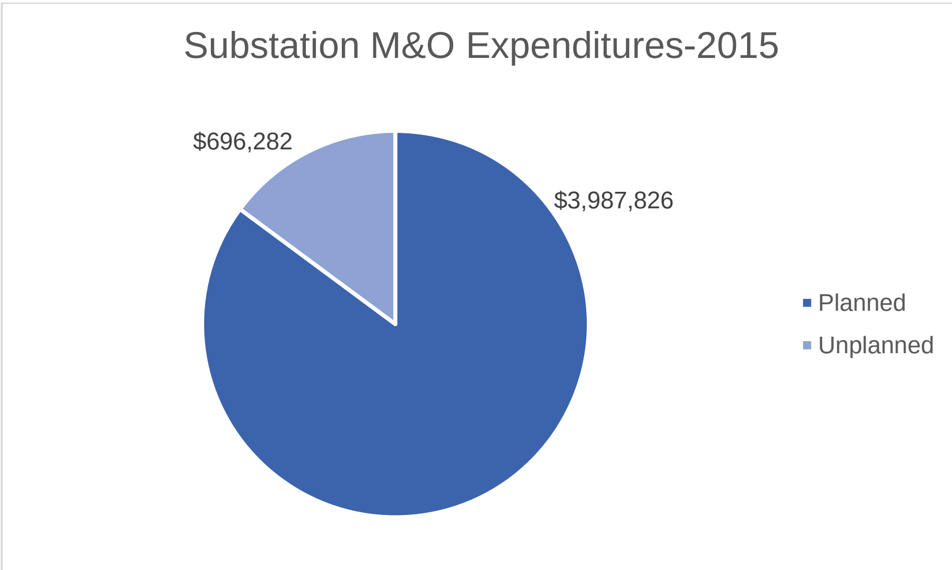


Figure 3: Substation M&O Expenditures

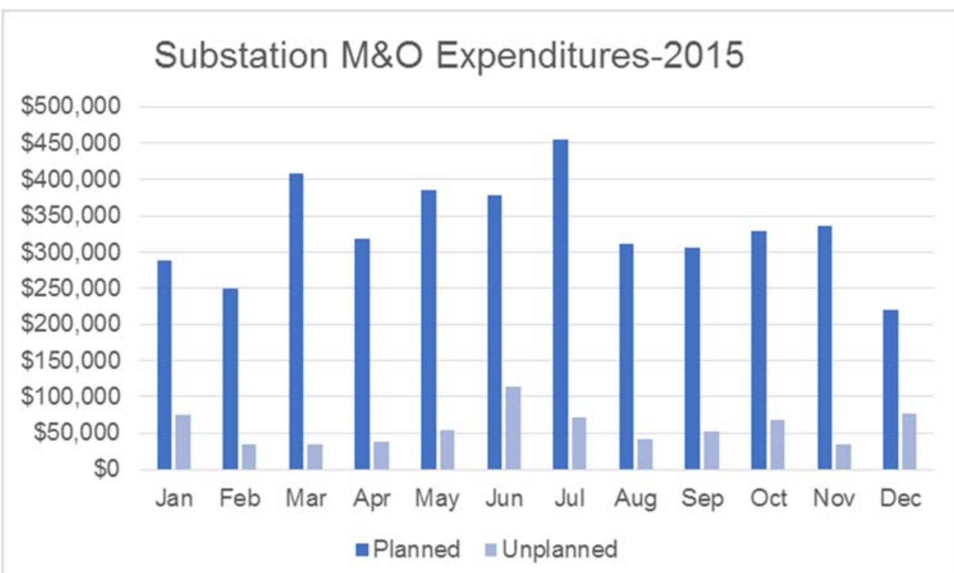


Figure 4: Substation M&O Expenditures by Month

Substation maintenance activities are tracked by both distribution and transmission tasks. As noted earlier, many of the substation locations provide both distribution and transmission services. For 2015, the allocation between transmission and distribution expenses, both maintenance and operations, along with unplanned expenditures, are shown in Figure 5.

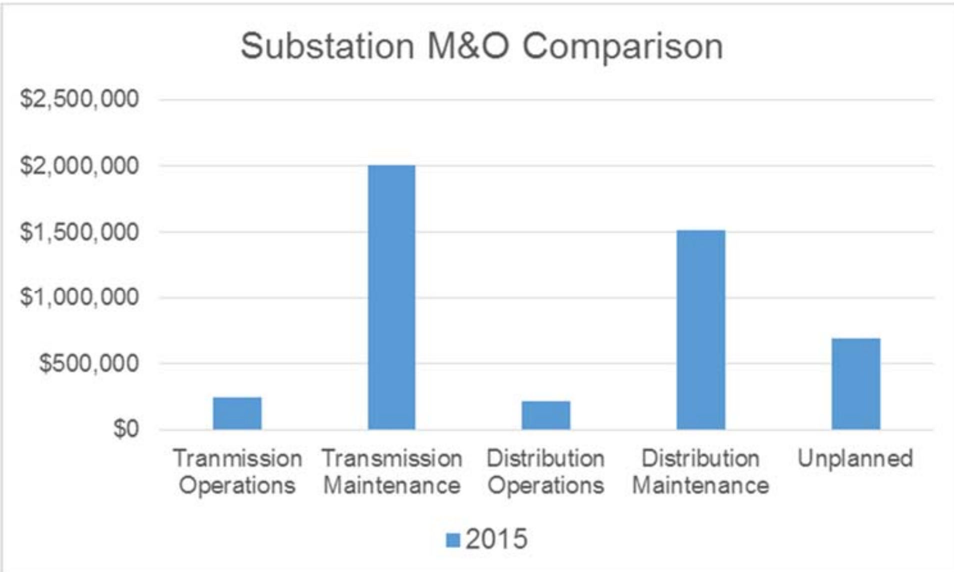


Figure 5: Substation M&O Comparison

Key Performance Indicators

Key Performance Indicators (KPIs) have been identified for tracking and review of key activities. These KPIs continue to be refined relative to the metrics monitored. The metrics are published on a monthly basis, providing a perspective about the implementation and use of Maximo, system reliability, and progress towards particular key project goals as linked to substation performance. A combination of lagging and leading indicators are tracked in order to provide both retrospective and prospective views. It is generally expected that the proper focus on the correct leading indicators will guide satisfactory results after a defined lag period. When this does not occur, deeper investigation and root-cause analysis may help to identify other factors affecting the expected causal relationship.

One of the primary goals of Asset Management is to optimally manage risk and performance relative to capital investment and maintenance expenditures. The nexus of planned maintenance and capital replacement activity compared to emergency repair costs, outages, lost profits and other possible outcomes over time should be clearly identified. Additional reviews of predicted activity versus actual outcomes for a variety of scenarios should also serve to help determine the continuation of or adjustment to ongoing programs and projects. The availability of sufficient reliable data to support these analytic opportunities continues to be a challenge, but is expected to be mollified as the Maximo implementation and structured use becomes integrated into the formal work processes. For example, safety incidents, emergency repair and replacement work, and other similar activities continue to be transacted in Operations under blanket accounts, precluding the ability to extract detailed transactional data associated with specific project and related work activities at a substation. The Asset Management group continues to suggest opportunities and support improvements to achieve the goal of a complete corporate implementation of Maximo.

The KPIs in Figure 6 and Figure 7 show projected and actual metrics relating to Work Orders within Maximo. Reactive Work Orders are associated with required Corrective Maintenance tasks that were in response to operational malfunction issues or items requiring attention following a planned inspection. Throughout 2015, the projected target has been achieved. The Average Age metric tracks the rolling number of days existing Work Orders have been active. This metric continues to not meet the expected performance level, though this topic continues to be addressed with the Operations teams.

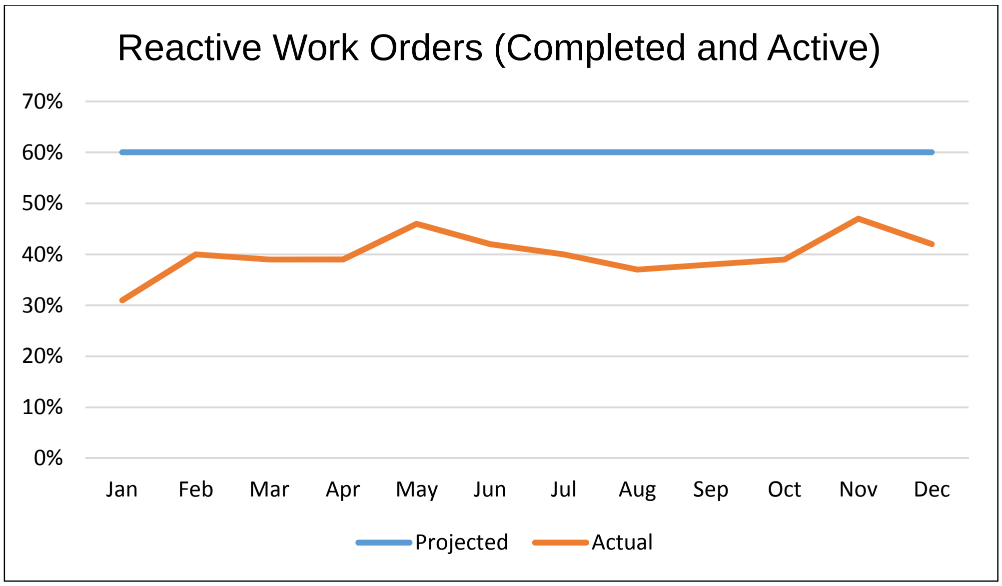


Figure 6: KPI-Reactive Work Orders

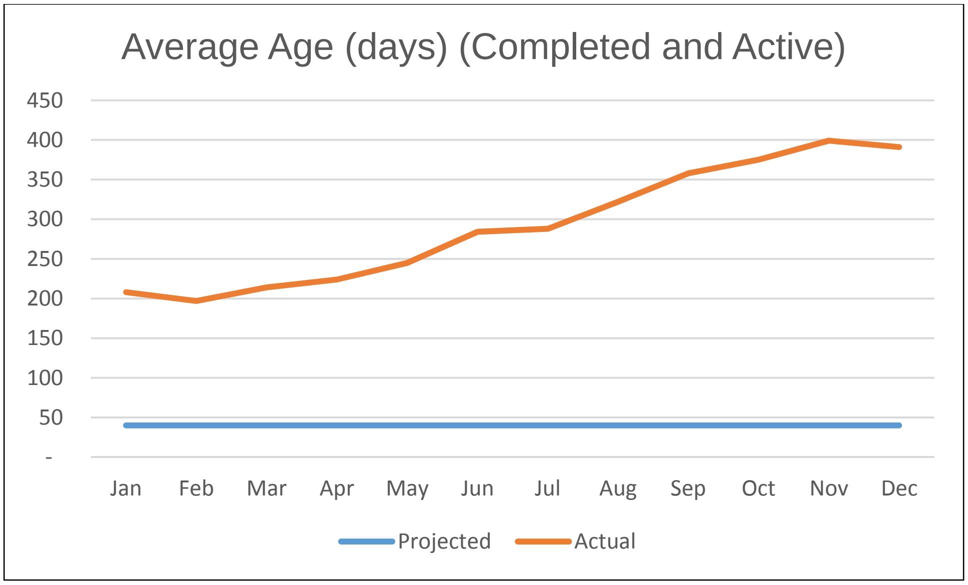


Figure 7: KPI-Work Order Average Age

Metrics associated with customer outages due to substation activity are shown in Figure 8 through Figure 11. In 2015, the projected outage metrics, whether time or quantity, have typically been satisfied, demonstrating the expected reliability of service for the end customer.

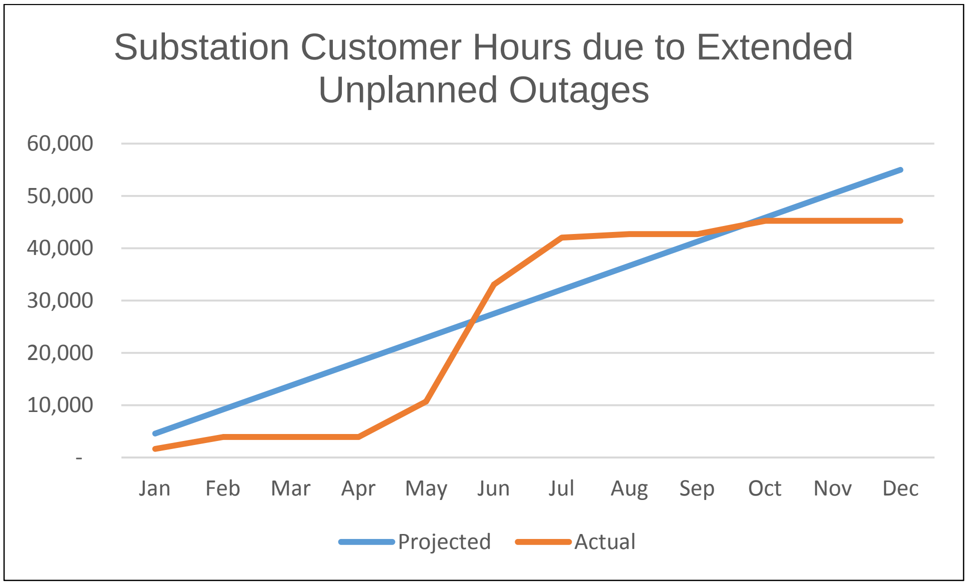


Figure 8: Hours of Unplanned Outages

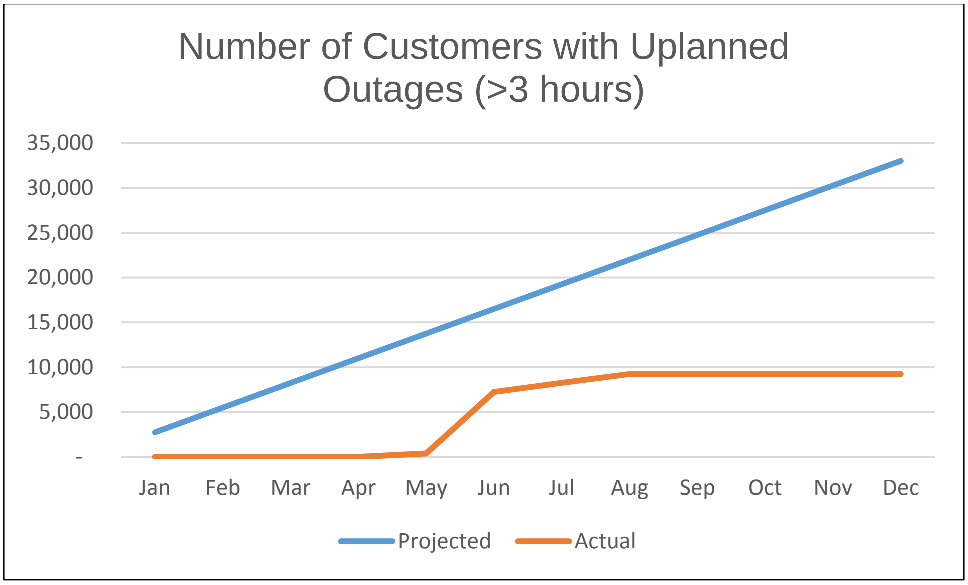


Figure 9: Customers Affected by Unplanned Outages

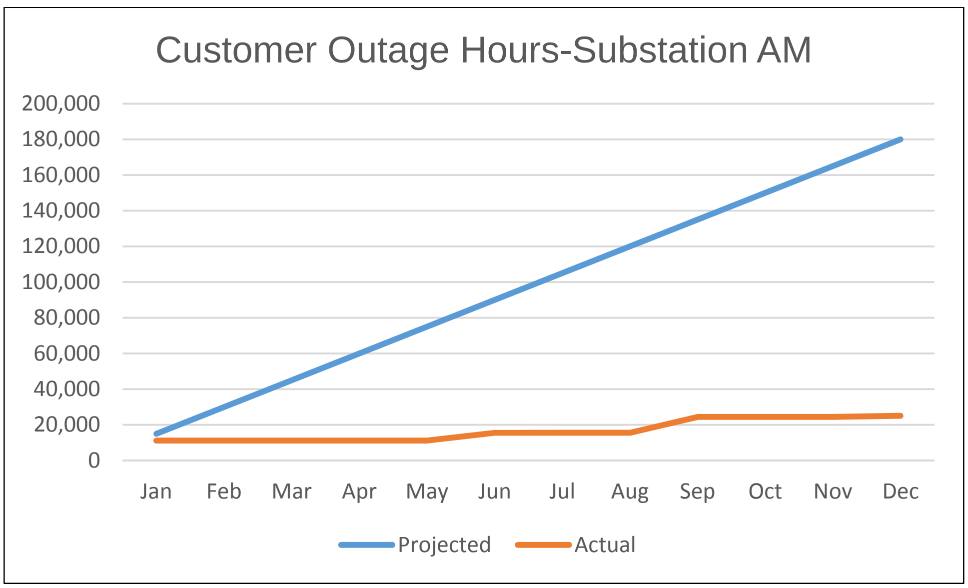


Figure 10: Customer Outage Hours

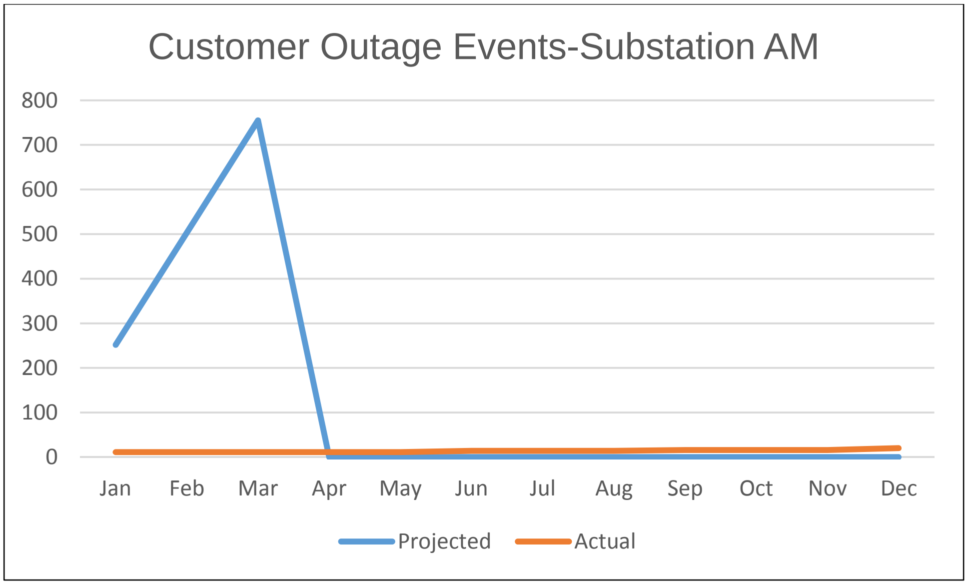


Figure 11: Customer Outage Events

The metrics shown in Figure 12 through Figure 15 relate to specific substation equipment-related programs. Figure 12 identifies the equipment replacement activities associated with the PCB Removal program, including qualifying equipment removed from substations. Equipment identified as a PCB-containing device continues to be prioritized for removal or replacement in conjunction with other related activities. The remaining three graphs represent power transformer, voltage regulator, and air switch assets.

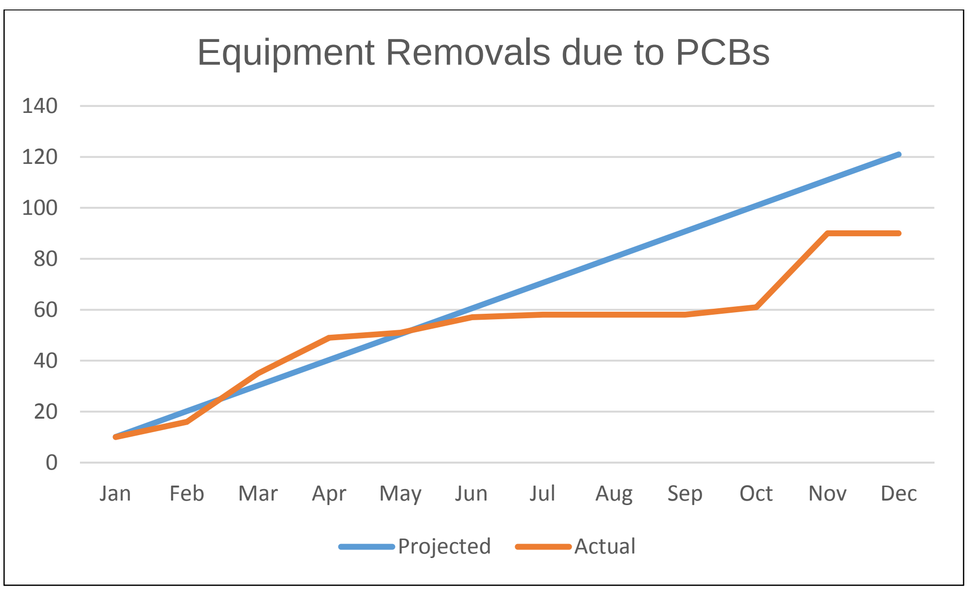


Figure 12: Equipment Removals due to PCB content

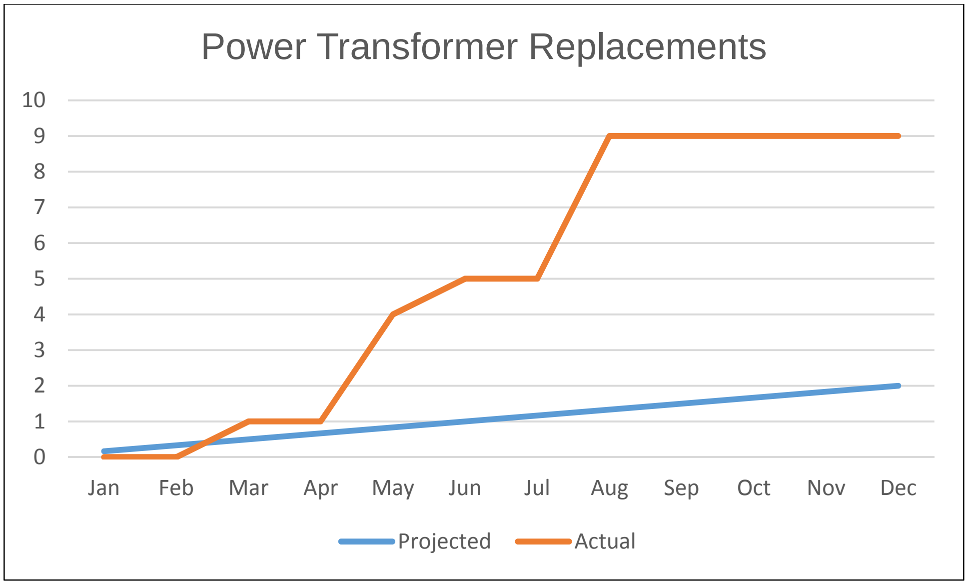


Figure 13: Power Transformer Replacements

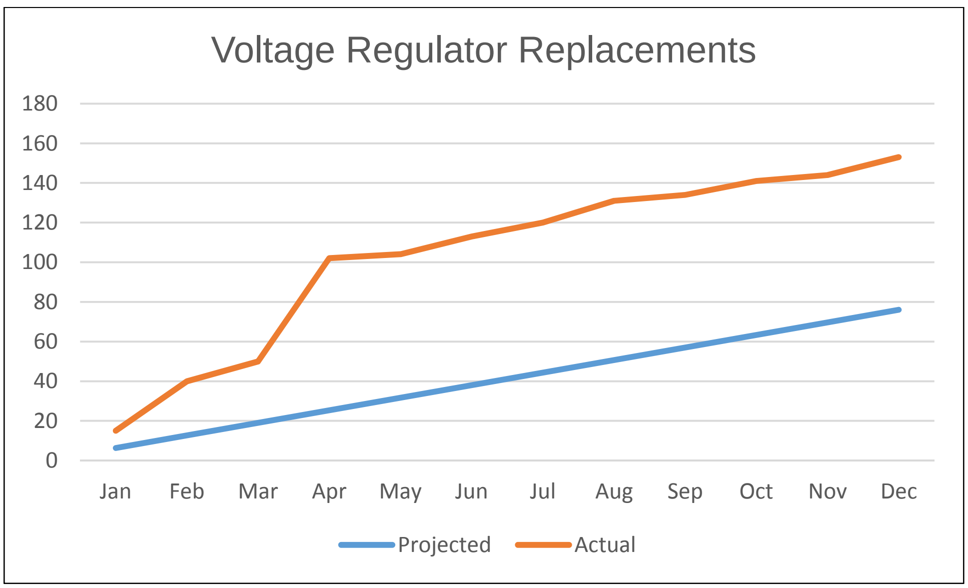


Figure 14: Voltage Regulator Replacements

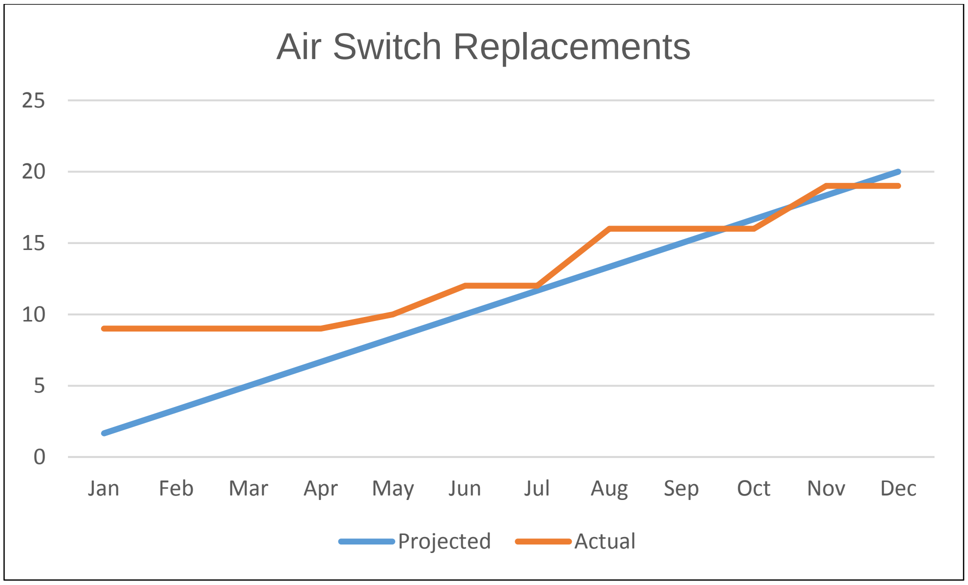


Figure 15: Air Switch Replacements

The Wood Substation Replacement program did not achieve a completed substation replacement during 2015 as noted in the graph shown in Figure 16.

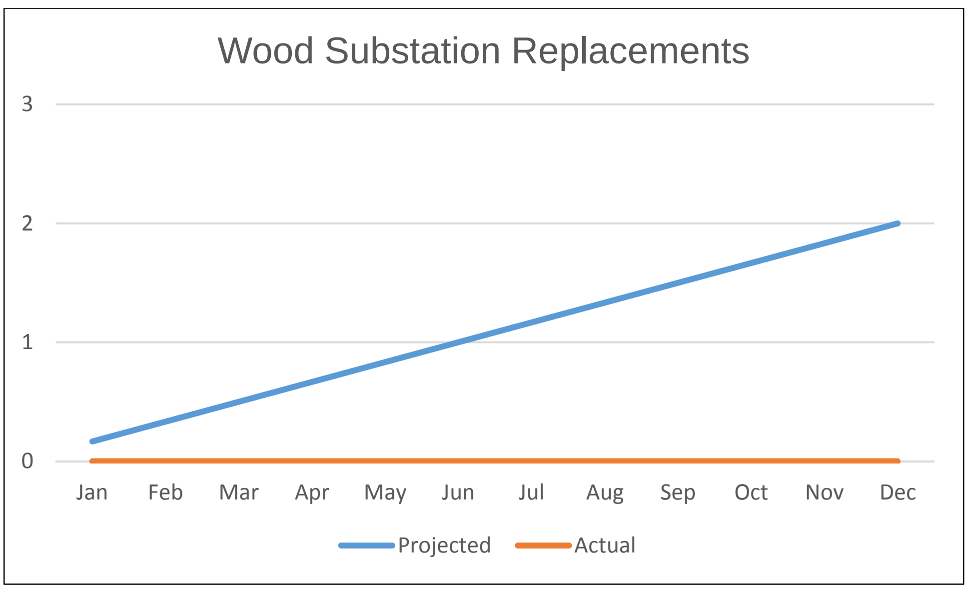


Figure 16: Wood Substation Replacements

These final two KPIs evaluate system awareness criteria regarding level of service. The Risk Action Curve metric in Figure 17 tracks outage event parameters, including frequency and severity, to signal additional action if the accumulated outage activity requires further review and analysis. The OMT High Limit in Figure 18 tracks to an acceptable limits of service statistical metric for outage events.

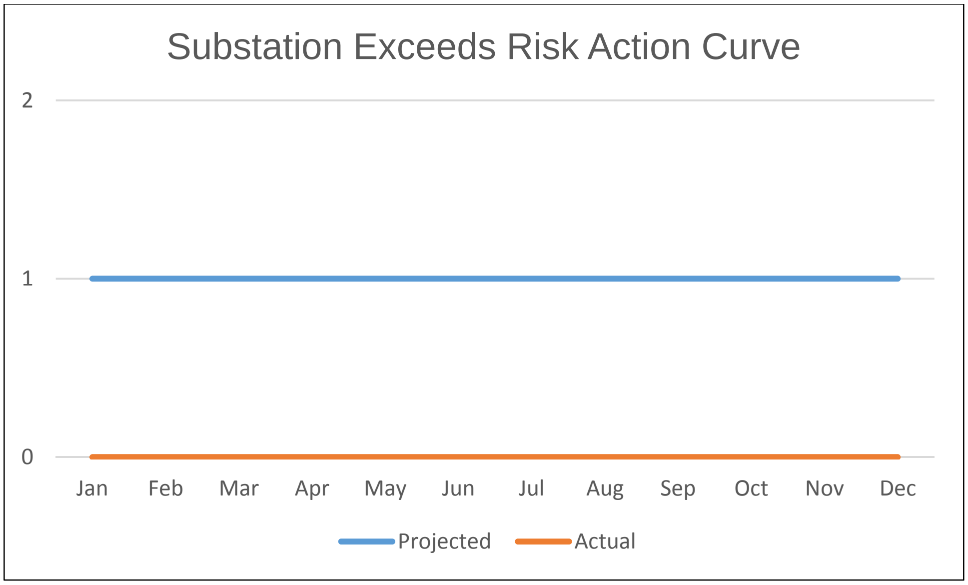


Figure 17: Substation Risk Action Curve

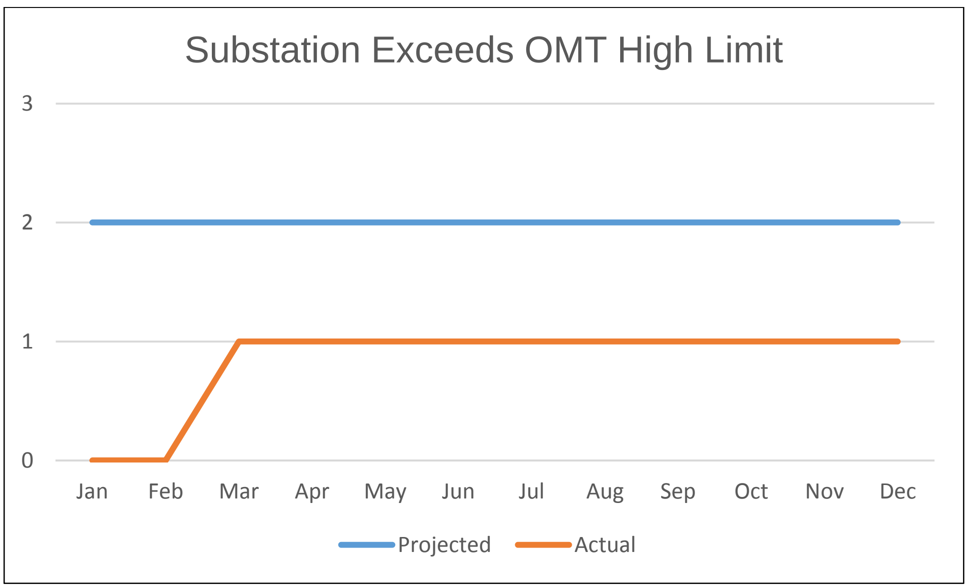
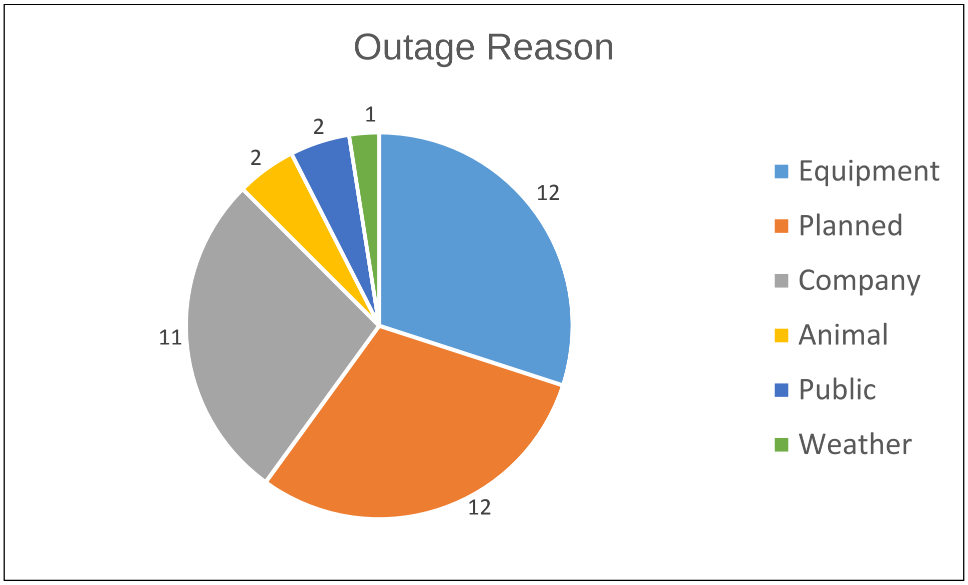


Figure 18: Substation OMT Limit

Outages

During 2015, 40 outage events occurred attributable to either planned or unplanned substation activity. For these outage events, the average duration was 2 hours 51 minutes and affected approximately 990 customers. Durations ranged from 5 minutes to 8 hours 48 minutes and impacted customers ranged from 1 to just over 4000. The data is derived from the annual reliability reports provided by Operations Management.



Programs

Substation PCB Removal

In 2010, an assessment was completed of equipment containing Polychlorinated Biphenyls (PCBs) within the Avista substation. PCBs are typically a minor constituent of oil within substation equipment including

- Power transformers
- Oil circuit breakers
- Voltage regulators
- Potential transformers
- Current transformers
- Station service transformers
- Capacitors
- Electromechanical relays.

Under the current process, the substation power transformers have been tested for PCBs and units with PCB concentrations of greater than 50 ppm are slated for removal. Voltage regulators, as brought in for repair, are tested and replaced if PCB concentrations of 50 ppm or greater are identified. Other substation equipment that is found to contain oil with the 50 ppm concentration of PCBs is evaluated on a case by case basis. The equipment may be decommissioned or reconditioned with clean oil and returned to service.

Additional regulation at both Federal and State levels continue to be monitored for refinement of this program.

Power Transformer Replacement

Avista's aging population of power transformers continues to be evaluated and included as key factors in substation upgrade projects or rebuilds. Transformer upgrades can provide significant energy savings based on the operational efficiency of the units, as well as additional configuration flexibility.

During 2014 and 2015, power transformer replacement projects have been completed at:

- Moscow 230 Spare (2013)
- Blue Creek #1 (2014)
- North Lewiston #1 (2014)

Voltage Regulator Replacement

Voltage regulators have been identified as significant contributors to substation reliability, and ongoing evaluation and modeling is in progress. The age profile is shown below Figure 19. In the conjunction with substation upgrades, older vintage voltage regulators are being replaced. The success of this ongoing program is shown by the shift in the age profile. Presently, the average age of installed base of voltage regulators is 15.5 years, though approximately 20% of the units have been installed for more than 30 years.

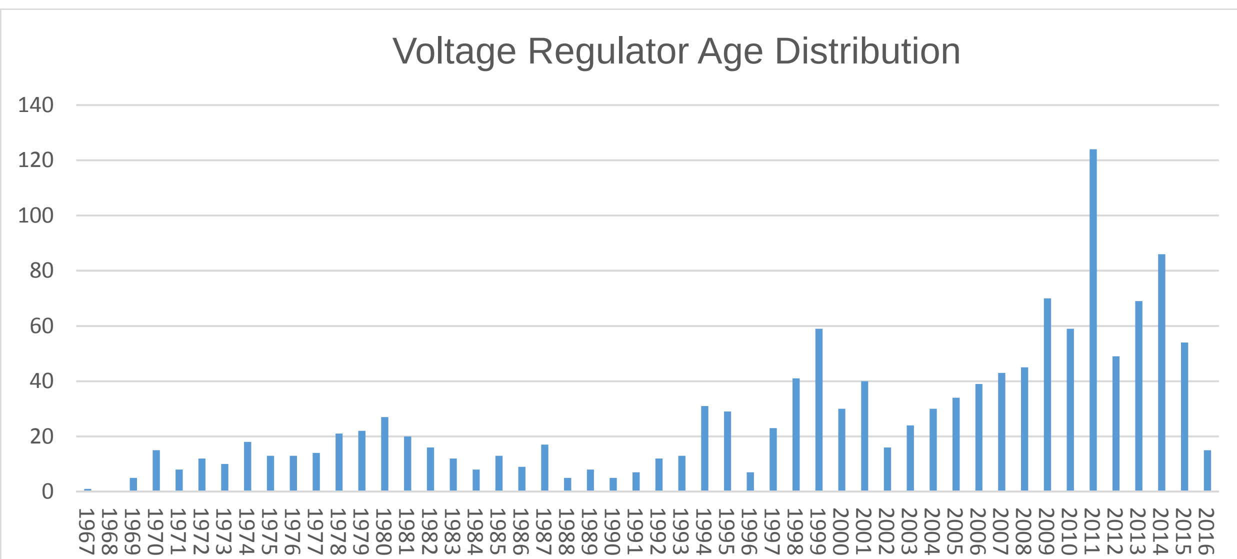


Figure 19: Voltage Regulator Age Distribution

Substation Air Switch Replacement

The Substation Air Switch Replacement program deals with both planned and unplanned replacements.

In the case where air switches do not operate properly, flashover and possible tripping of bus protection devices may occur. This can be the result of a component failure at the whips or vacrupter switch or other adjustment issues with the air switch itself. While most air switch missed operations could be prevented with regular inspection and maintenance, the limited scope of current maintenance procedures doesn't extend to the level of blade adjustments or the replacement of live parts, such as contacts and whips, or the repair of ground mats.

Many air switches are operated remotely. In these instances, Avista personnel may not be present to observe the opening of the switch, limiting the identification of potential issues. Minor functional issues could indicate the increasing probability of a major or catastrophic failure. Small quantities of emergency repair materials are maintained for the legacy population, but many of the air switches are out of production and replacement parts are difficult to procure.

Completed Substation Design and Construction Projects

The Substation Engineering group performs the scope, design, and project management functions for all facets of substation construction, including designated equipment replacement, rebuilds, and new site construction. The following tables describe the current status of projects within the engineering group's queue.

Substation Rebuilds completed in 2014 and 2015
Blue Creek – 115kV/13kV new construction
Clearwater 115kV/34kV substation upgrade
Lewiston Mill Road new construction
Moscow 230kV/115kV/24kV new construction
North Lewiston 115kV/13kV removal of equipment
Noxon Construction 230kV/13kV substation rebuild
Noxon Rapids 230kV west bus rebuild
Odessa 115kV/13kV substation upgrade
Irvin 115kV/13kV substation
Bruce Road 115kV/13kV substation

Table 4: Substation Rebuilds completed in 2014 and 2015

Completed Projects	BI Reference
Sunset - Replace MOAS A-184 (Four Lakes Tap)	AMS85
Grangeville - Replace A-337 Relay and Battery Cabinet	AMS09
Ross Park - 115kV Relay Upgrade	SS802
Third & Hatch - 115kV Relay Upgrade	SS802
Beacon - Upgrade A-605 Line Relays	SS802
Ninth & Central – Minor Upgrades	SS802
Noxon - Add Line Position for Noxon Reactor Station	AS202
Opportunity--Install 115kV Breakers	SS204

Table 5: Completed Projects

Projects in Design or Construction

The Substation Engineering group performs the scope, design, and project management functions for all facets of substation construction, including designated equipment replacement, rebuilds, and new site construction. The following three tables describe the current status of projects within the engineering group's queue.

Construction and Field Work in Progress	BI Reference
Bronx - HVP Upgrade	42P09
Oden - HVP Upgrade	42P09
Bunker Hill - HVP Upgrade	42P09
Nine Mile Substation - Install GSU 1	GG811
Noxon 230kV Reactor Station--New Construction	AS202
Greenacres--New 115kV/13kV Substation	SS644
Pine Creek - Replace Auto Transformer #1	AMS28

Table 6: Work in Progress

Engineering active and pending construction	BI Reference
Benton-Othello Transfer A-131 MOAS	AMS85
Beacon - Grid Modernization - Feeder 12F1	SS406
Beacon - Replace 13kV Breaker - 12F6	AMS83
Harrington - Rebuild to 115kV/13kV Substation	BS303
Mobile Battery - Add SCADA	XS951
Noxon - Hot Springs #1 and #2 Line Relay Upgrades	AMS07
Beacon--Replace Fence	AMS82
Beacon--115kV Line Relay Upgrade A-610, A-613	SS802
Noxon - Refurbish Existing East Bus	AS202
College & Walnut – Yard Expansion	AMS82
Sprague - Minor Rebuild	FS402
Deer Park--Metering/SCADA/Panel house	SS405
Othello - Replace Feeder 501 and 502 Breakers	AMS83
Othello - Replace Air Switch A-41	AMS83
Lolo - Communications DC Plant Refresh	
St. John - Replace 24kV Switches	AMS85
Shawnee - Communications DC Plant Refresh	
St. Maries - Upgrade AC/DC Station Service	AMS10

Table 7: Active and Pending Construction

Waiting prioritization or delayed	BI Reference
Replace SMP - Dry Creek	XS951
Replace SMPs - Post Street	XS951
Ramsey--Line Relay Upgrade A-669	CS802
Cabinet - Remove Relays and Change CT Ratios	AG103

Table 8: Delayed Projects

Future Projects	BI Reference
North Lewiston 230kV--Install Reactors	LS306
Kamiah - Rebuild	LS208
Gifford - Add 115/13kV Station to Substations	WS201
Westside - Increase Capacity; New Autotransformer	SS201
Priest River – Temporary Breaker Install	AMS83
Ford - Replace Transformer	AMS28
Ford - Install New 12F2 Feeder Position	BS202
Waikiki - Grid Modernization - Feeder 12F2	SS542
Priest River - Minor Rebuild - Distribution	AMS83
Irvin--New 115kV Switching Station	SS904
Hallett & White - Add Capacity	SS523
Rathdrum - Grid Modernization - Feeder 231	CS502
Rathdrum - Grid Modernization - Feeder 233	CS502
Juliaetta - Replace MOAS units A-120 and A-173	AMS85
Jaype - Remove and Salvage	
Colville - Replace Battery	AMS10
Chester - Replace Battery	AMS10
Rockford - Replace Battery	AMS10
Fort Wright - Replace Battery	AMS10
Beacon--Install Serveron DGA on both autotransformers	XS903
Ritzville - Replace A-94 MOAS Control Box	AMS85
Northwest - Add Fiber Redundancy/Upgrade	XS951
Millwood - Add Radios in Yard - 2 Poles	
Othello Switching Station - HVP Upgrade	42P09
Clearwater - Upgrade Metering	XS801
Clearwater - Replace Battery	AMS09
Oden - Replace 115kV Switches	AMS85
Bronx - Replace small conductor	AMS32
Garfield - Replace HV Fuses	AMS80
Clearwater--Microwave Refresh	

Future Projects	BI Reference
Beacon - Add Thermal Relays - A-603/A-607	XS002
St. Maries--Install SCADA	XS951
Ninth & Central - Rebuild Distribution Sub	SS514
S. Lewiston 115--Rebuild station, replace transformers	LS207
Ninth & Central - Move lateral line into substation	SS514
Moscow City—Upgrade SCADA/Integrate System	XS951
Indian Trail - Add Fiber; Upgrade Communications	XS951
Northwest - Rebuild	SS206
College & Walnut - Replace Breakers A-431 and A-432	AMS32
Davenport - Minor Rebuild	BS400
Colville - HVP Upgrade	42P09
Kooskia 115kV--Replace Transformer	AMS28
Milan - Replace A-599 MOAS	AMS85
N. Moscow - Install A-369 MOAS	AMS85
Warden - Replace Breakers	AMS32
Warden - Install SSVT for Station Service	XS905
Otis Orchards – Install SSVT for Station Service	XS905
Beacon--Upgrade SCADA/Integration System	XS951
Clearwater--Upgrade Relaying	AMS07
St. Maries - Install 115kV Arresters	AMS81
O'Gara - Install 115kV Arresters	AMS81
Lee & Reynolds--Add Transformer #2	AMS28
Upriver--Replace/Upgrade Metering	XS801
Dry Gulch--Replace/Upgrade Metering	XS801
Cabinet - Install substation fuses/Lighting circuits	AMS80
Clearwater - Replace/Upgrade SCADA	XS951
Little Falls – Rebuild	BS304
Tenth & Stewart--Station Upgrades/Rebuild	LS202
Valley - Rebuild Substation	WS402
Sunset - Rebuild Substation	SS890

Future Projects	BI Reference
Metro - Rebuild Substation	SS208
Big Creek - Rebuild Substation	KS201
Coeur Shaft - Minor Rebuild	TBD
Pound Lane - Rebuild Substation	TBD
Chester - Rebuild Substation	SS207
Othello - Rebuild Substation	TBD
Silver Lake - Rebuild Substation	TBD
Dalton - Rebuild Substation	TBD
Huetter - Rebuild 115kV Yard	CS503
Bronx - Rebuild Substation	AS203
Noxon Rapids - New Substation	AS202
Saddle Mt. - New Substation	TBD
Tamarack - New Substation	PS203
McFarlane - New Substation	SS516
Bovill - New Substation	TBD
Ross Park--Install Security Wall	06P98
Post Street Transformer Cooling Discharge	TBD
ORO - Grid Modernization - Feeder 1280	TBD

Table 9: Future Projects

System Planning Projects

There is considerable opportunity for more collaboration between Asset Management and System Planning on capital asset risk assessments, analyses and development of long-term asset management plans, where overlaps and synergistic opportunities present themselves. Risk is equivalent to the product of the probability and the consequence of a given event.

Currently, there are no substation System Planning projects that are covered by Asset Management.

Reference and Data Sources

Various information and data sources were used to compile the information for this report. As referenced in the Purpose introduction, the emphasis was placed on Avista's Maximo implementation for all inventory and date-specific asset details. This process will provide a tracking database for repeatable historical references, trending, and accurate data snapshots as the system continues to be deployed and data capture processes refined.

Other sources include Availability Workbench simulations, the legacy Major Equipment Tracking System (METS), Outage Management Tool (OMT) data, substation engineering files, substation engineering SharePoint site, and the substation Projects and Capital Budget spreadsheets.

2016

Electric Distribution System 2016 Asset Management Plan

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02-05-2016

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Scott Waples, Director of Planning and Asset Management

Table of Contents

Purpose

This report documents the asset plans for Electrical Distribution System for Avista. The plans discussed here represent what we believe to be the best approach to managing Avista's Distribution assets and provides the Key Performance Indicators (KPIs) and metrics Asset Management (AM) to support the plans and demonstrate the effectiveness of those plans implemented. The report also helps identify areas for improvement or opportunities to improve the value we receive from our assets.

Some of the metrics provide a basis for comparing how an asset performed with a program and how it would have performed without a program. The difference in performance provides an estimate of the cost saving of the program. The estimated savings is only a snapshot in time and may not represent the exact savings; it provides a relative comparison and supporting justification for AM decisions made in the past. Other KPIs and metrics provide indications of how well an asset is performing and helps determine when further work is required. KPIs and metrics tracking also help evaluate the accuracy of different AM models and determine when or if a model should be revised.

Executive Summary

The primary message of this asset management plan is that the programs in place have been positively impacting the number of outages and decreasing the cost to mitigate these failures. Continuous improvement upon these programs is necessary to maintain reliability and efficiency. Assets are aging faster than our current programs and plans can alleviate. However, programs are continually being analyzed and updated to continue to improve our overall management of the distribution assets.

If available, each of the below summaries include a ranking criteria table. This table includes the Customer IRR from the business case, the Benefit to Cost Ratio from our IRR calculation analysis and the Risk Reduction Ratio from the supporting business case.

Current Programs:

1. **Grid Modernization** – includes replacing poles, transformers (Pad Mount, Overhead & Submersible), cross arms, arresters, air switches, grounds, cutouts, riser wire, insulators, conduit and conductors in order to address concerns related to age, capacity, high electrical resistance, strength, and mechanical ability. The program also includes the addition of wildlife guards, smart grid devices and switched capacitor banks, balancing feeders, removing unauthorized attachments, replacing open wire secondary, and reconfigurations. Although this is a new program it does appear to be reducing outages for the feeders worked on. The program has slowly shifted from "Feeder Upgrade" to this new larger scoped Grid Modernization program. With only a few years of data since completion of the earliest feeders, this program needs time to mature, so the full value of the program can be realized.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
6.4%	-	0.7293

2. **Transformer Change-Out Program** – has run smoothly for the past few years with the targets and KPIs being met regularly. This program was largely implemented to reduce the environmental concern of Polychlorinated biphenyls (PCBs) in some Pre-81 transformers. The environmental risks have been heavily decreased, with a focus in areas that have a greater potential to impact our waterways. Since these are also old and inefficient transformers, our efficiency has increased. However, this program is about to switch over to the second phase. With this switchover the program will "piggy back" on Wood Pole Management for a complete cycle to finish removing the non-PCB Pre-81 transformers from our system. The effectiveness and efficiency of this second phase is yet to be determined.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
5% < 9%	-	0.0670

3. **URD Cable Replacement** – is the programmatic replacement of the pre 1982 unjacketed Underground Residential District (URD) cable. Originally the removal of all of the pre 1982 cable was to be completed in 5 years; however, funding didn't match the original target and some cable remains in use today. To date the program has paid great dividends towards reducing URD Cable-Pri events when compared to where it would have been without taking action. Although many feet of this type of cable remain in use, the outages have been greatly reduced and we are seeing few outages due to this early generation of cable.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
9% < 12%	-	0.1958

4. **Vegetation Management** – maintains the distribution system clear of trees and other vegetation. This reduces outages caused by trees and to a lesser extent outages caused by squirrels. This program has had a big impact on reducing our number of unplanned outages. Reducing these outages improves our reliability, reduces our risk during storms and decreases safety hazards for our employees working on the distribution system. Tree related outages continue to decline and the cost per mile to do this program have continually decreased due to efficiency gains, improved processes and new methods such as per unit costing; which in turn drives up the value of this program.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
63.39%	14.74	22.39

5. **Wood Pole Management** – inspects and maintains the existing distribution wood poles on a 20 year cycle. In addition to inspecting the poles, we inspect distribution transformers, cutouts, insulators, wildlife guards, lightning arresters, crossarms, pole guying, and pole grounds. The inspection of these other components on a pole drives additional action to replace bad or failed equipment along with replacing known problematic components. Overall, WPM has been effective at maintaining the current level of reliability to our customers, however, we will need to complete work on more feeder miles to control the impact on future reliability.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
7.42%	2.283	0.6879

6. **Area and Street Light** – replaces non-decorative high pressure sodium and mercury vapor lights with equivalent LED lights. The initial year of the program changed out 100W and 200W HPS and MV non-decorative street lights in Washington only. The scope was changed and going forward all wattage types of non-decorative lights for both area and street lights will be replaced in both Washington and Idaho. The first year of the program finished on budget with more lights completed than anticipated. The scope change and potential budget cuts may push this 5 year program out, however, the impressive first year gives hope that with an intact budget the program may complete closer to the 5 year cycle than not.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
7.92%	1.917	.0718

7. **Worst Feeder** – This program aims to improve the reliability of its most underperforming distribution circuits. Projects vary by individual circumstance but in many cases additional circuit reclosers are installed to reduce outage exposure and to automatically restore power to upstream customers or circuits in outage prone areas are converted from overhead to underground or circuits are effectively 'hardened' by shortening conductor span lengths or by increasing phase spacing. This programs goal is to selectively improve the feeders with the worst SAIFI and so far this program seems to be producing as planned. Not all feeders drop off the list after work is done but most have a large reduction in outages after work is done.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
5% < 9%	-	0.2062

8. **Segment Reconductor and Feeder Tie** – addresses specific congestion issues in the distribution system. The purpose of the program is to reconductor portions of circuits or to install additional 'tie' points to enable load shifts and transfers. In most situations, this involves that poles be replaced and that existing conductors remain in service during the majority of the work. Transformers, customer service wires, and other equipment including crossarms, insulators, guy wires, brackets, communication circuits, fuse holders, and other hardware must be installed new or transferred to new poles. This program helps maintain operational flexibility and circuit reserve capacity for our distribution system.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
0%	-	1.489

9. **Network** – Major network equipment falls into four categories: network transformers, network protectors, cable (primary and secondary), and physical facilities – duct banks, vaults, manholes, and handholes. There are no established performance metrics for this program. The network is designed with redundancies to prevent outages and our current outage management tool does not "see" network events, making it difficult to keep track of the typical metrics used in other programs.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
9% < 12%	-	1.285

10. **Protection** – Avista's Electric Distribution system is configured into a trunk and lateral system. Lateral circuits are protected via fuse-links and operate under fault conditions to isolate the

lateral in order to minimize the number of affected customers in an outage. Engineering recommends installation of cut-outs on un-fused lateral circuits and the replacement of obsolete fuse equipment (e.g. Chance, Durabute/V-shaped, Open Fuse Link/Grasshopper, Q-Q, Load Break/Elephant Ear, and Porcelain Box Cutouts). As part of the program, sizing of fuses will be reviewed to assure protection of facilities, as well as coordination with upstream/downstream protective devices. This program began as an obsolete replacement program but has grown to incorporate un-fused and wrong fused laterals. Cutout outages have decreased through this program but with the added scope a new metric will need to be made. This is a targeted program to ensure adequate protection of lateral circuits and to replace known defective equipment.

Customer IRR	Benefit/Cost	Risk Reduction Ratio
9% <12%*	-	0.0990*

*Original scope

To date the programs developed have made a huge impact in the number of outages on the distribution system. The cyclic programs need to continue to be analyzed and updated to maintain the improved reliability, reduced risk and decreased O&M costs. Since the assets continue to age faster than the current programs can mitigate, new programs or scope changes will be required going forward to continue to provide our customers with safe and reliable service.

Data Sources

Much of the information used in this report's metrics comes from three sources: Annual Sustained and Momentary outage data; Outage Management Tool (OMT) events; and Oracle (financial and supply chain database). The annual Sustained and Momentary outage data is generated by the Distribution Dispatch Engineer each month in a spreadsheet. The Sustained and Momentary outage data for years 2001 – 2007 was modified by AM to align the reasons and sub-reasons to coincide with the current descriptions. While the Sustained and Momentary outage data comes from OMT data and is a subset of OMT data, this data has been scrubbed by the Distribution Dispatch Engineer to improve its accuracy.

The OMT tracks outages and customer reports of problems on the Distribution system, Substations, and Transmission events that cause outages on the Distribution system. This data includes sustained outages, momentary outages, and events without outages. Events that only cause a partial outage or no outage at all do not show up in the Sustained and Momentary outage data, because the data does not fit the definition of a sustained outage or a momentary outage. However, the OMT data is sometimes subject to reporting an event more than once. The Distribution Dispatch Engineer reviews the data and strives to prevent duplication by rolling events up and editing the data. However, some duplication still occurs. OMT data is used to calculate number of outages, number of OMT events (outages, partial outages, and non-outage events), outage duration, number of customers impacted, response times, System Average Interruption Frequency Index (SAIFI) impacts, and System Average Interruption Duration Index (SAIDI) impacts.

Discoverer provides financial, customer information, and material usage information from our warehouse and financial systems. Spending and material can be tracked to the ER and BI level for capital work and the Master Activity Code (MAC) and Task for Operations and Maintenance (O&M) work.

Standard Calculations

See reference the “2010 General Metrics Data Collection and Analysis for System Reviews” for the details and examples of how different measures and metrics are calculated.

Review of OMT Data and Trends

Examining the data in OMT reveals a lot of information which helps Avista understand the condition of our assets and shows some trends we can address. Below, we will examine various trends within OMT Events per Year, SAIFI trends by OMT Sub-Reasons, and other measures.

OMT Events per Year

Table 1 shows the past seven years of data out of OMT by Sub-Reason and allows trend analysis. OMT Events represents cost and action for Avista, so it was selected as a basis for much of our trending. However, OMT Outage data (shown in Table 2) can have a different trend than OMT Events. Since the SAIFI analysis already includes outage data, AM selected to trend OMT Events and SAIFI contribution. Based on Table 1, we identified the top 10 increasing and decreasing trends in OMT Sub-Reasons. The Top 10 increasing trends in the number of OMT events by year is shown in Table 3 and the Top 10 decreasing trends in the number of OMT events by year is shown in Table 4.

Table 1, OMT Events by Sub-Reason and Year

OMT SUB-REASON	2009	2010	2011	2012	2013	2014	2015
Arrester	19	32	30	36	24	32	20
Bird	218	179	332	231	270	248	227
Capacitor	4	2	0	4	4	3	0
Car Hit Pad	139	105	98	105	117	104	88
Car Hit Pole	217	298	339	355	369	378	307
Conductor - Pri	42	64	81	110	142	135	83
Conductor - Sec	286	273	310	286	331	323	299
Connector - Pri	111	101	100	79	85	85	51
Connector - Sec	429	410	408	390	336	321	283
Crossarm-rotten	23	25	28	19	18	26	23
Customer Equipment	1626	1458	1384	1434	1368	1328	1200
Cutout/Fuse	197	217	176	209	171	196	109
Dig In	164	149	123	109	103	104	96
Elbow	7	5	8	2	10	6	5
Fire	157	203	234	230	282	200	206
Forced	51	63	67	33	63	68	29
Foreign Utility	724	894	720	734	720	602	765

OMT SUB-REASON	2009	2010	2011	2012	2013	2014	2015
Insulator	32	49	36	32	47	34	37
Insulator Pin	28	24	30	25	23	16	19
Junctions	2	2	1	4	6	7	2
Lightning	598	163	179	635	453	297	200
Maint/Upgrade	539	1571	3334	2589	1840	1880	1566
Other	394	414	426	483	472	467	344
Pole Fire	116	102	117	113	152	134	153
Pole-rotten	44	37	35	52	34	55	43
Primary Splice	0	1	1	0	0	0	0
Protected	18	10	4	5	5	3	4
Recloser	4	11	3	2	3	11	2
Regulator	14	20	17	13	17	18	13
SEE REMARKS	821	892	543	487	463	508	518
Service	123	188	197	230	191	124	172
Snow/Ice	988	565	167	352	122	243	1882
Squirrel	700	390	395	358	215	279	272
Switch/Disconnect	9	3	0	3	6	16	8
Termination	7	7	9	12	21	19	8
Transformer - OH	158	128	156	167	132	133	84
Transformer UG	57	53	51	50	71	60	62
Tree	55	53	51	56	46	60	47
Tree Fell	390	506	392	377	298	393	340
Tree Growth	375	330	335	335	349	400	280
Underground	0	3	1	3	2	2	0
Undetermined	1145	948	861	783	765	723	728
URD Cable - Pri	136	93	95	72	93	88	64
URD Cable - Sec	212	190	248	219	208	188	153
Weather	357	895	325	314	216	166	208
Wildlife Guard	3	0	1	2	0	0	0
Wind	294	1309	256	1042	1126	3238	6465

Table 2, OMT Outages and Partial Outages by Sub-Reason and Year

OMT SUB-REASON	2009	2010	2011	2012	2013	2014	2015
Arrester	18	31	30	32	21	29	19
Bird	213	175	322	225	259	244	216
Capacitor	4	1	0	3	2	0	0
Car Hit Pad	41	30	31	45	36	37	40
Car Hit Pole	104	135	131	158	152	164	159
Conductor - Pri	31	49	61	70	113	98	65
Conductor - Sec	117	104	126	124	147	148	151
Connector - Pri	102	84	82	59	68	70	44
Connector - Sec	272	263	270	267	227	227	211
Crossarm-rotten	11	20	24	17	15	21	18
Customer Equipment	1205	1121	1034	1099	1037	1011	932
Cutout/Fuse	175	194	161	185	155	180	98
Dig In	104	88	75	64	62	69	60
Elbow	7	5	7	2	10	6	5
Fire	8	69	72	82	102	74	108
Forced	51	63	67	33	63	66	29
Foreign Utility	78	103	61	62	90	66	175
Insulator	23	31	26	19	27	22	28
Insulator Pin	16	15	18	19	13	11	12
Junctions	0	1	0	2	2	5	0
Lightning	572	159	174	562	417	284	197
Maint/Upgrade	534	1566	3331	2587	1834	1873	1563
Other	247	275	261	282	282	258	202
Pole Fire	101	87	93	95	128	114	138
Pole-rotten	14	11	10	9	7	14	18
Primary Splice	0	1	1	0	0	0	0
Protected	17	7	4	5	5	3	4
Recloser	3	9	1	2	3	11	2
Regulator	10	16	14	10	10	13	13
SEE REMARKS	420	443	286	255	262	217	243
Service	59	89	86	59	55	44	62
Snow/Ice	592	347	135	291	103	202	1281
Squirrel	694	380	389	351	210	274	263
Switch/Disconnect	7	3	0	1	5	14	8
Termination	7	6	8	12	18	16	7
Transformer - OH	143	107	138	150	117	118	78
Transformer UG	42	44	36	42	59	49	54
Tree	42	39	36	39	35	43	40
Tree Fell	186	234	215	229	183	223	219
Tree Growth	101	77	71	93	90	123	87
Underground	0	1	1	3	2	2	0
Undetermined	1023	855	799	684	669	634	641
URD Cable - Pri	132	89	92	71	89	84	59

OMT SUB-REASON	2009	2010	2011	2012	2013	2014	2015
URD Cable - Sec	201	175	227	202	190	173	145
Weather	273	620	178	170	137	101	122
Wildlife Guard	3	0	0	2	0	0	0
Wind	229	982	195	802	840	2345	5721

Table 3, Top Ten Trends Upward in OMT Data by Sub-Reason based on 2009-2015 data

Top Ten Upward Trends	
OMT Sub-Reason	Slope Change per Year
Wind	709
Maint/Upgrade	79
Snow/Ice	62
Fire	12
Conductor - Pri	9
Foreign Utility	9
Car Hit Pole	9
Conductor - Sec	8
Pole Fire	7
Bird	3

Table 3 shows that the largest upward trend changed this year to Wind. This change was due to the large wind storm that impacted our service territory in November. Snow/Ice is also very high on the list and is mostly due to the snow storm in December. Without these major events then Maintenance and Upgrade would continue to be the largest trend upward. We have implemented many programs that increase our outages due to maintenance but decrease the number of outages due to failures. Bird has always been on this list but has slowly dropped to the number 10 spot with a much smaller trend upward suggesting the increase in wildlife guard installation has had a positive impact. Car Hit Pole remains pretty steady trending upward and will continue to be monitored. Both Primary and Secondary Conductor are both increasing at a steady pace and may need to be reevaluated. Primary Conductor is only addressed with our Grid Modernization and Segment Reconductor and Feeder Tie program. Fire has consistently been on the top 10 list but is a customer issue and not an Avista issue so this is not something Avista can mitigate. Foreign Utility is also a non Avista issue and does not need to be addressed within this document.

Table 4 shows the Top 10 OMT Sub-Reasons with a downward trend. The largest downward trend is in Undetermined. This Sub-Reason, as well as SEE REMARKS, have been trending downwards for a few years and is believed to be due to an increased focus on the importance of accurate and standardized outage data. Squirrel events continue to decline, as well. This is probably largely due to adding Wildlife Guards (WLG) on new installs and adding them to existing transformers as part of Wood Pole Management and Grid Modernization. The URD cable Replacement program for the first generation of unjacketed cable has paid great dividends when compared to where it could have been without taking action at reducing URD Cable – Pri events. Reduction in lighting strikes may simply be due to nature, however, the Wood Pole Management (WPM), Grid Modernization and Transformer Change-out Program (TCOP) may also be helping to mitigate this issue by adding lightning arrestors to new install transformers. The decrease in Cutout/Fuse Sub-Reasons can likely be attributed to Wood Pole Management, TCOP and Grid Modernization programs along with some contribution from other programs. The remaining Sub Reasons in the table have trend downward but the changes are not material at this point in time or are outside of Asset Management's control.

Table 4, Top Ten Trends Downward in OMT Data by Sub-Reason based on 2009-2015 data

Top Ten Downward Trends	
OMT Sub-Reason	Slope Change per Year
Undetermined	-61
Squirrel	-60
Weather	-55
Customer Equipment	-37
SEE REMARKS	-36
Lightning	-23
Connector - Sec	-11
Cutout/Fuse	-9
URD Cable - Pri	-8
Connector - Pri	-8

The overall trends in OMT Events are shown in Figure 1 along with the trends in AM related OMT Events (see Appendix A of the "2010 Asset Management Electrical Distribution Program Review and Metrics" and the table titled "List of AM Related OMT Sub-Reasons" to see which OMT Sub-Reasons are considered AM Related). Based on Figure 1, Avista sees the trend in the number of events decreasing over the past 5 years.

AM related OMT events are actually decreasing at a rate around 4%. Since the regional growth rates are less than 2%, the decrease is most probably due to the increase in maintenance in the system and replacement of aged infrastructure.

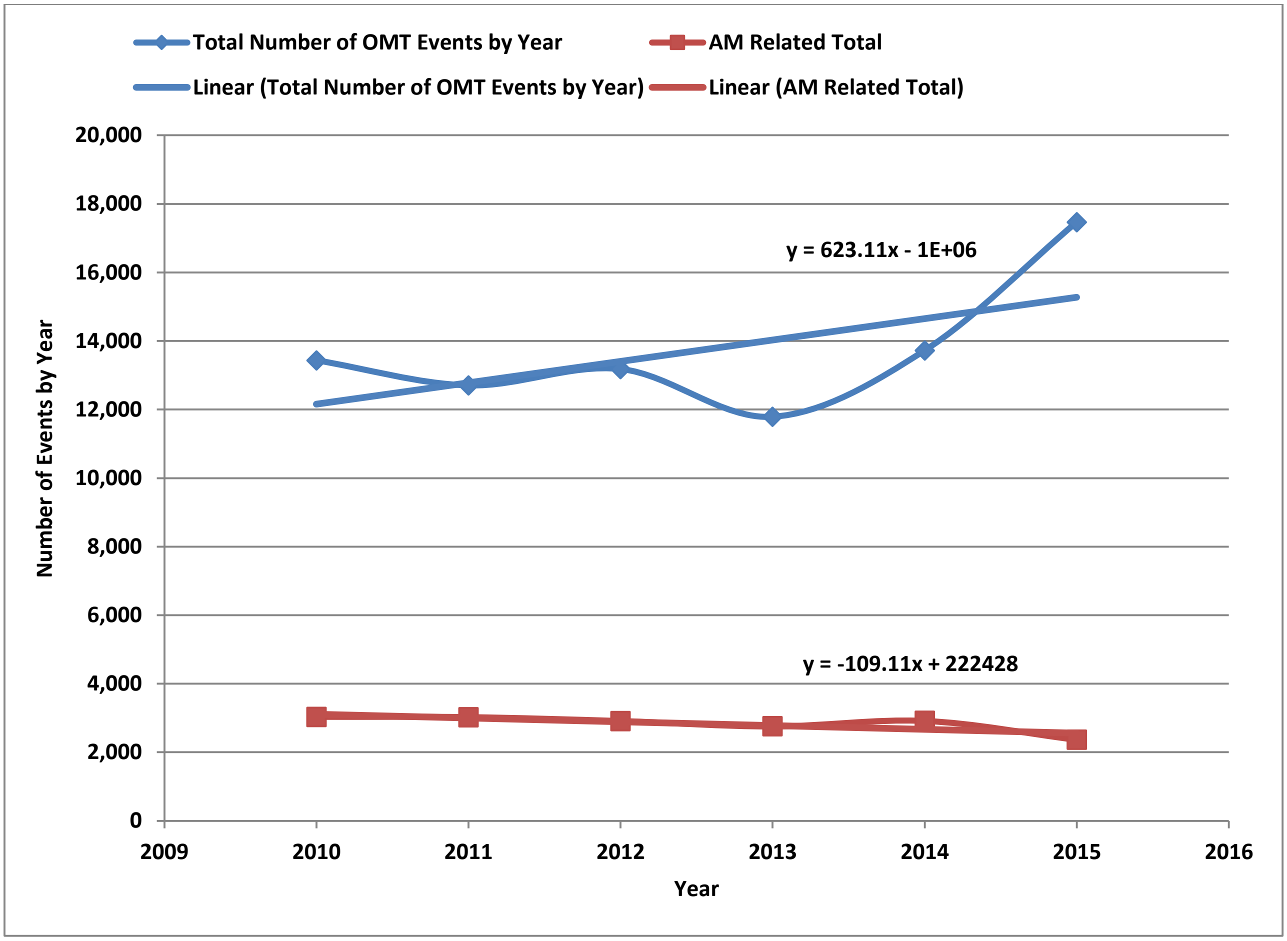


Figure 1, OMT Annual Number of Events and AM Related Event Trends and Trend Lines

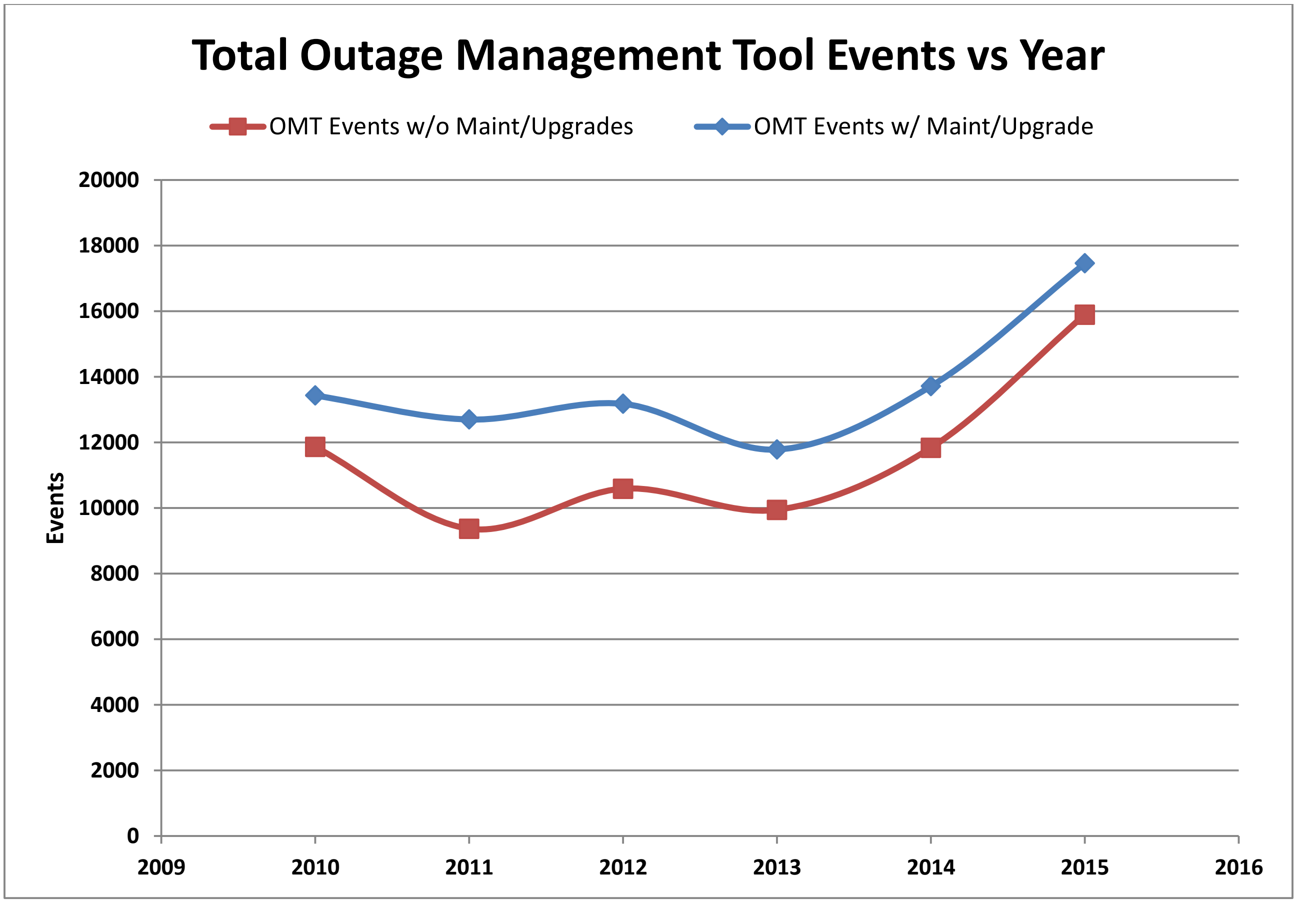


Figure 2, OMT Events with and without Planned Maintenance or Upgrades

SAIFI Trends by OMT Sub-Reasons

Examining how SAIFI changes each year is shown in Table 5. SAIFI values in Table 5 represent the annual value each event contributes to the overall SAIFI number. For example, in 2011, the average Arrester event in OMT added 0.003380523 to the overall SAIFI number for the year. While the number of electrical customers does typically grow each year, the main driver for changes in the average SAIFI number per event comes from the average numbers of customers affected by the event. Continuing our example with Arresters, in 2010 Avista had 356,777 electrical customers and the average Arrester outage event affected 102 customers, so the average SAIFI impact per event was 0.009230266. In 2011, our electrical customer count increased to 358,443 and the average number of customers affected by an Arrester related outage dropped to 40, and the average SAIFI impact due to Arrester events dropped to 0.003380523. The result for SAIFI was an increase in the average impact to SAIFI in 2010 compared to 2011.

While most Sub-Reasons in OMT have fluctuating value around an average value over the past five years, some Sub-Reasons have demonstrated a definite trend upward as shown in Figure 4. Figure 4 shows the top 10 Sub-Reasons based on the percentage change in 2015. Some of the Sub-Reasons in Figure 4 do not have a significant impact on the SAIFI number, however, the trend for all of these Sub-

Reasons are the top increasing SAIFI trends over 5 years which could eventually move them into the top SAIFI contributors over time.

Figure 5 and Figure 6 illustrate the makeup of the overall SAIFI value and overall OMT Sustained Outages. Figure 5 and Figure 6 show a different result because the number of customers impacted by each Sub-Reason is different. For example, we have very few Pole Fire caused outages, but they affect a large number of customers. So, Pole Fire shows a significant impact to SAIFI in Figure 5 but is insignificant on Figure 6.

Table 5, SAIFI Trends by OMT Sub-Reason Average per Outage

Average SAIFI by Sub-Reason Event						
OMT Sub-Reason	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Arrester	0.009230266	0.003380523	0.015245676	0.003562297	0.009598559	0.001364179
Bird	0.026835343	0.050143556	0.015659978	0.064285794	0.021842454	0.026664936
Capacitor	0.002842798	0	0.006147101	8.27074E-06	0	0
Car Hit Pad	0.001972404	0.00315424	0.004171572	0.004940524	0.003134	0.0051936
Car Hit Pole	0.055741604	0.034563763	0.078829605	0.061689509	0.07509589	0.042359382
Conductor - Pri	0.013459389	0.025213018	0.024181701	0.036457655	0.029884932	0.020986851
Conductor - Sec	0.001923463	0.001952154	0.003857768	0.002491023	0.003821952	0.004026636
Connector - Pri	0.029390854	0.022841718	0.023941651	0.01912657	0.023079128	0.00541549
Connector - Sec	0.001764569	0.001927718	0.002095065	0.001612901	0.001526051	0.002468959
Crossarm-rotten	0.010791352	0.017452881	0.004106797	0.001059746	0.015222287	0.000560328
Customer Equipment	8.43629E-05	4.18879E-05	0	4.96037E-05	0	3.39306E-05
Cutout/Fuse	0.029472485	0.014918168	0.027484801	0.01707108	0.018776702	0.009920028
Dig In	0.002911047	0.007751271	0.001543001	0.001766282	0.006145152	0.001637209
Elbow	9.54113E-05	0.000737521	2.50685E-05	0.001158911	0.000444984	0.000469738
Fire	0.000916016	0.001765849	0.004579849	0.012299424	0.001239404	0.007950852
Forced	0.026724006	0.011341762	0.01007956	0.035479695	0.010119982	0.019996134
Foreign Utility	0.06415389	1.9551E-05	1.10385E-05	3.04099E-05	0	0.006688417
Insulator	0.00947135	0.00767475	0.001619894	0.018937297	0.020106196	0.011789959
Insulator Pin	0.00609977	0.012718209	0.002646432	0.004556295	0.008017909	0.001082908
Junctions	5.63488E-06	0	0.002791077	0.000475014	0.000657922	0
Lightning	0.05153771	0.029986357	0.107700751	0.152792603	0.10038083	0.050646543
Maint/Upgrade	0.115272977	0.131045664	0.093958391	0.118799625	0.097069382	0.104791239
Other	0.177318475	0.156583826	0.114257941	0.085502603	0.082302999	0.115450196
Pole Fire	0.108242728	0.087722138	0.058825288	0.078650039	0.096520659	0.160560667
Pole-rotten	0.002027401	0.002475849	0.001111378	0.002186058	0.007843191	0.000477747
Primary Splice	1.40872E-05	0.000227493	0	0	0	0
Protected	0.005438117	0.000105902	0.000523814	0.000524546	0.000303026	0.00239954
Recloser	0.002520587	0.000212125	8.36386E-06	0.001310323	0.01501481	0.001838003
Regulator	0.019517299	0.003012273	0.020486437	0.010292094	0.015208638	0.011244625
SEE REMARKS	0.0263254	0.022946333	0.024001629	0.035782952	0.030523744	0.024167276
Service	0.001512913	0.001254413	0.001425234	0.001116933	0.00158065	0.001204447
Snow/Ice	0.091003627	0.039682871	0.109703932	0.035007006	0.078612086	0.304018091
Squirrel	0.021425719	0.039013725	0.050207568	0.026293232	0.039139515	0.030862207

OMT Sub-Reason	2010	2011	2012	2013	2014	2015
Switch/Disconnect	0.004582077	0	4.14971E-05	0.020930465	0.036865454	0.008279847
Termination	0.000152009	0.000173439	0.000637191	0.003063515	0.002290441	0.001269524
Transformer - OH	0.002407314	0.017106495	0.004874802	0.004093373	0.026346897	0.008655826
Transformer UG	0.001704189	0.001165537	0.001438726	0.006231495	0.009683188	0.001587665
Tree	0.013288743	0.000938339	0.011356792	0.002750215	0.015326026	0.002845582
Tree Fell	0.092136448	0.062998204	0.067319172	0.054556299	0.057820669	0.084106127
Tree Growth	0.007012046	0.003838547	0.005569335	0.005691876	0.009617668	0.003505633
Underground	2.81744E-06	2.80426E-06	3.87453E-05	5.48895E-06	5.45993E-06	0
Undetermined	0.110134471	0.234672203	0.177748096	0.157264023	0.14781125	0.119112398
URD Cable - Pri	0.005903606	0.008770789	0.002422167	0.006080464	0.005855776	0.0069458
URD Cable - Sec	0.000953008	0.001467391	0.001544569	0.001409578	0.000980058	0.001315704
Weather	0.195547002	0.051231256	0.053674679	0.033680951	0.041372627	0.025389892
Wildlife Guard	0	0	8.35232E-06	0	0	0
Wind	0.291134088	0.089836161	0.195492335	0.209669949	0.517115518	1.128419475

OMT Sub-Reason Events High Limit

The second metric used to determine if we must examine a problem is the deviation from the established mean discussed above for each OMT Sub-Reason. If the number of OMT events for a specific Sub-Reason exceeds the OMT Sub-Reason Events High Limit (High Limit) AM may need to conduct an investigation and try to explain why the annual values are exceeding the limit (see Appendix D of the "2010 Asset Management Electrical Distribution Program Review and Metrics"). The High Limit is based on the average of annual values for each Sub-Reason plus two standard deviations. This method is also used to calculate the quarterly High Limit as well. The data for the average is the OMT Data for 2005 through 2009. For 2015, the following OMT Sub-Reasons exceeded their High Limit are shown in Table 6. We anticipated that Avista would exceed these limits due to natural deviations for events outside our control and due to some cyclical nature we observe in our data. Our goal here is to help identify trends in time to potentially address them if possible.

Table 6, OMT Sub-Reasons Exceeding Annual High Limit

OMT Sub-Reasons Exceeding their associated OMT High Limit	Number of Years High Limit Exceeded
Car Hit Pole	6
Conductor – Pri	5
Wind	3

Based on Table 6, presently there are no issues requiring changes to our current plans. We will continue to monitor Conductor – Pri, as this may call for some kind of action in the future. Car Hit Pole is being analyzed by another group. If a program is implemented from this analysis then we should see that issue drop off the High Limit Exceeded chart. Wind has popped up on this chart due to a couple of fourth quarter large storms the past couple of years. We will continue to monitor all of these issues.

Figure 3 shows the quarterly trends that feed into the annual trends for the OMT High Limit. For all OMT Sub-Reasons since 2006, only five Sub-Reasons have had more than five quarters where they exceeded the High Limit, Car Hit Pole with 17 quarters above the limit, Conductor – Pri with 8 quarters above the limit, Fire with 6 quarters above the limit and Service with 9 quarters above the limit. This information is consistent with Table 6 above. We will continue to monitor Service for potential future action, but it currently does not warrant a maintenance or replacement strategy.

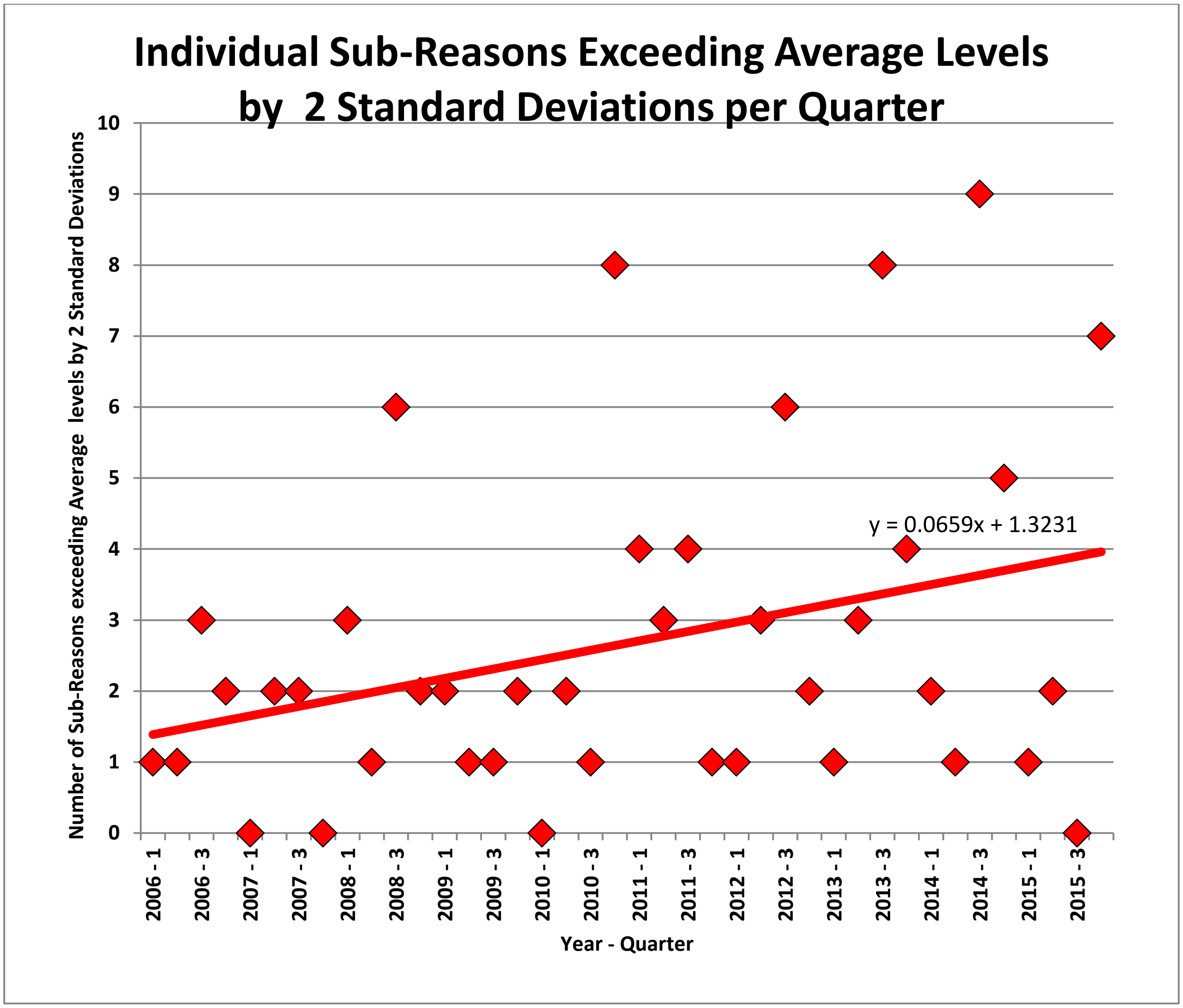


Figure 3, Individual Sub-Reasons exceeding Quarterly High Limits

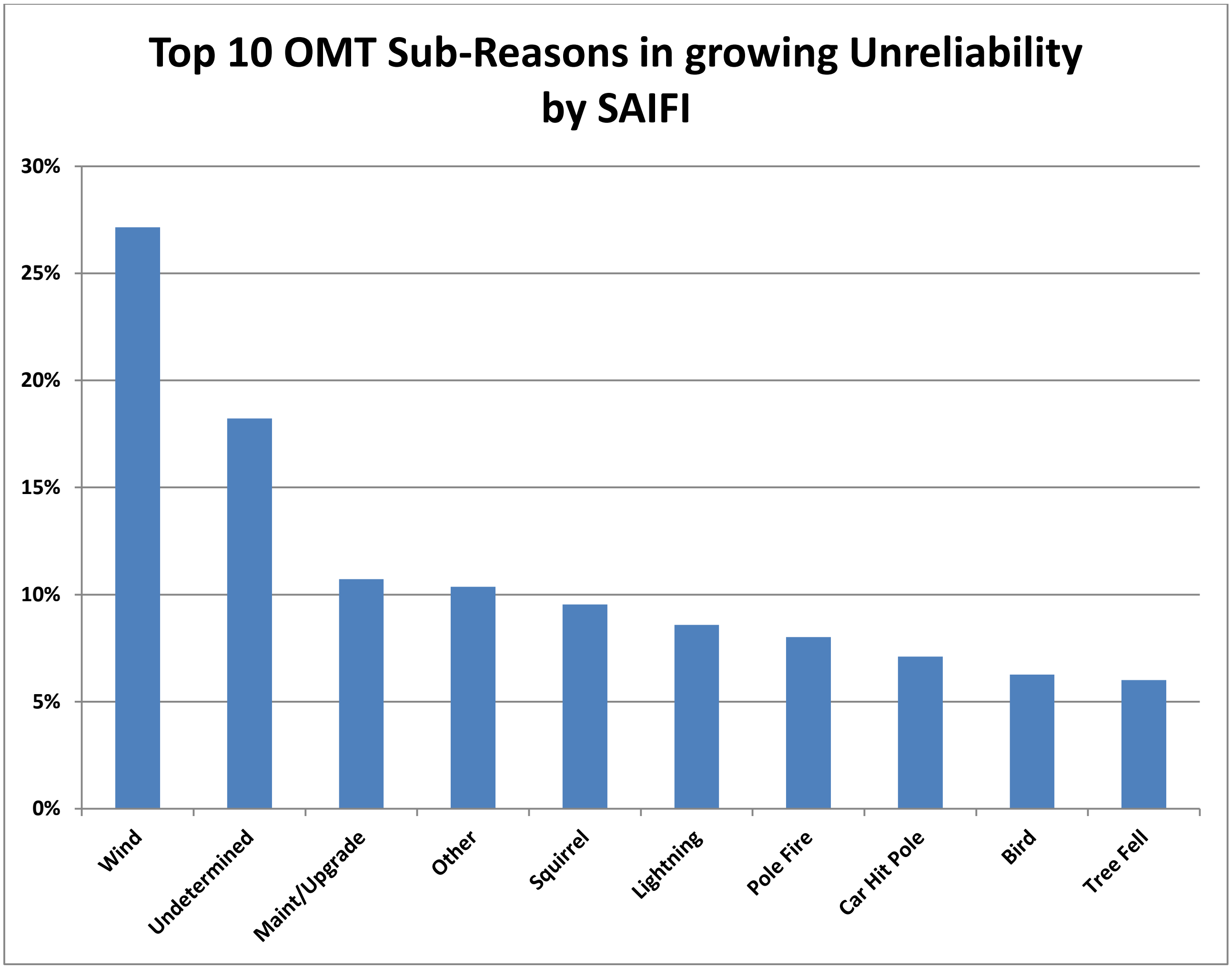


Figure 4, Top 10 Sub-Reasons with the Value of SAIFI Rising over Time

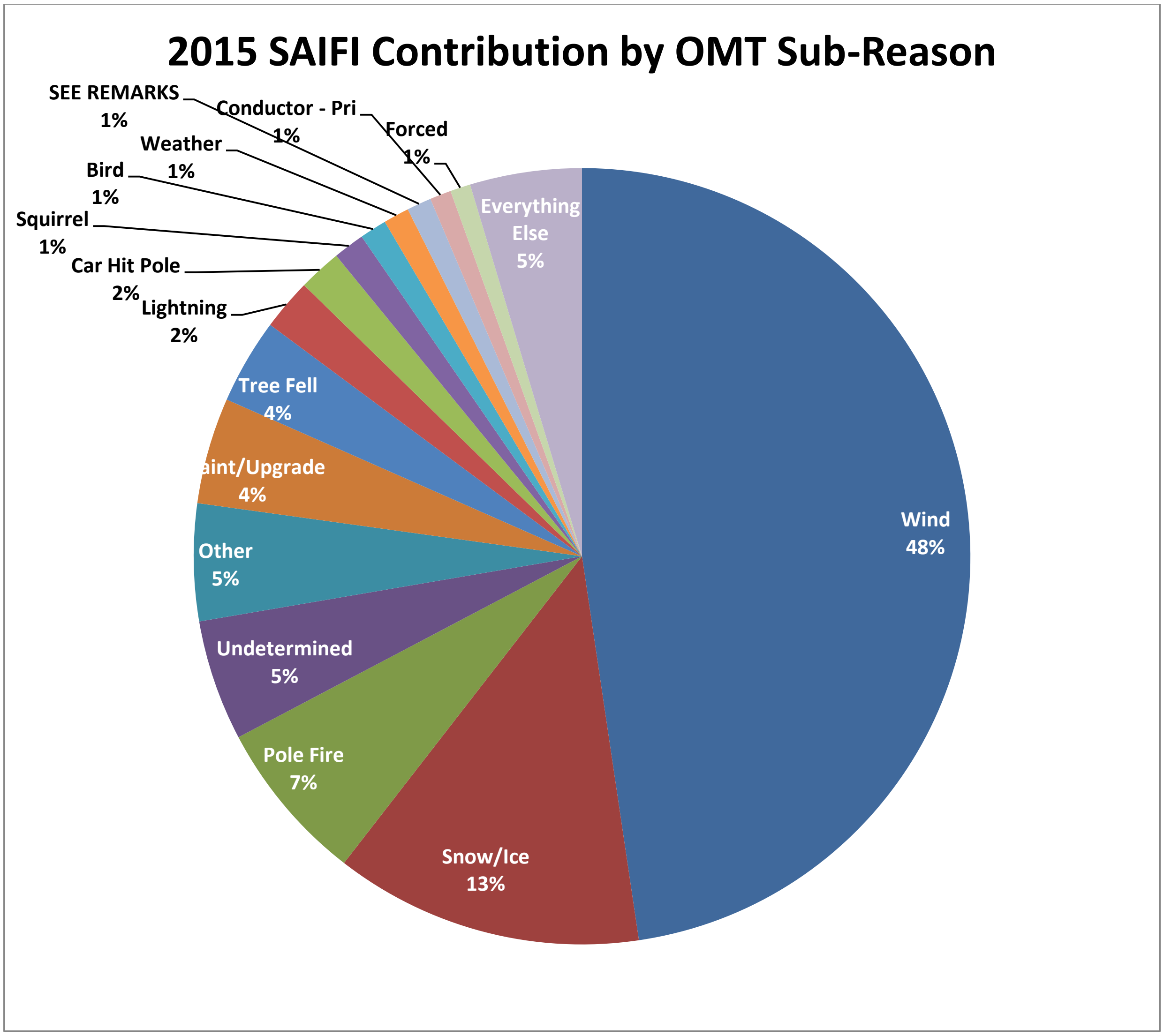


Figure 5, 2015 OMT SAIFI Contribution by Sub-Reason

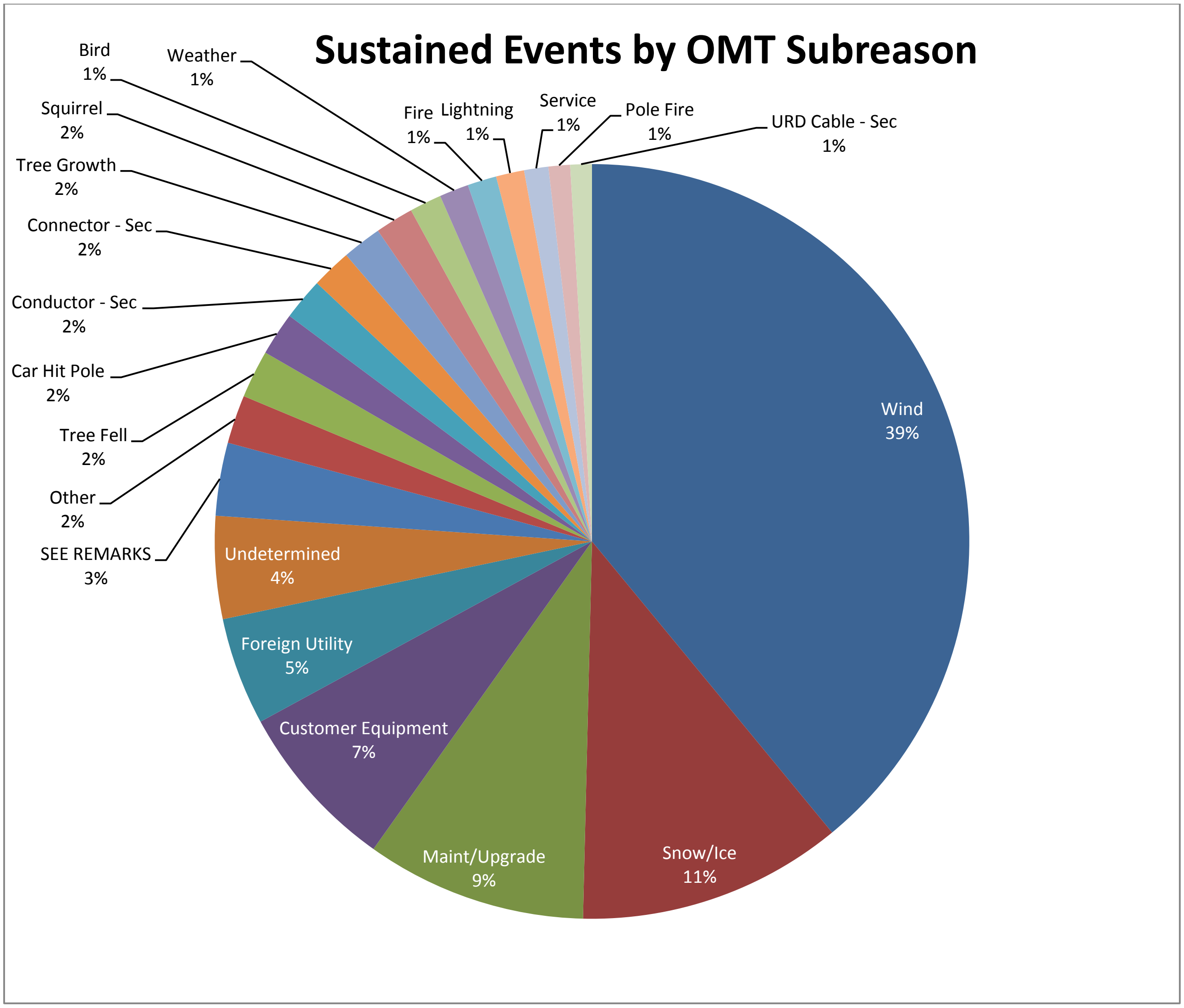


Figure 6, 2015 OMT Sustained Outage Comparisons

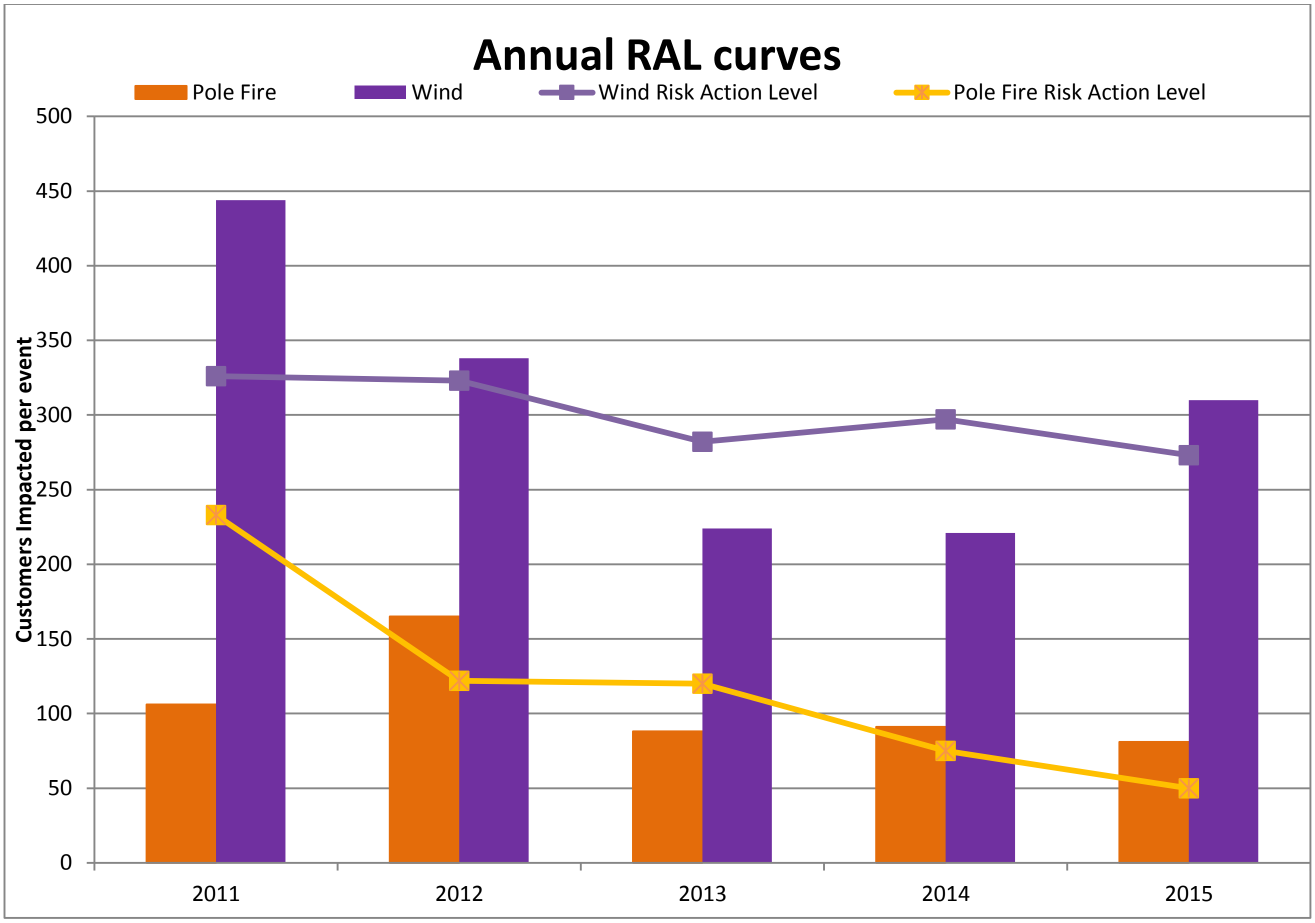


Figure 7, Customers Affected Per Event Exceeding Risk Action Levels

System

The distribution system has an equipment average life of 55 years with the replacement value of a little over $2 billion dollars. For Avista to maintain the system at its current level, just under $37 million a year would need to be spent on replacing aging infrastructure. The overall capital spending for the distribution was just over $85.5 million (this includes the large storm and growth). The total capital spending on just replacement work (with the large storm) was just over $83.5 million. Our replacement work, without the storm, still exceed our levelized spending required to keep the system at its current state. Avista also spent around $14 million in O&M on the distribution system.

Network

The downtown network has an equipment average life of 50 years with the replacement value of a little over $93.7 million. For Avista to maintain the system at its current level, just under $1.9 million a year would need to be spent on replacing aging infrastructure. The overall capital spending for the network was $2.7 million (this includes growth). The total capital spending on just replacement work was $1.3 million. Our replacement work last year did not meet our levelized spending required to keep the system at its current state.

Major Changes

The distribution system is a fairly constant system. Most programs are in place to maintain or improve infrastructure for current customers or build new to support new customers. Currently there is a program set to be completed next year that will change out the last area that Avista serves at the legacy 4kV voltage. This voltage is obsolete for serving utility distributions systems and we have very limited spare equipment to continue service at this voltage. This is a needed upgrade to our standard distribution class voltage and equipment that was delayed in 2014 due to resources, and was pushed into 2015 and 2016. This is also the first year that Avista has installed LED street lights. This marks the beginning of a complete system conversion from the more inefficient high pressure sodium and legacy mercury vapor lighting to LED lights for both Area and Street Lighting.

Specific Distribution Programs and Assets

In the following sections, AM reviews the different programs and work done to determine an AM action plan for particular assets. Some plans indicated the current case or no action was the best approach and others indicated there was an appropriate action for managing an asset. If a plan was implemented, then the available information will be reviewed to determine how the plan has impacted the system.

Distribution Wood Pole Management (WPM)

The current WPM program inspects and maintains the existing distribution wood poles on a 20 year cycle. Avista has 7,702 overhead circuit miles. The average age of a wood pole is 28 years with a standard deviation of 21 years. Nearly 20% of all poles are over 50 years old and we have an estimated 240,000 Distribution poles in the system. This means that about 48,000 poles are currently over 50 years old. Our inspection cycle allows us to reach approximately 12,000 poles each year. Along with inspecting the poles, we inspect distribution transformers, cutouts, insulators, wildlife guards, lightning arresters, crossarms, pole guying, and pole grounds. The inspection of these other components on a pole drives additional action to replace bad or failed equipment along with replacing known problematic components. These additional inspection items have expanded the current program beyond the original scope, but have proven to be a cost effective way of addressing more than just wood pole issues. The 2016 budget is set to be cut for this program and many others. The goals of this program would be to remain on the same 20 year cycle. The inspections would remain identical to the current scope, however, the follow-up work done through the WPM program would be a subset of the items above. WPM would no longer replace arresters, cutouts, wildlife guards or do any guying repairs, this work would be left up to the offices to complete at within their work plan.

Selected KPIs and Metrics

AM selected the number of OMT Events by Year related to WPM work and feeder miles of follow-up work completed verses miles of feeders inspected as KPIs to monitor WPM. These KPI relate to reliability performance, cost performance, and customer impacts. Our goal is to maintain or reduce the number of OMT events related to WPM. The current plan optimized the inspection cycle based on cost, so the impacts to reliability were addressed only as they relate to costs. The goal for these KPI is to stay below the number of events averaged over 2005 – 2009 for WPM Related OMT Events. See Table 7 for the goal and for the actual value for 2015. The OMT Events KPI is a lagging KPI and an indication of how well past work has impacted outages. The feeder miles of follow-up work completed verses miles of feeders inspected KPI is a leading indicator and reflects how outages in the future will be impacted by the work. The number of miles inspected is shown in Table 7 for the goal and actual values.

The feeder miles of follow-up work completed verses miles of feeders inspected KPI comes from the annual Distribution WPM inspection plan and is the sum of all miles of the feeders completed in that year. The completed number of miles for follow-up work on feeders comes from Asset Maintenance based on their tracking of the work as it is completed. The purpose of this metric is to evaluate how much backlog work is created each year in order to adjust future year's budgets. Asset Management has been working to increase the budget each year, with the goal of having no back log, by budgeting enough to inspect and follow up on a 20 year cycle.

Table 7, WPM KPI Goals by Year

KPI Description	WPM Goal Related number of OMT Events	Actual WPM Related number of OMT Events	Projected Miles Follow-up Work**	Actual Miles Follow-up Work Completed
2009	1460	1320	500	372
2010	1460	1004	450	435
2011	1460	1004	459	333
2012	1460	1013	416	435
2013	1460	816	445	329
2014	1460	905	412	385
2015	1460	760	390	364

*Note: Beginning with 2012, the Actual Miles Follow-up Work Completed will include WPM and Distribution Grid Modernization miles.
**To maintain a 20 year cycle the program only needs to complete 390 miles per year. The program is a little behind the targeted average of about 380 miles per year.

Metrics provide a more detailed review of WPM. WPM metrics involve more information and calculations than the KPIs and include: WPM contribution to the annual SAIFI number; number of distribution wood poles inspected; material usage for WPM by Electric Distribution Minor Blanket and Storms; number of Pole-Rotten OMT Events; Crossarms-Rotten OMT Events; and actual material use verses model predicted material use for WPM follow-up work (see

Table 8). The WPM contribution to the annual SAIFI number metric comes from data pulled out of OMT by Cognos and calculates the average impact to SAIFI per event by Sub-Reason.

The average impact to SAIFI per WPM event is the sum of the average impact to SAIFI for Arresters, Cutouts/Fuses, Crossarms, Insulators, Insulator Pins, Pole Fires, Poles – Rotten, Squirrels, Transformers-OH, and Wildlife Guards. The average impact to SAIFI for WPM events is then multiplied by the number of event causing an outage or partial outage (this is the sum of OMT events causing an outage or partial outage for Arresters, Cutouts/Fuses, Crossarms, Insulators, Insulator Pins, Pole Fires, Poles – Rotten, Squirrels, Transformers-OH, and Wildlife Guards). The goal for this metric is the five year average for 2005-2009. The purpose of this metric is to ensure WPM maintains the current reliability. Although the last two year's SAIFI goals were exceeded it was due in part to a couple large outages. Last year a couple of squirrel instances happened during Hot Line Holds causing a feeder lockout to occur. This year Pole Fire caused the biggest issue. There was a single event that required an entire feeder be taken off line to allow a cutout to be opened safely. This one occurrence impacted nearly 3000 customers. Removing these exceptions from the SAIFI drops the overall WPM SAIFI to an acceptable level.

The number of Distribution System poles inspected metric measures the annual plan for inspecting wood poles against how much work was actually completed. The AM plan calls for a 20 year inspection cycle which was originally estimated to be ~12,000 poles per year. The AM plan also represents inspecting 17.5 feeders a year. This metric ensures the WPM program meets the AM plan for Distribution Wood Poles.

The final metric, material use verses model predicted material use, tracks the actual number of key stock numbers (see Figure 12for assets monitored) against what the AM model predicted. Discoverer is used to pull stock number usage out for the applicable stock numbers and then they are compared to the AM model predictions. The purpose of this metric is to measure the performance of the model to predict the future outcomes.

Table 8, WPM Metric Goals by Year

Projected Metric Description	Projected WPM Contribution To The Annual SAIFI Number	Projected Number of Dist Poles Inspected	Model Predicted Material Use for WPM Follow-up Work	Projected Number of Pole Rotten OMT Events	Projected Number of Crossarm OMT Events
2009	0.214024996	12,600	4,792	137	32
2010	0.208489356	12,600	4,932	137	32
2011	0.211022023	12,600	5,010	137	32
2012	0.211022023	12,600	6,770	137	32
2013	0.211022023	12,600	8,592	137	32
2014	0.211022023	12,600	10,566	137	32
2015	0.211022023	12,600	12,606	137	32
Actual Metric Description	**Actual WPM Contribution To The Annual SAIFI Number**	**Actual Number of Dist Poles Inspected**	**Actual Material Use for WPM Follow-up Work**	**Actual Number of Pole Rotten OMT Events**	**Actual Number of Crossarm OMT Events**
2009	0.1863468	13,161	7,538	44	25
2010	0.19916836	15,553	7,904	37	23
2011	0.202462739	13,324	28,011	35	28
2012	0.16613099	17,318	28,120	52	19
2013	0.15640942	14,364	15,214	34	18
2014	0.241571914*	11,879	14,901	55	26
2015	0.225273848*	8,157	12,072	43	23

*The SAIFI number without the exceptions is within the bounds of the projected SAIFI

Figure 8 shows the trends in OMT events for the Sub-Reasons associated with WPM and generally the trend in OMT events is downward. The major contributors (Cutouts/Fuses, Squirrel, and Transformer – OH) all showed a level trend or a general trend downward over the past 5 years. Pole Fire had a slight increase this year but we had a dry hot summer which could account for some of the increase. Overall, WPM is controlling the number of OMT events. The leading indicator, Miles Follow-up Work Completed, shows we were falling behind in addressing issues identified during the inspection. If this backlog continues to grow, it will begin to impact the number of OMT events into the future. Funding limitations are preventing us from clearing out the backlog. We continue to strive to get funding for the back log.

The KPI "Actual Miles Follow-up Work Completed" provides an indication of what could happen to the other metrics (see Table 7). Simply inspecting the poles does not improve the systems performance. The follow-up work to the inspection needs to be completed. This metric shows follow-up work carrying over into 2016. The driver for WPM is a 20 year inspection cycle and if allowed to fall behind, the WPM follow-up work could become a major financial issue and reliability risk for future years

Grid Modernization, discussed later in this document, also impacts some of the same metrics as WPM (see Table 22 for the actual comparisons). In 2012, we revised the metrics and now include the miles of completed Grid Modernization work in the Table 7 since the work is coordinated with WPM and intended to help address the backlog in WPM.

WPM Metric Performance

The annual contribution to SAIFI showed a slight incline in 2015 but the overall trend continues to show improvement and, if the exceptions are removed from this year's SAIFI then it remains below the five year average value as shown in

Table 8 and Figure 9. Overall, WPM has been effective at maintaining the current level of reliability to our customers.

The number of Distribution poles inspected measures how well the program is performing against a 20 year inspection cycle. The goal is to inspect every feeder once every 20 years. The work to perform the wood pole inspections is tracked based on the number of poles inspected. Using miles works, but different feeders have different pole densities per mile and the way the contractor bills for the inspection work makes using the number of poles inspected easier. WPM did not hit the planned number of inspections shown in

Table 8. This is largely due to a budget cut towards the end of the year. The completed inspections are following the AM plan for WPM very nicely. Figure 10 shows how Avista's use of Distribution Wood Poles changed with time. This graph supports a growing number of pole and WPM related issues. Based on poles lasting 74 years before they will be replaced on a planned basis, Avista would need to replace 3,200 poles per year at equilibrium. We finally reached and exceeded 3,200 poles per year in 2011 and although the replacement is not a steady number we have remained above the 3,200 threshold since then. Figure 11 shows how an increasing number of poles are reaching 74 years.

WPM Model Performance

The AM model for WPM provided a decent baseline for estimating the costs of the WPM follow-up work, however, AM is currently reanalyzing this program and so there will be a new baseline in the near future.

WPM Summary

The main message from the KPI and metrics for WPM is that we are moving in the right direction, but we are falling behind and will need to complete work on more feeder miles to control the impact on future reliability.

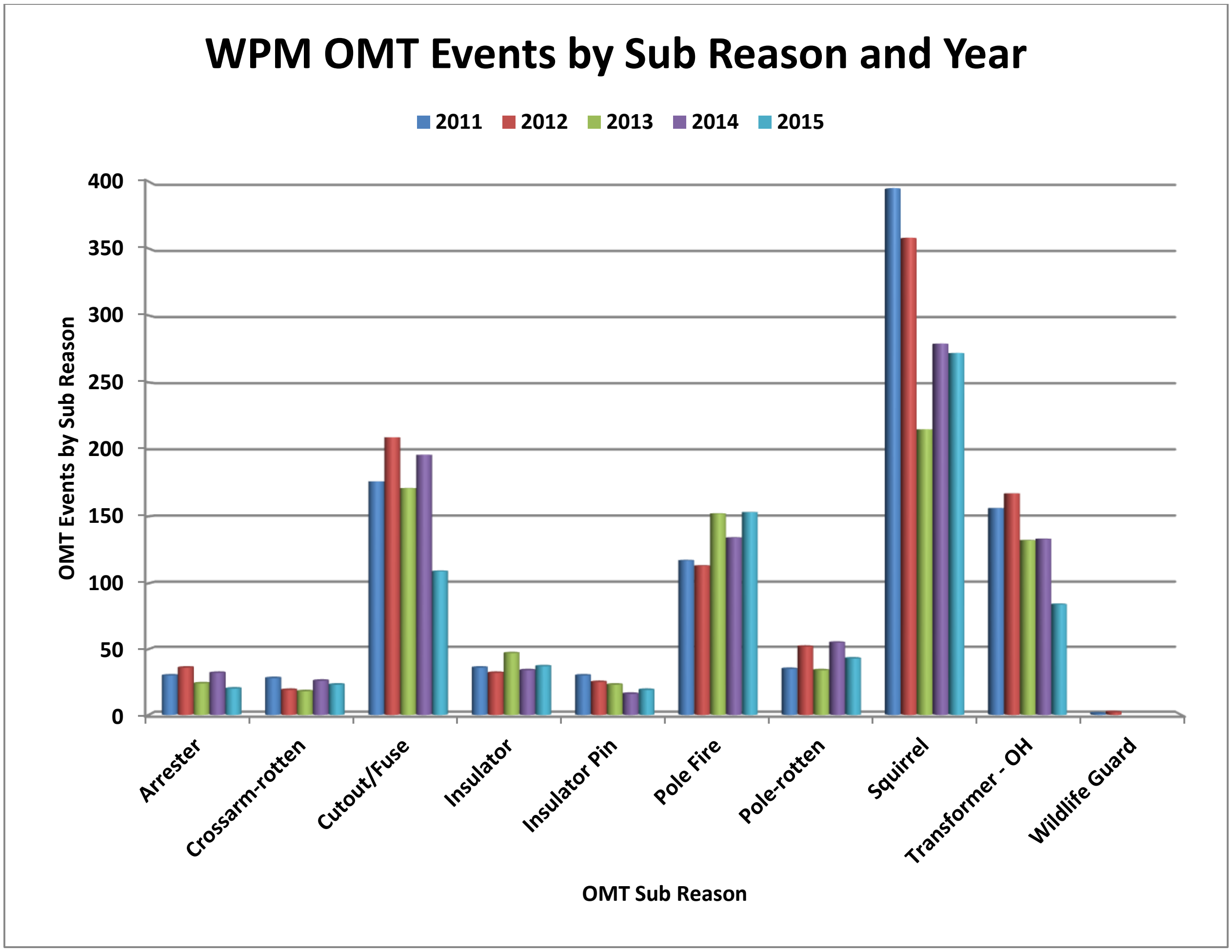


Figure 8, WPM OMT Event Trends

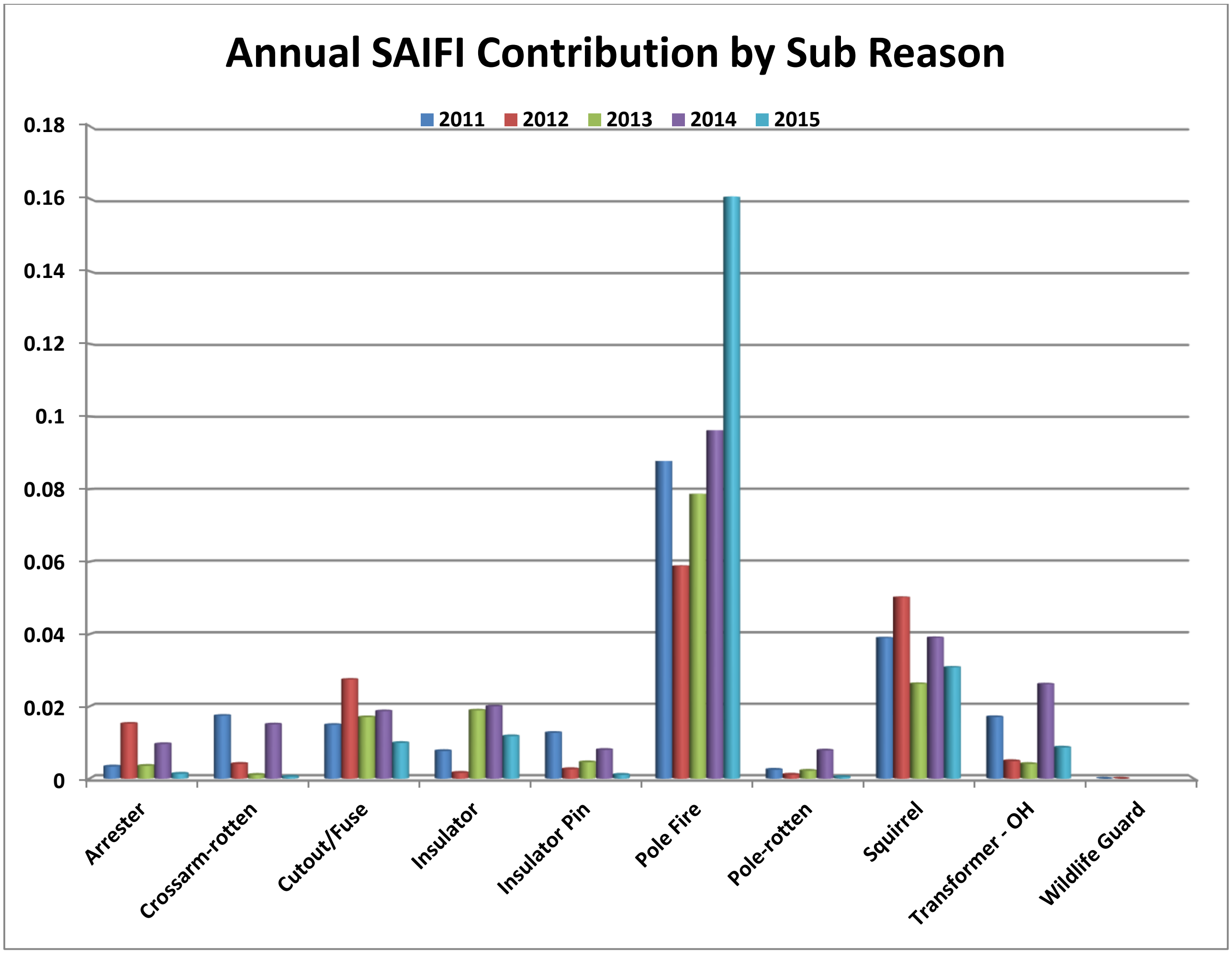


Figure 9, WPM Contribution to Annual SAIFI value by Sub-Reason and Year

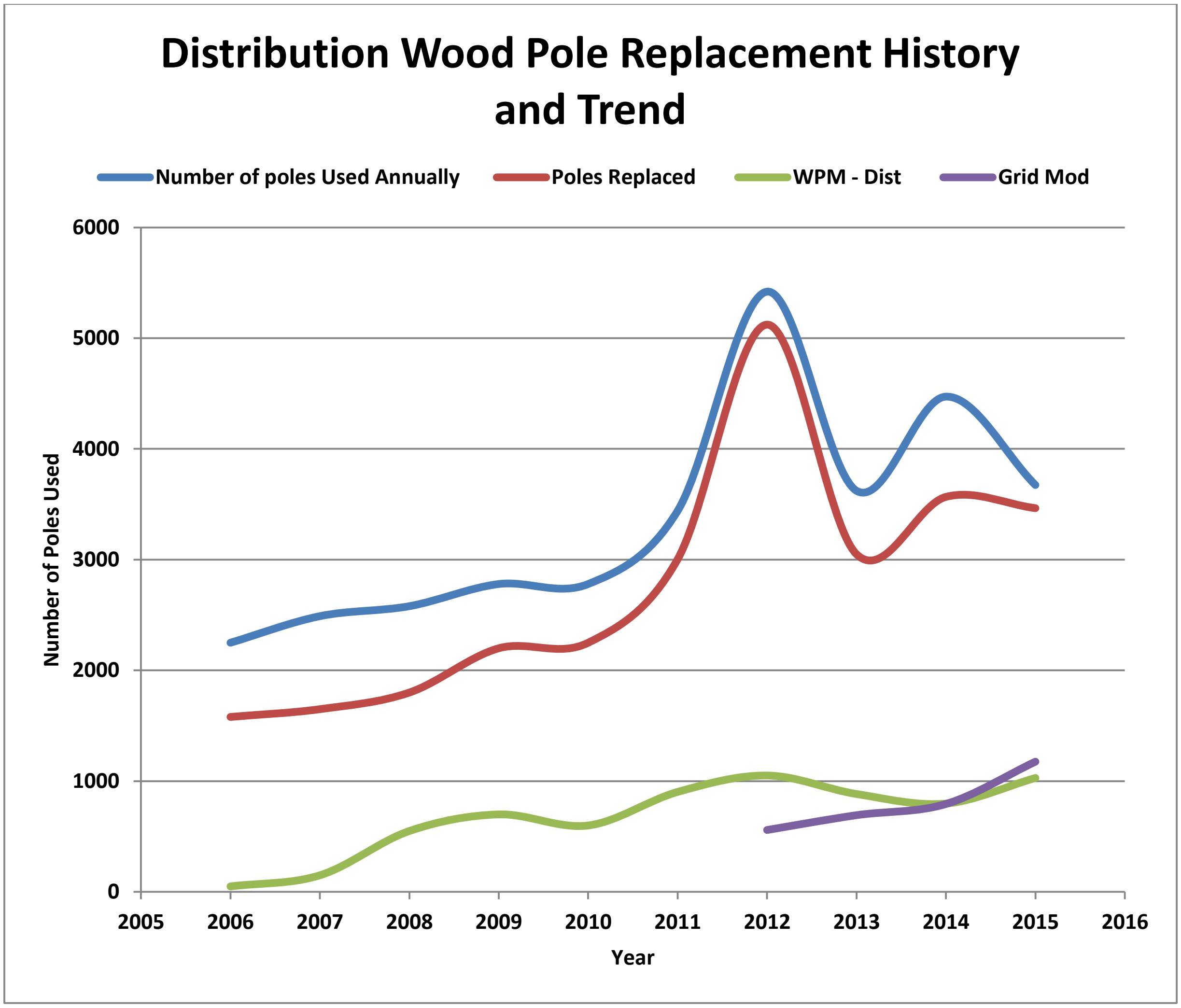


Figure 10, Wood Pole Used by Summarized Activity

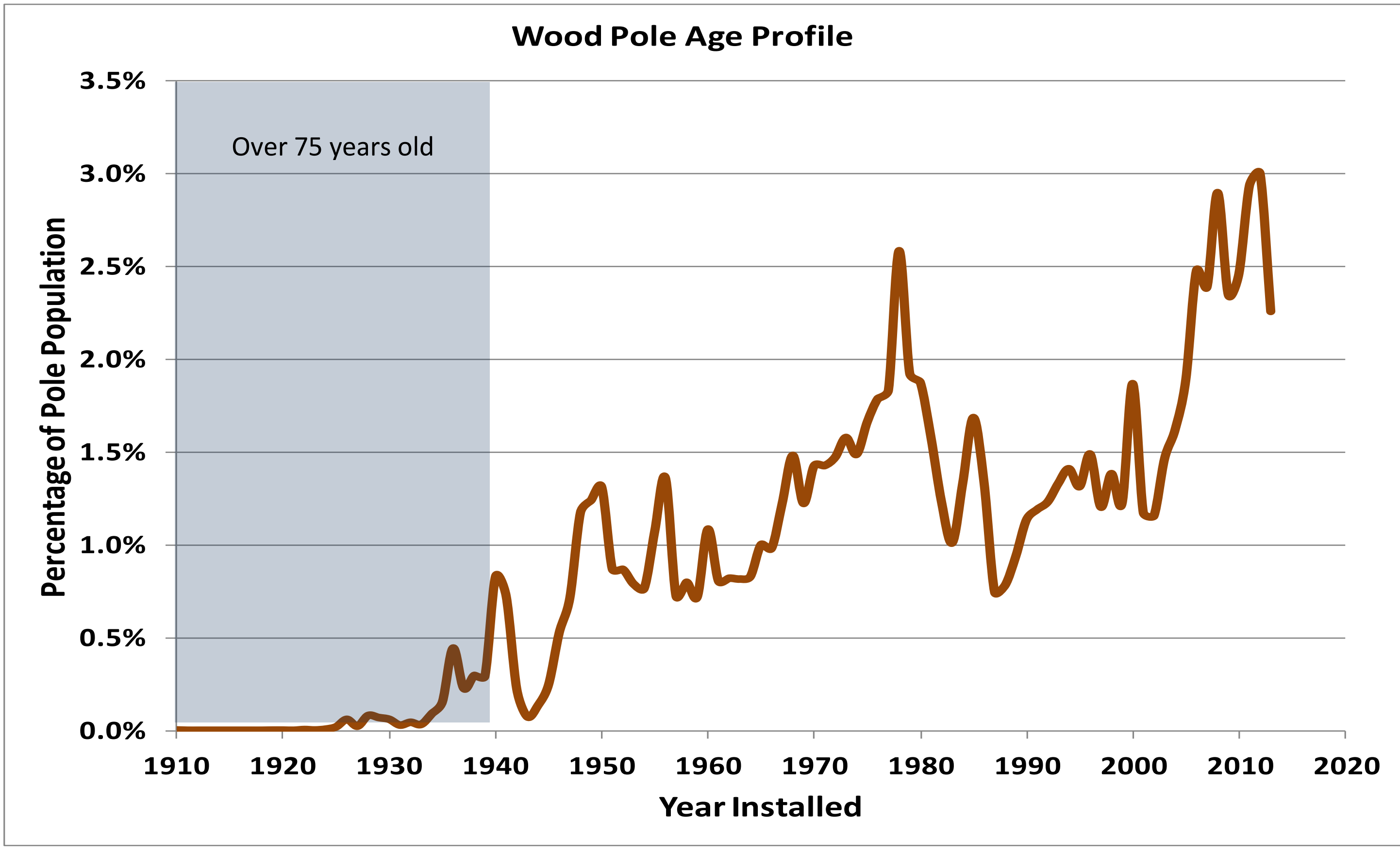


Figure 11, Distribution Wood Pole Age Profile
***Pole age data has not been updated in the past 4 years**

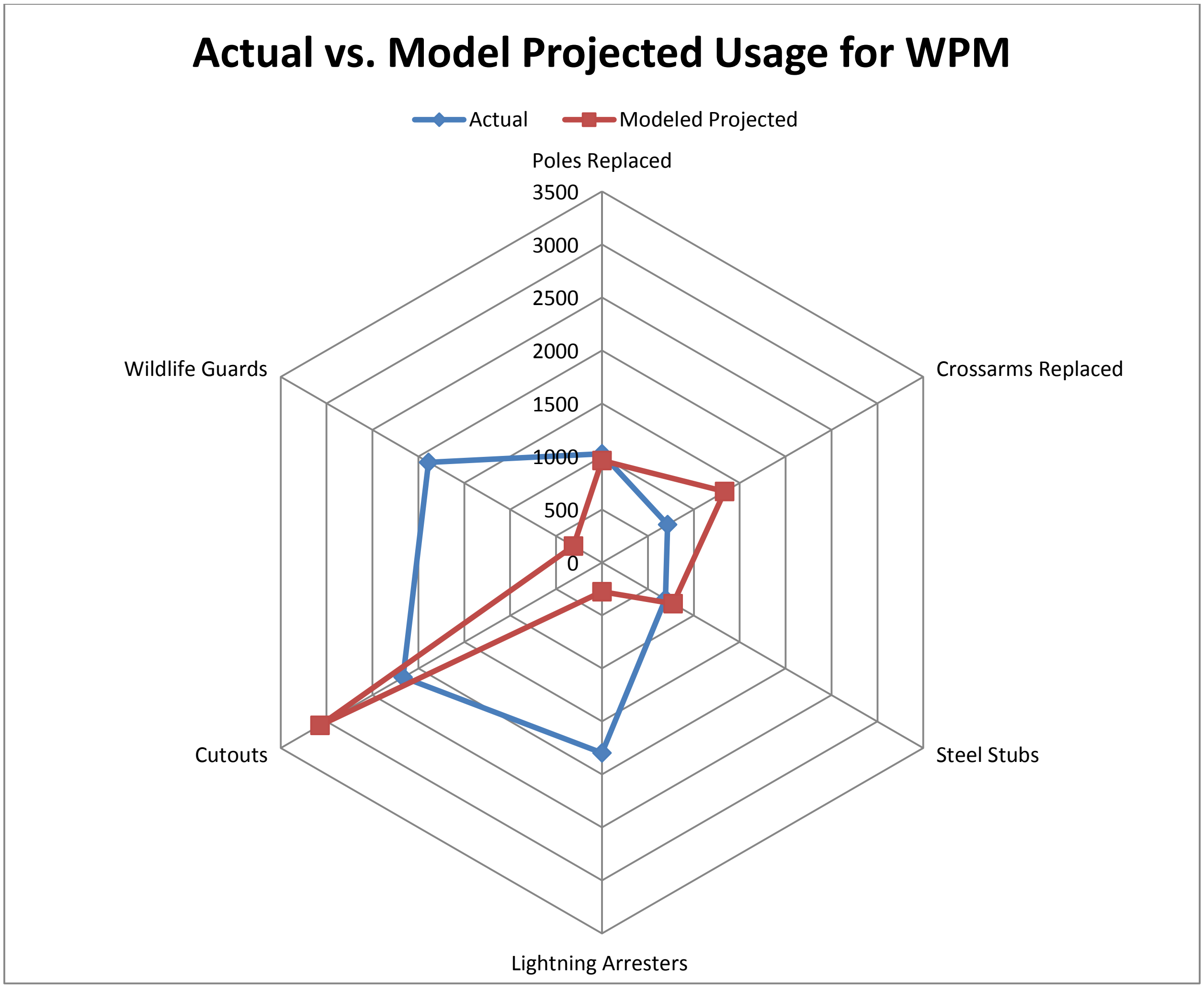


Figure 12, Actual vs. Projected Usage for WPM

Wildlife Guards

Wildlife caused outages have a significant impact on electric service reliability to customers. The improved outage tracking implemented in 2001 has consistently shown, within a percent or two either way, that animal's cause 19% of outages experienced by electric customers. While generally short in duration, labor impacts to respond are significant. In 2010, Squirrels accounted for only 6% of all sustained outages (see Table 9) which is a significant drop from 2009 value of 12%. This trend downward has continued and the percent of squirrel caused outages is now below 3%. We will continue to monitor this issue.

Selected KPIs and Metrics

The goal of the Wildlife Guards program is to reduce the number of Animal caused outages on the distribution system. More specifically, the program targets reducing the number of squirrel caused outages. The plan estimates that installing guards on the worst 60 feeders will reduce the number of Squirrel caused outages by 50%. 2006 was selected as the starting point, because the work performed that year was not influenced by the current AM plan. The final goal was a 50% reduction from the 2006 value of 902; however, this year's value of 272 exceeds the final goal and has for the past five years.

The second KPI used is the percentage of sustained outages caused by Squirrels. This KPI provides a relative impact that squirrel related outages are having on the system and represents the future value of installing Wildlife Guards on Distribution Transformers.

The only metric for Wildlife Guards is the annual avoided outage benefit from Squirrel related outages. We estimate approximately $82 in benefit for every outage avoided starting in 2011. Using this benefit per event, the projected avoided outage benefit by year is the difference between the projected number of events and the actual number of events for that year multiplied by the calculated cost per event for that year. The goals by year are shown in Table 10.

Table 9, Wildlife KPI Goals for 2010 - 2015

KPI Description	Projected Number of Squirrel OMT Events	Actual Number of Squirrel OMT Events	Percentage of sustained outages caused by Squirrels
2009	810	700	12.2%
2010	720	390	5.62%
2011	630	395	5.05%
2012	540	358	4.54%
2013	450	215	3.27%
2014	450	279	3.45%
2015	450	272	2.97%

Table 10, Wildlife Metric Goals for 2010 - 2015

Metric Description	Projected Avoided Outage Benefit due to Squirrel Caused Outages	Actual Avoided Outage Benefit due to Squirrel Caused Outages
2009	$36,000	$47,190
2010	$71,000	$157,466
2011	$22,000	$34,696
2012	$30,000	$37,935
2013	$37,000	$49,916
2014	$37,000	$46,045
2015	$37,000	$46,269

*Note: Avoided costs were revised from $390 per event to $82 for 2011 on. This change was based on a review of costs.

WILDLIFE GUARDS KPI Performance

Installing Wildlife Guards has exceeded expectations so far and has decreased the number of OMT events for Squirrels. The original model estimated costs were higher than actual costs because the model assumed more guards would be needed. So, the saved money has been used to work on more feeders than originally anticipated. This program officially ended a few years ago due to the quick pace of the work, however, the metrics are still being watched because other programs still have an indirect impact on the numbers.   These other programs continue to add WLG into our system on a less programmatic basis. Based on Figure 13 and Figure 14 you can see that few WLG were installed this year with WPM continuing to install the bulk of the WLG. However, the value and original scope of the program were realized years ago and so this is not a concern. This is the last year that this programs metrics will be reported on but we do envision a continued value for years to come.

WILDLIFE GUARDS Metric Performance

The main purpose of the Avoided costs metric shown in Table 10 is to demonstrate the savings associated with the work from the original model. In 2010, Avista saw savings nearly triple the projected amount. Other work such as Electric Distribution Minor Blanket and WPM continue to install Wildlife Guards on Distribution Transformers. However, the large increase in savings is most likely due to the increase in the number of WLG installed in 2010.

WILDLIFE GUARDS Model Performance

The Wildlife Guard model under estimated the impact of the work performed (see Table 9), so our performance has exceeded our expectations. This exceeds the goal of being within +/- 30% of the actual value. However, since the program has accomplished its purpose, no further work is planned.

WILDLIFE GUARDS Summary

The Wildlife Guard program showed real cost savings over time. The program ended a few years ago and more than exceeded expectations. We continued to report on the established metrics to help realize a more complete value of the program. Although, we will no longer report on these metrics, work in WPM and other efforts to install wildlife guards on Distribution Transformers may continue to create even more value.

Table 11, Worst Feeders for Squirrel related Events for 2015

Feeder	Sustained Outages	Percentage of all Squirrel related Outages	Running Percentage
PIN443	14	3.80%	3.80%
SLW1358	9	2.45%	6.25%
PDL1203	9	2.45%	8.70%
CFD1211	7	1.90%	10.60%
OTH501	6	1.63%	12.23%
SIP12F4	5	1.36%	13.59%
TEN1256	5	1.36%	14.95%
BLU321	5	1.36%	16.31%
CDA124	5	1.36%	17.67%
BUN426	5	1.36%	19.03%
SLW1368	5	1.36%	20.39%
SLW1348	5	1.36%	21.75%
STM633	5	1.36%	23.11%
CHW12F3	5	1.36%	24.47%

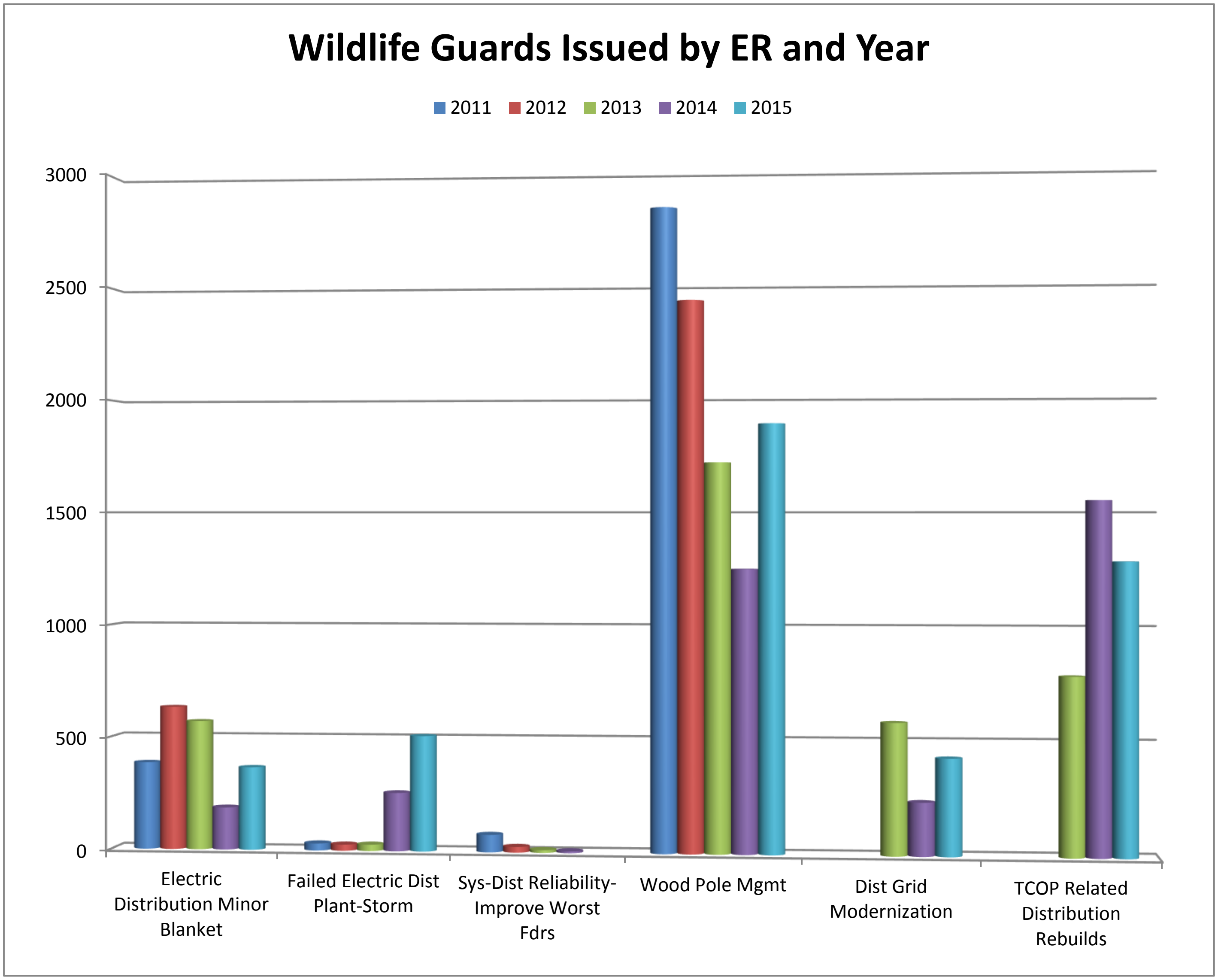


Figure 13, Wildlife Guards Installed by Year and Expenditure Request

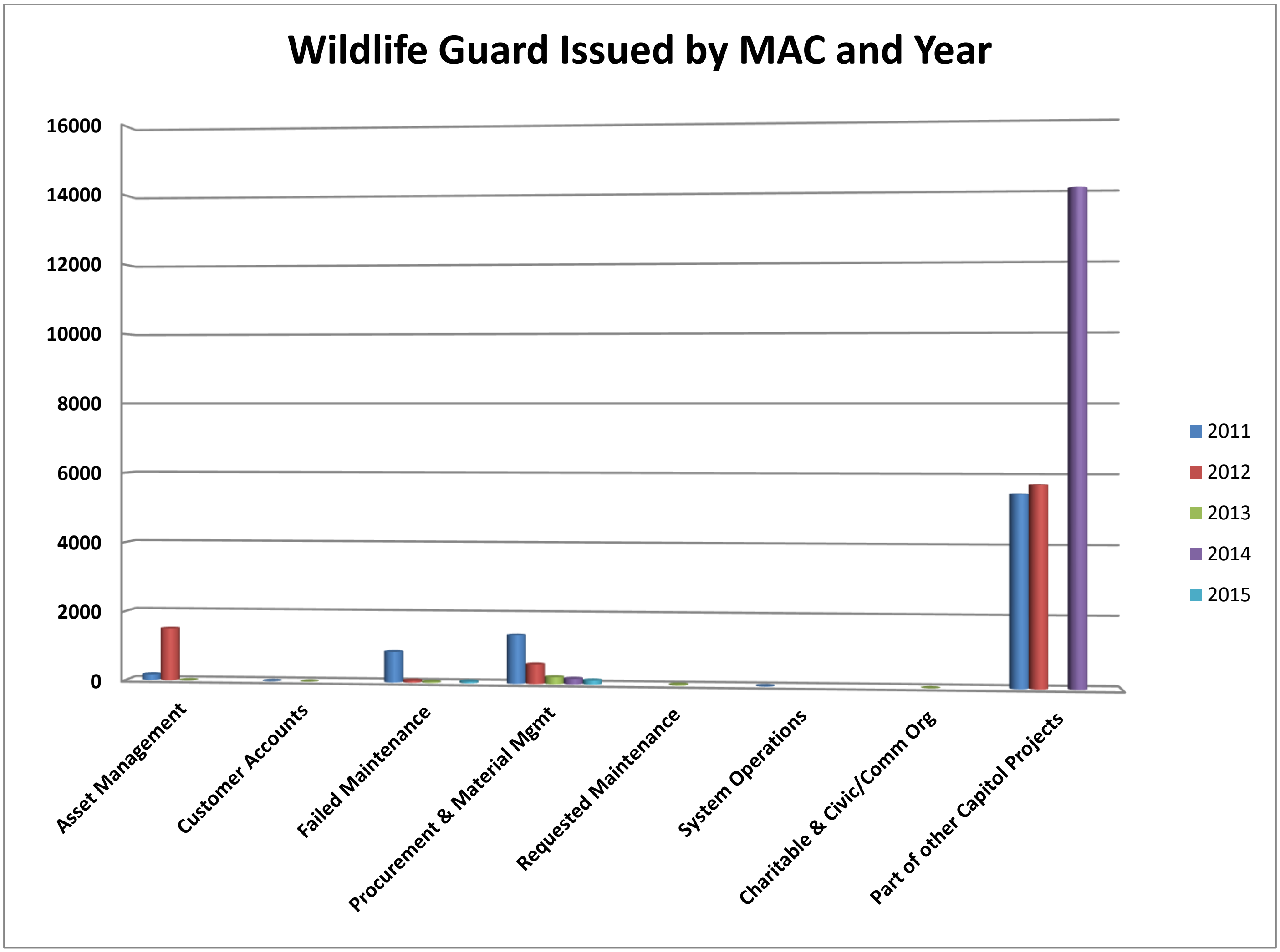


Figure 14, Wildlife Guards Usage by MAC for 2011-2015

URD Primary Cable

URD Primary Cable replacement addresses aging underground primary distribution cable. URD installation began in 1971. Over 6,000,000 feet of URD was installed before 1982. Outage problems exist on cable installed before 1982, cable installed after 1982 has not shown the high failure rate of the pre-1982 cable. Programmed replacement of the problem cable has been on-going at varying levels of funding since 1984. Emphasis is on the original vintage of URD. That cable was not jacketed with a protective layer of insulating material, neutral conductor was bare tinned copper concentric type construction on the outside of the cable. Insulating material was vulnerable to water intrusion.

Historically, over 200 faults of primary cable happen annually. There have been as many as 264 primary cable faults in 2003. During 2007 there were 168 primary faults. From 1992 faults increased from 2 per 10 miles of cable to 8 per 10 miles in 2005. The number of faults per mile has stabilized between 2005 – 2007 after steadily climbing between 1992 and 2005.

Funding for URD Primary Cable replacement was significantly increased in 2007 and began the current program. The program had an original estimate of 5 years to complete. Although the funding has not matched the original plan, almost all of the work was accomplished over six years. The year 2012 represents the last year of major funding for the program since the number of outages has significantly dropped and the worst feeder for URD Cable – Pri failures only had four outages. We anticipated some low level of funding for the remaining cable sections as they fail and are currently running this program on this smaller level.

Selected KPIs and Metrics

We selected two KPIs to track for URD Primary Cable replacement, URD Primary OMT Events and number of feet replaced each year. The goals for each of these KPIs came from the trends observed over the past few years and set a goal to complete the replacement of URD Primary cable in 2012. The program continued into 2015 but with a limited budget. Table 12 shows the goals for each KPI by year. The OMT events reflect the impact to our system of past work. The number of feet of URD Primary Cable replaced acts as a precursor to future OMT performance. After the first generation of URD Primary Cable has been replaced, the second generation will need to be monitored and plan may need to be established for addressing this vintage of cable.

Table 12, URD Cable - Pri KPI Goals

KPI Description	Projected URD Cable - Primary OMT Events	Actual URD Cable - Primary OMT Events	Projected Number of Feet Replaced	Actual Number of Feet Replaced
2009	143	136	178000	213,000
2010	119	93	178000	217,883
2011	94	95	178000	225,823
2012	70	72	178000	117,247
2013	45	93	0	35,874
2014	45	88	0	35,515
2015	45	64	0	24,155

The selected metric for URD Primary Cable is the avoided costs due to cable faults. The benefits are based on a projected number of failures without the program that are projected to be around 670 events for 2015. Currently, each event on average costs ~$2,800 due to the duration of the outage and the number of people involved in correcting the fault. While this indicator is based on a projection, it provides a reasonable estimate of the return on investment for the money spent to replace this vintage of cable. Table 13 projects the anticipated avoided outage benefit by year for the estimated number of avoided outages.

Table 13, URD Cable - Pri Metric Goals

Metric Description	Projected Avoided Outage Benefit due to URD Cable - Pri Caused Outages	Actual Avoided Outage Benefit due to URD Cable - Pri Outages
2009	$1,038,613	$1,056,113
2010	$1,228,275	$1,295,225
2011	$1,368,561	$1,352,648
2012	$1,516,159	$1,481,504
2013	$1,744,539	$1,494,738
2014	$1,898,311	$1,580,378
2015	$1,997,052	$1,720,020

URD PRIMARY CABLE KPI Performance

For 2015, the performance for URD Primary Cable did not meet expectations but performed well. Table 12 shows that URD Cable – Pri events have not met expectations for the past couple years, however, the outages continue to have a downward trend. Figure 15 shows the downward trend in the number of events. The second generation of URD Primary Cable is also being analyzed. If it begins failing at an increasing rate, it would signal the next round of cable replacements. We have some faults in newer cables and anticipate that this will be true for several years to come. If these faults begin to significantly increase over time, we will have to begin replacement of this cable since the earliest of the second generation cable is now approaching 30 years old.

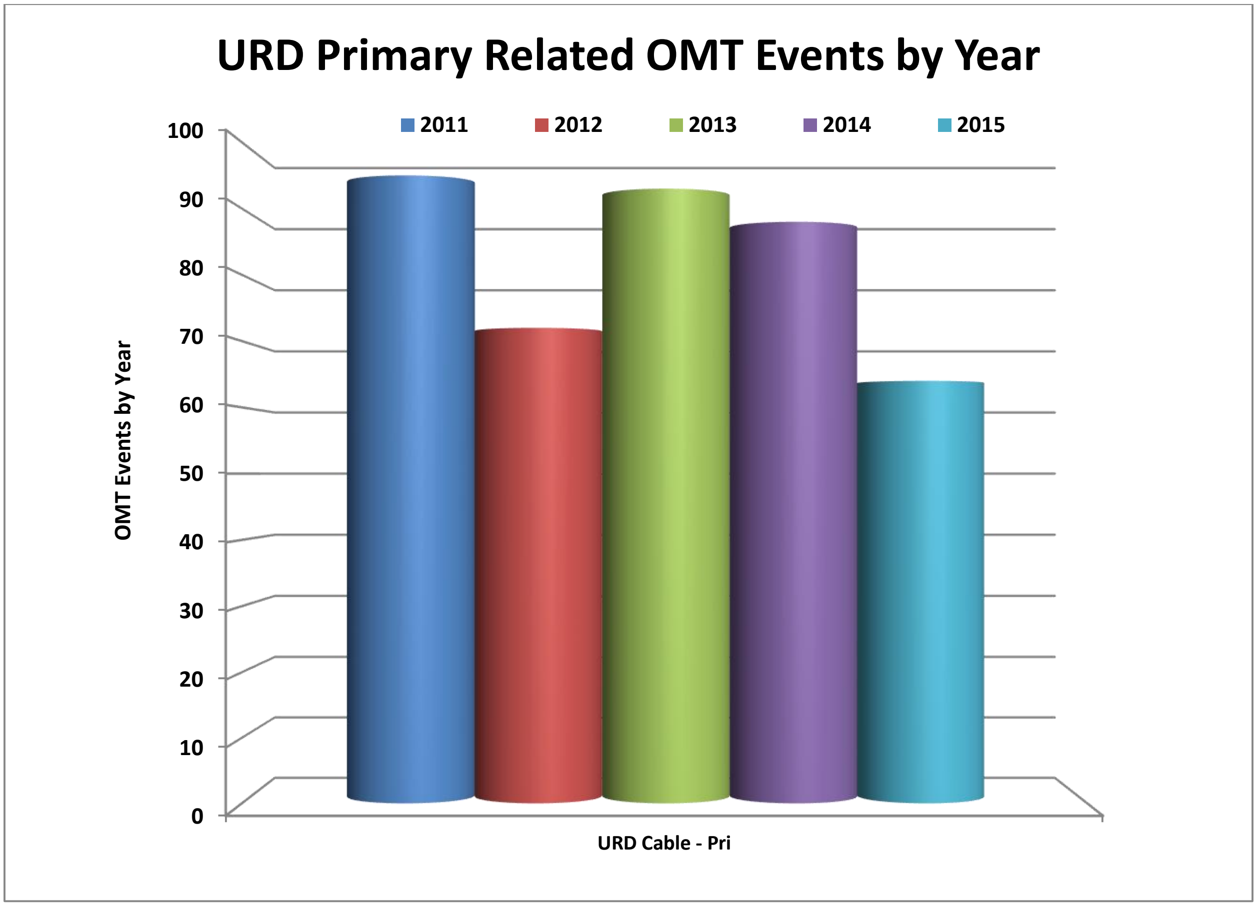


Figure 15, URD Primary Cable OMT Events by Year

URD PRIMARY CABLE Metric Performance

The projected savings and estimated savings due to avoided outage costs for Avista has typically come in very close as seen in Table 13. The avoided outage cost for this last few years has not performed as well as years past but overall the current program is performing as expected.

URD PRIMARY CABLE Model Performance

This AM model is an early vintage model and given the cash flow, did not match the model; but it has generally predicted performance reasonably well. Because of the good performance and limited remaining time for the program, the model will be retained as is and the program allowed to expire once all of the first generation URD Primary Cable has been replaced.

URD PRIMARY CABLE Summary

Several people have worked diligently on this program and it is now nearing completion. We anticipate another round of URD Cable replacements in the future, but we don't have any evidence indicating that the company has reached the end of life on the second generation of URD Cable. The program has succeeded in reducing O&M costs by avoiding long and costly outages. Since all of the work to replace the cable comes from capital spending, the program is a great example of how capital spending can reduce O&M. However, operations continue to find more cable than estimated remaining, so future funding is recommended to only cover planned work on known cable.

Distribution Transformers

In 2011, Avista implemented the Transformer Change Out Program (TCOP) to replace all Distribution Transformers containing PCB's followed by replacing all pre-1981 transformers. The driver for the program is to reduce the environmental risks associated with PCB's in transformers and improve the overall electric distribution system by eliminating higher loss transformers.

The program has two strategies associated with it. The first strategy is to eliminate all transformers containing or potentially containing PCB's. The initial focus was on areas near water sources. These transformers have specific work plans for removing them from the system. The second strategy uses the Wood Pole Management program to remove all pre-1981 transformers as part of their follow-up work on a feeder. The first strategy work should be completed in 2016 and the Wood Pole Management work should have all the pre-1981 transformers replaced by 2036.

Selected Metrics

Table 14 shows the metrics selected for TCOP. The number of transformers changed out represents the reduction of future risk from PCB's. It also provides a leading indicator of how many future transformer failures we may experience. The energy savings represents the value of changing out the less efficient transformers and quantifies the approximate amount of energy saved each year by replacing less efficient transformers with more efficient ones.

Table 14, TCOP Metrics

Year	Planned Number of Transformers Changed Out	Actual Number of Transformers Changed Out	Planned Energy Savings from Transformers (MWh)	Projected Energy Savings from Replaced Transformers (MWh)*
2012	2,687	2,529	2,304	2,430
2013	2,555	2,599	2,304	2,671
2014	2,930	2,625	2,304	3,002
2015	305	2,557	299	2,547
2015 – Pad/Subm	2,030	342	1,447	603
2016	1,419		1,265	
2016 – Pad/Subm	87		149	
2017	948		940	
2017 – Pad/Subm	259		466	
2018	347		330	
2018 – Pad/Subm	1,092		1,853	

- Note: values in red have missed the goal

***Conservative estimate based on no load loss**

Metric Performance

In 2015, we cut back the funding on the TCOP program but were still able to complete in total more transformer's than expected. Fewer padmount transformers were completed but many more overhead transformers were replaced instead. Budgeting for the last few years has had an effect on the expected program and will continue to impact the program going forward. New metrics have been developed to account for the extended program due to the decreased budget.

Summary

The TCOP is accomplishing it objectives and reducing Avista's and customer's risks associated with Distribution transformers containing PCB's and providing energy savings.

Area and Street Lights

Asset Management converted the existing area and street light data into our Geographical Information System (GIS) in 2012 and continued the work through 2014. This work updated and corrected the existing information and provided a platform to convert our High Pressure Sodium (HPS) lights to Light Emitting Diode (LED) fixtures beginning in 2015. The recent cost and reliability improvements in LED lights have made converting 100W HPS lights to LED fixtures cost effective. The rate schedule was approved for the state of Washington for 100W and 200W HPS street lights for 2015 and for all non-decorative wattage of both street and area lights for Washington and Idaho in 2016.

Selected Metrics

Table 15 shows the metrics selected for the Street light change out program. The number of lights changed out represents the reduction of maintenance costs due to the increased durability of LED lights. It also provides a leading indicator of how many future light failures we may experience. The energy savings represents the value of changing out the less efficient HPS lights and quantifies the approximate amount of energy saved each year by replacing less efficient HPS lights with more efficient LED ones.

Table 15, Area and Street Light Conversion Metrics

Year	Planned Number of Lights Changed Out	Number of Lights Changed Out	Planned Energy Savings from Lights (W)	Actual Energy Savings from Lights (W)
2015	3,500	4,166	262,500	312,450
2016	4,000		300,000	
2017	5,000		375,000	
2018	6,500		487,500	
2019	8,000		600,000	

Summary

This program is not unique, years ago a systematic change out of mercury vapor lights occurred. However, some of these lights remained well after the program ended. This program should have a better result due to the new technology in mapping being used for lights. This program may also expand to the remaining decorative lights in the future.

Distribution Vegetation Management (VM)

Our Vegetation Management program maintains the clearance zone free of vegetation for the distribution system clear of trees and other vegetation. This reduces outages caused by trees and to a lesser extent squirrel caused outages. Our Distribution System runs for 7,702 circuit miles in Washington, Idaho, and Montana. The Vegetation Management program also covers work on the Transmission System and the High Pressure Gas Pipeline system, however the purpose here is to only look at the Distribution System.

For the Distribution System, our analysis has shown that a pro-active maintenance program provides the best value to our customers. While our past practices were a four and seven year cycle based on vegetation type and had a reduced clearing diameter, our analysis has indicated a five year clearing cycle at a normal clearing distance has advantages. Our current goal is to be on a 5 year cycle, however, we don't always hit our target distance (Table 18) and are closer to a 6 year cycle.

The purpose of Vegetation Management is to meet regulatory compliance, provide the best value to our customers, and maintain current reliability. The Vegetation Management program continues herbicide spraying and enlarged the risk tree programs to further improve vegetation management. Both of these additions strive to improve the performance of the system by reducing vegetation related events.

Selected KPIs and Metrics

For VM, we selected one leading KPI and a lagging KPI. These KPIs were set for the old analysis and ended last year, we linearly progressed these numbers to buffer us until we can establish new KPI goals. The leading KPI is the number of Distribution Feeders miles managed each year. This indicates how well the actual work matches the planned work and the model. The results of the work in VM should directly impact the number of Tree Growth and Tree Fell events in OMT which is the lagging KPI. The number of Tree Growth events and Tree Fell events are summed for each year and compared to the AM models predictions if the plan is followed. The goals for each KPI by year are shown in Table 18. The AM model for Tree Growth events and Tree Fell events shows varying KPI's for each year due to the strict following of the 5 year cycle based on when the feeder was last done. For a VM metric, we selected the Tree-Weather OMT events by year. As seen in Figure 16, there is a relationship between weather events and VM. We assume that improvements in VM results should impact the number of Tree-Weather OMT events and set a goal shown in Table 18. The goal for Tree-Weather events is based on the AM models average value over a 10 year period. This metric was not included as a KPI, because weather events are very unpredictable and random in nature. Once the relationship has been better established, it may become a KPI.

Another metric selected for monitoring is the cost per mile for VM on the distribution feeders. While no goals have been established, this will measure how effective our AM spending gets the work done and how much work is required to clear the lines. The costs per mile should drop in future years, because the amount of work required to clear the feeders should decline after reaching a 5 year cycle. The total number of miles of all planned work was modified in 2011. Beginning in 2011, the costs per mile calculation includes all planned work and not just the miles cleared. So, the total number of miles for all planned work was included in the metrics.

Table 16, Vegetation Management Metric Goals

	Projected SAIFI - Tree Fall	Actual SAIFI - Tree Fall	Projected SAIFI - Tree Grow	Actual SAIFI - Tree Grow
2010	1.40E-07	0.092136448	8.84E-08	0.007012046
2011	1.40E-07	0.062998204	8.84E-08	0.003838547
2012	1.40E-07	0.067319172	8.84E-08	0.005569335
2013	1.40E-07	0.054556299	8.84E-08	0.005691876
2014	1.40E-07	0.057820669	8.84E-08	0.009617668
2015	1.40E-07	0.084106127	8.84E-08	0.003505633

Note: values in red missed the goal

VM KPI Performance

Both Figure 16 and Figure 17 show the same trends for Tree Growth, Tree Fell, and Tree Weather. Table 17 shows the results for Tree Growth and Tree Fell outages and how well these align with the projected outages. Table 17 shows the field confirmed outages due to Tree-Weather events. These are a subset of the OMT outages and only include outages that, after being field verified, were still deemed tree caused. For the last 5 years our average actual annual miles managed is just below the miles needed to remain on a 5 year cycle. Last year's missed goal was caused by budget cut late in the year and it is likely that the slightly less than anticipated average miles is due to this and other past budget cuts. It is important to keep the program funded at a 5 year pace to continue to achieve our anticipated Projected Tree Growth + Tree Fell OMT Events – 5 Year Cycle.

Table 17, VM KPI Performance

Year	Projected Tree Growth + Tree Fell OMT Events – 2009 Plan	Projected Tree Growth + Tree Fell OMT Events – 5 Year Cycle	Actual Number of OMT Events	Projected Annual Miles Managed	Actual Annual Miles Managed w/o Risk Tree or Spraying	Percent Model Error
2009	1120	556	765	1,220	790	136%
2010	620	540	836	1,560	1,304	155%
2011	790	500	727	1,560	1,747	145%
2012	1210	520	712	1,560	1,296	137%
2013	1390	630	647	1,560	1,459	103%
2014	1400	780	793	1,560	1,663	102%
2015	1730*	777*	620	1,560*	1,405	-

Note: values in red missed the goal
*Linear progression from previous metrics

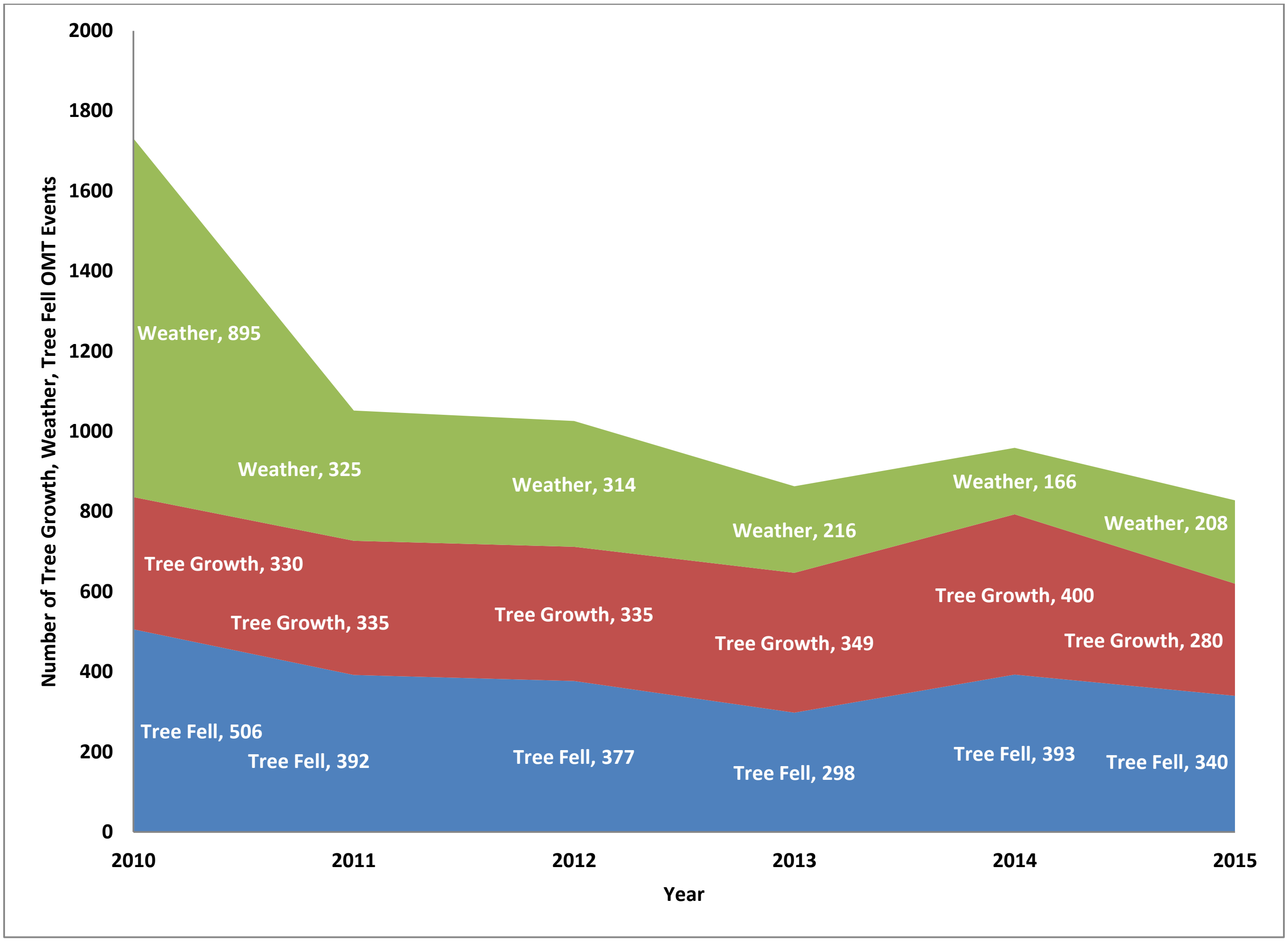


Figure 16, OMT Events Data Trends for Tree-Weather, Tree Growth, and Tree Fell Sub-Reasons

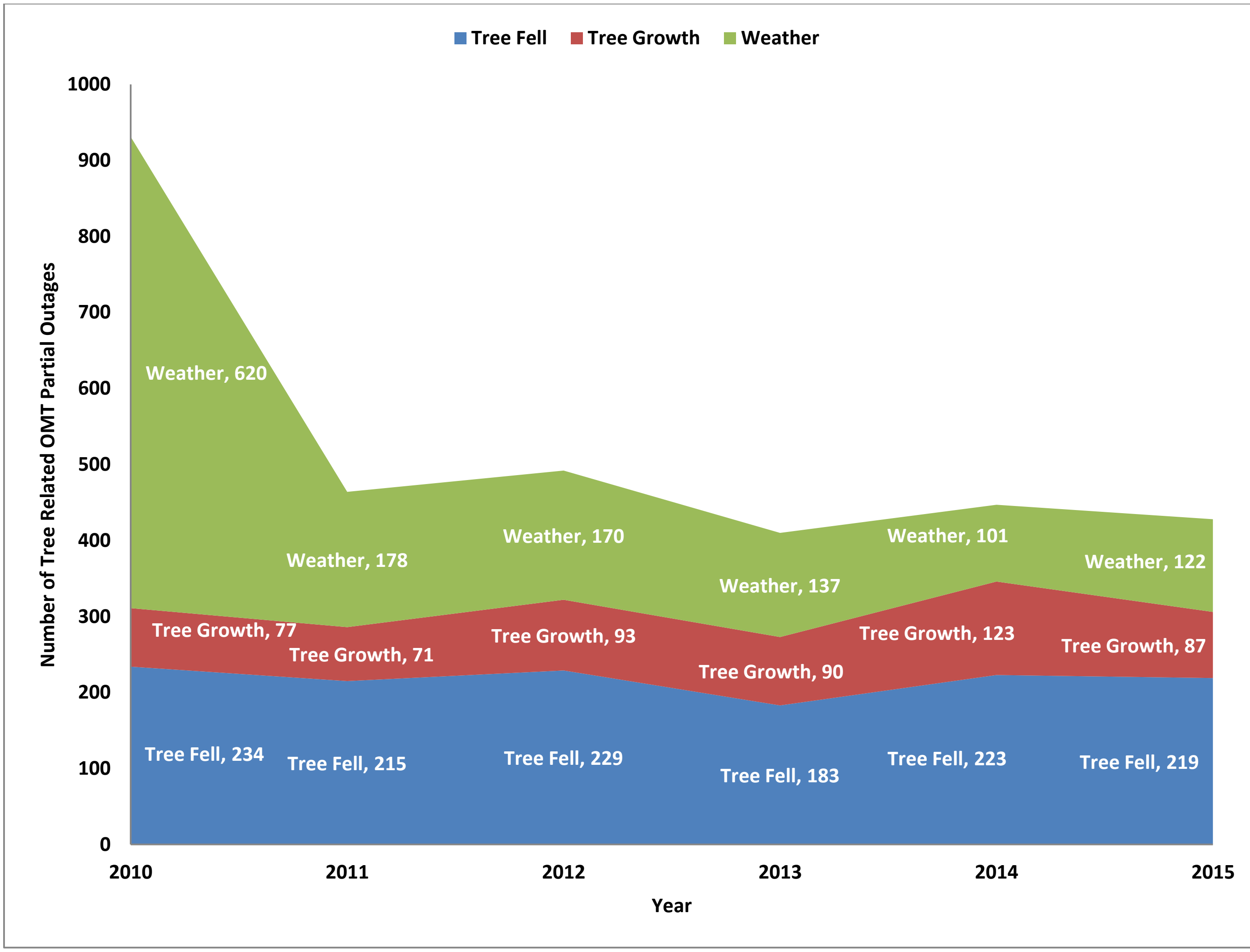


Figure 17, OMT Outage and Partial Outage Data Trends for Tree-Weather, Tree Growth, and Tree Fell Sub-Reasons

VM Metric Performance

The Tree OMT Events for 2015 continued to show improvement and were below the AM model projections (see Table 17). However, we must update the Vegetation Management models to improve projections and potentially update the program plan.

The cost per mile for VM in 2015 was $1,058 (see Table 19). This much lower than average. This is partially due to the large amount of miles of distribution that was inspected after the large storm in November of this year. We need to update the Vegetation Management model to address changes in the program which will help understand the impact to our system.

Table 18, Tree-Weather OMT Events Metric for Vegetation Management

Year	Projected Tree-Weather OMT Events – 2009 Plan	Projected Tree-Weather OMT Events – 5 Year Cycle	Actual Field Verified Tree Caused Weather Events	Actual Number of Tree-Weather OMT Events	Percent Model Error
2009	420	166	258	357	215%
2010	80	50	403	895	1790%
2011	220	70	159	325	464%
2012	580	70	150	314	449%
2013	800	170	121	216	127%
2014	1120	430	97	166	39%
2015	1358*	416*	84**	208	-

Note: values in red missed the goal

*Linear progression from previous metrics

**Extrapolated out to include December numbers. The field checking has not been completed for all December tree weather events.

Table 19, VM Cost per Mile and All Vegetation Management Work Metric

Year	Actual Annual Miles Managed all work	Cost per Mile of VM
2009	N/A	$6,575
2010	N/A	$2,990
2011	3,455	$2,612
2012	3,364	$3,272
2013	4,014	$1,657
2014	4,721	$1,439
2015	5,565	$1,058

VM Model Performance

The AM model for Distribution VM was revised in 2010, but the recent changes to the work performed and errors experienced justify updating the model. We anticipate completing the update in 2016.

VM Summary

Depending on how the program is evaluated, not enough miles are completed each year to achieve the goal of a 5 year cycle. The costs per mile may be too high and/or the current funding levels are too low and the impacts of herbicide spraying and enhanced risk tree work modify the meaning of work per mile. Vegetation Management's performance does show continued improvement but further analysis will provide an opportunity to re-evaluate our current performance and update future expectations.

Distribution Grid Modernization Program

Avista initiated a Grid Modernization Program designed to reduce energy losses, improve operation, and increase the long-term reliability of its overhead and underground electric distribution system. The program includes replacing poles, transformers (Pad Mount, OH & Submersible), cross arms, arresters, air switches, grounds, cutouts, riser wire, insulators, conduit and conductors in order to address concerns related to age, capacity, high electrical resistance, strength, and mechanical ability. The program also includes the addition of wildlife guards, smart grid devices, switched capacitor banks, balancing feeders, removing unauthorized attachments, replacing open wire secondary, and reconfigurations.

When funded to a level that allows 5-6 feeders to be upgraded per year, the continuous program represents a 60 year interval to upgrade all the feeders in Avista's system and coordinates all of its activities with Avista's Wood Pole Management. The objectives of the Grid Modernization Program are listed in Table 20.

Table 20, Grid Modernization Program Objectives

Objective	Objective Description
Safety	Focus on public and employee safety through smart design and work practices
Reliability	Replace aging and failed infrastructure that has a high likelihood of creating a need for unplanned crew call-outs
Avoided Costs	Replace equipment that has high energy losses with new equipment that is more energy efficient and improve the overall feeder performance
Operational Ability	Replace conductor and equipment that hinders outage detection and install automation devices that enable isolation of outages
Capital Offset	Avoid future equipment O&M costs with programmatic rebuild of failing system

Selected Metrics

The metrics selected include miles of work completed, OMT sustained outages on feeders with Feeder Upgrade work completed, and energy savings provided by completed work.

Based on Avista's 2015 Integrated Resource Plan dated August 31st, 2015, Table 8.3, the realized and anticipated energy savings by identified feeders is shown in Table 21.

Table 21, Energy Savings based on Integrated Resource Plan

Feeder	Service Area	Year Complete	Annual Energy Savings (MWh)
9CE12F4	Spokane, WA (9th & Central)	2009	601
BEA12F1	Spokane, WA (Beacon)	2012	972
F&C12F2	Spokane, WA (Francis & Cedar)	2012	570
BEA12F5	Spokane, WA (Beacon)	2013	885
CDA121	Coeur d'Alene, ID	2013	438
OTH502	Othello, WA	2014	21
RAT231	Rathdrum, ID	2014	0
M23621	Moscow, ID	2015	413
WIL12F2	Wilbur, WA	2015	1,403
WAK12F2	Spokane, WA (Waikiki)	2016	175
RAT233	Rathdrum, ID	2019	471
SPI12F1	Northport, WA (Spirit)	2019	127
Total			**6,076**

The miles of work planned is ultimately driven by the approved budget and generally can only be projected for 5 years. In order to maintain a 60 year cycle, Avista would need to address an average of 137 miles per year of overhead circuit miles.

For tracking the impacts of the work on outages, we will monitor the following OMT sub-reasons shown in Table 22. While the Grid Modernization will affect all of the sub-reasons listed in Table 22**Error! eference source not found.**, the sub-reasons identified as potentially avoidable represent the most direct impact of the work. We assume that the number of OMT sustained outages will be reduced by 0.1 outages per mile of overhead work completed.

Table 22, OMT Sub-Reasons impacted by Grid Modernization

OMT Sub-Reason	GM Potentially Avoidable	Wood Pole Management
Arrester	x	
Bird		x
Capacitor	x	
Conductor - Pri	x	
Conductor - Sec	x	
Connector - Pri	x	
Connector - Sec	x	
Cross arm - rotten	x	x
Cutout/Fuse	x	x
Elbow	x	
Insulator	x	x
Insulator Pin	x	x
Lightning		
Pole Fire		
Pole - rotten	x	x
Recloser	x	
Regulator	x	
Snow/Ice		x
Squirrel		x
Switch/Disconnect	x	
Transformer - OH	x	x
Transformer UG	x	
Undetermined		
Weather		
Wildlife Guard	x	x
Wind		x

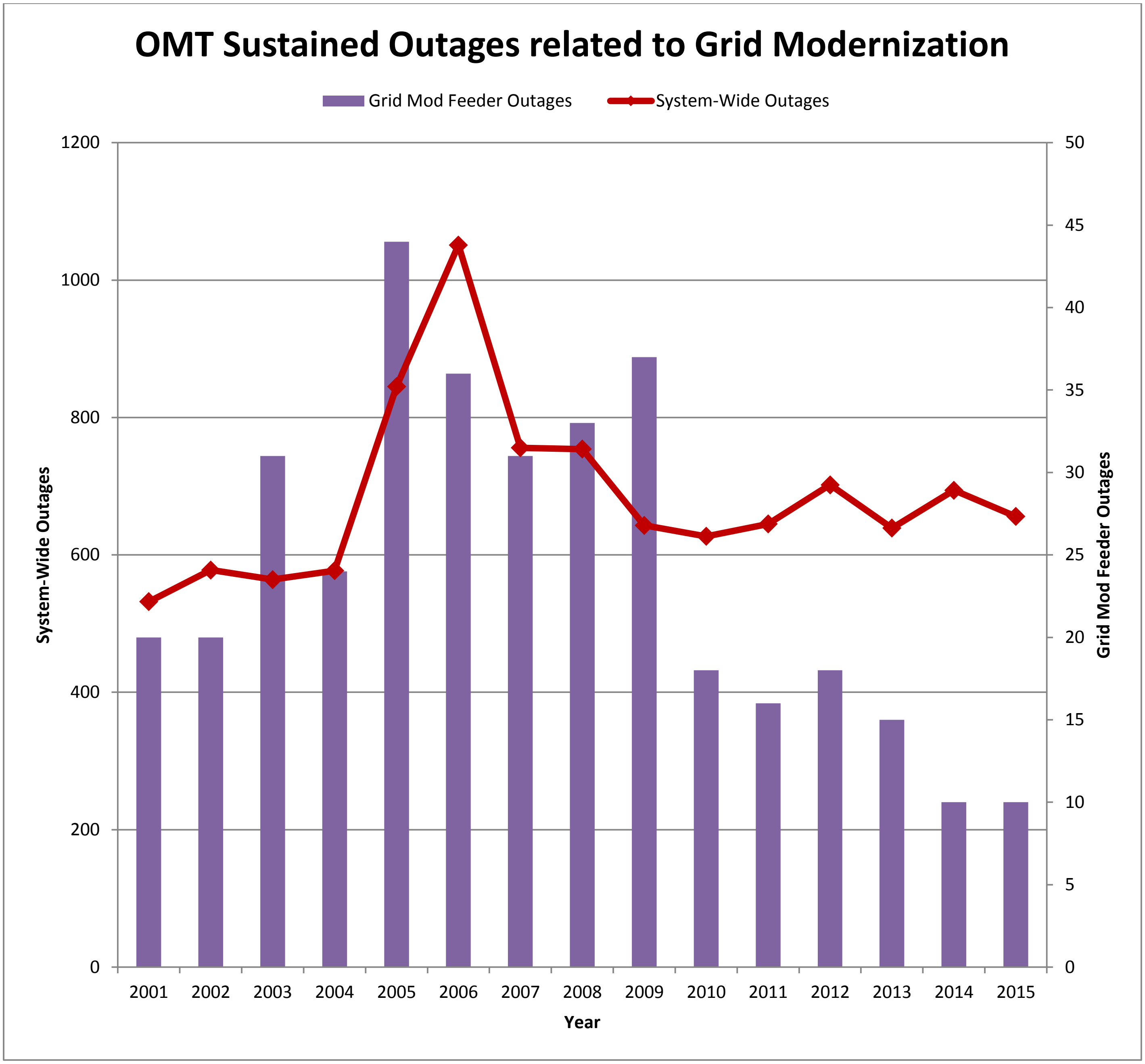


Figure 18, OMT Sustained Outages related to Grid Modernization

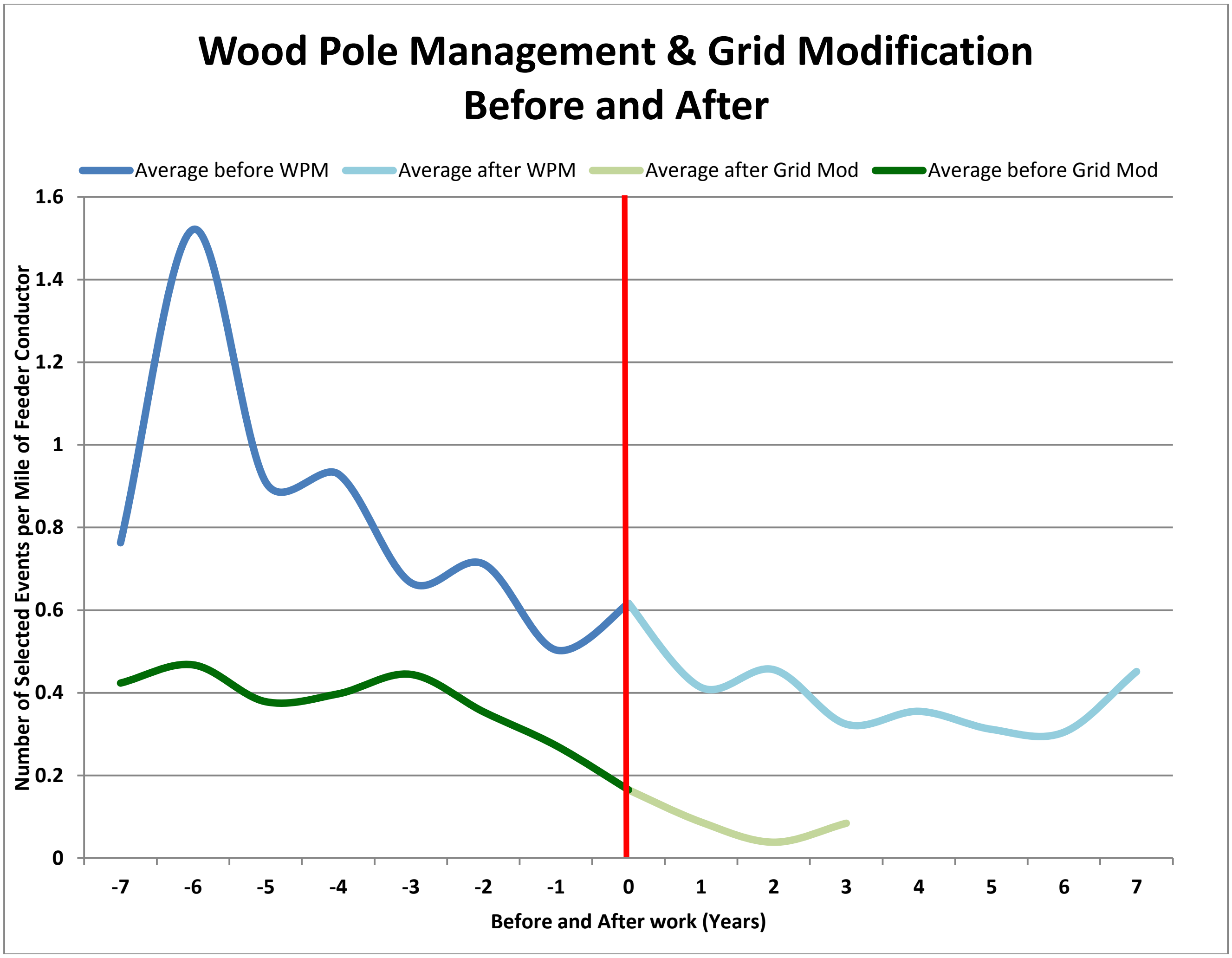


Figure 19, Wood Pole Management and Grid Modernization Before and After

Metric Performance

The results of the first four years work are shown in Table 23 the major event days from 2015 were removed to more accurately show program value). The year 2012 marks the beginning of the program. The number of miles actually completed missed the goal of 137 and the number of sustained outages just fell short of its goal. Figure 19 shows the prior and post trends for WPM and Grid Mod. These trends are broken down to be outage specific per program on a per mile of OH Conductor basis. The graph shows a steady trend downward for both programs after work is done on a feeder. Grid Mod work tends to trend down prior to the completion date due to the time it takes to complete the Grid Mod work and in some cases feeders being previously completed by WPM. A feeder may take multiple years to complete thus some portion of the benefits are gained in the couple years before completion. The before/after portion of the graph is set so that all the work done for these programs since 2008 is set to a zero year on the year it was completed. The program is reducing outages as seen in Figure 19 and Table 23 even though the planned miles have yet to be met. Missing this goal increases our program cycle, the current goal is a 60 year cycle. Continuing to miss this mileage can impact the sustained outages over time.

Table 23, Metric Performance for Grid Modernization Program

Year	Planned Miles for Modernization (Miles)*	Actual Miles Completed (Miles)**	Anticipated Number of Sustained Outages	Realized Number of Sustained Outages
2012	95	73.33	2340	2251
2013	137	53.83	2327	1840
2014	137	78.64	2313	1791
2015	137	85.2	2300	2342
2016	190***		2286	
2017	190***		2272	

*Note: The planned or anticipated values may be modified to match approved work plans for each year that more accurately align with the actual work planned. Overall outages are based on the Reliability Outage events considered

**Data from Grid Modernization Group

***Grid Mod works on both overhead and underground equipment. Future metrics and analysis will be based on total circuit miles

Summary

The Grid Modernization Program began in earnest in 2012 and represents feeder replacement work and upgrades founded on smart grid work. Overall the program is improving outages and improving the health of our system. The anticipated miles completed and cycle time may need to be modified in the future if the miles continue to miss the goal, however, the anticipated outage reduction appears to be on target and so the mileage is not an issue at this time.

Worst Feeders

Since 2009, Avista has invested $1-2M annually to improve the reliability of its most underperforming distribution circuits (aka – Worst Feeders). The Company operates over three hundred and fifty (350) individual circuits throughout Northern Idaho and Eastern Washington. Many of these circuits serve rural geographic regions and may extend for hundreds of miles. In most situations, rural circuits route through heavily timbered national forest areas and are subject to tree, wind, and storm related outages. Avista's SAIFI target in 2015 was 1.17. So, on average, an Avista customer could expect one sustained, contingency outage event in 2015. However, many rural customers experience three to five sustained outages per year with a few circuits topping the SAIFI chart at above six (see Table 24). Avista operating engineers are instructed to systematically review outage logs for these circuits and determine an appropriate level of treatment. Projects vary by individual circumstance but in many cases additional circuit reclosers are installed to reduce outage exposure and to automatically restore power to upstream customers. In other locations, circuits in outage prone areas are converted from overhead to underground. In other situations, circuits are effectively 'hardened' by shortening conductor span lengths or by increasing phase spacing. Of particular note is the Grangeville 1273 circuit. Though its SAIFI metric is the highest in the Company, the current average of 9.02 is a significant improvement over the previous three year average of 21.9. A program investment of $217,686 was made on this line and has help to improve its reliability performance. On another circuit, Roxboro 751, over 1 million dollars was invested to convert overhead line segments to underground cable and the SAIFI statistics improved from 5.35 to 2.67. In fact, Roxboro now ranks 35th in our feeder list and does not appear in the top twenty 'worst feeders' as depicted in the graphics. In 2016, Avista plans to invest $1.5 million dollars in ten (10) circuit projects. This includes the final phase of the Roxboro 751 project along with other multi-year projects including Gifford Feeders 34F1 and 34F2 together with Colville 34F1 projects. Other projects are first year efforts to improve the service reliability of rural distribution circuits. The 2016 capital plan for the worst feeder program is indicated in Table 25.

Table 24, Worst Feeder SAIFI 3 Year Average

FDR	2012-2014 SAIFI 3yr Avg
GRV1273	9.02
STM633	6.82
SPI12F1	6.40
ODN732	6.28
GIF34F1	5.21
GIF34F2	4.79
CHW12F4	4.48
VAL12F2	4.47
CLV34F1	4.44
RDN12F2	4.43
JPE1287	4.27
CHW12F3	4.25
CKF711	4.13
SAG741	4.11
SPR761	4.07
VAL12F1	3.54
SWT2403	3.47
CHW12F2	3.46
MIS431	3.45
RDN12F1	3.40

Table 25, Worst Feeder Projects and Costs

Project Code (SUB FDR SAIFI RANK- DESC)	$ in 000's
GIF 34F1 (5)	250
SPT4S21- Reroute heavily tree area	100
COT2404	50
RSA 431 - various locales	50
LAT 421- various	50
GIF 34F2 (6) - Twin Lake	250
JPE1787(11)-WEI1289(25)	100
CLV 34F1 (9)	250
ROX 751 OH/UG Conversion (35)	150
SPO- #6 Crapo Removal 8 miles	250

Feeder Tie Circuits

Urban distribution feeders can be connected to other feeders as a means of “back-up” to serve customer load. By closing a “tie” switch between the two feeders, it is possible to electrically “feed” a portion of the adjacent feeder.

Service reliability can be compromised by the contingency loss of substation equipment such as the substation transformer, and voltage regulator. Car-hit poles can cause lengthy outages. Critical issues with picking up an adjacent feeder include the reserve capacity of the host feeder and the end of line service voltage.

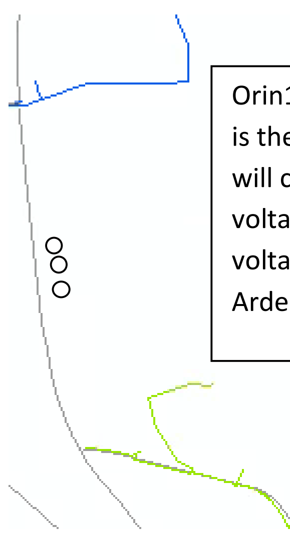
In rural areas, feeders with back-up capability are rare because the distance between adjacent circuits may be several miles. As with urban feeders, loss of substation equipment can cause feeder outages. Also, losing a portion of the main feeder trunk on a rural, radial feeder due to a tree through the line and/or via wind damage can also cause an outage that could be minimized with a “tie” feeder capability.

Feeder Tie projects increase the reliability of both of the circuits involved in the “tie”.

ARD12F2-ORN12F1 Tie Circuit

This feeder tie project will allow the Arden12F2 distribution feeder to be fed by Orin12F1. The “tie” is being built by installing new conductor between the “gap” in the two circuits (see Figure 20). The conductor has a cross sectional area allowing it to pick up the load of Arden12F2. In addition the voltage drop of the “tie” conductor is small. Also, a set of voltage regulators is being installed to increase the voltage on the Arden12F2 feeder to keep it within the required limits. If there is an outage on the Orin12F1 feeder, the Arden12F2 will be able to pick up a portion of Orin12F1, but not the entire feeder.

This is a two year project with a cost of $850,000 covering a distance of 2 miles between the two feeders.



Orin12F1 is the blue line. Arden12F2 is the green line. 556AAC conductor will connect the two feeders. A set of voltage regulators are used for voltage support when feeding Arden12F2 from Orin12F1.

Figure 20, ARD12F2 to ORN12F1 Tie

DAV12F2-RDN12F1 Tie Circuit

This circuit tie will allow Rearden12F1 to be fed from Davenport12F2 and vice versa. The “tie” is being built by installing new conductor between the “gap” in the two circuits (see Figure 21). Also, a set of voltage regulators is being installed to increase the voltage on the host feeder to support customer service voltage.

This is a multiyear project with a cost of $1.8 million dollars, connecting a distance of 10 miles between the two feeders.

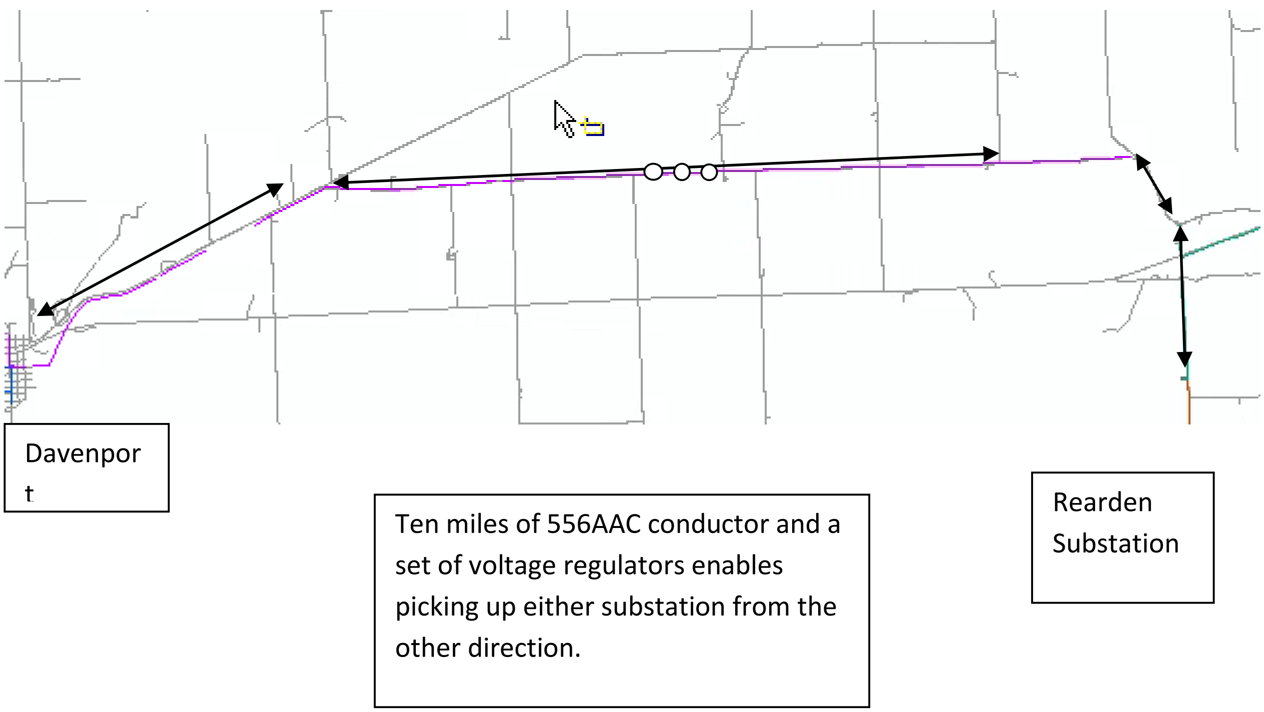


Figure 21, DAV12F2 - RDN12F1 Tie

At this point in time, approximately 5 miles of the tie circuit has been upgraded to 556 AAC. This new conductor will allow either substation to carry 4 MVA in the Summer, and 6 MVA in the Winter.

When all the conductor is upgraded, the load carrying capability will be doubled and either substation can pick up the other any time of the year.

Summary

This program is a new program and metrics have yet to be established.   Metrics will be worked on this year with the department running this program. We need to see the results from these future metrics before we draw any conclusions from the program.

Spokane Electric Network

Equipment Types and Aging

Major network equipment falls into four categories: network transformers, network protectors, cable (primary and secondary), and physical facilities – duct banks, vaults, manholes, and handholes.

Transformers and Protectors – some age, and maybe initial cost, data may be available via Maximo. A casual search indicates 27 transformers with purchase dates between 1930 and 1950 still in service in the network – these records are not verified. Another casual search of network protector records indicates units dating to 1947 still in service.

Cable – we do not have specific records regarding age of cables. A fair percentage is "OLD" – comments below.

Physical facilities – again, no specific records. Again, a fair percentage is "OLD".

KPI and Metrics

There are no established performance metrics for the downtown network. Given that the very nature of the network architecture is intended to prevent outages, and that OMT does not "see" network events, we have no specific outage data other than to state that the numbers would be small in comparison with the rest of the Avista system. Assuming the "network communications" project discussed in the "Non-routine Projects" section below actually comes to fruition, we would be better able to identify, track, and analyze outages should they actually occur.

Capital Budgets and Spending - Overview

CapX expenses in the downtown network fall into six general categories. Five are covered in "blanket" projects; the sixth category is funded by specific CPRs. Details:

1. New services: Commercial, residential, Street Lights
2. Replacement of old primary cable (Paper Insulated Lead Cable, "PILC")
3. Replacement of old secondary cable (PILC or Rubber Insulated Neutral Cable, "RINC")
4. Purchase and replacement of aging transformers and network protectors
5. Repair/refurbishment/replacement of vaults/manholes/handholes
6. The fifth category, covered by specific CPRs, may involve projects such as:
    a. Work required due to extensive city projects – e.g., the upcoming major rebuild of Lincoln and Monroe Sts where we have extensive existing facilities which will need major work or replacement
    b. Adding a "SCADA" and communications capability to the existing network – a trial project for Post West is budgeted.

New Services – Expenses

Generally self-explanatory. '15 budget $200K

Replacement of old PILC primary cable– Expenses

Our 2015 budget for PILC cable replacement was $340K. The PILC primary cable in our network is typically 30 years old or more; we do not have specific information on when much of it was installed.

Our network has about 96,700 feet of primary cable, about 47,900 feet is still PILC. We have targeted for replacing 7,500 feet of primary PILC each year. In 2015, due to personnel shortages and other more pressing work, we only replaced 6300 feet of primary cable.

The PILC cable has been very reliable through the years of service; however, as it ages, we have observed an increase in failures. Our goal of maximizing service in the downtown network drives the PILC replacement effort. Figure 22 and Figure 23 are illustrations of failures that occurred with older PILC cable.

Avista was fortunate in that we have only had one PILC cable failure in 2015 and one in 2013. This low failure rate is in large part due to the proactive replacement of the old cable. Owing to the redundant nature of our network, neither of these events resulted in customer outages.

Figure 22, A faulted PILC cable

Figure 23, A second faulted PILC cable

Replacement of old PILC and RINC secondary cable– Expenses

Factors driving replacement of PILC primary and PILC/RINC secondary are essentially the same. We replaced about 4,600 feet of secondary cable in 2015.

Purchase of new and replacement of aging transformers and network protectors– Expenses

Our 2015 budget for purchasing transformers and protectors was $920K; for replacement activities including associated cable, vault accessories, etc. was $1.1M.

We have 174 transformers in our network, each equipped with a network protector. Network transformers and network protectors are specialized devices specifically designed and built to ensure maximum operating reliability, and in the case of the protector, to improve and ensure safety for the crews working on the network.

We target replacing 12 transformers per year, and generally, the protector is replaced at the same time (there are exceptions). Replacement of a network transformer is a labor-intensive operation, and typically involves added expenses for hiring a crane to move the old and new transformers in and out of the vault, traffic control, and often crew overtime. We prioritize replacing very old transformers, transformers which are found to still have PCB oil, and transformers where routine oil sampling indicates contamination. In addition, transformers where oil sampling indicates high concentrations of combustible gasses (typically caused by internal arcing or similar events) are replaced immediately. In 2015 we replaced one transformer due to a high concentration of combustible gasses, one due to contaminated oil, and one ca. 1947 vintage transformer after a bulge was noted in the primary compartment case. We also replaced three aged transformers on a more "routine" basis.

A transformer failure can be a dramatic and dangerous event. Avista has been fortunate to not experience a violent transformer failure in recent years (a quick search indicates that the last one was in 2008.) Figure 24 illustrates the transformer which failed in 2008 due to some anomaly in the primary compartment.

Figure 24, A network transformer after a failure in the primary compartment

Repair/refurbishment/replacement of vaults/manholes/handholes– Expenses

Our 2015 budget for this work was $500K.

Our system contains 140 vaults, 325 manholes, and 295 handholes. Many of these, particularly manholes and handholes, date from the early 1900s and are still in service. In particular, where these are located in a traveled street, they have often deteriorated due to stresses from traffic, weather, and related factors. Vaults which have grated covers for circulating air for transformer cooling are often subjected to chemicals used for deicing streets in winter, which collects in the vaults and deteriorates the concrete.

When these facilities become deteriorated to the extent we have found in some cases, they represent not only the possibility of interruptions to service, but becoming traffic hazards as well. In the case of facilities in sidewalk areas, we have seen cases where cracking or buckling concrete, or deformed lids, have the potential to be a trip hazard for pedestrians.

Mitigating the vault, manhole, and handhole deterioration has ranged from being as simple as installing a new lid to removal and replacement of the entire facility. Figure 25 through Figure 27 illustrate various underground facility deterioration we have recently found, and some of the remediation efforts undertaken.

In 2015, we repaired or replaced 6 of these facilities. We have 3 more in queue pending a break in winter weather, and we have not started our 2016 inspection cycle.

Figure 25, Interior of a badly deteriorated old manhole in a heavily traveled street

Figure 26, Duct bank damage entering an old deteriorated manhole

Figure 27, Complete replacement of a badly deteriorated manhole

Non-routine Projects Being Carried Out on Specific CARs– Expenses

We had two open CPRs for network projects in 2015.

Network Communications Stage 1– Expenses

This project was budgeted for $122.4K

The scope of this pilot project involves adding communications capabilities to network protectors in a subset of the Post St West sub-network. This communications capability will enable remote reading of protector status (closed, tripped, locked open, number of protector operations), and remote instantaneous load readings. This capability will not immediately improve system reliability, but will pave the way for additional capability such as remote protector switching and remote indication of vault conditions (temperature alarm, unauthorized entry, etc.) which is expected to benefit overall network operation and maintenance. For convenience – think “smart grid” for the downtown Spokane network. The CPR was first opened in 2014, but to date, lack of personnel resources has resulted in no charges. This CPR remains open for 2016.

Monroe and Lincoln St Repaving– Expenses

This project was budgeted for $495K ($475K construction, $20K removal/retirement)

The City of Spokane has informed Avista of plans to extensively renovate and repave both Lincoln and Monroe Streets from 3rd Ave north to Main St in the main downtown corridor. This project will result in Avista needing to extensively modify, rebuild, and possibly even move network facilities in those streets. The CPR was opened in 2015 in anticipation of ordering long-lead items, but planning delays resulted in no expenditures in ’15. The CPR remains open for 2016.

Distribution Line Protection

Avista's Electric Distribution system is configured into a trunk and lateral system. Lateral circuits are protected via fuse-links and operate under fault conditions to isolate the lateral in order to minimize the number of affected customers in an outage. Engineering recommends installation of cut-outs on un-fused lateral circuits and the replacement of obsolete fuse equipment (e.g. Chance, Durabute/V-shaped, Open Fuse Link/Grasshopper, Q-Q, Load Break/Elephant Ear, and Porcelain Box Cutouts). As part of the program, sizing of fuses will be reviewed to assure protection of facilities, as well as coordination with upstream/downstream protective devices. This is a targeted program to ensure adequate protection of lateral circuits and to replace known defective equipment.

Assets Not Specifically Covered Under a Program

These assets do not have a planned AM program, so no specific metrics or KPIs have been identified. The general metrics discussed above for number of OMT Events (Table 1) and the associated action level; Risk Action Curve limits; and requests by responsible parties will determine in the future if a plan will be developed or if action is needed. In summary, Table 26 lists assets we continue to monitor to determine if and when planned actions are needed.

Table 26, Assets Not Specifically Covered Under a Program

Asset	Other information
Distribution Capacitors	Smart Grid added switch capacitors but our initial analysis did not indicate a strategy was justified
Distribution Cutotuts	Addressed through the WPM program and Distribution Line protection
Dead End Insulators	-
Distribution Mid- Line Reclosers	Substation Asset Management is analyzing strategies for this asset
Distribution Mid- Line Voltage Regulators	Substation Asset Management is analyzing strategies for this asset
Open Wire Secondary	Previous analysis indicated that this program was not financially justified. We believe Grid Mod will address many of these issues.
Primary Conductors	-
Primary Connections	-
Secondary Conductors	-
Primary Conductors	-
Riser Termination	--
URD Secondary Cable	Although we are monitoring this one closely we have yet to see a need to implement a strategy

Conclusion

In this report, we documented and examined the KPIs and metrics AM selected for the AM Distribution system programs and provided the results for 2015. Some of the metrics compared how an asset performed with a program and how it would have performed without a program. The difference in performance provide an estimate of the cost saving and value of an AM program. While the exact savings are impossible to calculate in most cases, it provides a relative comparison and supporting justification or motivation for change in AM decisions made in the past. Other KPIs and metrics provided indications of how well an asset performed and help determined if further work is required. Some AM models clearly need more work to better predict future conditions and will be scheduled in the future if it makes sense. This year other non-AM programs were included in this report and submitted by the group in charge of each program. These program write-ups did not follow the same template as the AM write-ups but were included within the document for project comparison.

Distribution Vegetation Management

2016 Washington
AIR12F1
AIR12F2
AIR12F3
CFD1210
CFD1211
CHE12F1
CHE12F2
CHE12F3
CHE12F4
CLA56
EWN241
FOR2.3
GIF34F2
INT12F1
INT12F2
L&R511
L&S12F1
L&S12F2
L&S12F3
L&S12F4
L&S12F5
LOO12F1
LOO12F2
MLN12F2
ROK451
ROX751
SE12F1
SE12F2
SE12F3
SE12F4
SE12F5
SOT522
SOT523
SPI12F1
TUR111
TUR112
TUR113
TUR115
TUR116
TUR117
TVW131
TVW132
VAL12F1
Idaho
CGC331
CKF711
DAL131
DAL132
DAL133
DAL134
GRV1271
GRV1272
GRV1273
GRV1274
KAM1291
KAM1292
KAM1293
KOO1298
KOO1299
RAT231
RAT233
SAG741
SPT4S21
SPT4S22
SPT4S23
SPT4S30
Montana
NRC352

2017 Washington
CHW12F1
CHW12F2
CHW12F3
CHW12F4
COB12F1
COB12F2
DVP12F1
DVP12F2
ECL221
ECL222
FWT12F1
FWT12F2
FWT12F3
FWT12F4
GLN12F1
GLN12F2
GRN12F1
GRN12F2
GRN12F3
L&R512
LEO611
LEO612
LF34F1
LIB12F1
LIB12F2
LIB12F3
LIB12F4
MEA12F1
MEA12F2
MLN12F1
OTH501
OTH502
OTH503

OTH505
ROS12F1
ROS12F2
ROS12F3
ROS12F4
ROS12F5
ROS12F6
Idaho
BUN422
BUN423
BUN424
BUN426
CRG1260
CRG1261
CRG1263
MIS431
NEZ1267
ODN731
ODN732
ORO1280
ORO1281
ORO1282
PIN441
PIN442
PIN443
POT321
POT322
PRA221
PRA222
PVW241
PVW243
WOR471
SWT2403
WIK1278
WIK1279

2018 Washington
3HT12F1
3HT12F2
3HT12F3
3HT12F4
3HT12F5
3HT12F6
3HT12F7
3HT12F8
9CE12F1
9CE12F2
9CE12F3
9CE12F4
ARD12F1
BKR12F1
BKR12F3
C&W12F1
C&W12F2
C&W12F3
C&W12F4
C&W12F5
C&W12F6
CLV12F1
CLV12F2
CLV12F3
CLV12F4
CLV34F1
DRY1208
DRY1209
GAR461
HAR4F1
HAR4F2
KET12F1
MIL12F1
MIL12F2
MIL12F3
MIL12F4
NW12F1
NW12F2
NW12F3
NW12F4
NW13T23
PAL311
PAL312
RDN12F1
RDN12F2
RIT731
RIT732
SPA442
SPU121
SPU122
SPU123
SPU124
SPU125
WAK12F1
WAK12F2
WAK12F3
WAK12F4
Idaho
BIG411
BIG412
BIG413
BLU321
COT2401
COT2402
HUE141
HUE142
LKV341
LKV342
LKV343
LKY551
M15511
M15512
M15513
M15514
M15515
M23621
NMO521
NMO522
OSB522
STM631
STM632
STM633

2019 Washington
ARD12F2
BKR12F2
DEP12F1
DEP12F2
DIA231
DIA232
EFM12F1
EFM12F2
H&W12F1
H&W12F2
KET12F2
LAT421
LAT422
LIN711
ORI12F1
ORI12F2
ORI12F3
SUN12F1
SUN12F2
SUN12F3
SUN12F4
SUN12F5
SUN12F6
WAS781
WIL12F1
WIL12F2
Idaho
BLA311
CDA121
CDA122
CDA123
CDA124
CDA125
JUL661
LOL1359
OGA611
OLD721
OLD722
OSB521
PF211
PF212
PRV4S40
SLW1316
SLW1348
SLW1358
SLW1368
SPL361
TEN1253
TEN1254
TEN1255
TEN1256
TEN1257

2020 Washington
BEA12F1
BEA12F2
BEA12F3
BEA12F4
BEA12F5
BEA12F6
BEA13T09
F&C12F1
F&C12F2
F&C12F3
F&C12F4
F&C12F5
F&C12F6
FOR12F1
GIF34F1
LL12F1
NE12F1
NE12F2
NE12F3
NE12F4
NE12F5
ODS12F1
OPT12F1
OPT12F2
PDL1201
PDL1202
PDL1203
PDL1204
PST12F1
RSA431
SIP12F1
SIP12F2
SIP12F3
SIP12F4
SIP12F5
SLK12F1
SLK12F2
SLK12F3
SOT521
SPI12F2
SPR761
TKO411
TKO412
VAL12F2
VAL12F3
Idaho
APW111
APW112
APW113
APW114
APW115
APW116
AVD151
AVD152
CKF712
DER651
DER652
HOL1205
HOL1206
HOL1207
IDR251
IDR252
IDR253
JPE1287
JUL662
LOL1266
N131222
N131321
PF213
SAG742
WAL542
WAL543
WAL544
WAL545
WEI1289

Distribution Wood Pole Management

2016	2017	2018	2019	2020
SOT522	BEA12F3	APW116	9CE12F1	LIN711
AIR12F3	BEA13T09	ARD12F1	9CE12F2	BLA311
APW114	COT2401 - ID	ARD12F2	9CE12F3	CHW12F1
APW115	COT2402 - ID	BEA12F4	BLU321	CHW12F2
CHE12F4	DVP12F2	BEA12F6	BLU322	CHW12F3
CLA56	F&C12F3	BIG411	FWT12F2	CHW12F4
L&S12F1	F&C12F4	CFD1210 - WA	GIF34F2	EWN241
L&S12F2	F&C12F5	CHE12F1	INT12F1	JUL661
L&S12F3	F&C12F6	CHE12F2	INT12F2	JUL662
L&S12F4	FOR12F1	CMP12F2	LAT421 - WA	KAM1291
L&S12F5	FOR2.3	FWT12F4	LAT422 - WA	KAM1292
LKV341	IDR253	JPE1287 - ID	LTF34F1	KAM1293
LKV342	OTH501	OPT12F1	NE12F5	LEO611
LKV343	PVW243	OPT12F2	PRV4S40	LOO12F2
LOL1359 - ID	SIP12F1	OSB521	RSA431	MIS431
MLN12F1	SIP12F3	PST12F1	SPI12F2	ORI12F1
MLN12F2	SOT523	PST12F2	WAK12F1	ORI12F2
NLW1222 - ID	SWT2403 - ID	SLW1348 - ID	WAK12F3	PIN441
SPT4S23		SPA442 - WA	WAK12F4	POT321
		SPT4S22		RDN12F1
				RIT731
				RIT732
				SPL361
				WEI1289

2021	2022	2023	2024	2025
CFD1210	ECL221	9CE12F4	BIG412	BKR12F1
CRG1260	ORO1282	BUN423	BKR12F3	CDA125
DVP12F1	PAL311	BUN426	CRG1261	CRG1263
FWT12F1	PAL312	CLV12F1	DER652	F&C12F2
FWT12F3	PIN443	GRV1274	H&W12F1	HAR4F2
HOL1205	POT322	M15512	H&W12F2	LEO612
HOL1206	RDN12F2	PDL1201	LIB12F3	LIB12F1
NE12F4	SPT4S21	PDL1202	ODS12F1	LIB12F4
PF213	STM631	SE12F1	ORI12F3	M15511
ROS12F3	VAL12F2	SLW1316	ORO1281	MIL12F1
SE12F3	VAL12F3	SOT521	SLK12F3	NEZ1267
SIP12F2		SUN12F1	WAL542	NLW1321
SLW1348		SUN12F3		NMO522
SLW1358				SIP12F5
WOR471				SUN12F6
				TUR116

2026	2027	2028	2029	2030
AIR12F1	DAL131	CLV12F2	3HT12F4	BIG413
CFD1211	DAL132	CLV34F1	BEA12F5	BKR12F2
DRY1208	DAL134	ECL222	C&W12F1	BUN422
GRV1271	MEA12F2	GRN12F1	CDA121	BUN424
HUE141	MIL12F2	ROK451	CDA122	DRY1209
KOO1298	MIL12F4	TKO411	CDA124	GRN12F2
KOO1299	PF212	TKO412	CLV12F3	GRV1272
OGA611	PRA221		CLV12F4	GRV1273
PDL1203	PRA222		HOL1207	HUE142
PF211	TEN1253		LKY551	KET12F1
WAL543	TUR117		MEA12F1	L&R511
WIK1278			NE12F3	L&R512
WIK1279			SE12F5	LKY552
WIL12F1			TEN1257	NMO521
				OSB522
				PIN442
				PVW241
				WAL544
				WAL545

2031	2032	2033	2034	2035
3HT12F1	CKF711	NW12F4	AIR12F2	BEA12F1
3HT12F2	CKF712	3HT12F5	CHE12F3	ODN731
3HT12F3	DIA231	3HT12F6	COB12F1	ODN732
CGC331	DIA232	3HT12F7	COB12F2	SPU121
M15514	EFM12F2	APW111	EFM12F1	SPU122
NRC351	HAR4F1	APW112	M15515	SPU123
ROX751	KET12F2	C&W12F2	MIL12F3	SPU124
SLW1368	LL12F1	C&W12F3	STM633	SPU125
SUN12F2	LOO12F1	C&W12F4	SUN12F4	TEN1254
TUR113	PDL1204	C&W12F5	SUN12F5	TUR111
	STM632	C&W12F6		TUR115
		NE12F2		VAL12F1
		NW12F1		
		NW12F3		
		SPT4S30		
		WAK12F2		

Grid Modernization

2016 Grid Modernization Plan Feeder	Design	Constr	State	Region	Area
BEA12F1		x	WA	West	Spokane
M23621		x	ID	South	Pullman/Mosc
MIL12F2	x	x	WA	West	Spokane
MIS431	x		WA	East	Kellogg
ORO1280	x		ID	South	Grangeville
PDL1201	x		WA	South	Lewiston/Clark
RAT231		x	ID	East	Coeur d'Alene
RAT233	x	x	ID	East	Coeur d'Alene
SPI12F1	x	x	WA	West	Colville
SPR761	x		WA	West	Othello
TUR112	x		WA	South	Pullman/Mosc
WAK12F2		x	WA	West	Spokane

2017 Grid Modernization Plan Feeder	Design	Constr	State	Region	Area
2016 Carryover	x	x			
F&C12F1	x		WA	West	Spokane
M15514	x		ID	South	Pullman/Mosc
MIL12F2		x	WA	West	Spokane
MIS431	x		WA	East	Kellogg
ORO1280		x			
PDL1201		x	WA	South	Lewiston/Clark
RAT233	x	x	ID	East	Coeur d'Alene
SPI12F1		x	WA	West	Colville
SPR761	x	x	WA	West	Othello
TUR112	x	x	WA	South	Pullman/Mosc

2018 Grid Modernization Plan Feeder	Design	Constr	State	Region	Area
2017 Carryover	x	x			
BEA12F2	x		WA	West	Spokane
DEP12F2	x		WA	West	Deer Park
F&C12F1	x	x	WA	West	Spokane
HOL1205	x		WA	South	Lewiston/Clark
M15514		x	ID	South	Pullman/Mosc
MIL12F2		x	ID	West	Spokane
MIS431	x	x	WA	East	Kellogg
TEN1255	x		ID	South	Lewiston/Clark
RAT233		x	ID	East	Coeur d'Alene
SPI12F1		x	ID	West	Colville
SPR761		x	WA	West	Othello

2019 Grid Modernization Plan Feeder	Design	Constr	State	Region	Area
2018 Carryover					
BEA12F2	x	x	WA	West	Spokane
F&C12F1		x	WA	West	Spokane
HOL1205		x	ID	South	Lewiston/Clark
M15514		x	ID	South	Pullman/Mosc
MIL12F2		x	WA	West	Spokane
MIS431	x	x	ID	East	Spokane
MLN12F1	x	x	WA	West	Deer Park
RAT233	x	x	ID	East	Kellogg
SPR761		x	WA	West	Othello
TEN1255	x	x	ID	South	Lewiston/Clark
TEN1256	x		WA	South	Lewiston/Clark
TUR112		x	WA	South	Pullman/Mosc

Transformer Change-Out Program

TCOP Work Plan Year	Program Working	Count
2016	GMP	305
2016	TCOP	1027
2016	WPM	180
2017	GMP	459
2017	TCOP	480
2017	WPM	64
2017 Predicted Non Detect	TCOP	204
2018	GMP	252
2018	TCOP	14
2018	WPM	138
2018 Predicted Non Detect	GMP	5
2018 Predicted Non Detect	TCOP	1031

Business Cases

Distribution Wood Pole Management

Investment Name:	**Distribution Wood Pole Management**		
Requested Amount	**Estimated Total Capital Expenditure**	**Assessments:**	
Duration/Timeframe	Indefinite Year Program	Financial:	7.42%
Dept.., Area:	Asset Maintenance	Strategic:	Life-cycle asset management
Owner:	Glenn Madden (Manager)	Business Risk:	Business Risk Reduction >5 and <= 10
Sponsor:	Cox/H. Rosentrater	Program Risk:	High certainty around cost, schedule and resources
Category:	Program		
Mandate/Reg. Reference:	NESC - See WPM Compliance Plan for details	Assessment Score:	93

Recommend Program Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
		Annual Cost Summary - Increase/(Decrease)			
Distribution Wood Pole Management Program inspects all Electric Distribution Feeders on a 20 year cycle and repairs or replaces wood poles, crossarms, missing lightning arresters, missing grounds, bad cutouts, bad insulating pins, bad insulators, leaking transformers, replaces guy wires not meeting current code requirements on poles replaced by WPM, and replaces pre-1981 transformers	Customer IRR = 7.42% and avoids an average of 1,700 additional events per year	$ 11,172,022	$ 530,943	$ 5,996,350	15

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
			Annual Cost Summary - Increase/(Decrease)			
Status Quo : No Wood Pole Management	Run wood poles and associated equipment to failure	Increase OMT events by 1,700 events	$ 8,186,361	$ -	$ 6,834,467	25
Alternative 1: Distribution Wood Pole Management - 20 Year Inspection Cycle	Distribution Wood Pole Management Program inspects all Electric Distribution Feeders on a 20 year cycle and repairs or replaces wood poles, crossarms, missing lightning arresters, missing grounds, bad cutouts, bad insulating pins, bad insulators, leaking transformers, and replaces pre-1981 transformers. Note: does not cover the additional costs associated with the backlog that is related to new requirements such as additional grounding and anchor rod replacements.	describe any incremental changes in operations	$ 10,712,022	$ 530,943	$ 5,996,350	15
Alternative 2: Distribution Wood Pole Management - 20 Year Inspection Cycle with Guy Wire	Distribution Wood Pole Management Program inspects all Electric Distribution Feeders on a 20 year cycle and repairs or replaces wood poles, crossarms, missing lightning arresters, missing grounds, bad cutouts, bad insulating pins, bad insulators, leaking transformers, replaces guy wires not meeting current code requirements on poles replaced by WPM, and replaces pre-1981 transformers	describe any incremental changes in operations	$ 11,172,022	$ 530,943	$ 5,996,350	0
Alternative 3 Name : Distribution Wood Pole Management - 10 Year Inspection Cycle with Guy	Distribution Wood Pole Management Program inspects all Electric Distribution Feeders on a 10 year cycle and repairs or replaces wood poles, crossarms, missing lightning arresters, missing grounds, bad cutouts, bad insulating pins, bad insulators, leaking transformers, replaces guy wires not meeting current code requirements, and replaces pre-1981 transformers	describe any incremental changes in operations	$ 17,296,437	$ 961,699	$ 4,920,632	0

Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ 21,393,700		$ -	$ 18,767,986
2015	$ 11,500,000			$ 10,600,000
2016	$ 11,200,000	$ 543,155	$ 4,564,898	$ 7,840,000
2017	$ 14,700,000	$ 555,648	$ 4,574,638	$ 12,000,000
2018	$ 14,700,000	$ 570,094	$ 4,588,630	$ 15,700,000
2019	$ 14,700,000	$ 584,916	$ 4,611,573	$ 16,060,000
2020	$ 14,700,000	$ 600,124	$ 4,634,631	$ 14,700,000
2021+	$ 15,700,000	$ 615,728	$ 4,657,804	$ -
Total	$ 118,593,700	$ 3,469,665	$ 27,632,174	$ 95,667,986

Associated Ers (list all applicable):

2060

ER	2016	2017	2018	2019	2020	Total
2060	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -

Mandate Excerpt (if applicable):

The current WPM program complies with the following part of the National Electric Safety Code: 013, 121, 212 A, 212 B, and 261 A.2

Additional Justifications:

Any supplementary information that may be useful in describing in more detail the nature of the Project, the urgency, etc.

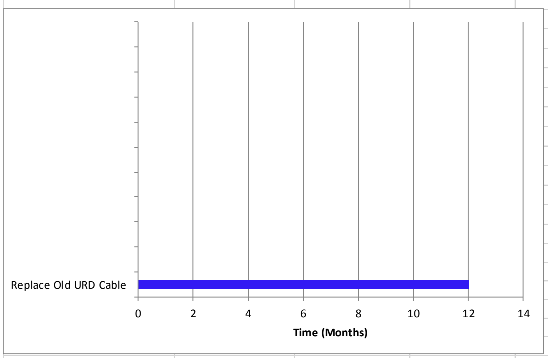
URD Primary Cable

Investment Name:	**Primary URD Cable Replacement 2013**		
Requested Amount	**$1,800,000**	**Assessments:**	
Duration/Timeframe	2 Year Project	Financial:	MH - >= 9% & <12% CIRR
Dept., Area:	Asset Management & Process Improvement	Strategic:	Life Cycle Programs
Owner:	Kevin Christie	Operational:	Operations improved beyond current levels
Sponsor:	Jason Thackson	Business Risk:	ERM Reduction >5 and <= 10
Category:	Project	Project/Program Risk:	High certainty around cost, schedule and resources
Mandate/Reg. Reference:	n/a	Assessment Score:	110

Recommend Project Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**ERM Risk Score**
		Cost Summary - Increase/(Decrease)			
Complete the replacement of the un-jacketed first generation of Primary URD cable	Customer IRR = 10% and avoids an average of 600 outages per year	$ 1,800,000	$ -	$ -	4

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**ERM Risk Score**
			Cost Summary - Increase/(Decrease)			
Status Quo :	Number of Primary URD Cable faults would increase and the cost to repair the cable would also increase. Without this work and the past 4 years of work, the increased O&M costs would sum up to $8.8 million over the next 5 years.	Increase number of Outage towards 700 per year	$ -	$ -	$ 1,300,000	10
Alternative 1: Primary URD Cable Replacement	Complete the replacement of the un-jacketed first generation of Primary URD cable	Customer IRR = 10% and avoids an average of 600 outages per year	$ 1,800,000	$ -	$ -	4
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name : Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Timeline



Construction Cash Flows (CWIP)

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ 19,852,679	$ -	$ -	$ 19,852,679
2012	$ 1,800,000	$ -	$ -	$ 1,982,000
2013	$ 1,000,000	$ -	$ -	$ 1,000,000
2014	$ 1,000,000	$ -	$ -	$ 750,000
2015	$ 1,000,000	$ -	$ -	$ 1,000,000
2016	$ 1,000,000	$ -	$ -	$ 200,000
2017	$ 1,000,000	$ -	$ -	$ 500,000
2018	$ 1,000,000	$ -	$ -	$ 1,000,000
2019	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ -	$ 800,000
Total	$ 27,652,679	$ -	$ -	$ 27,084,679

Milestones (high level targets)

November-11	Project Started	December-12	Plant In Service	mm/dd/yy	open
March-12	Project Plan	December-12	Project Complete	mm/dd/yy	open
June-12	Project Design	mm/dd/yy	open	mm/dd/yy	open
March-12	Major Procurement	mm/dd/yy	open		
September-12	Construction Start	mm/dd/yy	open		

Milestones should be general. In some cases it may be as simple as project start, project complete. Use your judgement on project progress so that progress can be measured.

Associated Ers (list all applicable):	Current ER	2054

Mandate Excerpt (if applicable):

Additional Justifications:

Transformer Change Out Program

Investment Name:	**Distibution Transformer Change-Out Program**		
Requested Amount	**$ 7,000,000**	**Assessments:**	
Duration/Timeframe	25 Year Program	Financial:	Medium - >= 5% & <9% CIRR
Dept.., Area:	Asset Management & Process Improvement	Strategic:	Life Cycle Programs
Owner:	Glenn Madden (Manager) & Al Fisher (Dir)	Operational:	Operations require execution to perform at current levels
Sponsor:	Don Kopczynski	Business Risk:	ERM Reduction >5 and <= 10
Category:	Program	Program Risk:	High certainty around cost, schedule and resources
Mandate/Reg. Reference:	n/a	Assessment Score:	89

Recommend Program Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
		Annual Cost Summary - Increase/(Decrease)			
The Distribution Transformer Change-Out Program has three main drivers. First, the pre-1981 distribution transformers that are targeted for replacement average 42 years of age and are a minimum of 30 years old. Their replacement will increase the reliability and availability of the system. Secondly, the transformers to be replaced are inefficient compared to current standards and their replacement will result in energy savings. Thirdly, pre-1981 transformers have the potential to have pcb containing oil. The transformers to be removed early in the program are those that are most likely to have pcb containing oil and their replacement will reduce the risk of pcb containing oil spills which are a safety, environmental, and a public relations concern.	When completed save an average of 5.6 MW per hour and eliminate PCB environmental risks	$ 5,800,000	$ 105,000	$ -	3

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
			Annual Cost Summary - Increase/(Decrease)			
Unfunded Program:	No planned replacement program for distribution transformers. Substancially higher risk of a pcb containing oil spill occuring.	n/a	$ 4,500,000	$ 200,000	$ 900,000	12
Alternative 1: Transformer Change-Out Program	The Distribution Transformer Change-Out Program has three main drivers. First, the pre-1981 distribution transformers that are targeted for replacement average 42 years of age and are a minimum of 30 years old. Their replacement will increase the reliability and availability of the system.	When completed save an average of 5.6 MW per	$ 5,800,000	$ 105,000	$ -	3
Alternative 2:	Distribution Engineering has proposed that any pole that the TCOP does work on needs to have the guy replaced with the new standard guy insulator (fiber cable).		$ 200,000	$ -	$ -	0
Alternative 3 Name :			$ -	$ -	$ -	0

Program Cash Flows

5 years of costs

	Capital Cost	O&M Cost	Other Costs	Approved
2012	$ 7,000,000	$ 100,000	$ -	$ 6,000,000
2013	$ 7,200,000	$ 102,000	$ -	$ 2,924,015
2014	$ 5,800,000	$ 105,000	$ -	$ 3,944,000
2015	$ 5,800,000	$ 107,000	$ -	$ 3,750,000
2016	$ 5,800,000	$ 110,000	$ -	$ 2,200,000
2017	$ 1,100,000			$ 1,900,000
2018				$ 1,700,000
Total	$ 32,700,000	$ 524,000	$ -	$ 22,418,015

Associated Ers (list all applicable):

Current ER	1003
	2060
	2535

Mandate Excerpt (if applicable):

Additional Justifications:

Area and Street Light

Investment Name:	**Street Light Management**			
Requested Amount	**$475,000**		**Assessments:**	
Duration/Timeframe	Indefinite	2014	Financial:	7.92%
Dept.., Area:	Operations		Strategic:	Life-cycle asset management
Owner:	Al Fisher		Business Risk:	Business Risk Reduction >5 and <= 10
Sponsor:	Don Kopczynski		Program Risk:	Moderate certainty around cost, schedule and resources
Category:	Program			
Mandate/Reg. Reference:	n/a		Assessment Score:	89

		Annual Cost Summary - Increase/(Decrease)			
Recommend Program Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
Street Light Maintenance Program. This program is a 5 year planned replacement of bulbs and 10 year planned replacement of photocells. This alternative has the starterboards running to failure.	7.92%	$ 475,000	$ (250,000)	$ (750,000)	8

			Annual Cost Summary - Increase/(Decrease)			
Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
Unfunded Program: Continue maintaining the street lights as failures occur	The lights are currently maintained based on customer feedback and/or due to being noticed by an Avista employee. Many street lights are out for long periods of time which can put us at risk. We also spend a large amount of time driving from issue to issue.	6.29% 2 - S3 event in 10 years	$ -	$ 1,500,000	$ 1,800,000	16
Alternative 1:	Street Light Maintenance Program. This program is a 5 year planned replacement of bulbs and 10 year planned replacement of photocells. This alternative has the starterboards running to failure.	7.92% 1.5 - S3 event in 10 years	$ 475,000	$ (250,000)	$ (750,000)	8
Alternative 2:	Street Light Maintenance Program. This program is a 5 year planned replacement of bulbs and starterboards and a 10 year planned replacement of photocells.	7.28% 1 - S3 event in 10 years	$ 890,000	$ (250,000)	$ (1,175,000)	12
Alternative 3:	Street Light Maintenance Program. This program is a 5 year planned replacement of bulbs and a 10 year planned replacement of photocells and starterboards.	7.82% 1 - S3 event in 10 years	$ 895,000	$ (250,000)	$ (1,165,000)	12

Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -
2014	$ 475,000	$ (250,000)	$ -	$ -
2015	$ 484,500	$ (500,000)	$ -	$ 2,400,000
2016	$ 494,190	$ (750,000)	$ -	$ 1,500,000
2017	$ 504,074	$ (1,000,000)	$ -	$ 1,500,000
2018	$ -	$ -	$ -	$ 1,500,000
2019	$ -	$ -	$ -	$ 1,500,000
2020				
Total	$ 1,957,764	$ (2,500,000)	$ -	$ 8,400,000

Associated Ers (list all applicable):

New ER

ER	2013	2014	2015	2016	2017	Total
New ER	$ -	$ 475,000	$ 484,500	$ 494,190	$ 504,074	$ 1,957,764
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ 475,000	$ 484,500	$ 494,190	$ 504,074	$ 1,957,764

Mandate Excerpt (if applicable):

Additional Justifications:

Grid Modernization

Investment Name:	**Distribution Grid Modernization**			
Requested Amount	**See Plan Below**		**Assessments:**	
Duration/Timeframe	Indefinite	Year Program	Financial:	6.4% Customer IRR
Dept.., Area:	Distribution Engineering		Strategic:	Life-cycle asset management
Owner:	Troy A. Dehnel		Business Risk:	Business Risk Reduction >15
Sponsor:	Don Kopczynski		Program Risk:	High certainty around cost, schedule and resources
Category:	Program			
Mandate/Reg. Reference:	Federal & State Clear Zone Mitigation Directives		Assessment Score:	133

Recommend Program Description:	Performance	Capital Cost	O&M Cost	Other Costs	Business Risk Score
		Annual Cost Summary - Increase/(Decrease)			
The Distribution Grid Modernization Program provides value to customers and shareholders by improving Grid Reliability, Energy Savings and Operational Ability through a systematic and managed upgrade of our aging distribution system. This program seeks cost effective opportunities to increase service quality performance and system availability through the identification of locations that would benefit from the addition of switched capacitor banks, regulators and smart grid devices. The long-term plan represented by the IRR of 6.4% aims to upgrade 6 feeders per year to cover the whole distribution system in a 60 year cycle. This coordinates well with Wood Pole Management's 20 year cycle. The average cost to rebuild each feeder is estimated to be $3.5M.	When completed save an average of 1,970 MWh* annually & Reduce Outages	$ 21,000,000	$ -	$ 198,000	4

Alternatives:		Performance	Capital Cost	O&M Cost	Other Costs	Business Risk Score
			Annual Cost Summary - Increase/(Decrease)			
Unfunded Program:	No systematic plan for wholistic address of conductors, reconfiguring services for better access, or adding devices that benefit the performance of the feeder.	n/a	$ 120,000	$ -	$ 1,980,000	25
Alternative 1: Brief name of alternative (if applicable)	The Dist Grid Modernization Program provides benefits to customers, employees, and shareholders by replacing problematic poles, cross-arms, cut-outs, transformers, conductor, etc. In addition, adding switched capacitor banks and smart grid devices is of benefit due to increased energy efficiency and system reliability.	When completed save an average of 1,970 MWh* annually & Reduce Outages	$ 21,000,000	$ -	$ 198,000	4
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ 7,308,357	$ -	$ -	$ 7,308,357
2014	$ 8,686,019	$ -	$ -	$ 9,586,000
2015	$ 11,000,000	$ -	$ -	$ 12,310,000
2016	$ 12,000,000	$ -	$ -	$ 7,000,000
2017	$ 13,000,000	$ -	$ -	$ 13,000,000
2018	$ 15,000,000	$ -	$ -	$ 15,000,000
2019	$ 18,000,000	$ -	$ -	$ 21,000,000
2020	$ 21,000,000	$ -	$ -	$ 20,800,000
Total	$ 105,994,376	$ -	$ -	$ 106,004,357

Associated Ers (list all applicable):	
Dist Grid Moderniz	2470
Sandpoint SG	2570
Grid Mod Automati	2599

ER	2015	2016	2017	2018	2019	Total
Dist Grid Modernization	$ -	$ -	$ -	$ -	$ -	$ -
2470	$ 11,000,000	$ 11,000,000	$ 13,000,000	$ 15,000,000	$ 15,000,000	$ 65,000,000
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Sandpoint SG	$ -	$ -	$ -	$ -	$ -	$ -
2570	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Grid Mod Automation	$ -	$ -	$ -	$ -	$ -	$ -
2599	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 11,000,000	$ 11,000,000	$ 13,000,000	$ 15,000,000	$ 15,000,000	$ 65,000,000

Mandate Excerpt (if applicable):

WSDOT Target Zero, an FHWA mandated initiative in MAP-21, requires that utilities move all non-breakaway structures out of the clear zone as defined in the 10/2005 AASHTO "A Guide for Accommodating Utilities Within Highway Right-of-Way. WA State law requires that we complete this task by year 2030.

Additional Justifications:

WAC 468-34-350 - Control Zone Guidelines, WAC 468-34-300 - Overhead Lines Location, RCW 47.32.130 Dangerous Objects and Structures as Nuisances, RCW 47.44.010 Wire and Pipeline and Tram and Railway Franchises - Application - Rules on Hearing and Notice, RCW 47.44.020 Grant of Franchise - Condition - Hearing.

Worst Feeder

Investment Name:	**Underperforming Elec Ckts (Worst FDRs)**		
Requested Amount	**$2,000,000**	**Assessments:**	
Duration/Timeframe	on-going Year Program	Financial:	Medium - >= 5% & <9% CIRR
Dept.., Area:	Engineering/Operations	Strategic:	Life Cycle Programs
Owner:	Dave James	Operational:	Operations require execution to perform at current levels
Sponsor:	Howell/H Rosentrater	Business Risk:	ERM Reduction >5 and <= 10
Category:	Program	Program Risk:	Moderate certainty around cost, schedule and resources
Mandate/Reg. Reference:	n/a	Assessment Score:	84

Recommend Program Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
		Annual Cost Summary - Increase/(Decrease)			
Initiating in 2009, ER 2414- "Worst Feeders" was proposed by Asset Management to improve the service reliability of the Company's worst-performing electric distribution circuits. Many rural feeders significantly exceed the Company SAIFI target of 2.1. This program is coordinated through divisional Area Engineers to identify treatment of these feeders. Work plans may include, reconstruction, hardening, vegetation management, conversion from OH to UG, enhanced protection, and relocation.	Improve the overall system performance of the Company's "top ten" worst feeders.	$ 2,000,000	$ -	$ -	12

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
			Annual Cost Summary - Increase/(Decrease)			
Unfunded Program:	Rural area reliability indices expected to worsen as infrastructure ages and deteriotes. Expect customer contacts to local media and state government and regulatory bodies.	Ten to twenty rural FDRs whose SAIFI exceeds 10	$ -	$ -	$ -	20
50% funding	Funding at $1,000,000 would restrict current treatment to top five worst feeders.	annual spend restricted to top five worst feeders	$ 1,000,000	$ -	$ -	12
25% funding	Funding at 500,000 would restrict treatment to enhanced protection only (adding midline reclosers, additional fusing)	work plan restricted to enhanced protection	$ 500,000	$ -	$ -	0
		describe any incremental changes in operations	$ -	$ -	$ -	0

Program Cash Flows

5 years of costs

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ 6,000,000			$ 5,050,550
2015	$ 2,000,000	$ -	$ -	$ 1,035,041
2016	$ 2,000,000			$ 1,500,000
2017	$ 2,000,000			$ 2,500,000
2018	$ 2,000,000	$ -	$ -	$ 2,000,000
2019	$ 2,000,000	$ -	$ -	$ 2,000,000
Total	$ 10,000,000	$ -	$ -	$ 9,035,041

Associated Ers (list all applicable):

Current ER	2414

Mandate Excerpt (if applicable):

Additional Justifications:

Any supplementary information that may be useful in describing in more detail the nature of the Program, the urgency, etc.

Feeder Tie Circuits

Investment Name:	**Segment Reconductor & FDR Tie Program**					
Requested Amount	**$4,000,000/year**	**Assessments:**				
Duration/Timeframe	on-going Year Program	Financial:	0.00%			
Dept.., Area:	Distribution Engineering	Strategic:	Life-cycle asset management			
Owner:	David Howell	Business Risk:	Business Risk Reduction - None			
Sponsor:	Heather Rosentrater	Program Risk:	Low certainty around cost, schedule and resources			
Category:	Program					
Mandate/Reg. Reference:	n/a	Assessment Score:	33			

Recommend Program Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
The Company's Distribution Grid system includes 18,000 circuit miles of overhead and underground primary conductors. As load and generation patterns shift, certain areas (segments) of the system become thermally overloaded. These constrained portions of the system are identified through systematic planning studies or from operational studyworks conducted by Area Engineers. In addition, FDR 'Tie' switches are installed to allow load shifts between FDR circuits to balance loads and in response to either maintenance or forced outages.	Electric Delivery Capacity	$ 4,000,000	$ -	$ -	4

Annual Cost Summary - Increase/(Decrease)

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
Unfunded Program:	Avista's Distribution System Planning criteria (e.g. 500 A Plan) mandates performance levels for distribution circuits including capacity and voltage requirements. This program is aimed at maintaining compliance with planning criteria.	n/a	$ -	$ -	$ -	16
Alternative 1: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	4
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name : Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
2015	$ 3,735,000	$ -	$ -	$ 3,573,505
2016	$ 3,810,000	$ -	$ -	$ 3,810,000
2017	$ 4,175,000	$ -	$ -	$ 4,175,000
2018	$ 3,900,000	$ -	$ -	$ 3,900,000
2019	$ 4,000,000	$ -	$ -	$ 4,000,000
2020	$ 4,000,000	$ -	$ -	$ 4,000,000
2021+	$ 4,000,000	$ -	$ -	$ -
Total	$ 27,620,000	$ -	$ -	$ 23,458,505

Associated Ers (list all applicable):

2514	2515	2516

ER	2016	2017	2018	2019	2020	Total
2514	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 10,000,000
2515	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 5,000,000
2516	$ 810,000	$ 1,175,000	$ 900,000	$ 1,000,000	$ 1,000,000	$ 4,885,000
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
0	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 3,810,000	$ 4,175,000	$ 3,900,000	$ 4,000,000	$ 4,000,000	$ 19,885,000

Mandate Excerpt (if applicable):

Avista Distribution Planning Criteria (500 Amp)

Additional Justifications:

This program is a foundational element of the Company's overall effort to maintain the electric delivery system. While many of the asset managmeent program such as WPM, TCOP, Worst Feeders, and Grid Mod are targeted efforts to maintain reliability, this program specifically identifies thermal, voltage, and capacity 'tie' constraints. The program represents the collective effort of distibution planners and area engineers to manager our ability to serve customer load, efficiently, and securely.

Network

Investment Name:	Spokane Elec. Network		
Requested Amount	$2,300,000 annually	**Assessments:**	
Duration/Timeframe	n/a Year Program	Financial:	MH - >= 9% & <12% CIRR
Dept.., Area:	Engineering	Strategic:	Life Cycle Programs
Owner:	John McClain	Operational:	Operations require execution to perform at current levels
Sponsor:	Cox/H Rosentrater	Business Risk:	ERM Reduction >5 and <= 10
Category:	Program	Program Risk:	High certainty around cost, schedule and resources
Mandate/Reg. Reference:	n/a	Assessment Score:	97

Recommend Program Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
Avista owns and maintains an underground electric network that serves the core business, financial and city government district of downtown Spokane from Division Street to Cedar and from Interstate 90 to the Spokane River. It is operated as a networked secondary system. Most mid to large cities in the United States operate similar electric grids. The system is configured to allow a single element forced outage (transformer, cable segment) without impact to customers. Outages can and do occur but those generally involve substation equipment failures or failures associated with work in progress. Like most utilities that operate networked secondary systems, Avista uses dedicated cable crew resources specifically trained to operate, construct, inspect and maintain these systems. All equipment and cables are located beneath city streets and adjacent properties. Topology in the Network is unique to Avista electric distribution and requires specialized material, equipment, tooling and training to perform maintenance repair, planned replacement and capacity growth projects. The scope of annual capital replacements and additions includes: 7500 feet of secondary cable, 7500 feet of primary cable, 10 refurbished manholes & vaults, 10 tranformer replacements, and 20 street light replacements.	Investments necessary to maintain current operations and to extend the life of current assets.	$ 2,300,000	$ 348,251	$ 215,000	6

Annual Cost Summary - Increase/(Decrease)

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
Unfunded Program:	Unfunding Network operations assumes zero PM activities and an eventual loss system functionality.	n/a	$ -	$ -	$ -	25
Alternative 1: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	6
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name : Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Program Cash Flows

5 years of costs

	Capital Cost	**O&M Cost**	**Other Costs**	**Approved**
Previous	$ 6,750,000			$ 6,338,007
2015	$ 2,300,000	$ 348,250	$ 215,000	$ 2,100,000
2016	$ 2,300,000	$ 348,250	$ 215,000	$ 2,300,000
2017	$ 2,300,000	$ 348,250	$ 215,000	$ 2,300,000
2018	$ 2,300,000	$ 348,250	$ 215,000	$ 2,300,000
2019	$ 2,300,000	$ 348,250	$ 215,000	$ 2,300,000
2020				$ 2,300,000
Total	$ 11,500,000	$ 1,741,250	$ 1,075,000	$ 13,600,000
	CapX Specific	O&M	O&B	

Associated Ers (list all applicable):

Current ER		2058	2237	2251
		CapX Repl.	Metro PILC	Post St PILC

Mandate Excerpt (if applicable):

Various WUTC tariff schedules are associated with customer classifications in downtown Spokane. NESC/WAC govern public and worker safety.

Additional Justifications:

Service to the core business district in Spokane is afforded a much higher level of service reliability than other urban or rural areas. This reflects the importance of continuous service to hospitals, law enforcement, city government, banking, legal, commerce, and retail sectors of the local economy.

Line Protection

Investment Name:	**Distribution Line Protection**					
Requested Amount	**875,000 5-years**	**Assessments:**				
Duration/Timeframe	On-going Year Program	Financial:	MH - >= 9% & <12% CIRR			
Dept.., Area:	Engineering	Strategic:	Life Cycle Programs			
Owner:	Dave James	Operational:	Operations require execution to perform at current levels			
Sponsor:	Cox/H. Rosentrater	Business Risk:	ERM Reduction >5 and <= 10			
Category:	Program	Program Risk:	Moderate certainty around cost, schedule and resources			
Mandate/Reg. Reference:	n/a	Assessment Score:	93			

Recommend Program Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**ERM Risk Score**
Avista's Electric Distribution system is configured into a trunk and lateral system. Lateral circuits are protected via fuse-links and operate under fault conditions to isolate the lateral minimize the number of affected customers. Engineering recommends treatment of the following: 1. Removal and replacement of Chance Cutouts 2. Removal and replacement of Durabute cutouts 3. Installation of cut-outs on unfused lateral circuits. This is a targeted program to ensure adequate protection of lateral circuits and to replace known defective equipment. The Chance fuse cutout devices are porcelain cutouts prone to mechanical failure at a much higher failure rate than peer group devices when manually operated by line craft personnel during various line switching scenarios. This presents a significant hazard to line personnel as	Investments necessary to maintain current operations and to extend the life of current assets.	$ 250,000	$ 10,000		8

Annual Cost Summary - Increase/(Decrease)

Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**ERM Risk Score**
Unfunded Program:		n/a	$ -	$ -	$ -	15
Alternative 1: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	8
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name : Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Program Cash Flows

5 years of costs

	Capital Cost	**O&M Cost**	**Other Costs**	**Approved**
2013	$ 250,000	$ 5,000	$ -	$ 250,000
2014	$ 250,000	$ 10,000	$ -	$ 250,000
2015	$ 125,000	$ 10,000	$ -	$ 125,000
2016	$ 125,000	$ 10,000	$ -	$ 125,000
2017	$ 125,000	$ 5,000	$ -	$ 125,000
2018	$ -	$ -	$ -	$ 125,000
2019	$ -	$ -	$ -	$ 125,000
2020				$ 125,000
Total	$ 875,000	$ 40,000	$ -	$ 1,250,000

Associated Ers (list all applicable):

Current ER	
2416	System Wide

Mandate Excerpt (if applicable):

Additional Justifications:

This program was funded for a 2-year period in the 2009-2010 timeframe. This request allows for completion of the Chance cutout replacements but also includes the installation of devices on unfused laterals.