WUTC DOCKET: UE-200900 UG-200901 UE-200894
EXHIBIT: PADS-28
ADMIT ☑ W/D ☐ REJECT ☐

BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

AVISTA CORPORATION d/b/a AVISTA UTILITIES,

Respondent.

DOCKET NOS. UE-200900 and UG-200901 (*Consolidated*)

PAUL J. ALVAREZ AND DENNIS STEPHENS

ON BEHALF OF THE
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT PADS-28

Avista Response to Public Counsel Data Request No. 105, Attachment A

April 21, 2021

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/02/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	Transm Ops/System Planning
REQUEST NO.:	PC - 105	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

SUBJECT: Capital Additions, Test Year

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 2, which references the "Avista Utilities Electric Distribution Infrastructure Plan June 2017".

Provide a copy of this Plan.

RESPONSE:

Please see PC-DR-105 Attachment A.

Avista Utilities

Electric Distribution Infrastructure Plan

June 2017

Avista Asset Management Group

Thanks & Acknowledgements

District Descriptions & Photos:

Chris Schlothauer (Coeur d'Alene)
Chris Sands (St. Maries)
Cesar Godinez (Colville)
Jesse Butler (Kellogg)
Steve Aubuchon (Lewiston/Clarkston)
Elizabeth Frederiksen (Palouse)
Kermit Olson (Spokane)
Kelly Donohue (Davenport)
Frank Binder (Deer Park)
Jeff Schwendener (Grangeville)
Ian Eccles (Othello)
Jim Kane (Sandpoint)
Chris Sands (St. Maries)
Reuben Arts (Downtown Network)
Ryan Bradeen (Downtown Network)

Amber Fowler – Transformer Analysis
Amy Jones – Distribution Wood Pole Management Data Analysis
Angela Moffat – Graphics
Casey Fielder – Graphics and District Maps
Chris Lum – Distribution Research and Analysis
Cody Krogh – PCB Replacement, Underground Cable, Content, Ideas and Improvements
David Howell – Content and Review, Project Support and Guidance
David James – Distribution Facts, Figures and Photos, Editing and Enhancements
Glenn Madden – Research, Data, Content and Review
Jeff Budke – Distribution Facts and Photos
Jeff Schlect – Content Checking
Jeff Smith – Data Analysis, Content Checking
Jeremiah Webster - Capital Budgeting Numbers
Jill Ham – Reliability and Outage Data
John Gross – Underground Cable Failures
Julie Lee – Financial Data, Distribution Vegetation Management Analysis
Karen Schuh – Transfer to Plant
Kyia Douglas – Charts & Graphs, Editing and Content Support
Laine Lambarth – Grid Modernization, Editing and Content Review
Larry Lee – Distribution Vegetation Management
Landen Grant – LED Street and Area Lights, Distribution Device Management
Mark Gabert – Wood Pole Management, Wood Pole Inspections and Photos
Marty Gulseth – Underground Cable and Downtown Network Data and Photos
Rob Cloward – GIS Information and District Analysis
Rob Gray – Report Editing and Content Review
Rodney Pickett – Wood Pole Management, Transformer and Underground Analysis
Rubal Gill – Budget and Actual Data
Shane Pacini – Grid Modernization, Editing and Content Review
Tyler Dornquast – Reliability Data
Valerie Petty – Distribution Research and Analysis

Lisa La Bolle – Chief Editor, Research, Drafting, Figures and Graphics, Report Production

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The arrows indicate two Avista employees working to restore service

Written on a customer's bill

Lineman's Safety Equipment

Executive Summary

Avista Utilities serves approximately 340,000 electric customers in Washington and Idaho over an extensive electric distribution system that is designed, built, operated and maintained by the Company. This infrastructure system consists of approximately 19,000 miles of distribution lines, including both overhead wire, underground cable and service lines, and customers' meters, all interconnected with 133 distribution substations. Avista must continually make new investments in this system in order to continue providing our customers with safe and reliable electric service, at a reasonable cost, and with service levels that meet our customer's expectations for quality and satisfaction.

Our Service is Reliable and Cost Effective

Avista is focused on maintaining a high degree of system reliability as an important aspect of the quality of our service. Providing a reasonable level of reliability for our customers represents a complex balance of customer expectations, cost, and system performance. We believe our prior and planned investments in distribution infrastructure enable the Company to effectively strike this balance and deliver a level of reliability that is satisfactory to our customers and that represents a cost-effective value. This assessment is evidenced by our high level of customer satisfaction with their overall service from Avista (which includes aspects such as electric reliability), by the low number of complaints we receive each year that are related to reliability issues, and our performance being in a reasonable range for the electric utility industry. The Company's overall system reliability has been fairly stable, with a slight trend toward improvement since 2005, as shown in Figure 1.

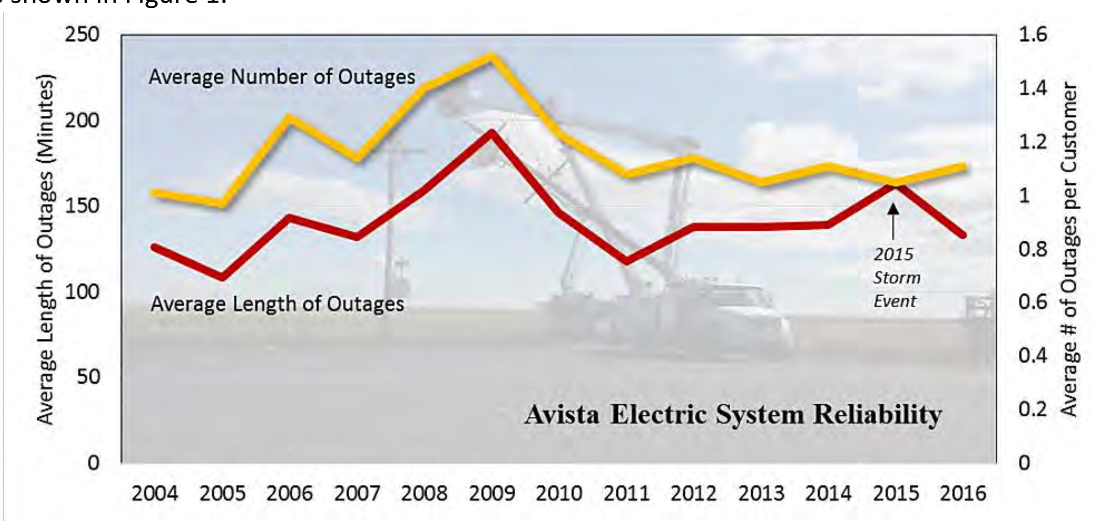


Figure 1. Avisa Electric System Outages

Increasing Capital Investments for Infrastructure Needs

In recent years, Avista has experienced an increasing demand for new infrastructure investment. The pattern of investments made by the Company during this period bear a striking resemblance to that of the industry, though Avista's investments have increased at a slower pace, as shown below in Figure 2. This similarity should not be a surprise, since we are all responding to the same investment drivers: the demand to replace an increasing amount of infrastructure that has reached the end of its useful life, and the need for reliability and technology investments necessary to build the integrated energy services grid of the future.

Avista's increase in electric distribution investments also reflects our adoption of new asset management-based approaches for assessing our infrastructure needs and developing strategies and programs to optimize the lifecycle value of our system.

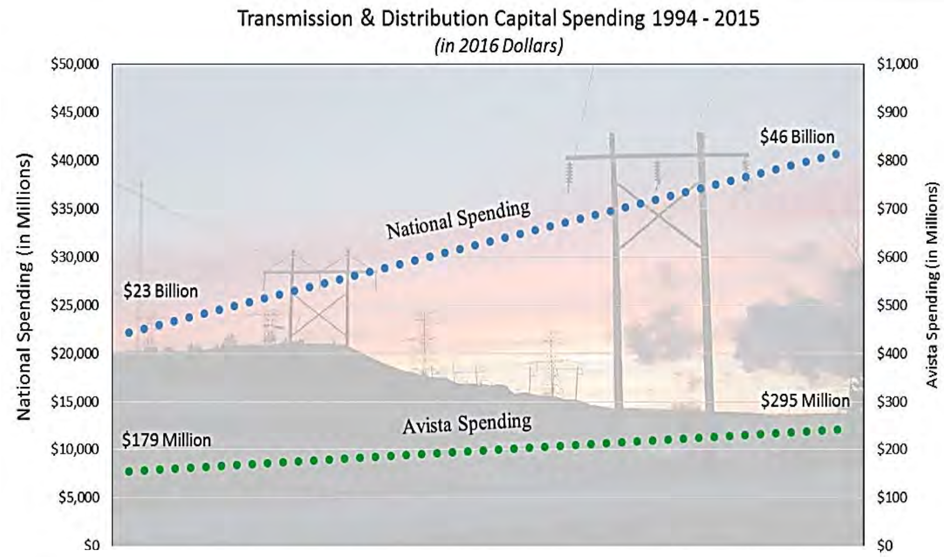


Figure 2. Infrastructure Investment Demands
Source of National Data: FERC Form 1

Despite the increased demand for new investment in our electric distribution system, however, our annual capital costs expressed on a per-customer basis are generally in line with that of the electric utility industry, as shown in Figure 3.

Avista's investments in electric distribution infrastructure were depressed for an early portion of this period due to the financial effects of the Western Energy Crisis, as reflected in our below average cost per customer. Our more recent investments (as described later in this report) pushed our annual per customer cost to the national average and slightly above; however, our above-average costs are largely the result of the significant spending in repairing and replacing equipment damaged by the windstorm of November 2015. Excluding these significant costs, the Company's per customer cost would be essentially equal to the national average.

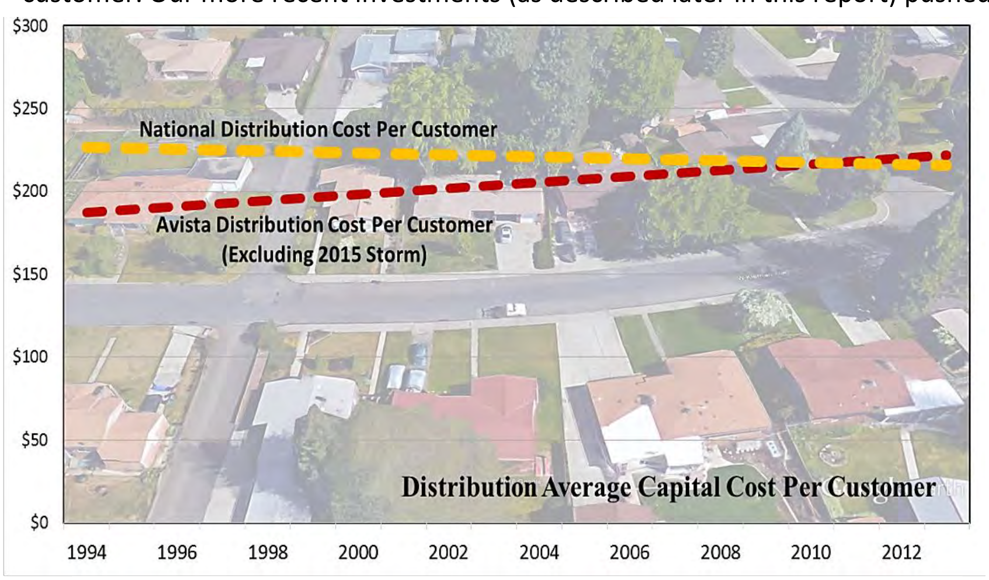


Figure 3. National & Avista Distribution Cost Per Customer
Source of National Data: FERC Form 1

When considering all of the Company's infrastructure investments measured across the entirety of our business over the past 65 years, Avista's capital cost per customer has varied, sometimes substantially, based on the intensity of our historic levels of investment and the number of customers we served at the time, as shown in Figure 4. Though increased over the prior decade, our current level of capital spending on a per-customer basis is generally in line with the trend over the last 30 years.

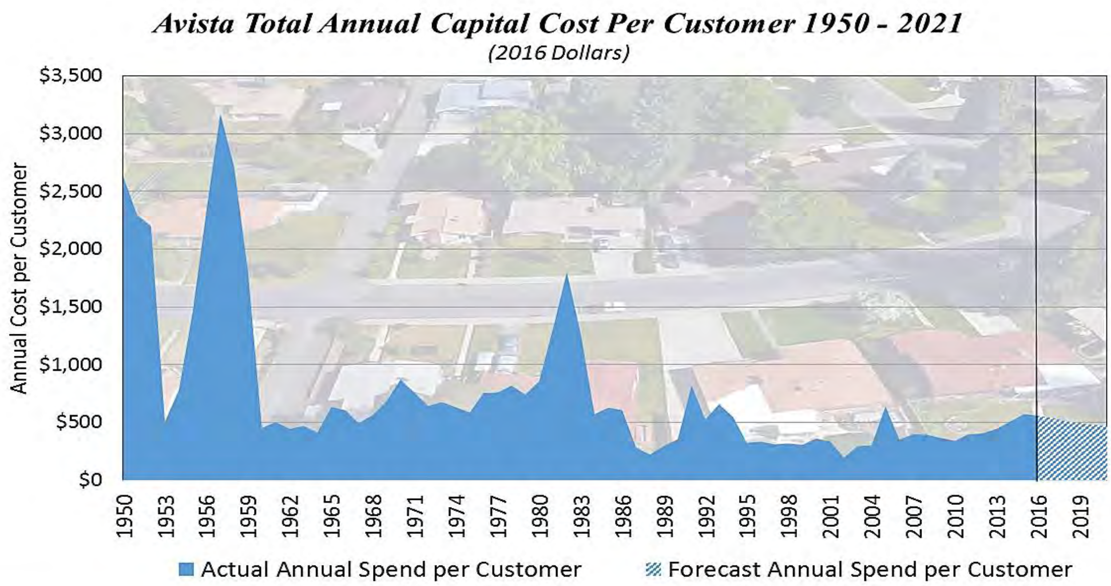


Figure 4. Avista Capital Cost Per Customer

Classification of Infrastructure Need by "Investment Drivers"

As a way to create more clarity around the particular needs being addressed with each investment, as well as simplifying the organization and understanding of our overall electric distribution plans, the Company has organized the infrastructure investments described in this report by the classification of need or "Investment Driver". The need for investments associated with each investment driver is briefly defined below, and in greater detail in the body of this report.

1. ***Customer Requested*** – connect new customers or enhance their service as requested.
2. ***Customer Service Quality & Reliability*** – meet our customers' expectations for quality of service and electric system reliability.
3. ***Mandatory & Compliance*** – compliance with laws, regulations and agreements.
4. ***Performance & Capacity*** – ensure our assets satisfy business needs and meet performance standards.
5. ***Asset Condition*** – replace assets at the end of their useful service life.
6. ***Failed Plant & Operations*** – replace failed equipment and prudently operate our business.

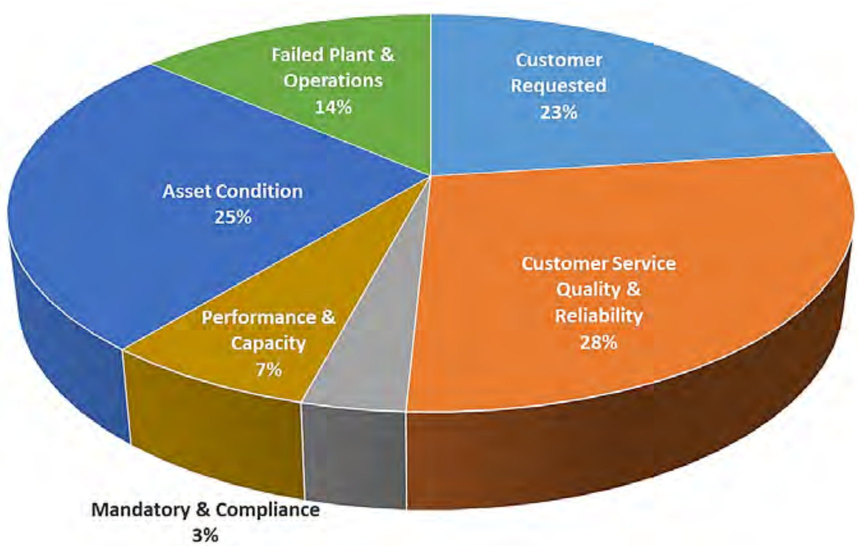
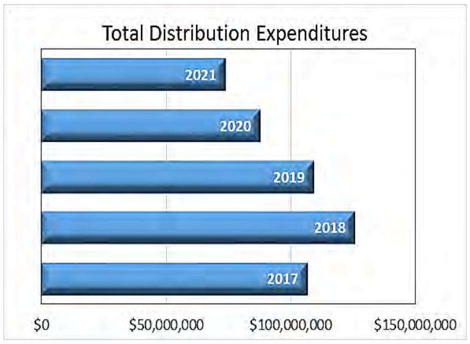


Figure 5. Avista Total Capital Expenditures by Investment Driver

Currently Planned Investments in Electric Distribution 2017 - 2021



For the current five-year planning horizon Avista expects to spend $503.4 million, allocated across the investment drivers described above and as shown in Figure 5 above. The planned annual investments for this period ranges from a low of $73.9 million (in 2021) to a high of $125.8 million (in 2018), with an annual average of $100.7 million. Avista's programs for electric distribution investments are summarized by investment driver below, and are discussed in detail in the remaining sections of this report.

Customer Requested

New Service Connects - Since 2005, the Company has responded to an average of 4,400 requests for a new electric service connection each year. For the current five-year planning period, Avista expects to connect an average of 6,200 new electric customers each year based on our economic and population forecasts. At our current and expected unit cost to connect each new customer, these new connects will result in an average annual investment of $23.1 million.

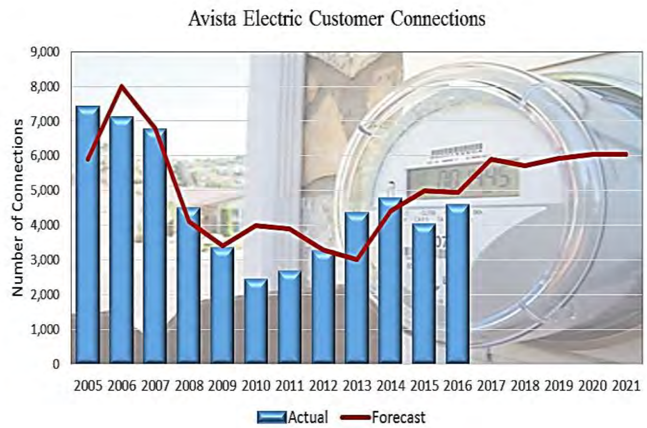


Figure 6. Total Annual Electric Customer Connections: Actual & Projected

Customer Service Quality & Reliability

Feeder Automation - Avista considers electric system reliability in nearly all its investment decisions, however, it does make certain investments solely on the basis of their reliability value. One such effort is the Company's Feeder Automation Program, which is carried out through our Distribution Grid Modernization effort. For this planning period, Avista expects to invest an average of $0.9 million each year to capture reliability benefits through feeder automation.

Advanced Metering Infrastructure (AMI) - Avista is in the process of deploying advanced metering infrastructure (AMI) across its Washington service territory. This effort keeps pace with the evolving metering standard of the industry and will deliver a range of cost-effective benefits to our customers. Among the benefits of advanced metering are tools to help customers better understand and manage their energy use, notify customers when their energy use meets predetermined targets the customer has established, enable smart home options to monitor and control energy use, reduce customer costs by deterring theft of electricity, eliminate manual reading of meters, reduce outage time for customers, save energy with more efficient feeder operation, and improve a range of administrative and back office work processes. The average annual investment for deployment of advanced metering is approximately $27.1 million.

Mandatory & Compliance

Electric Replacement / Relocation - Avista is required to move its electric distribution infrastructure in response to municipalities, counties and state-level agency projects to rebuild or realign roads, streets and highways, and other infrastructure projects. The estimated average annual investment required to comply with these requirements is $2.8 million.

Washington Department of Transportation (WSDOT) Franchising - In a closely related program, Avista works with this agency to renew and maintain crossing and encroachment permits, which at times requires the Company to move its distribution infrastructure at its own expense. The expected average annual investment related to these activities is $0.2 million.

Environmental Compliance - The Company must also comply with a range of environmental compliance rules that will have an expected annual average capital cost of $0.4 million.

Performance & Capacity

Distribution Segment Reconductor and Feeder Tie Program - The infrastructure investments made under this program remedy the overloading of electric equipment and cable, as well as the conductor sag that results from overheating of the overhead wire[1]. These instances of system overloading result from load growth and shifts in load demand that occur over time on the distribution system. As noted, Avista's distribution grid contains over 19,000 miles of overhead wires and underground cables.

The Segment Reconductor program targets areas of grid congestion where undersized and overloaded elements are identified through observation or computer simulation. Avista's internal guide is the Distribution "500 Amp" System Planning Manual[2]. This document establishes clear metrics with respect to system normal and single contingency performance. For example, in urban service areas (e.g. Lewiston-Clarkston Valley, Coeur d' Alene, Spokane, etc.), distribution circuits are supported via a network of 'feeder tie switches.' These interconnection points allow for load isolation and restoration during contingency or planned system outages. Over the next five years, system planners and engineers have identified over 30 reinforcement projects to mitigate thermal overloads and to accommodate load shifting under a variety of circumstances, including response to system peak loading events. The planned annual expenditures under this program are levelized at $5.0 million.

Light Emitting Diode (LED) Street and Area Lights – The Company is replacing all of its street and area lighting with new LED fixtures. In addition to providing customers with greater security and safety, the cost of this new investment is offset by a reduction in long term operating expenses and the energy savings captured with this highly efficient lighting technology. This program is slated for completion by year 2021, with an average annual investment of $1.8 million.

[1] When the overhead wire (conductor) on a distribution feeder is overloaded, the wire overheats and stretches, and in doing so, sags closer to the ground than designed, which can exceed electric code requirements for safety.
[2] Available upon request.

Asset Condition

Wood Pole Management - Avista has 347 overhead electric feeders that are supported by approximately 240,000 wood poles. Poles and equipment comprise the primary infrastructure of the Company's electric distribution system. Avista's wood pole population is inspected on a 20-year cycle interval, which means about 12,000 poles are inspected on average each year. The capital investments made under this program cover the needed repair and replacement of poles and attached equipment that is identified during the inspections. The average annual investment planned for this program is $9.8 million.

Distribution Grid Modernization – Avista is systematically rebuilding and upgrading its electric distribution feeders, and where cost effective, is installing feeder automation to improve the reliability of the system. This program was designed for a 60-year cycle interval and is dovetailed with the Wood Pole Management program to optimize capital work on our overhead feeders. While replacing assets at the end of their useful life, Grid Modernization delivers a range of benefits that include improved reliability, energy conservation, and reduced operating costs. The planned investments to be made under this program average $13.6 million annually.

Upgrading the Distribution System in Pullman
Phys.Org, June 10, 2015, https://phys.org/news/2015-07-nation-largest-smart-grid-demo.html

PCB Transformer Change-Out – The Company is systematically removing and replacing its aging fleet of distribution transformers that contain oil laden with PCBs. This program is planned to be ramped down by year 2020, when the great majority of the transformers will have been exchanged, at which time the remaining transformers will be replaced under the Wood Pole Management and Grid Modernization programs. The planned average annual investment is $1.3 million.

http://www.spokesman.com/stories/2014/jun/10/avista-replacing-transformers-to-eliminate-pcbs/

Underground Cable Replacement – Avista began programmatically replacing its first generation Underground Residential District (URD) cable approximately 15 years ago. While the systematic replacement program has ended, the Company continues to locate unmapped sections of this old cable during the course of each year, typically when the cable has failed. This program funds the ongoing replacement of remaining cable on an operational basis. The average annual investment planned for 2017-2021 is $0.9 million.

Failed Plant & Operations

Failed Plant – A portion of our assets in service fail each year due to asset condition and as a result of damage from storms, vehicle accidents, third-party dig-ins on underground equipment, etc. When this happens, the Company must quickly respond to replace the failed infrastructure in order to ensure the continuity of service to our customers. For the current planning period, based on our experience, we expect to spend an average of $2.2 million each year.

Operations capital – In addition to replacing assets that have failed, Avista's operations staff performs a wide range of limited capital infrastructure work that does not rise to the level of a project or program. These investments include the need to reconfigure, replace, repair and/or upgrade electric facilities for a variety of reasons, including those associated with customer requests. These improvements are beyond the tariffed costs for new services, replacement of equipment based on condition, and ameliorating system capacity deficiencies. Based on our experience, annual investments are expected to average $8.9 million.

Spokane Electric Network - Avista operates an electric distribution system in the core business district of downtown Spokane. This distribution "network" is configured as a fully redundant distribution grid that includes cables encased in concrete reinforced duct lines and major equipment such as underground transformers located in concrete vault structures. Much of this system has reached the end of its useful life or is near to doing so, with some assets installed over a century ago. Planned annual investments in this system for the 2017-2021 time frame are expected to average $2.3 million.

Conclusion

This report demonstrates that the investments in electric distribution infrastructure made by the Company over the prior decade were necessary and prudently incurred. The year-over-year growth in the level of our prior period investments is not unusual compared with our peers across the utility industry. Our capital investments on a per-customer basis are reasonably consistent with the industry, though our overall average spend has been below the industry average over the prior 20 years. Our distribution infrastructure programs have been thoughtfully developed, thoroughly analyzed and optimized, and adjusted and re-analyzed as appropriate to ensure that we deliver cost effective value for our customers. This report also demonstrates that the level of our investments is somewhat conservative as a result of our need to balance distribution priorities with our other infrastructure demands, as well as our effort to manage the impact of these investments on the costs paid by our customers.

Report Key Objectives:

- *Provide a comprehensive summary of the need for capital investment and the plan for implementation;*
- *Explain factors driving Avista's need for increased investment over the prior decade;*
- *Provide an overview of the Company's approach to electric system reliability;*
- *Simplify the understanding of the types of needs, or "investment drivers" shaping our investment plan;*
- *Provide visibility into why each capital project and program is necessary to meet our electric distribution system needs, and*
- *Provide a platform for continuous collaboration with our customers, Energy and Policy Staff, Commissioners, and a range of other Stakeholders.*

INTRODUCTION

Avista Utilities serves approximately 340,000 electric customers in Washington and Idaho over an extensive electric distribution system that is designed, built, operated and maintained by the Company. Avista must continually invest in its electric distribution system in order to provide our customers with safe and reliable electric service, at a reasonable cost, and with service levels that meet their expectations for quality and satisfaction. This report provides a summary overview of the Company's recent historic, current, and planned infrastructure investments in our electric distribution system for the period 2017 – 2021.

For the purposes of this report we have confined our discussion of "infrastructure investments" to the physical energy delivery facilities used to link our electric substations with each customer's meter. These facilities include overhead (conductor) and underground (cable) electric lines or "feeders," secondary transformers, service lines and electric meters.[3] We have also included several operations and maintenance (O&M) programs such as Vegetation Management that play a key role in helping us provide safe and reliable service.

Collectively, the investments described in this report allow Avista to effectively respond to customer requests for new service or service enhancements, meet its regulatory and other mandatory obligations, replace equipment that is damaged or fails, support electric operations, address system performance and capacity issues, and replace infrastructure at the end of its useful life based on asset condition. Moreover, the investments described in the plan are based on what we know about our business today, including a range of precision in future cost estimates, applicable laws, regulatory requirements, and the capabilities of current technologies. Though we frequently report out on many of the individual investment projects and programs that comprise our overall electric distribution infrastructure plan, we have not previously summarized this information in one comprehensive report.

[3] See Distribution Diagram (Figure 16) on page 18.

Accountable to Our Customers

Prudent Investment - With each investment, Avista demonstrates that the overall need, evaluations of alternatives, and the planned timing of implementation is judicious and in our customers' best interest. Avista believes this report demonstrates that our recent past, current, and planned investments in electric distribution infrastructure are necessary and prudent, and explains why the failure to make these investments would impair the performance of our system and harm our ability to deliver safe and reliable service to our customers. We explain that the investments we make to uphold the current reliability of our electric distribution system are conservative, thoroughly evaluated, and cost effective for our customers. We believe the report demonstrates that our distribution investments are needed and necessary in the timeframes planned in order to prudently conduct our business. Finally, the report also notes identified and proven needs for investment that are not fully funded in the current planning cycle in an effort to balance other priority investment needs.

Managing Our Costs - With the increasing levels of distribution and other plant investments made by the Company in recent years, we have worked to mitigate the cost impact by moving to our present level of investment more gradually over a period of several years. This effort often requires Avista to fund programs at less than an optimum level in an effort to balance the many competing infrastructure needs we currently face. The Company's efforts to manage the impact of these increasing infrastructure needs, as well as all other normal increases in expenses, has allowed us to hold the annual increases in our customers' electric bill to a reasonable average of 1.9% over the past eight years, keeping Avista's electric bills below the national average, below the average for Idaho (since 2013) and somewhat below the average for electric customers in the state of Washington.[4]

Providing Reliable Electric Service – Avista is focused on maintaining a high degree of reliability as an important aspect of the quality of our service, particularly as our society becomes ever more reliant upon electronic technologies. The Company's objective has been to generally uphold our current level of reliability, which we believe has been satisfactory to our customers.[5] Providing a level of system reliability that is adequate for our customers represents a complex balance of customer expectations, cost, and performance. Because it is expensive to achieve every new increment of system reliability, and because these investments must be sustained over a period of many years before the benefit is realized, it is important to ensure that we are investing only the amount of money it takes to achieve an acceptable level of performance. Avista believes the current reliability performance of our system effectively achieves this balance, and represents a cost-effective value for our customers. This assessment is evidenced by our high level of customer satisfaction with their overall service from Avista (which includes aspects such as electric reliability), national awards for customer service[6], by the low number of complaints we receive each year that are related to reliability issues, and our performance being in a reasonable range for the electric utility industry.

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[4] See Appendix A: Avista Customer Costs for a statewide and national customer cost comparison.
[5] 2016 Avista Service Quality Report Card, Found in Appendix B.
[6] Avista has won national awards for customer service, including the Edison Electric Institute National Key Accounts Award for Outstanding Customer Service in 2017 (http://3blmedia.com/News/Avista-Receives-National-Utility-Customer-Service-Award) and was rated high by JD Powers in 2016 (http://www.prnewswire.com/news-releases/electric-utility-business-customer-satisfaction-reaches-8-year-high-in-jd-power-study-300203512.html)

Each year we track and report on how well our system has performed as measured by the number of service interruptions (electric outages) and the duration or length of time of interruptions that are experienced by our customers on average. The Company's annual reliability performance for the years 2004 through 2016 is shown in Figure 7. Note that we do not directly measure customer satisfaction for reliability alone.[7]

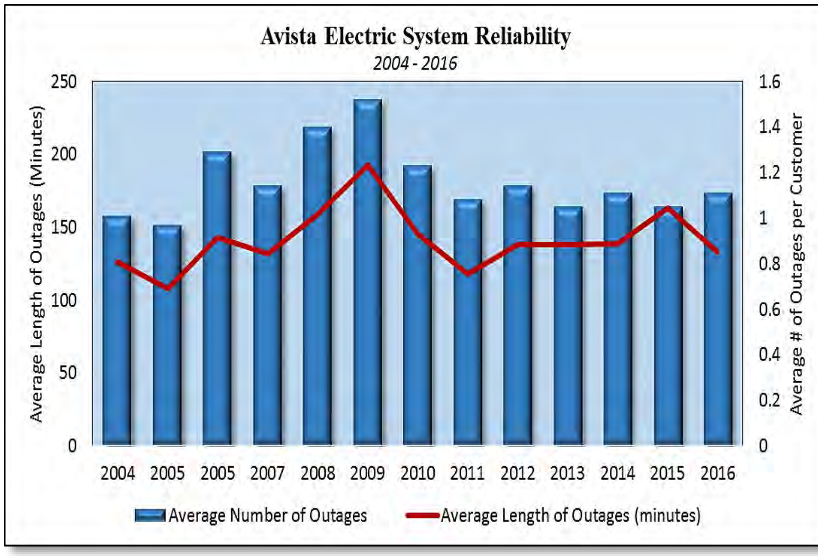

Figure 7. The Average Number and Duration of Electric System Outages

Although our overall reliability trend is generally stable; the year-to-year fluctuation in performance is a common feature of utility electric systems and is the result of factors that can be quite variable each year and that are largely beyond the control of the Company, such as wind and ice storms, fires, heavy snowfall, animals, vehicle accidents, etc.[8] In addition to these primary statistics, we report on several other utility-wide measures of reliability, the geographic areas of greatest reliability concern on our electric system, and our plans to improve service performance in those areas of greatest concern.

Historic and Industry Patterns of Overall Investment

Because the Company's annual capital expenditures, including those for electric distribution, have increased substantially in recent years, we believe it is helpful to provide some context related to Avista's historic pattern of investment as well as that of the industry in general.

The bulk of Avista and the nation's energy delivery systems were constructed in the period after World War II and generally into the 1970s and 1980s[9] when economic growth and expansion fueled the demand for new energy infrastructure.[10] Nationwide, utility investment generally slowed during the 1990s. This slowdown was attributed to several factors, particularly the uncertainty around disaggregation of vertically-integrated utilities and concerns of how new plant investment might be treated under the then-impending federal utility deregulation. Another driver of reduced spending was the opportunity to take advantage of the robust capacity in distribution, transmission and generation resources built up in prior decades. By the late 1990s, however, the country's utility industry recognized the need for increased investment to keep pace with customer growth, replace or rebuild aging facilities, and to meet increasing customer and regulatory expectations for greater power quality and

[7] 2016 Avista Service Quality Report Card, Found in Appendix B.
[8] The measuring protocol for SAIDI and SAIFI excludes outages caused by very large outage events such as the windstorm of November 2015. These major events are referred to a "major event days." Even with these major events excluded, however, we can still experience substantial variability caused by storms, for example, that do not qualify as major events.
[9] This cycle of utility investment ended as early as the 1960s for some utilities and through the early 1980s for others, including Avista.
[10] "Powering a Generation: Power History #3. http://americanhistory.si.edu/powering/past/h2main.htm.

system reliability. Avista's pattern of overall investment generally follows this national trend, as reflected in Figure 8.

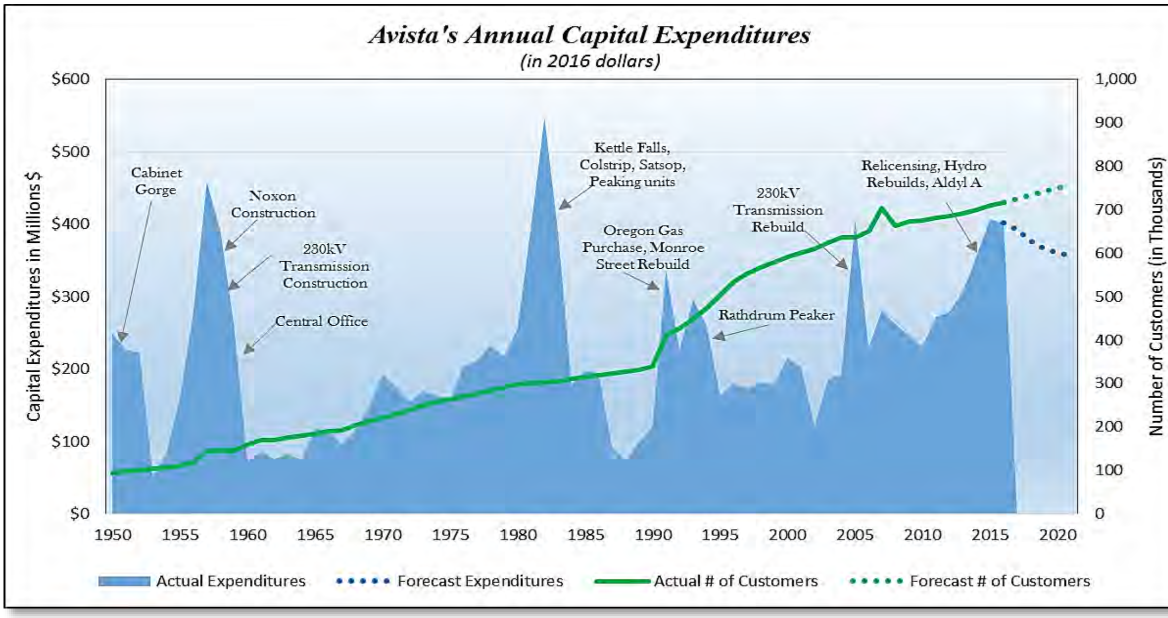

Figure 8. Avista's Annual Capital Expenditures, 1950 to Present, With Large Projects Noted

The Company's investments in the 1950s were driven primarily by new generation and transmission facilities, with more modest growth in electric distribution, office and operations facilities.[11] Investment growth in the 1960s and early 1970s was focused primarily on electric and natural gas distribution assets. The surge in infrastructure spending beginning in the late 1970s and continuing into the mid-1980s supported several new thermal generating resources that included our Kettle Falls station, a share in the Satsop nuclear station,[12] peaking resources, a share in Colstrip units 3 and 4, and associated transmission in eastern Montana. The significant decline in capital spending experienced by the Company in the late 1980s was a direct result of the financial hardship caused by the suspension and termination of the Satsop projects.

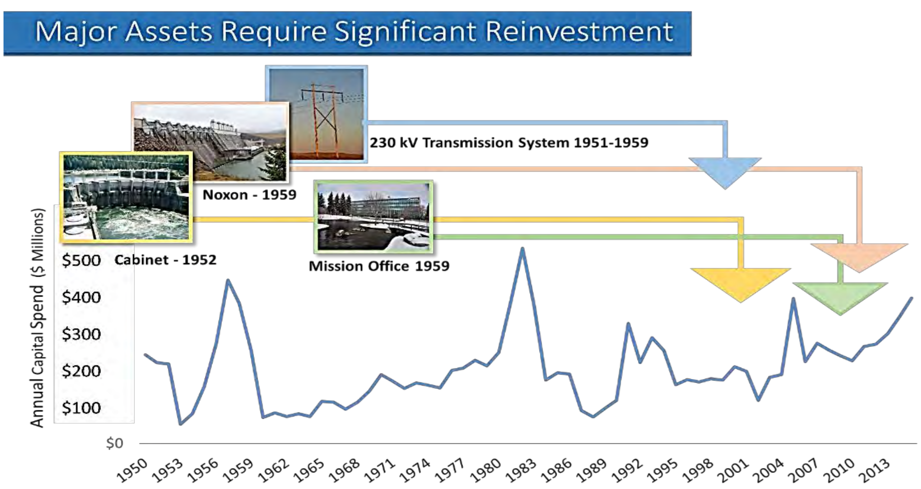

Figure 9. Avista's Aging Infrastructure Timeline

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[11] Avista's natural gas operations commenced in 1959 with its purchase of the Spokane Natural Gas Company.

[12] The Satsop Nuclear Generating Station was the showcase project of the Washington Public Power Supply System's (WPPSS) nuclear program. Satsop consisted of two developments, abbreviated as WNP-3 and WNP-5. Avista (The Washington Water Power Company) invested approximately $200 million (nominal) in a 5% share of WNP-3; construction was suspended for this unit in 1983 due to the default on municipal bonds numbers 5 and 6 by the WPPSS. The plant was approximately 76% complete. The failure of WPPSS to effectively manage cost overruns and delays and their resulting bond default, coupled with forecasts of load growth for the region that did not materialize, nearly forced the bankruptcy of the Company.

The Company's investments in the 1990s focused on distribution plant additions required to serve new electric and natural gas customers. Avista, like the broader industry, began to increase its annual infrastructure investments at the end of the 1990s; however, our planned increase in spending was disrupted and delayed by the events associated with the Western Energy Crisis in 2000 and 2001[13] which had a financial impact on the Company's ability to acquire capital on reasonable terms. Investment, while cut sharply, was restored and then increased to support significant new transmission and other investments. Avista's transmission spending in the period 2004 – 2007 was focused on our 230 kV system, which after 50 years in service, combined with issues of regional congestion, required major re-investment.

Some Recent Investment Requirements

- Vegetation Management
- Wood Pole Management
- First Generation Underground Electric Cable
- Priority Aldyl A Pipe Replacement
- New License Conditions for Spokane River Hydro Projects
- Major Hydro Project Redevelopment
- Ever-increasing Complexities of Information Technology Systems
- Rapidly Evolving Technology Platforms

Like the reinvestment in its 230 kV system, the Company has responded to other cyclical demands for capital spending needed to refresh other major infrastructure investments, such as those made in the 1950s, as shown in Figure 9 above. Examples include investments required by new FERC license conditions for our Clark Fork River hydroelectric projects, Cabinet Gorge and Noxon Rapids, as well as the overhaul of the major assets at these plants. Other significant reinvestments include the 230 kV transmission system (already noted above) and our central operating facilities in Spokane.

In more recent years, Avista, like the industry in general, has made cost-effective investments in smart grid systems and technologies designed to improve the reliability and resilience of our distribution system. The Company also invested in early asset management initiatives such as vegetation management and wood pole replacement. Other examples of investments made during this period are shown in the text box above.

The increasing demand for infrastructure investment experienced by the Company over the prior decade is essentially in step with the situation across the industry, as shown in the example for electric transmission and distribution investments in Figure 10.

[13] Referred to as the "Western Energy Crisis," this period of time was characterized by an electricity demand and supply gap created by energy companies, mainly Enron, to create an artificial shortage. Energy traders took power plants offline for maintenance in days of peak demand to increase the price. Traders were thus able to sell power at premium prices, sometimes up to a factor of 20 times its normal value. https://en.wikipedia.org/wiki/California_electricity_crisis#Some_key_events

The pattern of investments made by the Company during this period bear a striking resemblance to that of the industry, which should not be a surprise (as was previously mentioned) since we are all responding to the same investment needs. First, the need to replace an increasing amount of infrastructure that has reached the end of its useful life, and second, responding to the need for reliability and technology investments required to build the integrated energy services grid of the future.

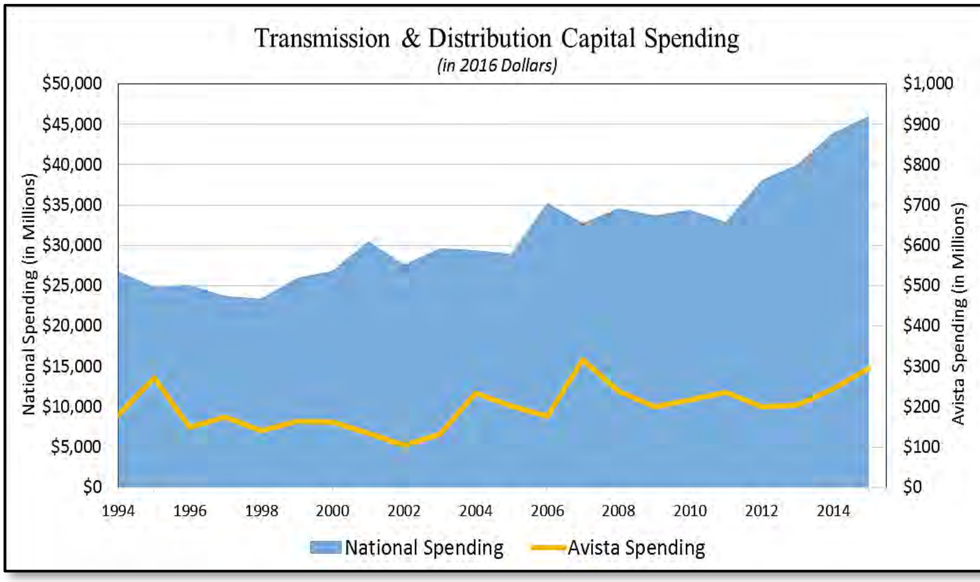

Figure 10. National & Avista Transmission & Distribution Capital Spending
Source of National Data: FERC Form 1

With the increasing levels of investment made by the Company in recent years, Avista has worked to manage the annual price impact to our customers by moving to our present level of investment more gradually. But more important than the total amount of the infrastructure investment we make each year is the annual investment divided by our total number of customers, or the 'capital cost per customer.' Over the past 65 years Avista's capital cost per customer has varied, sometimes significantly, based on the amount of our historic levels of investment and the number of customers we served. As shown in Figure 11, our current level of capital spending on a per-customer basis is generally in line with our trend over the prior 30-years, which has remained fairly stable.

> ***"Industry-wide capex has more than doubled since 2005… 157% greater than the investments made in 2004. The 2016 projections, if realized, will be a new high for this industry."***
>
> 2015 Financial Review: Annual Report of the U.S. Investor-Owned Electric Utility Industry, Edison Electric Institute

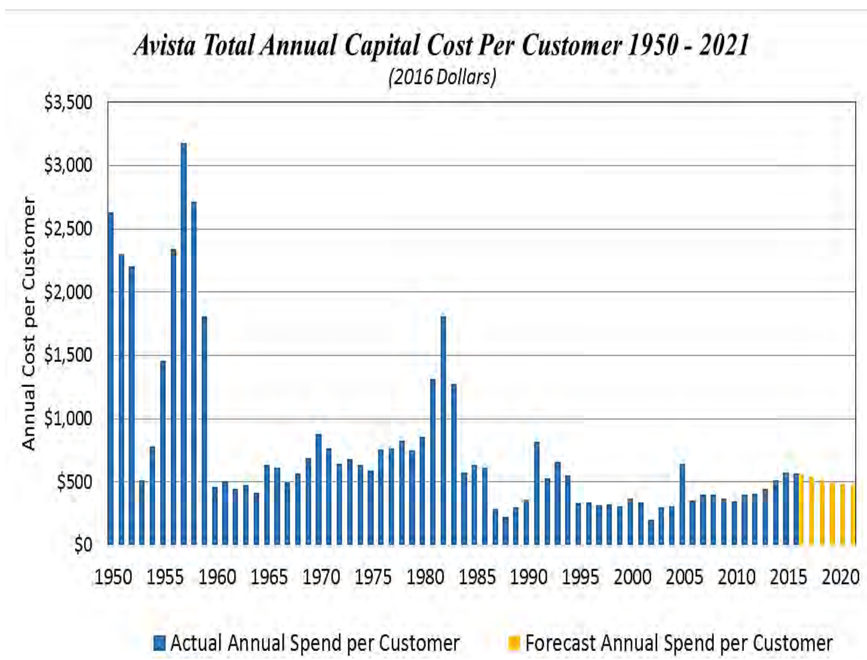

Figure 11. Avista Cost Per Customer Trend Over the Last 30 Years

Investments in Electric Distribution Since 2005

Avista "Smart" Transformer

The Company increased its annual capital spending over this period in direct response to the growing need for new investment. This increasing need included a modest increase in the number of new customers connected each year. The principal driver has been the Company's adoption of new asset management-based approaches for assessing our infrastructure needs and developing strategies to optimize the maintenance of our electric distribution system. Referred to "Asset Maintenance Programs," these annual investments have increased from about $2 million in year 2005 to over $20 million today.

Many of these programs are driven by reliability and customer service, such as the Grid Modernization ("Smart Grid"), Wood Pole Management, and Underground Residential District (URD) Cable Replacement Programs[14] which overhaul aging equipment and help reduce the number and length of outages.[15] Others include safety and environmental stewardship such as the PCB Transformer Change-Out Program, while others provide energy efficiency and cost savings for customers, such as the Street Light/LED Lighting Replacement Program.[16] The pattern of investments for these five programs, for the period 2005 – 2016 is shown in Figure 12.

Each of these infrastructure programs is discussed in detail in the remaining sections of this report. This discussion illustrates the need for these investments, and identifies the consequences to our system and our ability to deliver safe, reliable and cost effective service to our customers if these investments are not made in a timely manner by the Company.

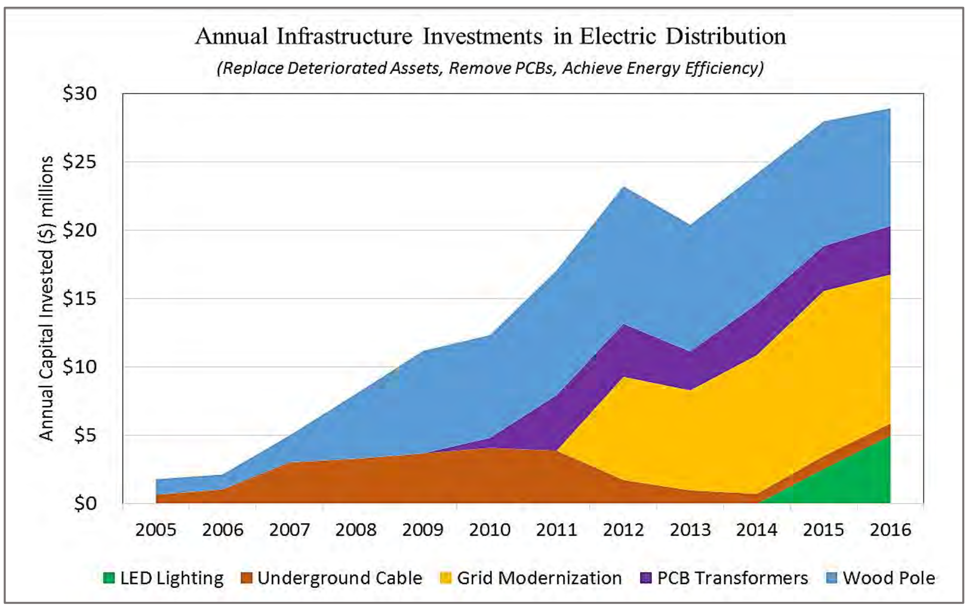

Figure 12. Electric Distribution Investments 2005 - 2016

Similar to the overall pattern of investment, as shown above in Figure 10 on page 13, the Company's annual distribution investments have been in step with those of other electric utilities on a cost per customer basis.

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[14] Wood Pole Replacement identifies and replaces structures likely to fail; the Underground Cable Replacement Program is replacing all underground cable installed prior to 1982, which has a high probability of faulting due to a lack of external jacket to protect the cable from damage or stray voltage.

[15] Smart Grid/Grid Modernization uses automated equipment on the feeder, such as reclosers, along with communication devices and an integrated distribution management system application, to quickly assess how to isolate the particular section of the feeder where the outage has occurred, and to reconfigure the feeder system in a manner that allows us to reconnect customers quickly beyond the isolated section of the feeder.

[16] Light Emitting Diode ("LED") lighting is super energy efficient, using approximately 80% less energy than High Pressure Sodium lamps, which are common throughout Avista's service territory.

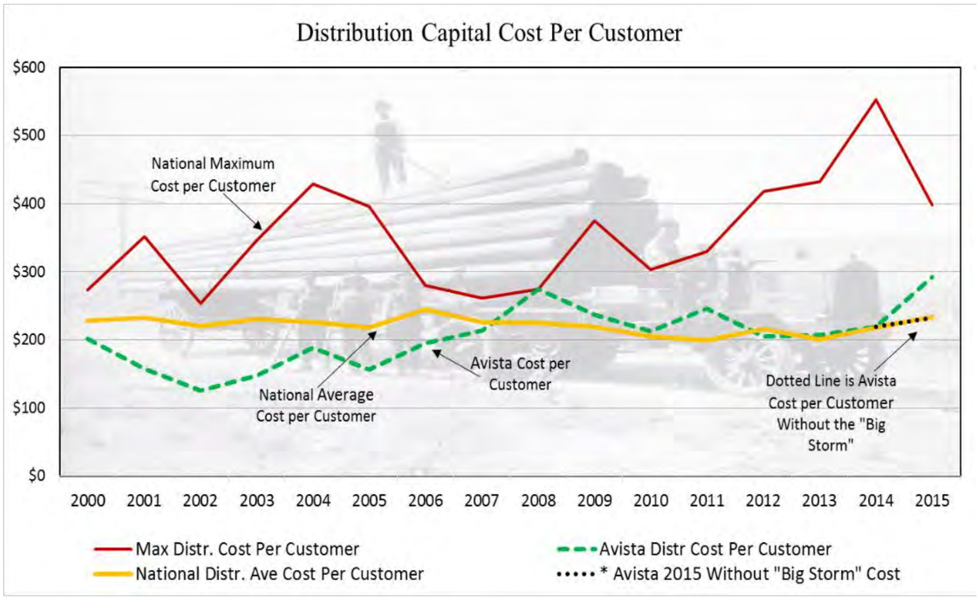


Figure 13. National & Avista Electric Distribution Capital Cost Per Customer
Source of National Data: FERC Form 1

Figure 13 shows the annual average electric distribution capital cost per customer for all FERC-regulated electric utilities, as well as the Company's annual capital cost per customer. This chart shows the maximum and the average annual distribution capital cost per customer for this national group as compared to Avista's distribution expenditures over the same time period.

Avista's expenditures tracked the industry average in the late 1990s and then fell well below the average, when the Company's investments in electric distribution infrastructure were depressed during and following the Western Energy Crisis, as reflected in our below average cost per customer. Our need for much greater investment following this period, as described above, pushed our per customer cost above the national average in 2007. However, our costs have generally converged with the industry group average since 2012 (and would be equal to the national average in 2015 as well, if the costs of the "Big Storm" are removed, as shown by the dotted line in the chart above). Avista's average capital cost per customer for investments in electric distribution has been slightly below the average for this utility group over the prior 15+ years.

November 17, 2015

The massive windstorm that Avista experienced in November 2015 caused nearly $23 million in damage to our equipment and affected over 180,000 customers for nearly two weeks, the worst storm in our history.

Currently Planned Distribution Investments (2017 – 2021)

Over the next five years Avista expects to invest an average of $101 million annually in its electric distribution system across its six investment drivers, as shown in Figure 14. The average investment by driver for this period is shown in Figure 15. Detail on the projects and programs that comprise the Company's electric distribution investments for the next five years are provided for each investment driver in the following sections of this report.

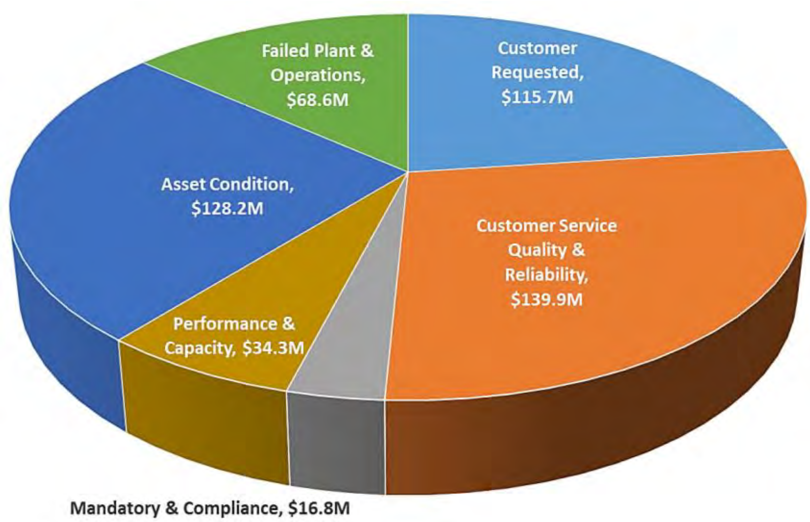


Figure 14. Average Distribution Expenditures by Investment Driver for 2017-2021

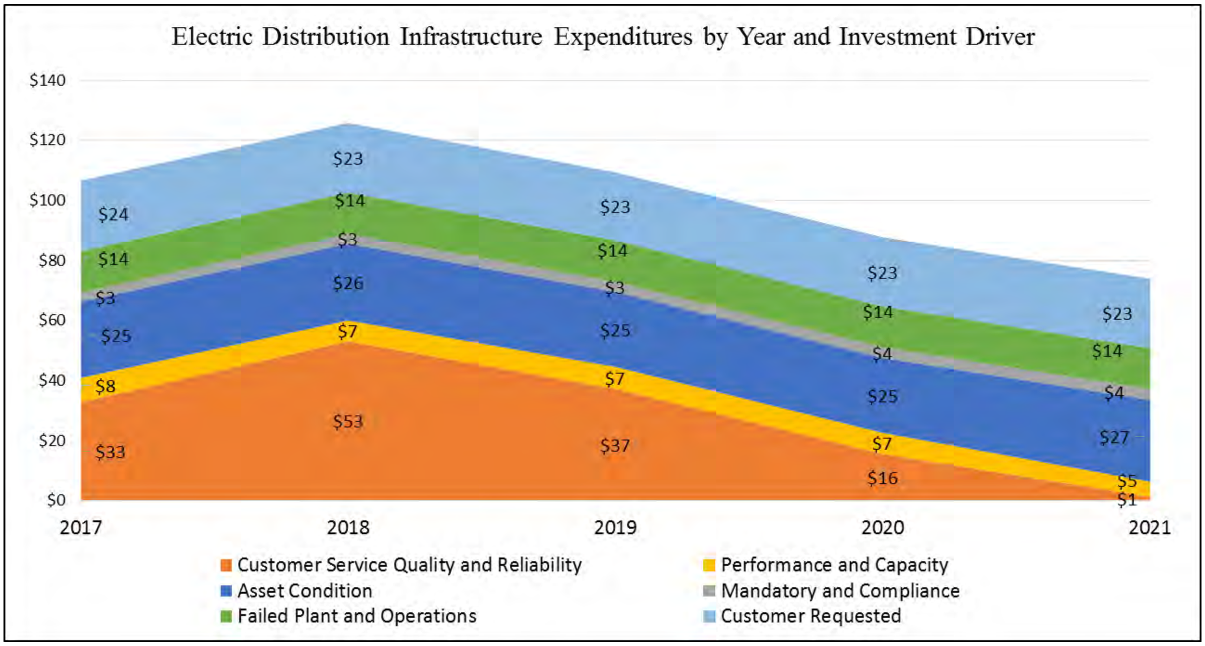


Figure 15. Average Infrastructure Investment by Driver: 2017-2021

The individual investments included in Avista's Distribution Infrastructure Plan represent a portfolio of projects and funding levels intended to optimize:

1) *The overall demand for distribution investment,*
2) *The specific requirements of the projects and programs proposed for funding, and the potential consequences associated with deferring needed investments, and*
3) *A balance among the needs and priorities of all investment requests across the enterprise, and the Company's investment planning principles.*[17]

The result demonstrates a reasonable balance among competing needs required to maintain the performance of our systems, as well as our prudent management of the overall enterprise in the best interest of our customers.

Because of the time horizon over which the Company must budget its infrastructure investments, there are inevitable changes in the actual projects funded, program budgets, and implementation timing. Such changes may be due to changes in project scope, changing material or resource costs, changing customer needs, or a more refined estimate based on where the project is in its development planning. External factors, such as new regulatory or legislative requirements, also drive changes in the plan and budget. The projects in the Company's portfolio are continuously reviewed for changes in assumptions, constraints, project delays, accelerations, weather impacts, outage coordination, permitting/licensing/agency approvals, and system operations, performance, safety, and customer-driven

[17] In setting its overall infrastructure spending limits, the Company considers a range of factors referred as "key planning principles."

needs that arise. The portfolio will be continually updated throughout the year to remain as accurate as possible. As the Company continues to refresh its infrastructure plan going forward, it will net out currently-funded projects slated for completion in the five-year plan, in conjunction with including new incremental needs for investment as we continue to forecast our long-term need for capital.

Outlook for Future Utility Investment Needs

Though utilities across the country, including Avista, have increased investment levels in transmission and distribution infrastructure in the past 10 years, there remains a demand for new incremental spending well into the future. The American Society of Civil Engineers in 2011 conducted an extensive review of then-current trends in electric utility investments, and identified a $37 billion "investment gap" between those current plans and the infrastructure investments needed by year 2020.[18] Their report on electric infrastructure was updated in 2016, noting the *significant increased investment that had been made by the industry* compared with the 2011 forecast of planned investments, but it still identified an $18 billion investment gap between current spending plans and the investments that will be needed by year 2025. The report noted that 54% of the $18 billion gap was attributed to the needs of electric distribution systems alone.[19]

Adding Grid Modernization Technology to a Feeder

Though the Company has raised its annual capital investments over the prior decade to the current plan of $405 million, we continue to have infrastructure needs that have not been fully funded. For example, the Company's Wood Pole Management Program initially targeted an inspection cycle time of 20 years.[20] Though we have remained on track with the 20-year inspection cycle, the follow-up work to perform needed repairs and replacements identified during the inspection needs additional funding to remain on schedule. In addition to the incremental investment needed for existing follow-up work, Avista's forecast of the number of poles that will need to be replaced each year shows a steady increase over the next 20 years, as is discussed in detail in the Wood Pole Management section of this report (page 57). The increasing number of poles and attached equipment that need to be replaced each year will drive an additional need for new investment.

Stubbing a pole can add an additional 20 years or so to the life of a pole

Other examples where the Company will have to increase the level of its current investments include our Grid Modernization Program to rebuild electric distribution feeders at the end of useful life,[21] and ongoing effort to correct reliability issues causing some customers to experience several times the annual outage rate experienced by our average customer.

[18] Failure to Act. The Economic Impact of Current Investment Trends in Electricity Infrastructure. American Society of Civil Engineers. 2011, http://www.infrastructurereportcard.org/wp-content/uploads/2016/10/ASCE-Failure-to-Act-2016-FINAL.pdf, page 16.
[19] Ibid., pages 16 and 17.
[20] In a 20-year cycle, the inspection / replacement activities would cover all of the wood poles in the Company's system, or approximately 240,000 poles.
[21] This effort includes the Company's "grid modernization" and "worst feeders" programs.

Overview of Avista's Electric Distribution System

Overview

Avista operates over 19,000 miles of distribution lines, including both overhead wire and underground cable systems, interconnected with 133 distribution substations[22] in the portion of our system depicted in Figure 16 below:

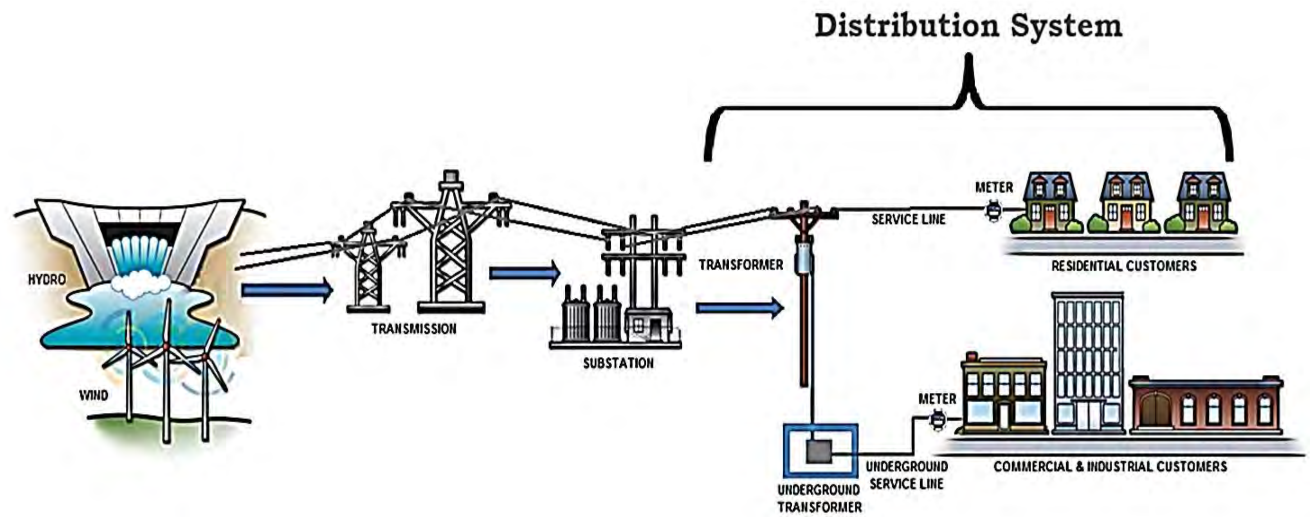


Figure 16. Primary Elements of Avista's Electric Generation, Transmission and Distribution System.

Though the bulk of our electric lines (or feeders) are concentrated in urban areas including Spokane, Coeur d'Alene, Moscow, Pullman, Lewiston and Clarkston, we also serve many rural towns, mining districts and agricultural and forest areas. Far from being homogenous, Avista's electric distribution system is composed of a wide range of equipment and diverse operating conditions, and is managed in 12 geographic units or 'operating districts' in Eastern Washington and Northern Idaho. These districts are shown below in the map in Figure 17.

Each operating district has its own unique characteristics and associated challenges, including heavily forested areas, steep mountainous terrain, dense and very sparse customer numbers, diversity in the size of customers, exposure to wildfire risk, and ease of accessibility for crews and equipment. Some of the key characteristics of each operating district are shown in Table 1.

AVISTA'S DISTRIBUTION SYSTEM	
Electric Substations	133
Overhead Lines	7,685 Miles
Underground Electric Cables	4,277 Miles
Service Lines	6,970 Miles

Distribution Line destroyed by wildfire

[22] Though interconnected with electric distribution feeders, substations are not considered part of the distribution system for the purposes of this plan and report.

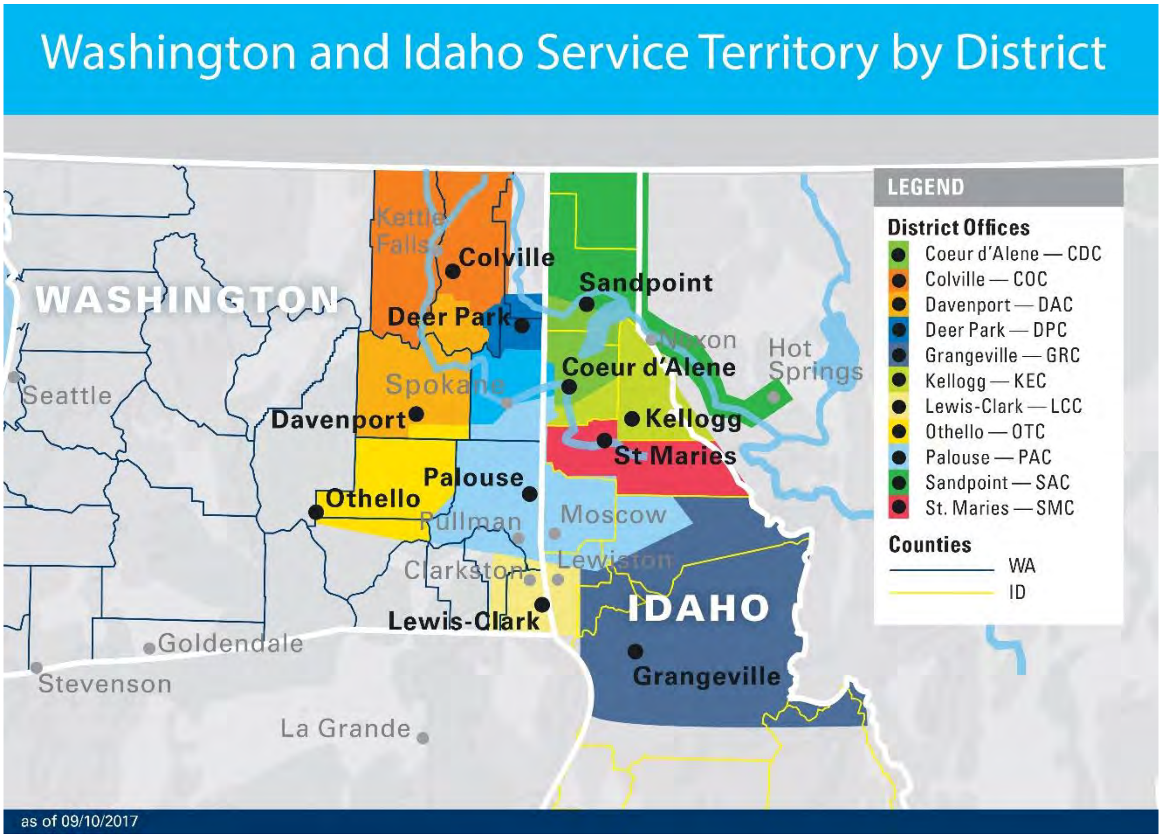


Figure 17. Map of Avista's Service Territory in Washington and Idaho

District Office:	Overhead Circuit Miles	Underground Circuit Miles	Elec. Customer Meter Count	# Primary Meters	Customers per Circuit Mile	Number of Feeders	Number of Transformers	Number of Structures
Coeur d'Alene	530.7	609.0	55,136	13	48.4	38	9,468	23,148
Colville	1521.7	999.6	19,681	7	7.8	26	8,956	23,250
Davenport	541.6	87.6	5,941	4	9.4	13	3,935	11,720
Deer Park	320.9	248.8	10,934	0	19.2	9	3,025	8,069
Grangeville	474.5	216.9	10,106	12	14.6	22	4,495	9,648
Kellogg	293.0	140.1	9,834	13	22.7	19	3,353	7,637
Lewis-Clark	390.2	143.0	29,615	24	55.5	28	7,676	13,000
Othello	397.5	60.4	7,008	5	15.3	15	3,629	8,011
Palouse	1029.5	393.2	40,486	17	28.4	46	9,381	22,094
Sandpoint	422.2	243.3	14,993	2	22.5	17	4,963	11,902
Spokane	1535.4	835.2	171,384	55	72.3	116	28,112	59,536
St. Maries	223.8	136.5	4,575	2	12.7	4	2,159	4,878

Table 1. Avista District Office Statistics

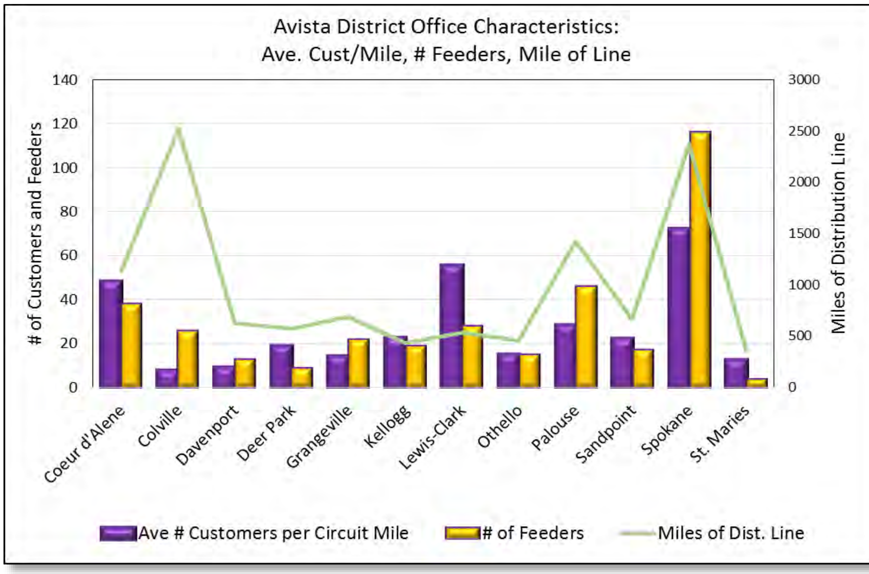


Figure 18. Avista District Office Characteristics: Customer Count and Miles of Line

Some of the key differences among the statistics for these districts are shown in Figures 18 and 19. For example, the Colville and Spokane districts have nearly the same numbers of miles of overhead feeder line, but Colville has a greater number of overall feeder miles when underground facilities are included. While Spokane has over 170,000 customer meters and approximately 72 customers per mile of line, Colville has just under 20,000 electric meters and just under 8 customers per mile.

The more striking difference between these districts, however, is in the number of feeders that comprise the total miles of line: Spokane – 116, and Colville – 26. This difference means that the average customer in Spokane is connected to a feeder that is just over 20 miles in length, while the average Colville customer is connected to a feeder that is 97 miles in length. Since the length of the feeder is one measure of the exposure of customers to a service outage, one can easily see how the operating conditions among our districts can vary widely. A brief description, written by the Districts themselves, of the characteristics of each operating district is provided below.

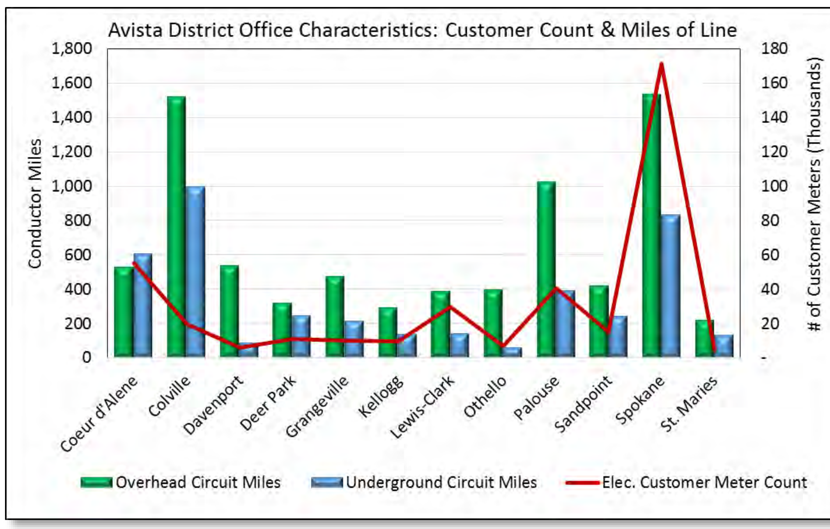


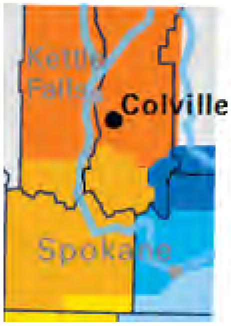
Figure 19. Avista District Office Characteristics: Ave. Cust/Mile, # of Feeders, Miles of Line

Left: Windstorm Rolling into Richland, WA
(Picture by Skyking3286 at Kadlec Hospital in Richland

Right: Linemen in Spokane working on congested lines

Colville District

Avista's Colville service territory is one of the company's largest at approximately 2,400



square miles, serving about 20,000 electric customers. It is also the most rural, with an average of only 7.8 customers per circuit mile, the lowest average in the Company. However, Colville also has more underground circuit miles (999.6 miles) than our largest operating district (Spokane) and almost identical amounts of overhead circuit miles (1521.7 miles). They are also responsible for 61 miles of electric transmission line and a high pressure natural gas line (as well as the associated regulator stations) starting north of Deer Lake and ending in Kettle Falls. This huge area is served by two electric line crews, two servicemen, and five local representatives plus one gas local representative and a four man gas contract crew, all supported by a staff of six.

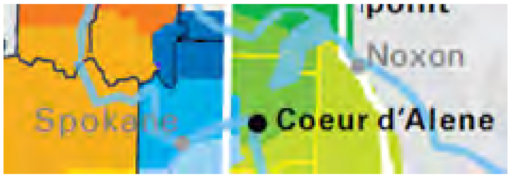
This Office maintains some of the Company's most geographically challenging terrain. They serve extremely remote locations as well as heavy timber, mountains, rivers, canyons, marshes and swamps, farmland and pastures. Though often stretched thin by the vast geographical service territory and the amount of infrastructure that it contains, this office always finds time to volunteer in their community, serving on the Colville City Council, Rotary, Lions Club, Kiwanis, and other civic organizations.

Above: Restoring power after a washout. Right: Wind storm damage

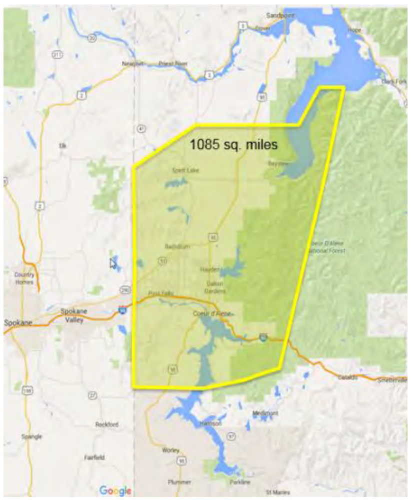
Colville	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	1521.7	999.6	19,674	7	7.8	26	8,956	23,250

Coeur d'Alene District

The Coeur d'Alene Operating District encompasses over 1,000 square miles of Kootenai County, Idaho, made up of both urban and rural landscapes and geography,



from city regions to mountainous and heavily timbered areas. This Office provides power to over 55,000 customers (at about 48 customers per mile) in urban areas including Coeur d'Alene, Post Falls, and Hayden, to more rural areas in Rathdrum, Spirit Lake, Lake View, and most of the Coeur d'Alene Lake area. They support and maintain approximately 531 overhead distribution circuit miles and 609 underground distribution circuit miles as well as 14 substations that connect 38 feeders. The District is also responsible for 156 miles of 115 kV and 230 kV transmission circuit. The office is comprised of four line crews and four line serviceman who are faced with challenges including snow, ice and heavy winds.



Overhead distribution work

Transmission line repair in Coeur d'Alene District

Coeur d'Alene	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	530.7	609.0	55,123	13	48.4	38	9,468	23,148

Kellogg District

The Kellogg office serves all of the Silver Valley, which has a long and rich mining history. In the 1970s, half of the world's silver came from mines located in this valley. In fact, the Galena and Lucky Friday mines are two of the largest customers served by the Kellogg office. These mines require an immense amount of power to pump air in and pump water out of the mines. The office also serves other large customers, including two major ski resorts.

The Kellogg District covers over 1,200 square miles, starting at the top of 4th of July Pass and extending east to the Montana border. Its northern reach is just past Murray, Idaho and it runs south to Medimont, Idaho. The majority of this territory is mountainous, heavily timbered, rugged and extremely difficult to access. There are 11 employees in the Kellogg office serving approximately 10,000 electric and 6,000 natural gas customers in small towns including: Cataldo, Kingston, Pinehurst, Smelterville, Kellogg, Osburn, Silverton, Wallace, Mullan, Prichard and Murray. This office is also responsible for approximately 154 miles of electric transmission lines, 421 miles of electric distribution and 230 miles of natural gas pipeline.

Over 114 average inches of snow per year is just one of the challenges faced by the Kellogg office.

The topography, weather and remote location of the infrastructure in this area requires employees to access and work on many structures without the use of bucket or line trucks; frequently, isolated transmission lines require the use of a helicopter to patrol and access the lines when the lights go out. The Coeur d'Alene River and its tributaries flood annually, which also creates many challenges. Wildlife, specifically elk and deer, are a constant presence and hazard while driving in the winter. Some of the towns served are above 3000' elevation and receive a substantial amount of snow, an average of 114 inches per year in some locations, presenting additional complications.

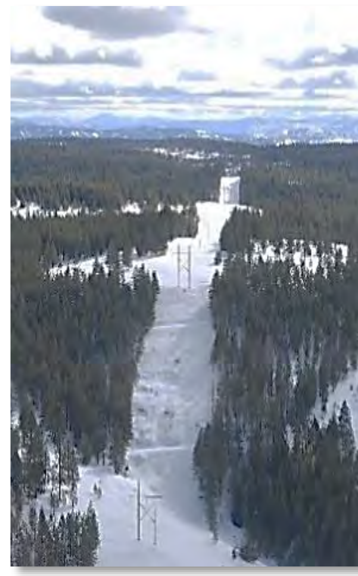
Kellogg	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	293.0	140.1	9,821	13	22.7	19	3,353	7,637

Lewiston-Clarkston District

The Clarkston Office is situated in the “Banana Belt” of the Lewis-Clark Valley, serving nearly 30,000 electric and natural gas customers. This District is made up of two Electric Crews, one Natural Gas Crew, a combination crew, and four Servicemen, plus a support staff of six.

Springtime high above the Snake River

This group is responsible for maintenance and construction of the electric and natural gas operations in Washington and Idaho as well as over 120 miles of transmission systems spanning Idaho, Washington, and Oregon.



Above: Typical transmission right-of-way

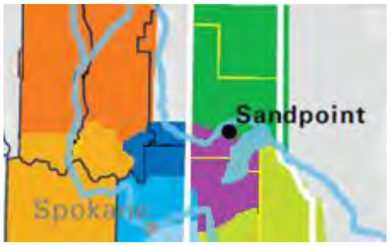
The Clarkston crews provide and support service under varied and diverse conditions, from urban to rural, wildfires to heavy snowfall. Their territory includes extreme back country which requires Snow Cats, ATV’s and helicopters to access their lines and equipment. Due to the size and complexity of their service territory, they often partner with the Palouse and Grangeville Districts on large-scale projects and outages, resulting in more rapid restoration of service to customers. This group is also very community minded; they are famous in the area for their participation in local events and civic organizations.

Right: Building an access road to reach downed lines in the winter

Lewiston & Clarkston	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	390.2	143.0	29,591	24	55.5	28	7,676	13,000

Sandpoint District

The Sandpoint Operations staff (approximately 20 employees) serve roughly 24,000 electric and natural gas customers in 14 small towns that are nestled deep in the mountains of North Idaho and Western Montana. Sandpoint's service area includes some of our Company's most northern communities, with service territory stretching to within 20 miles of the Canadian border. This team maintains over 160 miles of distribution and transmission lines; the Company's two largest hydroelectric generating stations are also within their area of support.



Above: accessing poles on a mountaintop

Left: repairing a transmission structure at Noxon Rapids Dam

Sandpoint has the highest average snowfall of all Avista's service territory and is located at the bottom of Schweitzer Mountain. Along with the beauty of rugged mountains and plentiful lakes and rivers comes challenges for accessing power lines and natural gas facilities. During winter months much of the transmission in this District is only accessible by helicopter or by hiking in with snowshoes, especially along the extreme rugged cliffs that border Lake Pend Oreille. Winter storms can bring with them large scale power outages. For a 2015 windstorm, Sandpoint called in 32 crews to help restore service following a major outage.

Perhaps the most challenging environmental condition this office regularly faces is water. A tremendous amount of sloughs and swamps surround many of the lakes and rivers, and flooding is often an issue. These crews also support a major transmission line that runs into Montana, crossing the Clark Fork River 15 times. The Clark Fork often floods in the spring, and at times conditions are so treacherous that crews cannot even reach downed lines by boat. There are many areas in this operating district that are only accessible during a three month period between July and September.

Snow in Sandpoint

Sandpoint	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	422.2	243.3	14,991	2	22.5	17	4,963	11,902

Deer Park District

Located just north of Spokane, Deer Park is a historical sawmill town. At its peak, the town had as many as eight sawmills in operation, the lumber from which was used to help rebuild Spokane after the great fire of 1889. The Deer Park District Office encompasses several towns including Loon Lake, Deer Lake, Clayton, Deer Park, Elk, Chattaroy, Colbert and the North Mead area. It's ten employees serve approximately 11,000 electric and 5,100 gas customers, and sustain and support approximately 50 miles of transmission, 420 miles of distribution and 330 miles of natural gas lines. The Kettle Falls High Pressure Gas Transmission Line runs through the Deer Park District from North Spokane to our Kettle Falls Generation plant, and this team (in combination with the Spokane Crew) helps manage the associated regulator stations and farm taps.

Deer Park Crew repairing transmission

The area they serve is heavily treed, especially around the lakes, and is rugged and extremely difficult to access, including no truck access at all in some areas, requiring occasional use of helicopters. Wildlife challenges include bear, cougar, elk, deer and moose. Being located in the snow-belt creates additional difficulties during the winter months, and spring runoff often makes the ground unstable for the trucks. Some outages and repairs require line crews to access facilities on foot.

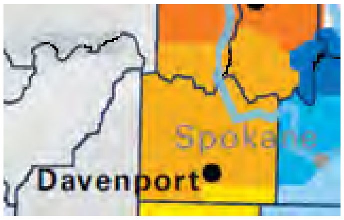
Upgrading Distribution

Deer Park employees are also active in the communities they serve, including City Council, Chamber, Rotary, Settlers Day Parade, Kiwanis, Christmas Lighting celebrations, food banks and other civic organizations. They are building a new service center starting in 2017 which should be completed in the spring of 2018.

Working on a substation issue

Deer Park	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	320.9	248.8	10,934	0	19.2	9	3,025	8,069

Davenport District



The nine-person Davenport District Office is a microcosm of Avista's rural service territory. It encompasses heavily timbered areas, sagebrush desert, and extensive farmland; it includes approximately 6,000 electric and natural gas customers in many small towns, including the Spokane Reservation in Wellpinit, Ford, Almira, Creston, Edwall, Fruitland, Harrington, Hunters, Odessa, Reardan, Springdale, and Wilbur, with an average of only 9.4 customers per mile of feeder. At approximately 1,000 square miles, the Davenport four man crew has to cover a lot of ground. In addition, they are responsible for maintaining two 115 kV transmission lines that were built in 1924 and 1962, about 80 miles long each, and which require frequent repairs in order to maintain service. Davenport's territory is troubled by yearly wildfires which have occasionally destroyed significant segments of these lines in the summer, and by heavy frost/fog ice loading which causes multiple outages every winter. The size of this territory and its diverse topography can cause longer than average outages due to travel time, rough terrain, and cross country power lines.

Above and below: The Davenport crew managing equipment and restoring service through wildfires and floods

Left: Crews work diligently during a snow storm to restore power.
Photo courtesy of Infinity Rose Photography
https://www.facebook.com/InfinityRosePhotography/

Almira, Washington – Kari McKay Photography, http://www.almirawashington.com/

Davenport	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	541.6	87.6	5,937	4	9.4	13	3,935	11,720

Grangeville District

The Grangeville service territory is comprised of approximately 10,000 customers spread over 1,000 square miles, overseen by nine field personnel. This territory includes regions such as Elk City, Cottonwood, Orofino, Pierce, Kamiah, Nez Perce and Winchester. In some of these areas the transmission and distribution lines run through rugged terrain, heavily treed with little or no access by truck even in summer months. During the winter, these regions are buried under feet of snow and ice, which can require extraordinary efforts to restore power to customers during outage situations. This region is also home to rich farmland, creating unique challenges during the wet season in accessing structures without harming landowner's crops or property. The diverse terrain of this area creates risks and a wide range of hazards in maintaining and restoring service.

Grangeville is home to some of the area's most productive farmland

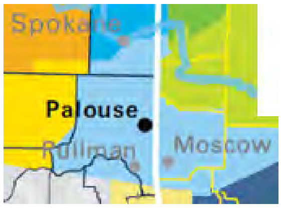
Grangeville District terrain

Grangeville's terrain presents some major challenges. At times helicopters must be used to access lines.

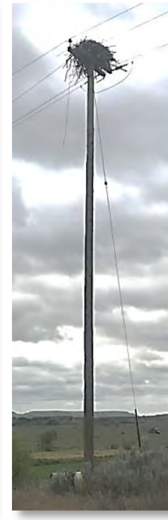
Grangeville	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	474.5	216.9	10,094	12	14.6	22	4,495	9,648

Palouse District

The Palouse Construction District Office has approximately 30 employees and is located between Pullman, WA and Moscow, ID. The District covers around



5,000 square miles and serves nearly 41,000 natural gas and electric customers. This group is made up of two electric crews, one natural gas crew, two electric serviceman, two gas serviceman and five electric local reps along with supporting staff, performing both distribution and transmission work.



Left: moving poles and lines for a county road project

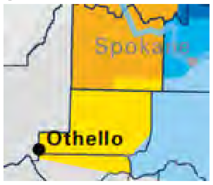
With such a large service territory, the crews work in diverse terrains including farm fields, rivers and creeks, mountainous and back country, along with cities and small towns, daily facing the challenges that come with each. Often the work must be scheduled around when areas are even accessible. Located in the Palouse, honoring the farming community is an abiding concern. For example, farm fields in the winter time are too wet to access, but these fields are tilled and planted from approximately May until middle of August, giving crews a very small time window to try to address any issues in the fields. The crews use several different kinds of vehicles to access equipment in the different terrains, such as ATV's, Snow Cats and sometimes helicopters. Even then, at times the crews have to hike into areas in order to inspect an issue. This service area also intertwines with other utility companies. Whenever our work involves both, there is a lot of planning and coordination required for both companies. They also work closely with neighboring Avista District Offices to share resources and equipment when needed.

Left: taking care not to damage valuable farmland
Above: Palouse crews use a variety of equipment to access their lines

Palouse	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	1029.5	393.2	40,469	17	28.4	46	9,381	22,094

OTHELLO DISTRICT

The Othello District Office consists of nine dedicated employees who serve roughly 7,000 electric and 3,000 gas customers in the Company's western-most portion of its electric service territory. Although most who've



driven through Othello think of it as very flat, it actually contains very rugged country that is nearly inaccessible. Having been formed by the great Missoula floods, there are many basalt cliffs and sandy valleys through which the transmission and distribution lines run. When troubles arise, primarily wind storms, a helicopter is used to patrol the hundreds of miles of transmission lines rather than attempt to navigate the basalt scablands with vehicles. At times, the team has to travel up to 160 miles to reach a line.

Upgrading Othello transmission lines

Powerful windstorms in the Othello area can cause major damage

This office is responsible for one of the Northwest grid's key 230 kV transmission lines, which carries power from the Wanapum Dam on the Columbia River 80 miles towards Walla Walla. They also maintain the 115 kV transmission lines that span from the Hanford Nuclear Reservation to Warden, Washington, and from Sprague to Othello. In addition, they are responsible for nearly 400 miles of distribution lines spread out over 15 different feeders, serving the towns and areas around Othello, Lind, Ritzville, Sprague, and Washtucna.

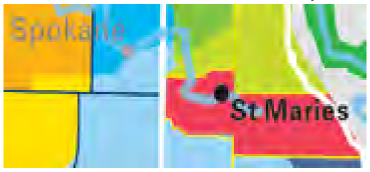
Othello is home to the majority of the Company's irrigation load, as it is in the heart of the Columbia Basin Irrigation Project, the largest water reclamation project in the United States, supplying water to over 680,000 acres. With the highly productive crop land comes enormous processing plants, two of which are Avista's 5th and 6th largest customers, McCain Foods and Simplot, respectively. These plants supply French fries to most of the world's McDonalds and Burger King Restaurants.

Othello is growing rapidly thanks to its agriculture base, with large residential developments being built along with large crop storage buildings and processing plants. To accommodate this growth, an additional 30 MW transformer is being added to one of the three Othello substations in the next year.

Othello	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	397.5	60.4	7,003	5	15.3	15	3,629	8,011

St. Maries District

The St. Maries district consists of a four man line crew and one local representative serving



approximately 5,000 rural customers in the St. Joe River Valley, including the community of Harrison and the surrounding areas on the east side of Lake Coeur d'Alene. The majority of this district is in mountainous terrain; falling trees and limited access are continuous hurdles for this small crew. This District office also serves two major sawmills, Potlatch and Stimson.

The area is subjected to heavy snows in the winter and major flooding in the spring, creating significant challenges in serving customers. Fortunately this crew is ingenious in coming up with quick and reliable solutions. In one example, heavy snow loading in the trees next to a line was causing multiple outages over a seven day period. The crew brought in a logger with a specialized piece of equipment to knock all the snow out of the trees (see the picture on the far right) next to their rural feeders to help minimize outages. What a great example of Avista employees thinking outside the box to keep our customers in service!

Above: Logger shakes snow off trees next to a line to prevent further snow-shedding outages

St. Maries	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	223.8	136.5	4,573	2	12.7	4	2,159	4,878

Spokane District

The Spokane Electric Operations group constructs and maintains roughly 1,500 miles of overhead circuits and 850 miles of underground circuits, as well as over 230 miles of transmission lines within the Spokane District, which covers 853 square miles in and around Spokane County. The Spokane Operations Team serves approximately 175,000 residential and commercial electric customers, making it the largest customer-based service territory within the company. This team of 77 employees is comprised of ten Line Crews, six servicemen, craft personnel, leadership, and office staff. These crews are flexible, as they are frequently called to aid and assist outlying districts with transmission and distribution support.

Spokane Linemen deal with the complexity of multiple foreign utilities located on their poles

The Spokane service territory is mostly urban, but does include several rural locations. Because of the mostly urban environment of the Spokane service area, these crews face some unique challenges when constructing and maintaining the distribution system in and around Spokane. Working conditions are often congested, with multiple foreign utilities rights-of-way on their poles as well as vehicle and human traffic. In addition, these crews deal with the same environmental conditions faced by the other districts, including wind, snow, ice and fire as well as the unique accessibility issues that come with a high customer density.

Above: Setting a pole in a backyard with a crane due to accessibility issues
Below: Stuck in the mud

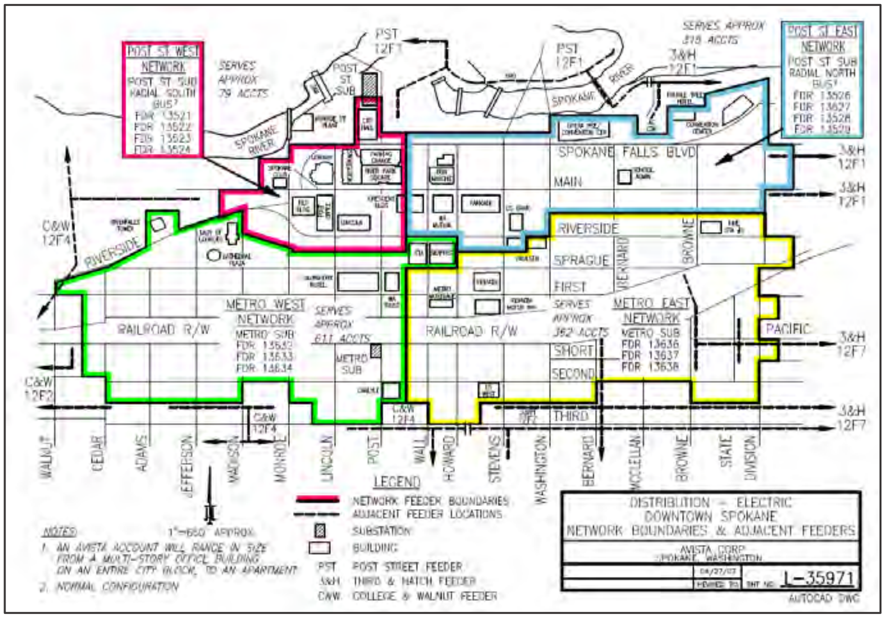
The Spokane District is responsible for a number of transmission lines

Just like the more rural Districts, Spokane has it's share of difficult circumstances and terrain

Spokane	Overhead Circuit Miles	Underground Circuit Miles	Customer Count	Number Primary Meters	Number Customers Per Mile	Number of Feeders	Number of Transformers	Number of Structures
	1535.4	835.2	171,329	55	72.3	116	28,112	59,536

Spokane Downtown Network

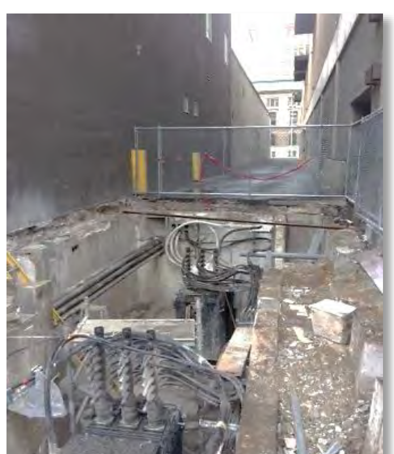
Avista operates an underground electric distribution system in the core business district of downtown Spokane. This distribution "network" is configured as a fully redundant distribution grid that includes cables encased in concrete reinforced duct lines and major equipment such as underground transformers in concrete vault structures. The Spokane Electric Network encompasses over a thousand underground manholes, hand-holes and vaults. Within the Network's boundaries there are 176 three-phase subway style transformers, 176 network protectors, 176 relays and an equal number of submersible three-phase transformers, all maintained by Network cable crews.



The complex process of filling paper insulated lead cable with lead to create a solid splice is a specialty of this crew

One of the primary issues faced by the Downtown Network is aged equipment. Many of the Network's 741 electric services were installed as early as 1907. Over half of the primary cabling in the Downtown Network is underground Paper Insulated Lead Cable (PILC) installed in the 1930's. The Network also continually deals with the complexities of city road move and construction projects and load growth. Even facing these issues, the Network is inherently reliable, designed to keep customer lights on during the loss of any one piece of distribution equipment. This system has proven to be very effective - customer outages are rare, averaging 1 event every 3 years over the past 40 years, with the longest customer outage recorded at less than 8 hours.

The Network is truly unique, in its electrical connectivity (everything is loop fed), its facilities (all vaults must be custom designed) and its work (splicing, especially for their underground cables), but handling unique and specialized equipment under trying circumstances is part of a normal day for this elite group.



Many of the vaults in Downtown Network are decades old

Planned Spending by Investment Driver

Customer Requested Investments

Avista defines these investments as "<u>*customer requests for new service connections, line extensions, transmission interconnections, or system reinforcements to serve a single large customer*</u>." We have often in the past referred to new service connects as "growth," as in growth in the number of customers, however, these investments are beyond the control of the Company, and as such they do not reflect a plan or strategy on the part of Avista. Responding quickly to these customer requests is a requirement of providing utility service.[23] Customer requested activities are typically limited to the electric distribution system, but may be extended to include substation infrastructure and dedicated high voltage transmission facilities, which are not the subject of this report. Typical projects include installing electric facilities in a new housing or commercial development, installing or replacing electric meters, or adding street or area lights per a request from an individual customer, a city, or county agency. As would be expected, fluctuation in the number of new customer connections is largely dependent on local economic conditions both in the housing and business sectors. Population growth rates in the Avista service territory typically range from 1-3% with specific outliers such as Liberty Lake and Pullman, where commercial business development is driving greater increases in local populations.

New Service Connects

Avista currently serves approximately 377,000 electric customers. The pattern of new connections shows that our service area is still recovering from the economic downturn of 2007-2011, as shown in Figure 20.

The five-year forecast for new customer connections for the period 2017 - 2021 is approximately 30,000, for an annual average of approximately 6,000, as shown below in Figure 21. This higher forecast rate of new additions is based in part on expected improvements in local economic activity. In addition to the economic forecast, the expected number of new connections is also based on

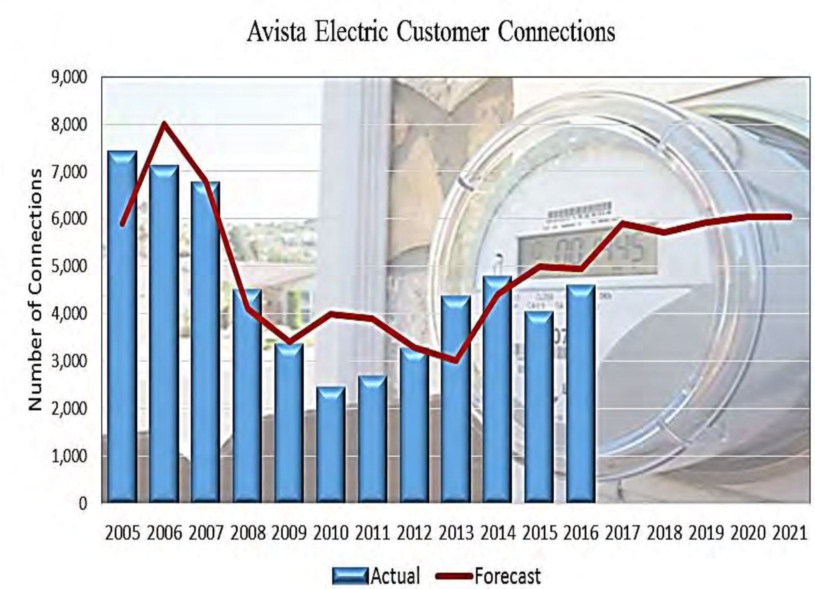
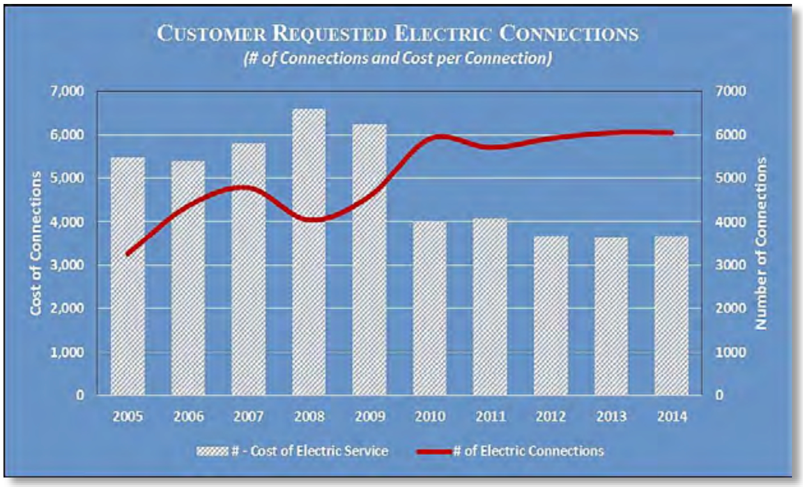


Figure 20. Avista Electric Customer Connection Requests – Actual & Forecast

[23] Avista Corporation provides electric and natural gas service in five states including Alaska and Montana, however, this report covers only the regulated electric operations of Avista Utilities in our service areas in the states of Washington and Idaho.



population trend data and city and county building permit applications. The investments needed to support new customer connects generally reflect the extension of existing distribution infrastructure rather than substantial modification to existing assets.

Figure 21. Avista Electric Customer Number of Connections & Cost Per Customer

Cost of Service

Avista tracks the costs required to meet customers' requests for electric service in the following six categories:

1) ***Electric Service Extension*** – the cost of installation labor, material, procurement, design and associated costs to extend electric primary and secondary wires and cables from Avista's distribution grid to the customer's point of service.
2) ***Electric Meters*** – the cost to purchase and install electric meters including commercial and industrial class equipment.
3) ***Distribution Transformers*** – the cost to purchase and install overhead and pad mount transformer equipment.
4) ***Street Lights*** – the costs to purchase and install roadway street lights.
5) ***Area Lights*** – the costs to purchase and install customer premise area lights.
6) ***Transmission & Substation*** – the costs to construct high voltage transmission lines and associated substation equipment.

Table 2 shows the forecasted costs by category, the overall expected investment, the number of new connections, and the overall cost of service (total investment / number of new connects) for each year in the current planning period.

Customer Requested Electric Connections	2017	2018	2019	2020	2021
Extension	$19,272,801	$18,574,437	$19,174,489	$19,574,521	$19,472,818
Meters	$2,027,379	$2,051,316	$2,114,092	$2,172,453	$2,217,720
ERTs	$1,112,771	$1,131,677	$1,166,113	$1,199,109	$1,227,269
Regulators	$482,795	$481,515	$496,489	$509,220	$515,989
Total	$22,895,746	$22,238,945	$22,951,183	$23,455,303	$23,433,796
# Electric Connections	6,245	6,019	6,213	6,343	6,310
Cost per Service	$3,666	$3,695	$3,694	$3,698	$3,714

Table 2. Forecast Electric Customer Connections

Investments in Customer Service Quality and Reliability

Customer Service Quality and Reliability investments are those "investments required to maintain or improve the quality of services we currently provide our customers, to introduce new types of services and options based on an analysis of customer needs and expectations, to ensure we achieve our customer service quality requirements, and to meet our electric system reliability objectives." Distribution investments in this category include such programs as the Company's current deployment of advanced metering infrastructure (AMI) in our Washington service area and deployment of feeder automation systems to reduce the impact of an outage on our customers. The trend towards automation, distributed resources, energy storage, and direct consumer interaction is transforming the century-old model of energy delivery to the "grid services platform" of tomorrow. As the industry adapts and conforms to these economic and societal drivers, Avista must carefully evaluate and consider how best to align resources towards common goals and objectives.

Reliability Investments

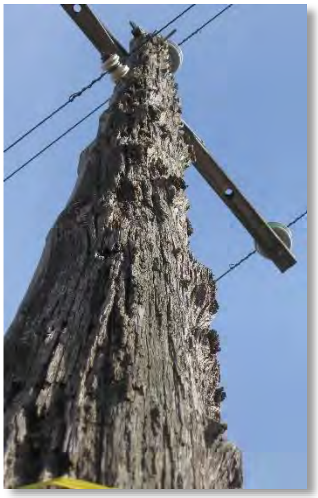
Avista has in the past referred broadly to individual investments we make as having the purpose of "improving reliability." This attribution reflects the fact that many investments, especially distribution investments made to replace deteriorated assets, are very likely to improve the reliability of the specific infrastructure that is being rebuilt or replaced. This is the case because the likelihood of failure of an asset generally increases with age and deterioration over its service life. Avista's many infrastructure investments often include at least a mention of these reliability benefits, and some are quantified and discussed extensively, as in the Company's Grid Modernization Program. In the great majority of cases, however, the *predominant* need for these investments is to replace assets that have reached the end of their useful life, or to a lesser degree, to solve capacity and performance issues, and not for improving reliability.[24] But this timely replacement of assets is crucial to our ability uphold and maintain our current levels of reliability performance. Accordingly, we separate electric system investments that are related to reliability into two groups: "Reliability as a Factor" and "Reliability Projects and Programs," both discussed below.

Old equipment increases reliability risk

Reliability as a Factor – Reliability benefits are considered in almost every program and project in Avista's portfolio as well as in the alternatives considered. As an example, our Wood Pole Management Program inspects, repairs and replaces wood poles and associated equipment based on asset condition. One of the alternatives considered was a shorter inspection cycle. This option was considered based on potential reliability benefits, but those benefits were superseded by the additional costs of the shorter cycle and the length of time it would take for any potential reliability increases to actually enhance overall reliability. To further illustrate this concept, even though reliability is obviously a factor when we replace equipment damaged by storms or required by the state when a road is relocated, it is not the primary driver, as this work is required regardless.

[24] In this discussion we distinguish between cases where the rebuilding of a deteriorated feeder will very likely result in that feeder being more reliable when completed, versus the impact that feeder rebuild has on the reliability of Avista's overall distribution system. The investment will likely improve the reliability of that feeder for those customers it serves, but from a system perspective, that investment serves to "uphold" and maintain our current overall level of system reliability.

Reliability Projects and Programs – In contrast with the consideration of "Reliability as a Factor", Avista defines Reliability Projects and Programs as being made primarily or exclusively to meet a reliability objective. In other words, were it not for the intended reliability benefit, the investment would likely not be made. An example of this type of investment is the installation of remote communication capability to a feeder in conjunction with remotely operated equipment. This combination allows a feeder to be "sectionalized"[25] to isolate that portion where the outage is located, thus reducing the number of customers who experience a sustained outage. Though this investment achieves other incremental value beyond the reliability objective, it is made primarily to benefit the reliability of that feeder for customers. Without that predominant reliability objective, the incremental investment for the additional equipment would most likely not be made. Even in this example, however, the overriding reliability objective is to uphold our current level of system reliability, not to improve it.



Some of the Avista Distribution poles installed in the 1920's and 1930's are still in service today… and it shows!

Evaluation of Reliability Results

A key focus in our annual reporting is understanding and analyzing the causes of outages, particularly those associated with major events, and identifying any particular pattern that merits further investigation. As can be seen in Figure 22, over a third of our outages are generally considered outside of our control (weather, fire, and public caused outages), with weather alone accounting for an average of 26% of our outages over the past 16 years. In addition to these outages, 17% are "planned" outages where service must be disconnected in order to perform work on the system.[26] Together, these outages required for system maintenance, upgrade or repair and those beyond our control account for over half of our overall distribution outage events.

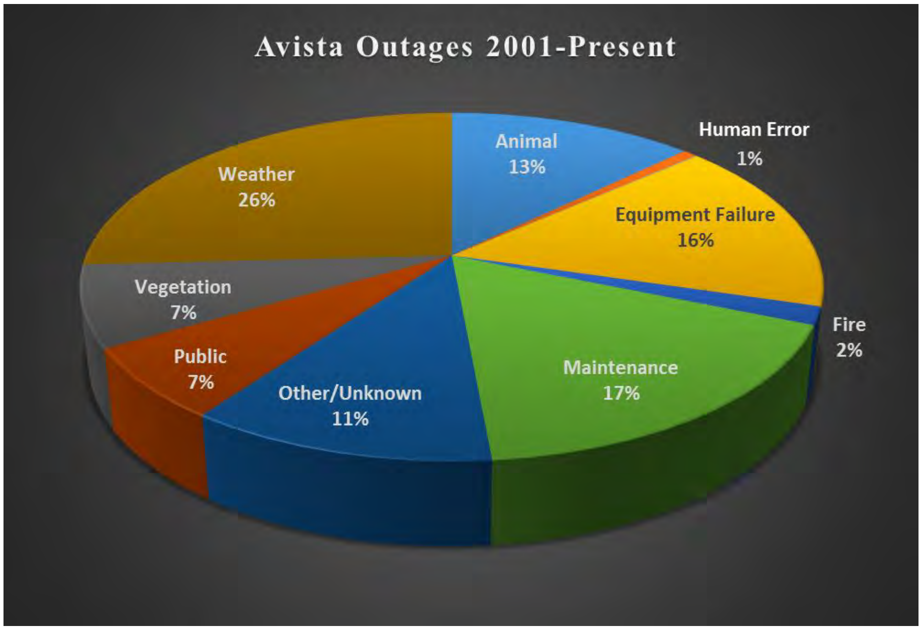


Figure 22. Outage Causes 2001 - Present

Excluding planned outages and those beyond our immediate control, Avista's "base" system reliability performance is the product of a complex network of factors, and the sum of the individual performances of a wide range of individual assets (e.g. transformers, meters, conductor, insulators, etc.). While our overall reliability trend meets our objective of upholding and maintaining our current reliability performance, the underlying story is more complex.

[25] This refers to the use of a switch(es) located along the feeder midline that can be opened to effectively divide the feeder into two segments, allowing service on the section not associated with the outage to be quickly restored.
[26] Avista follows a standardized customer notification process for work that requires us to interrupt their electric service.

The reliability of assets is based on how they tend to deteriorate over time, the manner in which they are maintained, the point in their life cycle when they are replaced, and the impact of specific asset condition or reliability improvement projects and programs. Avista's Grid Modernization and Wood Pole Management[27] Programs have had a positive impact on the reliability of overhead distribution infrastructure by replacing assets based on condition. In addition to repairing and replacing wood poles, these programs, working jointly, also install new equipment including crossarms, transformers, grounding, lightning arresters, and cutouts.[28] Through the actions of these programs, these equipment assets are replaced at the end of their useful life but before they are likely to fail, which would have resulted in an outage for our customers. Replacement of these assets, based on the Company's asset management strategy, has had a positive impact on the number of outage events experienced by our customers, as shown for transformers and cutouts in Figure 23.

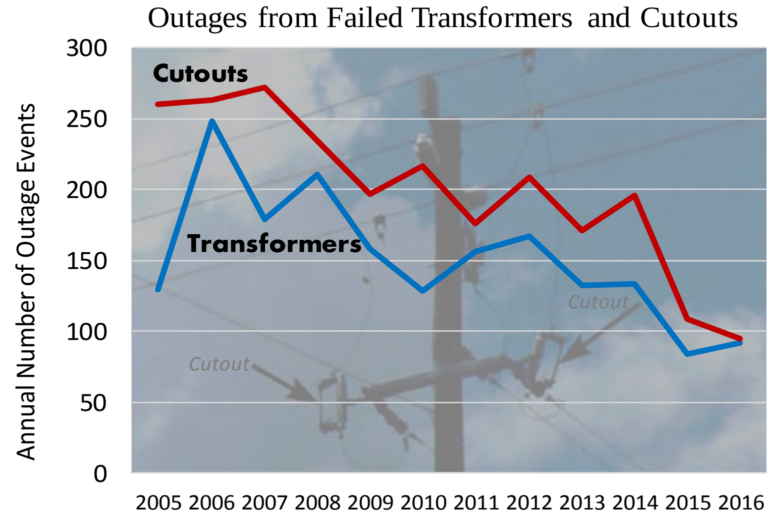


Figure 23

Squirrel Guard

While these improvements derive predominantly from the end of life replacement of assets (or "reliability as a factor"), the Company, as explained above, also makes investments that are primarily to improve system reliability. Among examples of these programs is the Company's effort to evaluate and install "squirrel guards" across targeted areas of our system. A squirrel guard is a protective rubber boot that is installed over the insulator and conductor on transformers, reclosers, and other distribution equipment. The squirrel guard program has achieved a substantial reduction in the number of animal-caused outages on feeders where they have been installed, as shown below in Figure 24. This treatment has helped Avista achieve a substantial reduction in outage events each year, and squirrel guards are now standard on new installed Avista equipment.

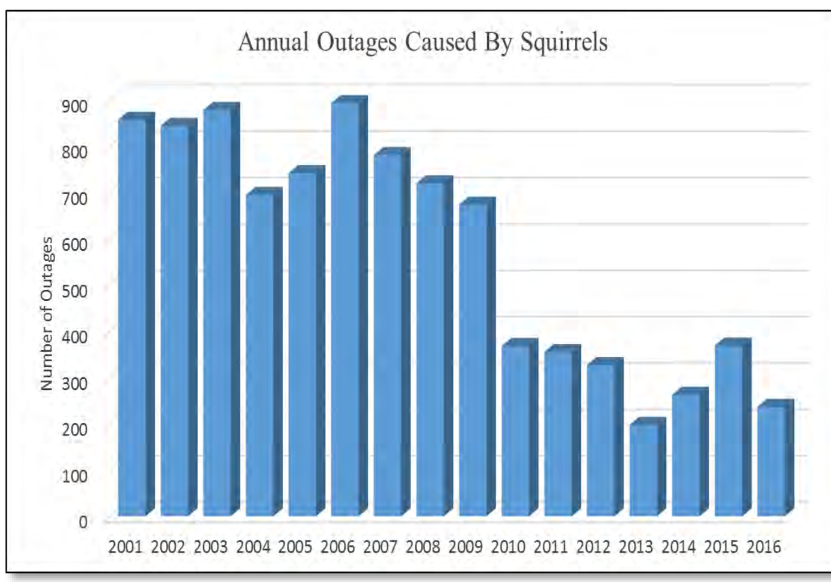


Figure 24. Squirrel Related Outages

[27] Please see the Wood Pole Management Program discussion (beginning on page 57) and the Grid Modernization Program (beginning on page 64 in this report) discussions and charts for distribution system reliability impacts.
[28] Definitions of these asset types are provided in the Wood Pole Management section (beginning on page 57 in this report.)

In the example noted earlier, equipping a feeder with remote operations capability through feeder automation has also had a positive impact on our overall system reliability. Automation provides Avista with the ability to sectionalize the line to isolate an outage and restore service to customers served from the feeder section that is still serviceable. Through this remote operation the Company has been able to avoid sustained outages for customers that have totaled an average of over 400,000 minutes per year since 2013.[29]

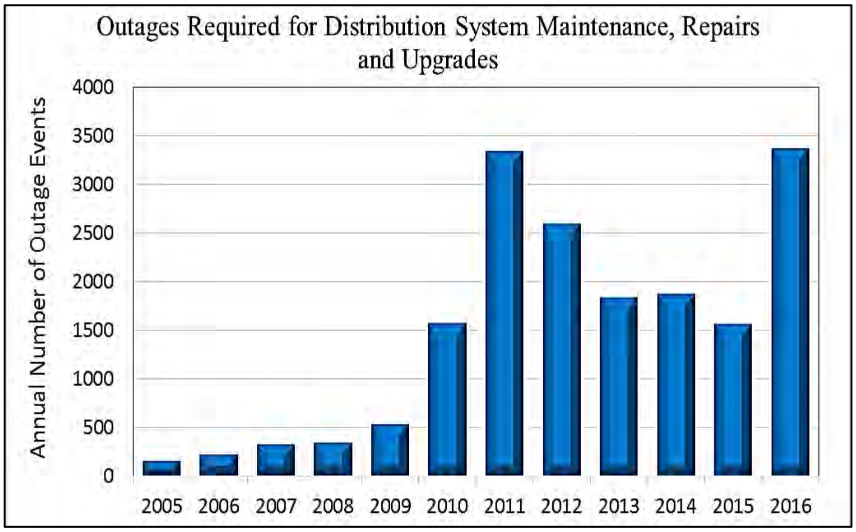


Figure 25. Outages Required for Planned Work

While these management strategies have a positive impact in reducing the number and duration of outage events we experience on our system, there are other trending factors that are at the same time diminishing the reliability of our system. An example is the number of outage events that result from the Company's need to "de-energize" the system in order to complete maintenance, repairs and upgrades. As Avista has increased the level of its investments in electric distribution infrastructure over the prior decade, as described above, we have experienced a corresponding increase in the number of planned outages required to complete this work, as shown in Figure 25.

The Company is also experiencing an increasing trend in the number of outages caused by poles in its system that fail, as shown in Figure 26. While the Company's Wood Pole Management Program reduces the number of poles that would be failing if not for the actions taken under the program, they are not sufficient to stabilize the long term reliability and performance of our wood pole population. This result is due to the changing age profile of our pole population combined with our conservative 20-year inspection cycle, which is expected to result in an increasing number of pole failures in year 2017 and beyond.

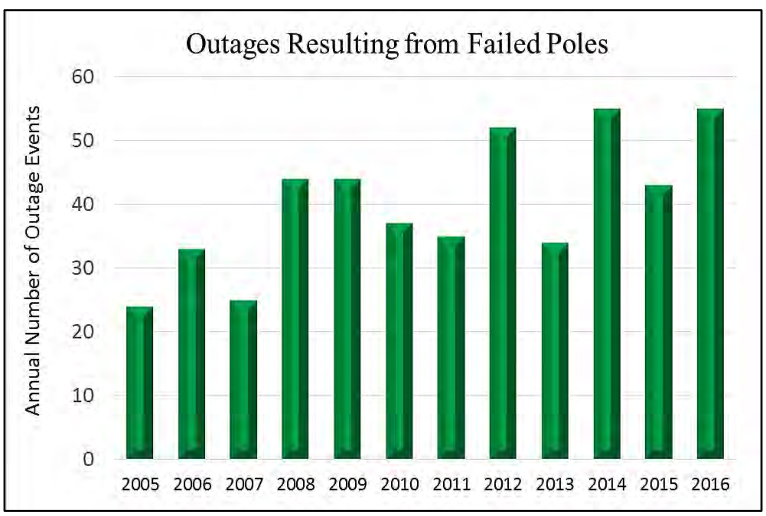


Figure 26. Outages Resulting from Failed Poles

Another important consideration in evaluating the Company's approach to managing its system reliability is the significant impact that the type of outage event has on the number of system interruptions (SAIFI) and outage duration (SAIDI). For example, the

[29] Analysis available upon request.

failure of a distribution transformer will likely impact from one to five customers, the same as with the failure of a cutout or an outage caused by a squirrel. Accordingly, the outage benefits provided by the reduction in these types of outages has a proportional impact on the overall reliability of the system. By contrast, the failure of a pole may interrupt service for an entire feeder, impacting up to several hundred customers, and, depending on the location of the pole, may cause an extended outage.

The same type of magnitude in reliability improvement can be applied to the benefits provided by feeder automation. When an outage results in the interruption of service on the entire feeder, remote operations can be used to sectionalize the line and avoid a sustained outage for many of the customers served on the feeder. For outages resulting from planned work on the system, the interruption ranges from impacting a single customer to affecting an entire feeder, and in unusual cases, an entire substation, which interrupts all of the feeders tied to that station (potentially in the range of several thousand customers).

This very brief discussion is intended to illustrate why we often consider investments in electric distribution as being made to "improve reliability." Whether we are avoiding outages that would have occurred due to failures in deteriorated assets, such as with wood poles, or cases where we are actually bringing the base assets to a higher reliability standard, as in the case of squirrel guards and feeder automation, we are increasing the reliability performance of the targeted infrastructure. But from an overall system perspective, these individual improvements in reliability, when combined with the cumulative performance of all of our assets, allow us to generally uphold and maintain our overall current level of reliability performance.

Though Avista and other utilities report their reliability for their overall system, this look masks the wide range in electric reliability among the feeders in an operating district and among the districts themselves. For example, as described earlier in the overview of the Company's electric distribution system, the Colville district has approximately 2,500 miles of distribution feeder lines, both overhead and underground. These feeders are predominately rural and serve approximately 19,000 customers. This number of feeder miles actually exceeds that of the Spokane district, which serves approximately 170,000 customers. More importantly, though, Colville has only 26 individual feeders, compared with 116 feeders in Spokane. This means the individual Colville feeders are, on average, almost 4.5 times as long as those in Spokane. Because the number of feeder miles and the length of feeders represent an index of customer exposure to outages, our Colville customers have a much greater risk of experiencing an outage than do our customers in Spokane.

Typical terrain in Colville

In addition to the number of miles and the length of feeders in Colville, the locations of the lines themselves also play a role in service reliability. Colville feeders tend to be located on narrow cross-country rights-of-way as constructed by the local public utility district (PUD) in the years before Avista acquired the system. These conditions not only increase the likelihood of an outage, but they make it difficult for crews to patrol the line to find the cause of the outage and to get material and equipment to the site in order to perform repairs, thus extending the length of outages. A lengthy trip for our line crews may also be required to reach the site, since this District encompasses over 2,400 square miles. These differences in feeder characteristics are manifest in the average number and duration of outages expected for Spokane and Colville in 2017, as shown below:

Reliability Measure	Spokane	Colville
System Number of Outages (SAIFI)	0.72	3.7
System Duration of Outages (SAIDI)	87 Minutes	707 Minutes

As expected from the feeder data discussed above, Colville customers on average can expect to see five times the number of outages and 8 times the outage duration as the average customer in the Spokane District.

In each of our districts, outages are analyzed by individual feeder to assess areas of concern for reliability performance. These “feeders of concern” are most often rural since it’s normal to have a greater number of outages per customer on these often lengthy and extensive systems. For its “feeders of concern”, Avista develops work plans with individual treatments designed for each feeder. These treatments include such improvements, when cost effective, as moving sections of overhead lines onto public road rights-of-way for easier access, converting them to underground circuits, accelerated or targeted vegetation management and wood pole inspection, improved fuse coordination, dividing individual feeders into two separate feeders, as well as using feeder automation to sectionalize individual feeders.

Reliability Strategy

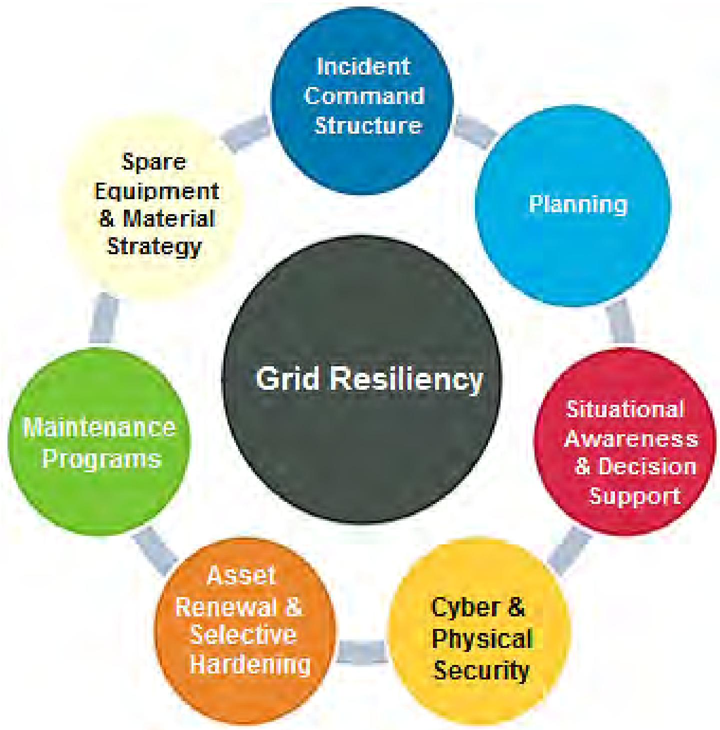
When it comes to the future reliability of our electric system, Avista must be attentive to understanding the evolving expectations of our customers and evaluating our forward capabilities for meeting them. In this respect, we must constantly judge whether our overall service quality meets the expectations of our customers, balancing the costs and lead time required to deliver that level of service.

In recent years Avista’s approach to electric system reliability has been to generally uphold the current performance of our overall system, which we believe has been satisfactory to our customers as well as cost-effective. While we believe we have been successful in striking a reasonable balance among our customers’ reliability expectations, the characteristics of our extensive and often rural system, the quality of our services, and the cost associated with delivering those services, we also understand that across the industry, customers’ expectations for service reliability are increasing. This trend, coupled with the outage consequences of recent extreme weather events in our service area, regionally, and nationally, has prompted the development of new regulatory strategies designed to address the aspect of reliability referred to as “resilience.”

Resilience - In the electric utility world, the term "reliability" is changing to include the concept of resiliency.[30] Basically this is focusing on the ability to harden the system against – and quickly recover from – high impact, low frequency events such as severe weather, natural events such as wildfire or earthquakes, and attacks (physical and cyber). As an indication of the value of considering resiliency, in focusing storm hardening on just 1% of their most at-risk poles, Florida utilities believe they are providing customer benefits of almost $49 million per year in reduced outages and/or outage duration.[31]

Resilience is "*robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event.*" - National Association of Regulatory Utility Commissioners (NARUC)

The National Association of Regulatory Utility Commissioners (NARUC) believes that resiliency is separate and distinct from traditional reliability; they note the difference between *utility cost of outages* and *lost value to customers.*[32]



The "Circle of Resiliency" from IEEE Standards Association, https://standards.ieee.org/events/nesc/bradish-fleeman.pdf

Resiliency measures do not necessarily prevent damage; rather these measures enable energy systems to continue operating despite damage and/or promote rapid return to normal operations when unexpected events do occur. This concept incorporates system hardening (such as undergrounding or vegetation management), robustness (ability to bounce back from unanticipated events as quickly as possible), comprehensive emergency response strategies, and the concept of incorporating lessons learned to stay on a path of continuous improvement.

Avista has put significant effort into developing a detailed plan for rapidly and effectively dealing with large scale emergencies. In 2016 the Company won the Edison Electric Institute "Emergency Recovery Award" for "extraordinary efforts to restore power in times of crisis."[33] This award is presented twice annually to EEI member companies to recognize their extraordinary efforts in restoring power to customers after service disruptions caused by severe weather conditions or other natural events.

[30] The National Infrastructure Advisory Council, "Critical Infrastructure Resilience Finance Report and Recommendations," September 8, 2009, on page 8, The National Infrastructure Advisory Council (NIAC) says: "Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to and/or rapidly recover from a potentially disruptive event."

[31] Kury, Ted, "Evidence-Driven Utility Policy with Regard to Storm Hardening Activities,", August 27, 2012, http://bear.warrington.ufl.edu/centers/purc/DOCS/PRESENTATIONS/Kury/P0812_Kury_Evidence_Driven_Utility.pdf, page 20

[32] Keogh, Miles and Christina Cody, National Association of Regulatory Utility Commissioners, "Resilience in Regulated Utilities", November 2013, https://pubs.naruc.org/pub/536F07E4-2354-D714-5153-7A80198A436D

[33] EEI Emergency Response Awards - http://www.eei.org/about/awards/Pages/default.aspx and http://www.spokesman.com/stories/2016/jun/15/avista-gets-award-for-restoration-work-after-winds/

Avista believes the time is right for us to evaluate our current reliability posture in light of the current and trending expectations of our customers, the likely future performance of our system, and in consideration of the value of resiliency as an emerging and integral piece of the reliability picture. In an increasingly digitized world, power quality now plays a major role; even small transients or fluctuations can be more disruptive than full power loss. The value of lost service is growing each year as people depend more and more on what they consider essential services. Thus, Avista will continue to explore how resiliency fits into our overall reliability strategy. In addition, given the very long life of our electric transmission and distribution assets as well as the size of the investments and timeframe required to significantly change their overall performance, frequently revisiting our reliability and resiliency objectives will help us make targeted and timely adjustments to our strategy in ways that meet customer expectations and deliver the greatest optimized value.

Setting Actionable Targets

Frequently in our industry, there has been interest in establishing performance goals, targets, or benchmarks for system reliability that the utility is required to meet on an annual basis. As described above, setting annual targets based on the results of metrics such as the average outage frequency and duration indices may make no realistic sense, because the often highly-variable results year-to-year are largely out of the control of the utility, and investments designed to improve these values usually have to be made over a period of many years in order to meaningfully improve the trends.

Avista has used reliability indices for goal setting inside our organization. However, the intent has been more to create a management and employee focus on finding innovative ways to support our reliability goals. Going forward, the Company will be evaluating options for establishing what we refer to as “actionable” goals and targets for reliability in lieu of the lagging outage frequency and duration results. We expect these goals to be based on the accomplishment of activities:

1) That are within the control of the Company;
2) That have a *demonstrable* impact on the reliability of our system;
3) That are needed to support our overall reliability objectives;
4) That are cost-effective and make sense for our customers.

Transmission Poles showing distribution lines “underbuilt” below the transmission lines, which puts additional strain and wear on the poles

In this effort, Avista’s aim will be similar to the approach taken in California where performance targets based on SAIFI and SAIDI (with penalties for non-performance) were abandoned as ineffective and replaced by a programmatic approach to grid investments that are more likely to ensure that long-term system reliability goals are achieved.[34]

[34] Approaches to Setting Electric Distribution Reliability Standards and Outcomes, pages 130 - 136. The Brattle Group, Ltd., 2012

Investments to Uphold Customer Service Quality and Reliability

Distribution Vegetation Management - Avista's Distribution Vegetation Management group is responsible for insuring that vegetation-caused outages are kept to a reasonable and cost effective minimum across our 7,800 miles of overhead electric distribution lines. This group utilizes a multi-pronged proactive approach to identify and address potential vegetation-related issues before they result in outages for our customers.

Over the prior six years our Avista/contractor team has essentially re-written the book on how this department conducts its business. Every aspect, from work planning and prioritization to contracting philosophy, work practices, and contractor relationships have been reviewed and re-vamped as needed to help raise the bar on our core principles of safety, reliability, and customer service. New strategies focused on innovation and results have led to new business processes and increased efficiencies, as can be seen from the results listed in the text box on the right.

A foundation of the program has been the Company's development of a comprehensive tree inventory database, currently containing data for about 300,000 trees across Avista's service territory. The information in this database, which is constantly updated, is used to help design our vegetation management approaches under three distinct programs:

- *Routine Cycle Maintenance*
- *Risk Tree Mitigation*
- *Right of Way Clearing*

Routine Cycle Maintenance is conducted on a five to six year interval and is focused on trimming practices that are tailored to the type of landscape and species of trees along our rights of way, organized by individual geographic zones referred to as "polygons." Organization of the work by polygons involves the prioritization based upon the predominant vegetation and the geographic location of identified "problem

DISTRIBUTION VEGETATION MANAGEMENT: A SUCCESS STORY

- ✓ **Technology**: Converted to electronic/paperless operation
- ✓ **Documentation**: Created a tree inventory of nearly 300,000 trees system wide
- ✓ **Quality Assurance**: Certified arborist on every crew
- ✓ **Accountability**: Keep detailed metrics and perform in depth auditing
- ✓ **Process Improvement**: Focused on efficiency in manpower and work performed, increasing the number of trees trimmed or removed
- ✓ **Cost Control**: Created contracts to keep prices flat for over six years
- ✓ **Customer Service**: Higher number of trees worked with fewer complaints – and an almost equal number of compliments!
- ✓ **Results**: Reduction in outages and wild fire risk
- ✓ **Savings**: $700,000 in O&M every year over the next ten years due to program efficiencies

trees" that require the most attention during the trimming operation. This tailored approach allows Avista to maximize the efficiency of the work crews; they focus on areas most likely to cause a problem, then customize work cycles for trimming based upon tree and vegetation type and physical location. For example, some species of tree can be allowed a fifteen foot clearance (fast growing species), others (slow growers) can be allowed within five feet of our lines.

	Avista	Industry Average
Cost Per Customer	$14	$60
Contribution to SAIFI	0.11	0.60

Another part of this routine work involves the targeted removal of individual trees that Avista refers to as "cycle busters," meaning they will grow quickly enough to require an additional trim during the middle of the cycle interval, which is very inefficient and expensive. Often the Company will replace a "cycle buster" tree with a tree species that will not ever reach a height to pose reliability problems for the overhead feeder line.

The work process for this routine maintenance can generally be divided into the four key activities briefly described below:

1) Crew work planners identify areas that need to be addressed and the work required.
2) A map, location details, tree species information, and the specifics of the trimming required is created for the crew so they go to the job prepared.
3) Notification postcards are sent to customers two weeks in advance of the work so they can also be prepared. (Note: 64,000 postcards were sent out in 2016.)
4) Crews trim vegetation to a level with a goal of five years clearance.

The Risk Tree Mitigation program targets individual trees that pose a hazard based on their potential to either fall across or to grow into lines during the cycle interval. These trees are identified by the following methods:

- Crews on the ground identifying dead, diseased and dying trees as they perform work in the field
- Light Detecting and Ranging (LiDAR), a remote sensing technique that uses pulses of light from an aerial sensor (such as an airplane or helicopter) using specialized technology to evaluate tree health[35]
- 3-D imaging to detect low chlorophyll levels (an indicator of health) and to produce data to model growth patterns and clearance issues.[36]

Interesting Vegetation Management Technique
https://www.ceati.com/collaborative-programs/transmission-distribution/vmtf-vegetation-management/

Once identified in our database and prioritized, the health of these individual trees is tracked to determine

[35] "Light Detection and Ranging (LIDAR): An Emerging Tool for Multiple Resource Inventory," Stephen E. Reutebuch, Hans-Erik Andersen, and Robert J. McGaughey, September 2005, http://forsys.cfr.washington.edu/JFSP06/publications/Reutebuch_et_al_2005_PR.pdf
[36] "Tree-mapping drone start-up has sky-high ambitions," BBC World Service, May 2014, http://www.bbc.com/news/technology-27485418

whether they need to be removed and, if so, when this should occur. The cycle of removal for these risk trees is "as needed," based on the risks the individual trees pose as they age.

Avista's Right of Way Clearing program involves the physical removal of brush and undergrowth on the feeder right-of-way using heavy mowing equipment and the selective application of herbicides. This work is tailored to the characteristics and needs of each feeder polygon, as needed, and is generally conducted near the mid-point of the routine maintenance cycle. Avista completes this work on approximately 1,200 – 1,500 circuit miles each year, generally during the months of May through October. Performing this work on a regular periodic basis prevents the undergrowth from reaching the point where a more expensive complete trimming and removal is needed to safely clear the feeder right of way.

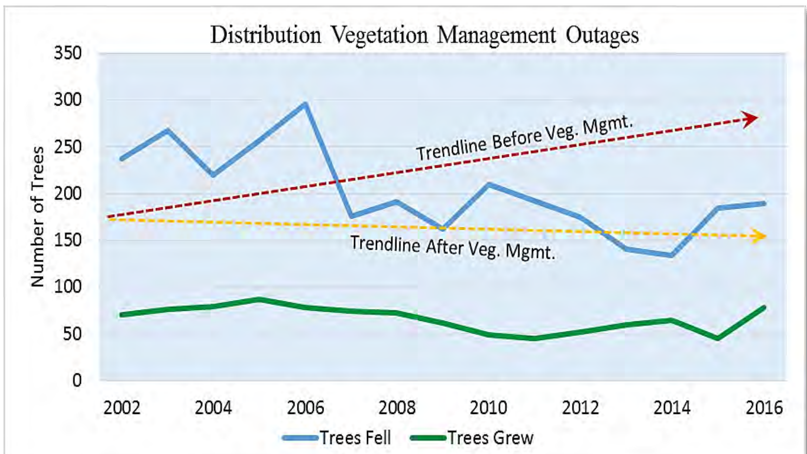


Figure 27. Distribution Vegetation Management Related Outages

Since the implementation of the Company's new Distribution Vegetation Management Program in 2011, tree related outages have been significantly reduced, as can be seen in the trend lines shown in Figure 27. The impact on electric system reliability caused by reductions in the budgets for this program is also clearly evident in the figure for years 2015 and 2016, as outages clearly increased.

Short-term budget reductions in those years resulted in a third of our contract tree crews being idled from October 2015 through May of 2016. Crews cannot afford to remain unemployed (and they are also in high demand), so they find other work. When budgets are restored, crews may be committed to other projects and no longer available to Avista for up to several months, thus a budget reduction can, in one year, have a ripple impact into the next year or even longer. The corresponding reduction in work performed has an almost immediate impact on reliability, as can be seen in the increased numbers of tree-related outages for the years impacted by budget reductions shown in Figure 27.[37]

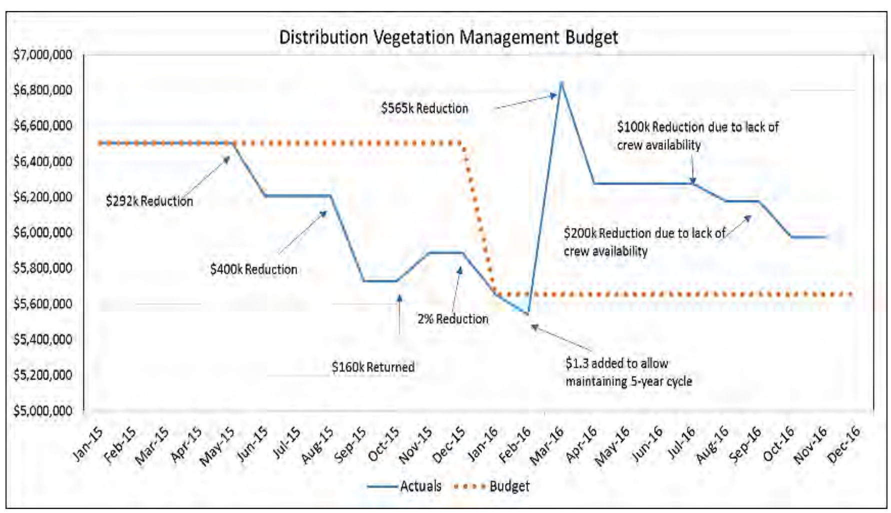


Figure 28. Distribution Vegetation Management Budget Cut Impacts

[37] For more information on the impacts of cutting vegetation budgets: "The Economic Impacts of Deferring Electric Utility Tree Maintenance," D. Mark Browning and Harry V. Wiant, T&D World, http://www.tdworld.com/programs/economic-impacts-deferring-electric-utility-tree-maintenance

Table 3 indicates the budget and the funding Vegetation Management actually received; Table 4 indicates the budget needed to maintain the program at levels that allow the Company to keep up with tree growth or dying trees that have been identified as having the potential to impact our system.

	2018	2019	2020	2021	2022	2023
Ideal Budget to Maintain Program	$10,973,382	$11,357,451	$11,754,961	$12,166,385	$12,592,208	$13,032,936

Table 3. Distribution Vegetation Management Actual and Budget

	2012	2013	2014	2015	2016	2017
*O&M **Budget** for Veg. Mgmt.*	$6,402,000	$6,518,000	$6,521,860	$6,842,150	$5,595,179	$6,150,000
*O&M **Actual** for Veg. Mgmt.*	$6,114,964	$6,653,020	$6,642,465	$5,809,349	$5,796,369	$3,047,615

Table 4. Distribution Vegetation Management Budget Needed to Maintain Program Schedule

Avista depends heavily upon the experience and expertise of the contract crews, and together we have created a culture focused on customer engagement. Their creative solutions have proven to be effective with customers. Even with the increased workload their new processes have allowed, complaints last year (39) were almost equal to the number of kudos received (30). In another example, we are encouraging customers to select utility-friendly tree replacements that will never have to be trimmed in exchange for removal of old trees. Avista's Vegetation Management Program has been awarded the Arbor Day Foundation Tree Line USA Award[38] for the last five years. This award is given for best utility practices in arboriculture based on the quality of their tree care, training, best practices, and public education, and tree-based conservation efforts.

Above: Before Vegetation Management Work Begins
Right: After Work is Complete

Condition-Based Asset Replacements - When we evaluate replacement strategies for varied types of assets based on age, condition or performance, the importance or value associated with its service reliability is considered in the analysis. Since the failure of some assets does not immediately impact our security, safety or reliability, they may be managed under the strategy known as "run to failure." In other instances, the failure of an asset may result in an immediate impact to customer service reliability, or a prohibitive cost to replace it after it has failed. In these instances, Avista evaluates the customer benefit of replacing the asset at the end of its useful life, but prior to its likely failure, in determining the overall strategy for managing this asset. In many such cases an increment of reliability value is included in the determination of the appropriate replacement strategy. The increment of reliability value considered is generally aimed at upholding our

[38] https://www.arborday.org/programs/treeLineUSA/

current level of service reliability, and the incremental cost component is embedded in individual projects. An example of these types of investments include the Company's Wood Pole Management and Grid Modernization Programs (which are described under the investments based on asset condition).

Washington Advanced Metering Infrastructure Project (AMI) - Avista is in the process of deploying advanced metering infrastructure across its Washington service territory. This effort keeps pace with the evolving metering standard of the industry and will deliver a range of cost-effective benefits to our customers.[39] Avista is planning to begin deploying advanced metering in its Idaho service territory in 2020. Some of the benefits of AMI include:

Avista Smart Meter

- It is a tool to help customers gain more control over their energy use and participate in actively managing (and hopefully reducing) their own bills;
- Better understanding by the utility of customer usage patterns in order to customize services;
- Increased communication, including text or email alerts to let customers know when their usage hits predetermined targets set by the customer, and providing customers detailed information to help them make more informed choices;
- Smart home options including customer ability to monitor and control home appliances, HVAC systems and a range of other internet-enabled technologies;
- Easier energy theft detection;
- An end to estimated bills, which are a major source of complaints for many customers, as well as increasing meter reading accuracy, another issue of great interest to customers;
- A reduction in outage duration and impact to customers due to our rapid awareness that an outage has occurred.

In addition to energy conservation achieved by customers, Avista will also use the Advanced Metering Information system to save energy through conservation voltage reduction (CVR)[40]. Energy savings can thus delay the need for additional utility resources required to meet loads. The advanced metering system will also help Avista reduce the average duration of system outages, as advanced meters immediately notify the

Company of an outage event, its magnitude, and the exact location of the customers impacted. This capability reduces the average time between the outage event and when the Company becomes aware of the outage, understands its full extent, and can dispatch crews to restore service.[41] The Company has prepared a complete business case for its advanced metering program, which is available on request. The planned annual capital investments for the upcoming five-year period are shown in Table 5.

[39] Avista's Advanced Metering Infrastructure program business case is available from the Company upon request.

[40] Conservation Voltage Reduction or Voltage Optimization saves energy by keeping the voltage on a distribution circuit to the lower end of a tolerance band so loads draw less power. Customers don't even notice the change, but it can save up to 4% on a circuit, 80-90% of which is on the customer side of the meter, a direct customer savings. http://blogs.dnvgl.com/energy/is-conservation-voltage-reduction-truly-energy-efficiency

[41] Today, Avista is generally made aware of an outage event when a customer calls in to report their loss of service. While the elapsed time in many instances will be fairly small, there are many other cases where the delay in notification can be substantial, such as outages that occur late at night when customers are asleep, when they are away from home, or when they are not part of a primary outage event (the portion of the grid where repairs are being made).

	2017	2018	2019	2020	2021
Washington AMI	$32,000,000	$53,000,000	$36,000,000	$14,300,000	$0

Table 5. Washington AMI Planned Annual Investments

Distribution Systems Automation - In the prior decade Avista has taken advantage of the opportunity to deploy new technology systems and equipment that enable us to detect an electric outage and to automatically restore service to many of the impacted customers much more quickly, thus reducing the number of customers impacted by a sustained outage. Introduced as the "smart circuits" program, this approach uses automated equipment on the feeder, such as reclosers, along with communications with these devices and an integrated distribution management system, to quickly assess how to isolate the particular section of the feeder where the outage has occurred, and to reconfigure the feeder system in a manner that allows us to reconnect customers quickly beyond the isolated section of the feeder. This "feeder automation", which is part of the Company's Grid Modernization Program, covers the installation of remote communications to a feeder, combined with equipment that can be remotely operated as needed. Implementation of feeder automation improvements is guided by the Company's Feeder Automation Strategy.[42] If the Company did not make these reliability investments, it would likely result in a greater investment made in other programs as part of our ongoing effort to uphold and maintain our current level of system reliability. An average of approximately 8.3%[43] of the planned annual capital investment under the Grid Modernization Program is used to fund feeder automation improvements, shown in Table 6.

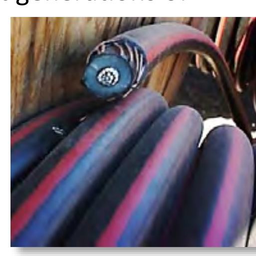
Viper Recloser

	2017	2018	2019	2020	2021
Grid Modernization	$800,000	$100,000	$1,204,950	$1,246,500	$1,288,050

Table 6. Grid Modernization Planned Investments

Accelerated Replacement of Problematic/Failing Assets - A particular class of reliability investments that are a subset of asset condition-based replacements are those targeting particular assets whose performance is deteriorating more quickly than was initially expected, and often at an accelerating rate. Though these replacements may be properly classified as based on asset condition, their expected rates of failure rises to level of a significant reliability impact. An example includes the earliest generations of underground electric cable first installed by Avista in the 1970s. Because of the tendency of the cable insulation to fail, the accelerating rates of failure we were experiencing, and because of the substantial repair time associated with failed cable, Avista began a systematic replacement of this material in the 1990s, which has continued to the present time. This replacement program has helped us avoid what would have been significant impacts to our customer's service reliability.

Old cable, susceptible to failure



New generation of underground cable

[42] Report available upon request.
[43] The average of actual and expected spend for the period 2015 through 2018 is 8.3 percent. This percentage was applied to the expected total transfers to plant for the Grid Modernization Program for 2019 – 2021 to estimate the automation costs shown in Table 6.

Mandatory and Compliance Investments

This category of capital spending includes "*investments driven typically by compliance with laws, rules, and contract requirements that are external to the Company*." Avista operates in a complex regulatory and business framework and must adhere to national and state laws, state and federal agency rules and regulations, and county and municipal ordinances. Compliance with these rules, as well as contracts and settlement agreements, represent obligations that are generally external to the company and largely outside of our control. The types of electric distribution investments that fall into this driver include our obligation to relocate our facilities to accommodate state, county and municipal infrastructure projects, (frequently transportation related) and our compliance with environmental regulations.

Unlike compliance requirements with our electric transmission system and our federal hydroelectric licenses, as examples, Avista has only three electric distribution investments that are mandatory and largely outside the control of the Company, and which are described in the brief narrative that follows.

Electric Replacement / Relocation

Each year Avista is required to respond to the projects of municipalities, counties and state-level agencies to rebuild or realign roads, streets and highways. When these projects impact our distribution facilities located

in public rights-of-way, the Company is required to remove and rebuild them in the clear zone of the new roadway, or to place them on a new purchased private easement. This work must be performed at the Company's expense, and while Avista may have some latitude to negotiate the timing of the construction, it has no choice with regard to removing and relocating its infrastructure and paying all of the associated costs. Our estimated capital expenditures for replacement or relocation are shown in Table 7:

	2017	2018	2019	2020	2021
Elec Replacement/Relocation	$2,450,000	$2,700,000	$2,800,000	$3,000,000	$3,100,000

Table 7. Required Replacement/Relocation Planned Investments

Washington State Department of Transportation (WSDOT) Franchising

As in electric replacement / relocation above, Avista works closely with the Washington State Department of Transportation (WSDOT) to renew and maintain crossing and encroachment permits. This work may require the Company to realign or modify existing infrastructure to comply with state clear zone, conductor clearance, and other regulations regarding the location of poles, guy wires, pad mounted equipment, and overhead conductors. Expected capital expenditures are shown in Table 8:

	2017	2018	2019	2020	2021
Frachising WSDOT	$200,002	$200,002	$200,002	$200,002	$200,002

Table 8. Estimated Washington Dept. of Transportation Required Investments

Environmental Compliance

These required investments include implementation of U.S. Forest Service Special Use Permits, waste oil disposal (including transformers containing PCBs), and environmental compliance with storm water management, water quality protection, property cleanup and related issues tied to the Company's electric distribution system. The forecast investments under these programs are based on analysis of historic activities, as well as any specific knowledge of planned major projects. Planned capital investments are shown in Table 9:

	2017	2018	2019	2020	2021
Environmental Compliance	$350,000	$350,000	$350,000	$350,000	$350,000

Table 9. Estimated Environmental Compliance Investments

Performance and Capacity Investments

Avista's projects and programs grouped in this category of need include "a range of investments that address the capability of assets to meet defined performance standards, typically developed by the Company, or to maintain or enhance the performance level of assets based on a demonstrated need or financial analysis."

PERFORMANCE

These types of investments target the maintenance or improvement of the performance of Company infrastructure based on demonstrated need or financial analysis, and in cases not governed by engineering or other standards.

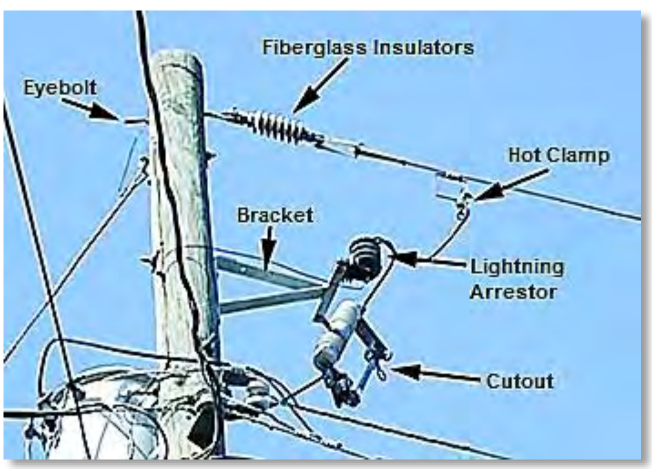
STANDARDS

The performance of distribution systems is guided by industry accepted practices, but prescribed by internal company policies, procedures, and standards. These standards have been developed to ensure the safe, efficient, reliable and prudent management of utility infrastructure and operations. A common example is our objective to operate within established thermal limits for electrical equipment. When the Company determines its operations no longer meet a given standard, we must assess the infrastructure needs and make the timely capital investments necessary to remain within the limits of the standard.

Virtually all electric energy delivery projects or programs have a direct or indirect link to the National Electric Safety Code (or Code). The Code represents the collective engineering and operating knowledge for electric utility systems with special emphasis on transmission, substation, and distribution networks. Though Avista develops and maintains multiple internal standards guiding the design, construction, and operation of electric distribution facilities, each standard is linked to the Code, which has a significant bearing on our practices and decision-making strategies. In addition to the need to comply with prudent operating standards, Avista is also attentive to investment opportunities to improve the performance of our distribution system, when supported by a study or analysis that demonstrates the cost-effectiveness of the benefits achieved for our customers. The Company has two electric distribution programs included under this investment driver: the Distribution Segment Reconductor program and the LED Street and Area Light replacement program.

Distribution Segment Reconductor and Feeder Tie Program

The annual investments made under this program represent 6.9% of our planned distribution investments, and remedy the overloading of electric equipment and cable, as well as the conductor sag[44] that results from overheating of the overhead wire. These instances of system overloading result from load growth and shifts in load demand that occur over time on the distribution system. Loads on the grid are always changing as a result of many factors including weather, temperature, economic conditions, conservation efforts, customer usage, and seasonal variability.



Avista's distribution system follows the industry standard of using relatively short sections of feeder main trunk supporting longer connected lateral lines that carry electricity to the customer's service. Though the overall load on a feeder as it leaves the substation is often known and monitored in real time, the actual loading on the downstream trunk and lateral branch circuits must be estimated using a specialized computer model. Avista uses the Synergee load-flow model to identify and predict problems with equipment overloading, which we subsequently field test to verify whether a problem exists. Resolving these overloading issues involves a combination of two strategies known as "load shifting" and "segment reconductoring."

[44] When the overhead wire (conductor) on a distribution feeder is overloaded, the wire overheats and stretches, and in doing so, sags closer to the ground than designed, which can exceed electric code requirements for safety.

The strategy of *load shifting* involves extending existing lines on one feeder to an adjacent feeder that has the available capacity to carry the additional transferred load. Shifting the load from one feeder to another not only solves the overloading issue but also helps us capture additional value from our current investments.

Reconductoring involves the removal of the wire or conductor that is too small in diameter for the current loading and replacing it with larger conductor that can easily and more efficiently carry the load. It is the most direct approach for mitigating overloaded circuits; however, Avista considers a range of options that not only meet the current need to relieve the loading but that also provide for the optimization of the overall distribution system. The Company has 30 known projects across our system that are planned for this five-year cycle, with an expected annual average capital cost of about $5 million as shown in Table 10.

	2017	2018	2019	2020	2021
Segment Reconductor and Feeder Tie Program	$5,175,848	$4,899,994	$5,000,505	$5,000,000	$5,000,000

Table 10. Estimated Segment Reconductor & Feeder Tie Program Investments

Avista's LED Street and Area Lighting Program

Light Emitting Diode (LED) lighting technology emerged as viable alternative to all types of conventional and fluorescent lighting around 2009, and by year 2012 over 14 million units had been installed in the U.S. alone. This rapid adoption of LED lighting represents one of the fastest technology shifts in human history. It is estimated that LEDs will save U.S. consumers and businesses $20 million per year within a decade, and reduce U.S. CO_2 emissions by up to 100 million metric tons per year. LED bulbs cut electricity use by up to 85% compared with incandescent bulbs, and 40% compared with fluorescent lighting.[45]

Government jurisdictions generally take on the responsibility of providing adequate lighting at night for streets and paths, sidewalks, and/or highways because of its statistically proven reduction in vehicle, bicycle, and pedestrian accidents, as well as reduction in property thefts.

LED (left) vs. Sodium (right)

Avista operates approximately 35,000 street lights we have installed for many of these jurisdictions across our service territory as well as area lights requested and paid for by individual customers. In 2013, in response to the superior safety performance of LED lighting, the energy savings potential, and the opportunity to reduce long-term energy costs, Avista evaluated the benefit of converting all our Schedule 42[46] street lights from High Pressure Sodium (HPS) to LED fixtures. In evaluating the potential benefit, the Company studied the customer benefits associated with three different alternatives, which are summarized in the text box on the next page. For all three cases, Avista used the Availability Workbench model to assess and compare the public safety risks, resource costs, energy savings, and the overall financial benefits for each case. Though the optimized base case provided the highest benefit to customers based solely on the capital installation and long-term maintenance costs, the LED case ultimately provided the greatest overall customer benefit due to the incremental value for the electricity

[45] https://thinkprogress.org/5-charts-that-illustrate-the-remarkable-led-lighting-revolution-83ecb6c1f472.
[46] Schedule 42 available at: https://www.myavista.com/-/media/myavista/content-documents/our-rates-and-tariffs/id/id_042.pdf?la=en

savings[47] that were not achieved in the base and optimized base cases. When considering all factors, the LED case provided our customers the greatest level of benefit.

Converting High Pressure Sodium (HPS) to Light Emitting Diodes (LED) - The Alternatives:

1) **Base Case** - Continue to rely on our high pressure sodium street and area lights, and continue to replace the bulbs and fixture as failed lights are identified on our system.
2) **Optimized Base Case** - Optimize the continued use of our high pressure sodium street and area lights by systematically replacing all of the bulbs in our system over a period of five years, and systematically replacing the photocell component of the fixture over a period of 10 years.
3) **LED Case** - Systematically replace our existing high pressure sodium street and area lights with new LED fixtures.

The program was launched in 2015 and focused initially on replacing our 100 watt conventional ("cobrahead") street lights. Replacing 200 and 400 watt lights was added to the program due to subsequent price reductions for these wattages. Avista has targeted this program for completion in 2019, in part to capture an additional benefit for our customers offered by the State of Washington's Transportation Improvement Board (TIB). In 2015, this Board established a statewide grant program known as Relight Washington[48], which is administered for the state by Avista. This program provides small communities in our Washington service area an offset to their street lighting costs when their community is converted to LED lighting. The Company expects that the timing of this program will provide our customers with an additional benefit of $2,289,000 that is above and beyond the customer benefits evaluated in the three alternatives.[49] The total investments for the LED lighting replacement represent approximately 2.6% of the total distribution investments planned for this period.

Actuals for the LED program are shown in Table 11; planned capital spending for the Distribution Segment Reconductor and LED Street and Area Light Programs, which comprise all distribution infrastructure investments under the Performance and Capacity investment driver, are shown in Table 12 (see footnote[50]). Note "CPG" is the Capital Planning Group.

	2017	2018	2019	2020	2021
LED Change Out Program	$2,899,925	$1,999,994	$2,319,930	$2,000,000	$0

Table 11. Actual LED Change-Out Program

Year	Initial Funding Request	CPG Initial Approved Budget	CPG Revised Final Budget	Actual Investment	TIB Credits	Planned Replacements	Actual Replacements	Planned Energy Savings (Watts)	Actual Energy Savings (Watts)
2015	$2,320,000	$1,500,007	$2,400,000	$2,551,878		4,055	5,378	262,500	312,450
2016	$2,320,000	$1,558,788	$4,110,000	$4,983,589	<$443,866>	10,292	13,604	300,000	
2017	$3,300,000	$2,899,937				9,538		375,000	
2018		$2,000,000				4,965		487500	
2019		$2,320,000				4,957		600,000	
2020		$2,000,000							

Table 12. Estimated LED Change-Out Program Investments **See Footnote 50*

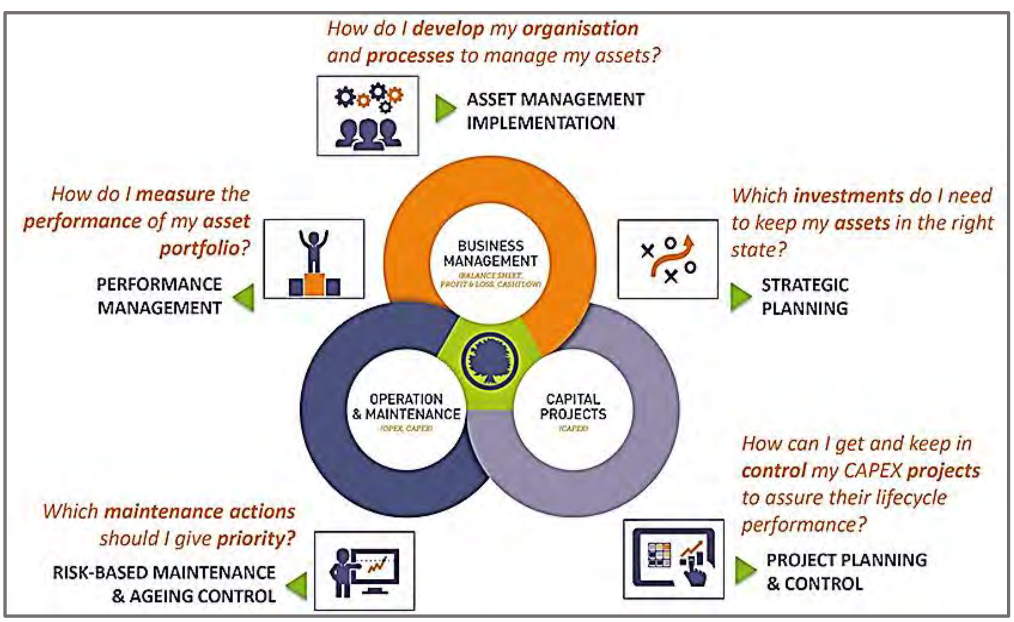
47 In addition to saving our customers money, the energy saved also contributed to meeting the Company's mandated targets for energy conservation.
48 http://www.tib.wa.gov/grants/smallcity/LEDSmallcity.cfm
49 Annual Energy Savings are estimated to be 75 watts per fixture (100 watt High Pressure Sodium (HPS) bulbs consume 135 watts. These bulbs are replaced with 100 watt LED bulbs which consume 60 watts.)
50 Avista's Oracle financial system reflects the individual fixtures charged against the program each year as presented here. Avista's program manager reports the actual number of installed for 2015 and 2016 as 4,057 and 8,096, respectively. Note that TIB credits are received when all work has been completed, which does not necessarily fall within the budgeted year.

Investments Based on Asset Condition

Assets of every type will degrade with age, usage and other factors, and must be replaced or substantially rebuilt at some point in order to ensure the reliable and acceptable continuation of service. Projects or programs in this category of need are defined as: "*investments to replace assets based on established asset management principles and systematic programs adopted by the Company, which are designed to optimize the overall lifecycle value of the investment for our customers*." The replacement of assets based on condition is essentially the practice of removing them from service and replacing them at the end of their useful life. Across the utility industry, and likewise for Avista, the replacement of assets based on condition constitutes a substantial portion of the infrastructure investments made each year. At Avista, we aim to manage our assets in a manner that optimizes their overall value over the lifecycle of each particular class of asset. We say that asset replacement strategies are "optimized" in the sense that a given approach may not achieve the overall lowest possible lifecycle cost, but rather the lowest cost that allows us to meet a variety of important performance objectives, such as electric system reliability or the efficient use of employee crews. Because failure of critical assets is unacceptable, they must be replaced near the end of their useful life even though they are still providing reliable service. In other instances it may be reasonable to wait until an asset fails before it is replaced, a strategy known as "run to failure." Examples of distribution asset management programs employed by Avista include the replacement of wood poles based on condition as determined in routine inspections, replacement of transformers based on age and PCB removal, and replacement of first generation (and failure-prone) underground electric cable.

Overview of Asset Management

All developed economies are underpinned by a vast public and private infrastructure comprised of roads and other transportation systems, water and waste, telecommunications, internet, and energy systems. Most of these systems are taken for granted until something fails or no longer provides the expected level of service.



Infrastructure, such as our electric and natural gas systems, represents a major investment, much of which has been built up progressively over the last 100 years or longer, and which can often have an expected service life of many decades. Maintaining the function, achieving performance goals, optimizing the useful life, as well as planning for the timely replacement of infrastructure is the province of the modern science of asset management, as depicted in the diagram.

The "International Organization for Standardization (ISO) has defined the requirements for an asset management system, which have been adopted for widely ranging infrastructure types, including energy systems.[51] For the "how" to implement an asset management program, industries rely on the International Infrastructure Management Manual (Manual).[52] The manual articulates multiple approaches and methodologies for performing various functions in asset management, as well as providing case studies that demonstrate the applications. These approaches range from more-easily implemented qualitative processes to more sophisticated quantitative methods, and combinations of both. Avista's asset program is guided by these standards, and the Company relies on the Infrastructure Management Manual for implementation support.

Asset Management at Avista

Avista's program began with an initial evaluation of the Company's electric system assets completed in 2003. In a later step we adopted a Reliability Centered Maintenance (RCM) approach to asset management that focused on development of work plans and financial analyses for each class of assets. In 2006 the Company acquired the asset management analytical software "Availability Workbench." Developed by the firm Isograph,[53] this reliability-centered maintenance model can perform integrated analysis on a single asset, a system of assets, or an entire asset system, such as a generating station, based on identified needs and objectives.[54] This analysis is used to optimize maintenance and replacement strategies, analyze individual assets in context of an asset system, develop lifecycle costs estimates, and provide future projections of performance, allowing actual results to be validated and the model refined.

Avista's asset management goal is to optimize the value of the infrastructure investments we make in the service of our customers.[55] To this end, an asset management system supports decisions on what assets we should build or purchase, the type of maintenance program needed to support each asset, how factors such as system reliability are considered in asset life and performance decisions, and when and how an asset should be rebuilt or replaced. This optimization allows us to drive down the total cost of ownership while

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[51] The International Organization for Standardization (ISO) standards 55000 and 55001 specify the requirements for establishment, implementation, maintenance, and improvement of a management system for asset management. They do not define how an organization should implement asset management. Rather, as discussed in standard 55002,[51] the organization's context and needs should define and drive the asset management system that is ultimately implemented. In this context, the ISO standard focuses on "what an organization should do." Together, standards 55000, 55001, and 55002, encompass the evaluation of costs as well as benefits, risks, and asset performance, both internal and external to the organization. BSI Standards Publication, BS ISO 550001:2014. http://www.iso.org/iso/home.html

[52] http://www.nams.org.nz/pages/273/international-infrastructure-management-manual-2011-edition.htm.

[53] Isograph, founded in 1986, is one of the world's leading companies in the development and provision of integrated Reliability, Availability Maintainability and Safety software products. The company has offices near Manchester, UK and Salt Lake City, Utah.

[54] Availability Workbench essentially sums all of the probabilities and associated costs and benefits for an asset or system over a given period of time. The model resolves the complexity of the multiple probability functions, including schedule of maintenance activities and different ages and costs of assets, to produce mathematical curves representing forecasted failure rates and lifecycle costs. The model integrates asset-related risks, resource requirements for labor, and material and equipment to produce cost estimates and projections for alternative management decisions.

[55] Whether the investment touches the customer directly, such as our customer service or metering systems, or indirectly, such as improving the capability and efficiency of our employees and work processes, each capital dollar we invest ultimately supports our ability to provide our customers with safe, reliable, and cost-effective energy services that meets their expectations for quality of service and value.

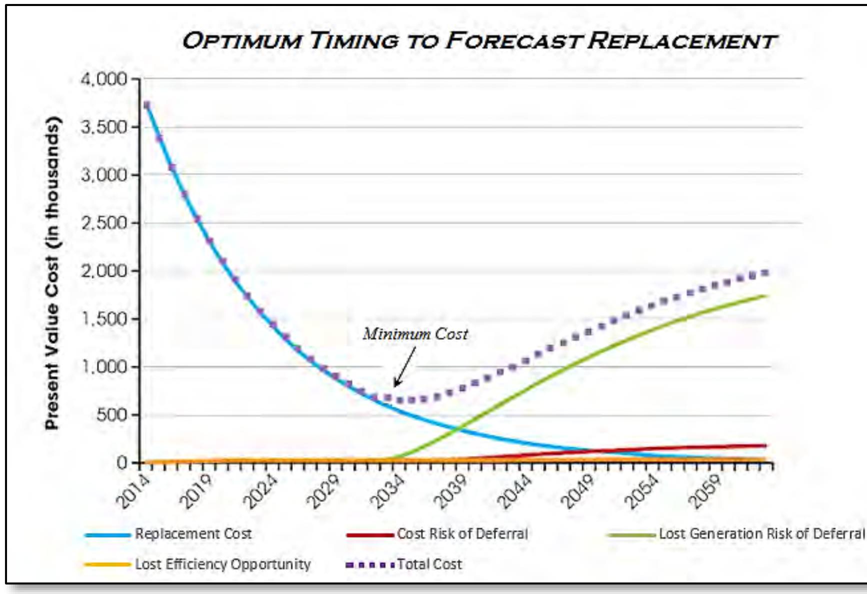


Figure 29. Forecast of Optimum Replacement

achieving important performance criteria and objectives. In its simplest form, this optimization is depicted in the Figure 29 line graph.

In this depiction for a generating asset, the present value of the replacement cost declines with increasing service life, which is offset at some future point by the present value of the increasing costs associated with maintenance requirements and the consequences of failure. The objective of asset management is to identify the strategy that achieves a reasonable total lifecycle cost for each type of asset while meeting a range of other important objectives (i.e. identifies that lowest cost point on the line). Importantly, each type of asset will have a unique lifecycle cost curve based on the expected life, maintenance needs, and likelihood and consequence of failure.

Maintaining a hydro unit

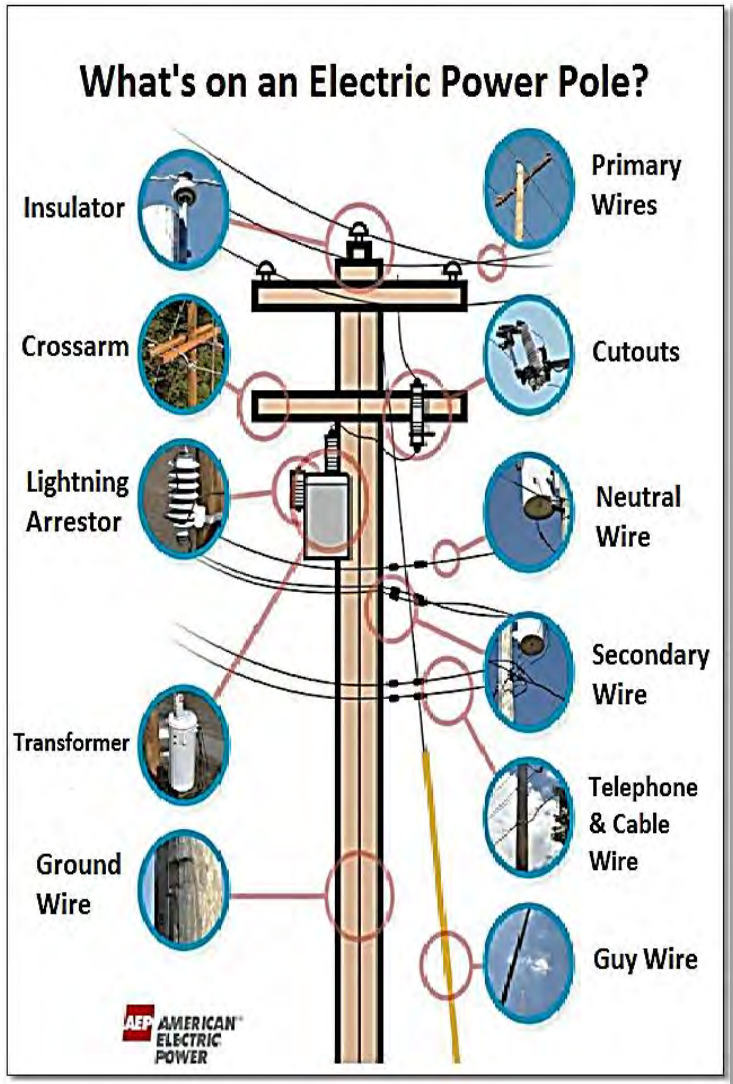
Assets supporting critical business functions such as a generator (i.e. where the consequence of failure is not acceptable) must be replaced earlier in their lifecycle to avoid the risk of failure, while certain assets can remain in service until they actually fail before being replaced (i.e. any negative consequence of failure is outweighed by the lifecycle value associated with longer service life).

Avista's electric distribution infrastructure programs under the Asset Condition driver include Distribution Wood Pole Management, PCB Transformer Change-Out, Underground Cable Replacement, Grid Modernization, and Worst Feeders. Collectively, the Company relies on these primary programs for making systematic investments in our distribution plant, which allows us to cost effectively maintain a safe and highly reliable system that meets the expectations of our customers. Four of these programs were developed with support from the Company's asset management group, which has continued to support them as needed through the course of implementation. These programs are discussed in more detail below.

Wood Pole Management

As noted earlier, Avista has approximately 347 overhead electric feeders that are supported by approximately 240,000 wood poles. These poles are predominantly cedar (90%) as well as larch, fir and steel. The attached equipment includes crossarms, transformers, cutouts[56], insulators and pins,[57] wildlife guards, lightning arresters, guy lines,[58] and pole grounding.[59] Poles and equipment comprise the primary infrastructure of the Company's electric distribution system.

Inspection Cycle Time Interval – In managing these assets it is the Company's goal to repair or replace aging poles and equipment in our system before they actually fail, but late enough in their expected life span to capture the overall value of the initial and any follow-up investments. The practical way to accomplish this is to systematically inspect each pole in the system on a regular basis and to make any investments needed to replace failed poles and equipment, ensuring they don't fail before the next inspection cycle. The central question is what time interval to use for the inspection cycles.[60] Generally, more frequent inspections (shorter cycle time) reduce the likelihood that poles and associated components will fail sometime during the interval between inspections, but they also cost more because the annual number of poles inspected is greater than with a longer cycle interval. The optimum interval for the inspection cycle can be mathematically determined based on the characteristics of the wood pole population, the associated operating expenses, and the likelihood and cost of customer service outages resulting from any poles or equipment that fail between inspections.



Our focus on wood pole management began in 1988 and attempted to address the feeders in greatest need based on local area knowledge. Early funding was limited in part by the lack of system data and overarching program goals. The Company's initial evaluation of the cycle interval, performed in 2008, pointed to a 20-year cycle as preferable to both a shorter 10-year interval and a much longer 100-year interval.[61] At the time Avista conducted this analysis, its effective cycle time was in the

[56] Fuse devices that protect the feeder and equipment in the event of a fault on the line.
[57] The overhead wire or conductor that carries the electric current is attached to insulators that prevent the conductor from faulting, and each insulator is attached to the pole or crossarm with a pin.
[58] Guy lines are the wire support attached at the upper part of the pole and anchored into the ground diagonally to counteract tension on pole as needed to keep it stable, upright and plumb.
[59] Pole grounding is used to ensure the pole and equipment is electrically grounded so that any fault goes safely to ground.
[60] The inspection cycle interval is the period of time within which every pole in the system will have been inspected and treated as needed.
[61] In this evaluation, the 100-year interval, which was longer than Avista's effective interval at the time, represented a scenario where most of the poles that failed would be replaced on an unplanned basis instead of being treated or replaced during the follow-up to inspection.

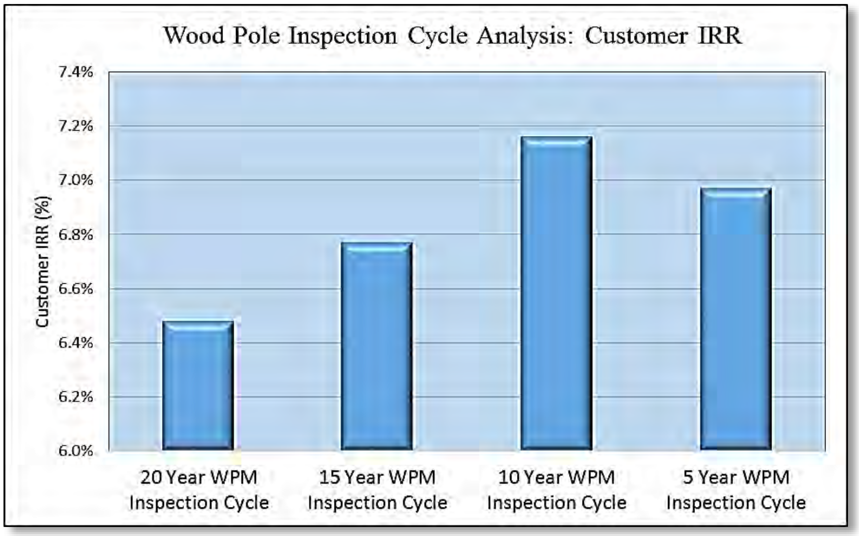
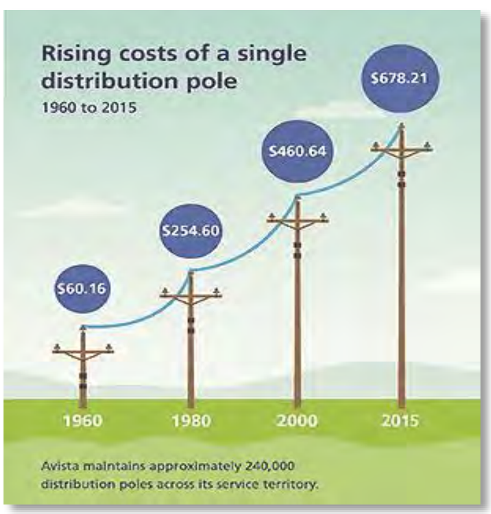


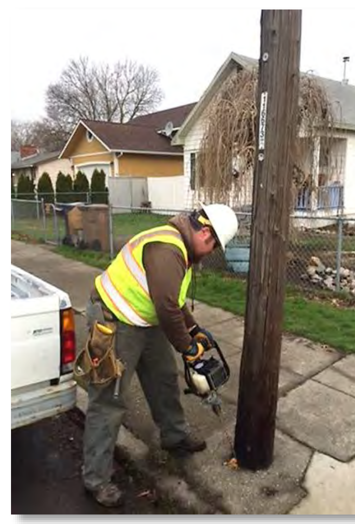
Figure 30. Wood Pole Inspection Cycle Analysis

range of 40+ years, and based on this evaluation, the Company chose to reduce its inspection interval to 20 years. In 2012 Avista again evaluated the impact of cycle interval on the long term value for customers using the Availability Workbench model. In addition to better analytical tools, we also had better data on our pole population as well as costs for inspections and follow-up capital work. Four cycle intervals were evaluated ranging from 5 to 20 years and results of the analysis are shown in Figure 30.

This analysis pointed to ten years as the cycle interval, followed in order of value by the five-year, fifteen-year and the twenty-year cycles. The incremental increase in value captured by a cycle interval shorter than 20 years is the result of avoiding failures in poles that would otherwise occur with longer inspection cycles, which results in more customer outage time and increased capital and expenses required for unplanned replacements. Essentially, these increasing costs for unplanned repairs and outage time outweigh the additional expense of more frequent inspection intervals (in the range of 10 years).



Although the above results demonstrate a greater overall customer value for a cycle interval of 10 years, the Company is continuing with its 20-year inspection cycle. The reason is that any reduction in cycle time requires an up-front increase in expenses to pay for the increased number of poles inspected each year, and a corresponding increase in requirements for capital replacements. Though a cycle time shorter than 20 years would likely provide our customers greater value over the long term, Avista believed the incremental increase in costs at that time, in addition to the incremental increase already absorbed by adopting the 20-year cycle in 2009, would put too much near-term price pressure on our customers, considered in combination with Avista's many other infrastructure investment needs.[62] The Company remains cognizant of the potential for capturing greater value with a shorter cycle interval as a reliability improvement strategy, particularly if at some point, we were to adopt a reliability strategy intended to improve the overall performance of our system compared with the status quo.



Avista Pole Inspection

[62] Please see the report: Avista Utilities Infrastructure Investment Plan, May 2017.

Inspection Program – Avista's current Wood Pole Management Program has four primary components: Inspections,[63] Design, Construction/Follow-up, and Auditing. In order to achieve a 20-year cycle interval Avista crews must inspect an average of approximately 12,000 distribution poles and crossarms each year. The number of poles inspected in each year of the program is shown in Figure 31.

During the inspections the actual condition of each pole is assessed to determine whether any issues need to be addressed, rather than relying only upon age information to categorize the health of the pole. The inspection process identifies damage from insects, animals, lightning, fire, decay, mechanical damage, equipment failure (such as a leaking transformer), unauthorized attachments, and other damage such as a broken guy wire or grounding/soil issues. Decay is the most common reason for pole failure and is readily detectable with proper inspection.

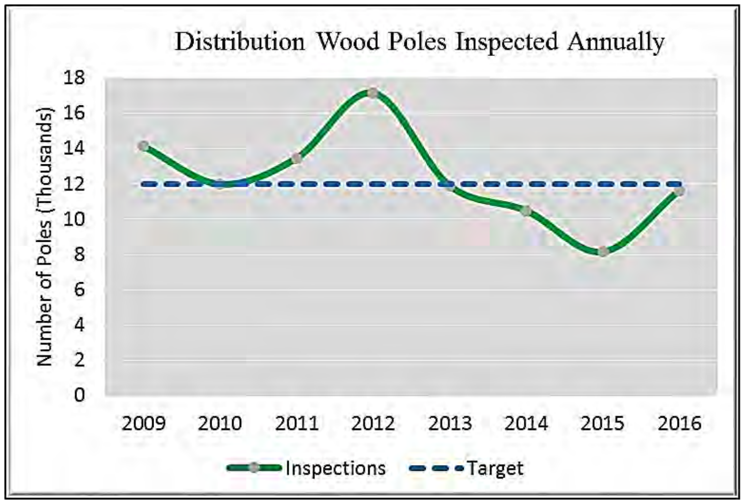


Figure 31. Wood Pole Annual Inspections

Results of the inspections are used to design the capital repairs and replacements that need to be performed under the activity referred to as "follow-up work." In 2012 Avista initiated the Grid Modernization Program (described below) which is dovetailed with the Wood Pole Management Program to make optimized use of crews and materials supporting the Company's wood pole management. In order to remain on a 20-year inspection cycle, Avista must complete the necessary follow-up work on approximately 385 miles of feeder lines each year, combined between the Wood Pole and Grid Modernization Programs.

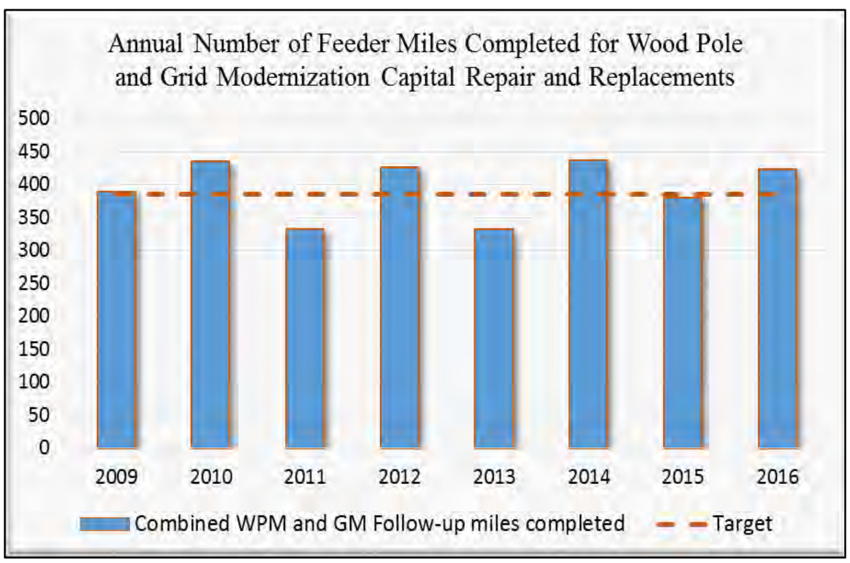


Figure 32. Wood Pole Feeder Miles Completed

Since 2008 the Company has inspected and completed follow-up capital work on approximately 3,456 miles of overhead electric feeders. The miles of follow-up work completed each year since 2009 are shown in Figure 32.

Since initiation of the program, Avista's wood pole management protocol has evolved to more effectively utilize crews performing the inspections. Personnel now identify the need to replace pre-1960s transformers, identify transformers that may be inefficiently sized, install grounds or guy wires where needed, and insure that equipment meets current safety standards. Numbers of individual assets that have been replaced or reinforced (repaired) during the capital follow-up work are shown in Figure 33 (next page).

[63] The inspection activities for this program are an operating expense and are not capitalized.

In each 20-year cycle, all of the distribution wood poles in our system will have been inspected and treated as needed, at which point the cycle commences again. Starting in 2020 funding from the PCB Transformer Change-Out Program will be incorporated into the Wood Pole Management and Grid Modernization Programs in order to replace the remaining pre-1981 transformers in our system. Planned and actual capital investments for the Company's Wood Pole Management Program from 2005 – 2016, as well as the forecast through year 2021, is shown in Table 13 (see footnote[64]). Note "CPG" is the Capital Planning Group.

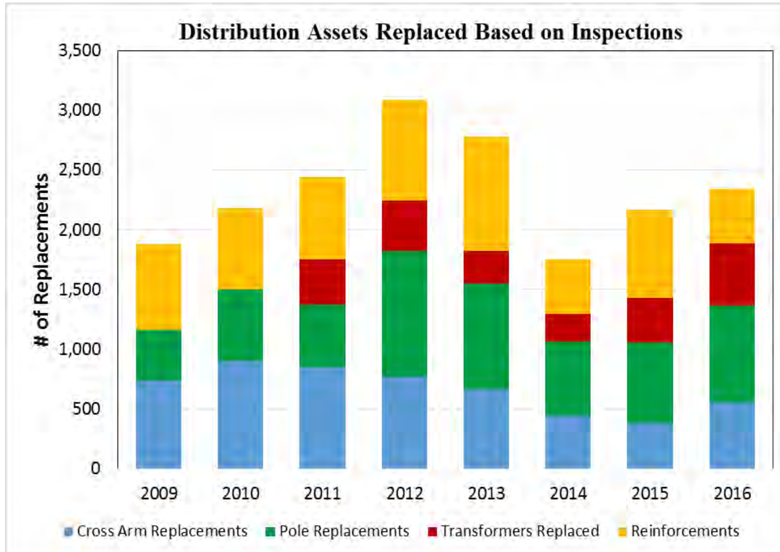


Figure 33. Wood Pole Management Assets Replaced

Year	Initial Funding Request	CPG Initial Approved Budget	CPG Revised Final Budget	Actual Investment	Planned Circuit Miles Addressed *	Actual Circuit Miles Addressed *
2005		$1,200,003		$1,128,419		
2006		$1,200,000		$1,085,406		
2007		$1,454,635		$1,968,437		
2008		$4,923,001		$4,750,573		
2009		$3,700,001		$7,494,569	500	372
2010		$6,884,001		$7,507,144	450	435
2011		$8,899,976		$9,118,377	459	332
2012	$10,486,300	$9,485,710	$10,121,300	$10,064,203	416	353
2013	$9,486,300	$9,281,686	$9,281,686	$9,258,713	445	278
2014	$11,500,000	$9,900,011	$9,550,000	$9,512,319	412	273
2015	$11,500,000	$11,000,009	$10,600,000	$9,111,453	390	279
2016	$11,200,000	$7,840,001	$8,440,000	$8,601,732	223	326
2017	$14,700,000	$9,000,001			336	

Table 13. Wood Pole Management Program **See Footnote 64*

Growing Demand for New Investment - Beyond this current planning period, the need to fund end-of-life asset replacements for our overhead electric feeders will continue to increase for the foreseeable future. The primary driver for this increasing need is the age distribution of the Company's wood pole population now in service. Avista's distribution wood poles have an average life span of approximately 80 years as they are managed in our system today. The current age profile of the population is shown in Figure 34 (next page). This age profile shows the estimated number of poles by age group in the Company's distribution system. The brackets and the dashed trend lines highlight the difference between the numbers of poles still in service that were installed prior to and during the Second World War, compared with the much greater

[64]Units of Work are in Circuit Miles Addressed.

numbers installed in the period following. The difference in the rates of growth in our system between these two periods of time is depicted as the difference in "steepness" between the two dashed trend lines.

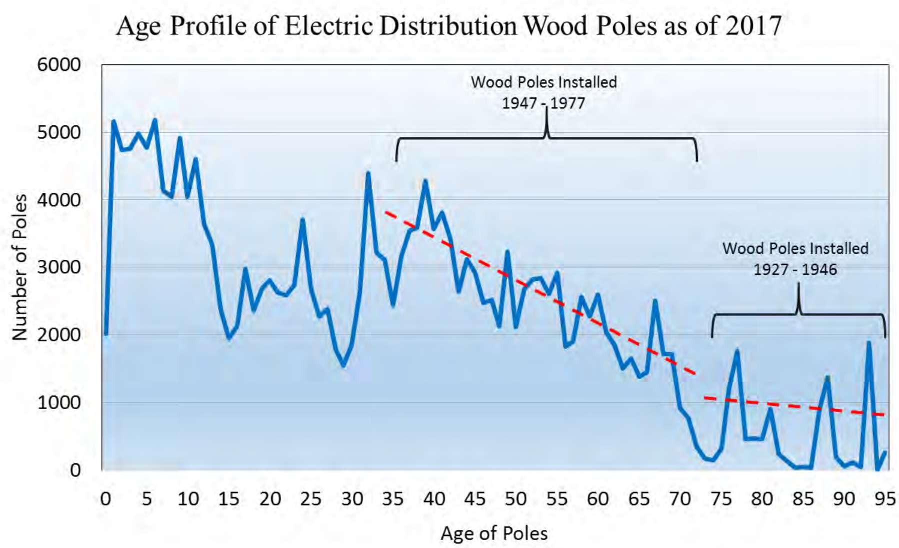


Figure 34. Wood Pole Age Profile

Crews face a variety of unique situations in inspecting wood poles

To demonstrate the effect of this age profile on the Company's future need for investment, Figure 35 shows the same age profile, but only for those poles currently 65 years and older which number about 22,000.

As the overall population continues to age each year, again, due to the shape of this age profile, the number of poles in this 65 years and older group will increase as depicted in Figure 36 (next page). In this example the number of poles in this age group will have increased from 22,000 today to over 30,000 by year 2024, and the upper bound of the age range will have increased from 95 to 103 years.[65]

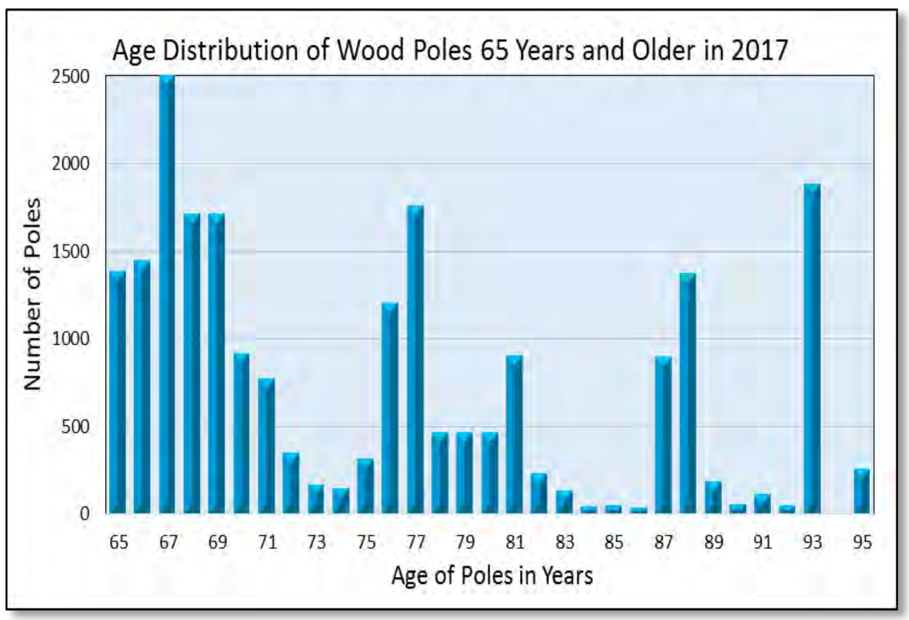


Figure 35. Wood Pole Age Profile as of 2017

Wood poles tend to fail at increasingly greater rates each year as they age, thus the

[65] This increase in the number of poles aged 65+ years, including the upward extension of the maximum age to over 100 years, does not include the number of poles that are expected to fail over this period of time, which have been accounted for and subtracted in this forecast.

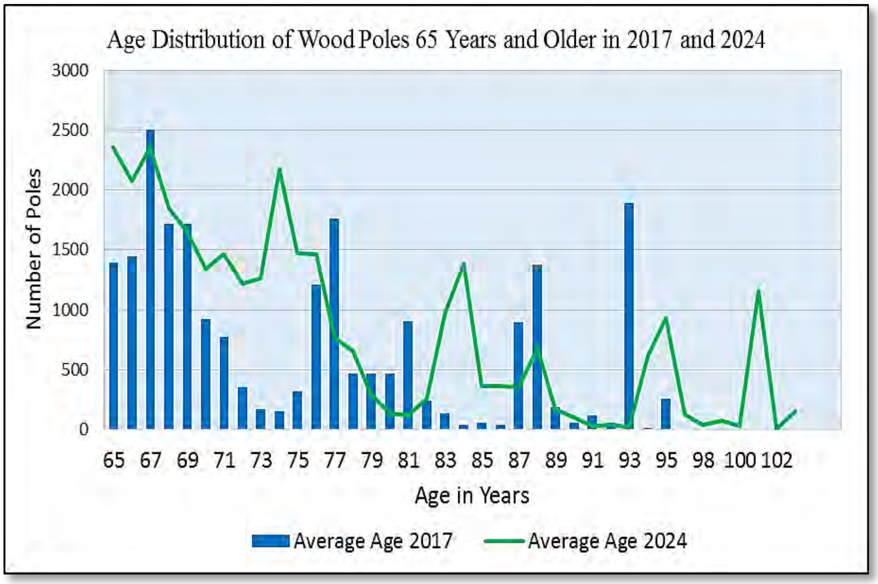


Figure 36. Wood Pole Age Distribution – 2017 and 2024

greater number of poles in this older age group results in a greater number of poles that will have to be repaired or replaced every year. As a result, the amount of capital repairs and replacements that will need to be completed during the follow up work each year will increase in proportion to the increased number of older poles in the system. Based on this population data, Avista used the Availability Workbench model to forecast the number of wood poles, conductor and related equipment that will have to be replaced each year based on continuing our 20-year inspection cycle interval. The known effects of the shifting age profile in our overhead distribution system allow us to forecast future investment needs with relative confidence. By year 2040 the expected annual investment for the Wood Pole Management and Grid Modernization Programs will rise from the current annual level of about $24 million to approximately $70 million, as shown below in Figure 37.[66]

As noted earlier, this upward trend in distribution investments is far from unique in our industry, where investments tend to be cyclical,[67] as exemplified by the difference in our system growth rates over time. The once-new investments that came in "waves" generations ago now require a wave of re-investments to refresh that infrastructure, which has delivered a lifetime of service. Whether noted in numerous trade publications, identified in government reports, documented in studies like the "investment gap" report by the American Society of Civil Engineers, or as demonstrated here by the Company, investments in electric distribution infrastructure are on the rise and the need for increasing levels of investment is expected to continue for many years to come.

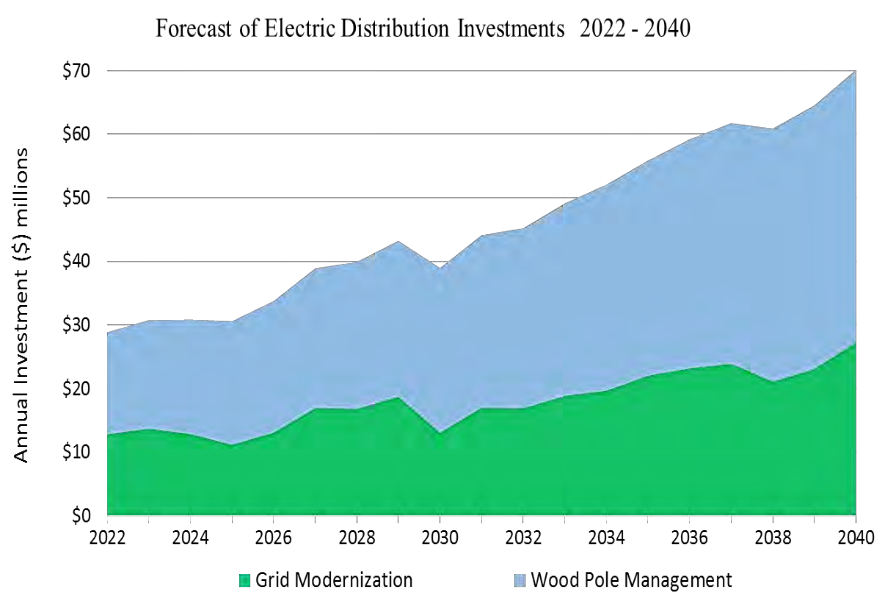


Figure 37. Projected Electric Distribution Investments

[66] An annual inflation rate of 2% is assumed for each year in this forecast.
[67] 2015 Financial Review: Annual Report of the U.S. Investor-Owned Electric Utility Industry. Edison Electric Institute, http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Documents/FinancialReview_2015.pdf

Distribution Grid Modernization

Purpose - The purpose of this program is to cyclically rebuild and upgrade every electric feeder in Avista's distribution system, with the objectives of improving service reliability, capturing energy efficiency savings, and improving operational ability, code compliance and safety. These objectives are accomplished through the systematic replacement of aging equipment that has reached the end of its useful life, such as old poles, conductor and transformers, with new and more energy efficient equipment that ensures the long-term operability of the system. On qualifying feeders, additional system reliability value is captured by installing distribution line automation devices to help isolate outages, reducing the number of customers that experience a sustained outage (feeder automation).

Above: Spokane Smart Grid Switching Device

Left: "Smart" transformers provide the exact amount of power needed, respond to fluctuations and act as a voltage regulator

Initial Program Scope - The program was initiated in 2013 and was built on the 2009 Avista's existing Feeder Upgrade program and the Distribution System Efficiencies analysis and report which evaluated the energy savings potential that could be captured by replacing end-of-life assets across Avista's distribution system. The report also prioritized the individual feeders based on their potential treatment costs and benefits to our customers. The assessment of costs and benefits was based on analysis of energy losses in feeder conductors, distribution transformers, and service lines, the potential savings associated with reactive power compensation,[68] and overall economic analysis. Early in the program, staff developed a Feeder Prioritization Tool that was used to assess, score and rank each of the Company's 347 electric feeders, as discussed below.

Grid Modernization Integrated Programs

- Wood Pole Management Program
- PCB Transformer Change-out Program
- Vegetation Management Program
- Segment Reconductor and Feeder Tie Program
- Various budgeted maintenance programs

The initial scope of Grid Modernization also included the evaluation and deployment of distribution line automation devices based in part on the methodology Avista developed for deploying such technology under the Company's Smart Grid Investment Grant through the U.S. Department of Energy.[69] A key objective of this feeder automation effort is to take advantage of the value remote operability provides to quickly

[68] In a simplified explanation, alternating electric current (AC) has two components, being active power (sometimes also called real power), which provides the energy used by our customers, and that portion of power that is essentially stored energy that returns to the source of generation in each cycle, known as reactive power. The degree to which these two components are in-phase or out-of-phase determines the amount of active power that is delivered. Since the types of customer loads on a feeder have an impact on the respective balance of these two power components, installing devices that help balance the components can result in energy conservation savings for customers.
[69] https://www.smartgrid.gov/recovery_act/overview/smart_grid_investment_grant_program.html

sectionalize a feeder in order to reduce the overall impact of service outages for our customers. To accomplish this, Avista installs automated line devices, such as midline reclosers, switchable capacitor banks, air switches, and the digital communications necessary for the Company to operate the devices from our dispatch center in response to an outage event.[70] In addition to the energy conservation analyses derived from the distribution system efficiencies work, Grid Modernization developed estimates of the capital investment required to implement the efficiencies programs. The effort also relied on the Company's asset management group using the Availability Workbench model to forecast the long-term reduction in operating expenses resulting from rebuilding feeders.

Assets addressed under the program include: undersized and deteriorating conductor, failed and end-of-life assets including wood and steel poles, cross arms, fuses, insulator guys, arresters, cutouts, grounds, street and area lights, and avian protection. Other issues addressed on each feeder include: pole re-alignment to address accessibility issues, rights-of-way concerns, potential feeder undergrounding, coordination of joint use facilities and clear zone compliance. This systematic approach is enabling Avista to cost-effectively deliver an up-to-date and more robust electric distribution system that is more energy efficient, easier and less costly to maintain, and more reliable for our customers.

Grid Modernization was initially optimized at a cycle interval of 60 years, meaning that over that period of time the program would rebuild and upgrade every feeder in the distribution system. Selection of this interval related to the average life span of our distribution infrastructure as well as the 20-year interval cycle for the Wood Pole Management program. These two programs are integrated in several important ways. Grid Modernization relies on the inspection data from Wood Pole Management for its asset condition assessment, and targets the timing of feeder construction to optimize the value of wood pole inspections and follow-up work already performed. Wood Pole Management relies on the poles replaced by the Grid Modernization Program as contributing to the total number of poles they have to inspect and address each year to remain on the 20-year cycle.

Changes in the Program - Grid Modernization's scope has been expanded to include replacement of all pre-1981 distribution transformers during a feeder rebuild, under guidance of the PCB Transformer Change-Out Program, discussed later in this report. Avista's Distribution Feeder Management Plan was updated and refined in 2016 to address the need for additional guidance in making incremental investment decisions under the Grid Modernization Program. This work, which included engineers from the Company's Asset Management and Distribution

Asset Groups Rebuilt

- *Undersized Conductor*
- *Deteriorating Conductor*
- *Failed Infrastructure*
- *End-of-life Infrastructure*
- *Wood poles*
- *Cross Arms*
- *Fuses*
- *Insulators*

Treatments

- *Accessibility Issues / Pole Realignment*
- *Right-of-Way Concerns*
- *Potential for Undergrounding*
- *Coordinating Joint Use Facilities*

[70] Midline reclosers allow prevention of tripping downstream of a fault. Switchable capacitor banks help support voltage and provide power factor correction – the ability to switch allows them to be used only when needed. Air switches can allow isolating a section of overhead line when a fault occurs.

Standards groups, was also used to help refine the scope of the program. As an example, based on that evaluation, data on the average lifespan of our wood poles was used to optimize the age at which our poles are replaced when a feeder is rebuilt. Grid Modernization now replaces cedar poles older than 60 years and larch poles older than 40 years. Also in 2014, the Company enhanced its engineering support for the program, which allowed us to develop a more robust analysis in our Feeder Baseline Reports (more details on this report are shown in the text box) that included additional scoping guidance and recommendations for load balancing, power factor support, segments in need of reconductoring due to capacity limitations, and recommendations for installation of feeder automation devices.

Grid Modernization Baseline Report

- *Analysis of reliability results for three indices from 2006 to present*
- *Study of the actual loadings on each phase of the feeder under a range of seasonal conditions*
- *Modeling average and peak loadings expected after the phase loads are balanced*
- *Capacity of the overhead conductors, by segments on the trunk and laterals, identifying any limitations as well as potential for energy savings*
- *Prospective benefits of a range of physical reconfigurations of the feeder to improve:*
    - *Voltage settings*
    - *Fuse coordination*
    - *Line losses*
    - *Transformer losses*
    - *Power factor*
- *Potential benefits of automation*
- *Integration of asset age and condition data*

The Grid Modernization scope provides a holistic approach for optimizing the value captured with each feeder project. This approach integrates work performed under various operational initiatives at Avista including the Wood Pole Management Program, the PCB Transformer Change-out Program, the Vegetation Management Program, the Segment Reconductor and Feeder Tie Program, and various budgeted maintenance programs. As an example of this coordination, a targeted feeder or segment will have its older wood poles and cross arms inspected and replaced (Wood Pole Management), end-of-life and transformers containing PCBs replaced (PCB Transformer Change-Out Program), new communications and remotely operated equipment installed (Grid Modernization), and new higher-capacity conductor installed to avoid overloading or to meet future capacity requirements (Segment Reconductor and Feeder Tie Program), all performed by one crew, one set of right-of-way or clearance zone agreements, and resulting in only one outage to customers and only one street closure while the work is performed, versus the potential for causing multiple outages if each portion of the work was performed under the individual programs at different times.

Distribution Grid Modernization represents a comprehensive approach to infrastructure management, from its data- and engineering-driven analysis and evaluation to the way it serves as a platform to better integrate a portion of the capital investments we make each year in our electric distribution system.

In late 2016, the Company developed its Feeder Automation Strategy[71], which is used as a reference and guidance document

[71] Available upon request.

by Grid Modernization to help determine what types of automation equipment (if any) will be installed on each feeder.

Grid Modernization Benefits

- *Reliability Index Analysis*
- *Load Balancing*
- *Feeder Reconfiguration*
- *Trunk Conductor Analysis*
- *Lateral Conductor Analysis*
- *High Loss Conductor Replacement*
- *Feeder Tie Creations*
- *Voltage Quality Improvement*
- *Voltage Regulator Setting Recommendations*
- *Fuse Sizing & Coordination Study*
- *Reduced Line Losses*
- *Power Factor Analysis*
- *Power Factor Correction*
- *Distribution Line Automation Devices Deployment*
- *Open Wire Secondary Identification, Analysis & Replacement*
- *Pole Analysis & Replacement*
- *Transformer Evaluation & Replacement*
- *Underground Cable Analysis & Replacement*
- *Vegetation Management*

Please see Appendix C for the details related these benefits.

Feeder Selection and Treatment Design - Candidate feeders are targeted for Grid Modernization if they have a higher likelihood of failing, resulting in unplanned outages. They are replaced with new energy efficient equipment that is more reliable (because it's replacing deteriorated equipment), has greater operational capability (which improves reliability) and additional safety features for our customers and employees. While focused on rebuilding feeders that are at or nearing the end of their useful life, the evaluation is complimented by a range of other selection criteria, such as customer density, urban versus rural service, and balance among Company operating districts and jurisdictions. The selection process incorporates comprehensive data from the Feeder Prioritization Tool noted above, which incorporates analysis and prioritization information for each of our 347 feeders, including:

- ✓ Inventory of the individual equipment assets associated with each feeder;
- ✓ Reliability performance data;
- ✓ Estimated energy savings from replacing transformers and undersized conductor and installing feeder automation;
- ✓ Estimated capital savings modeled based on the feeder rebuild;
- ✓ Modeled reliability savings, and
- ✓ Estimated operations and maintenance savings.

In order to normalize the comparison of data for feeders with widely-varying characteristics across our system, Avista converts nominal data into fractional values on the same scale relative to each feeders' data for each category. These normalized values are then weighted using the selection criteria weightings that were established at the beginning of the program. The summation of the values for each of the three categories creates the overall score for each feeder. This score is how the feeder is initially ranked for selection. These results provide a robust quantitative foundation for further evaluating and selecting the feeders to be rebuilt under the program.

For feeders that are selected, the Grid Modernization engineer publishes detailed feeder information, analysis and proposed treatments in the form of a Feeder Baseline Report. Such information includes analysis of reliability results for three indices over the period 2006 to present, study of the actual loadings on each phase of the feeder under a

range of seasonal conditions, and modeling of the average and peak loadings expected after the phase loads are balanced. They also model the capacity of the overhead conductors, by segments on the trunk and laterals, to identify any limitations as well as potential for energy savings. Extensive modeling is also performed to evaluate the potential benefits of a range of physical reconfigurations of the feeder, taking into account opportunities to improve voltage settings, fuse coordination, line losses, transformer losses, and power factor, as well as the potential benefits of feeder automation. By integrating all of this information, along with the full range of asset age and condition data, engineers recommend a comprehensive set of treatments that will be applied to the feeder, identifying the investment requirements and the cumulative estimated benefits. An example of the reliability improvement measured on feeders that have been rebuilt under the program is shown in Figure 38.

Future Plans - Avista expects the scope of the program to remain fairly stable for the foreseeable future, though the structure may change to better optimize the functions of feeder rebuilding and the installation of feeder automation. Delivery of these two investments in one project is efficient from a planning and work coordination perspective, but it also challenges the selection of feeders because conditions have to be right to maximize the value of both the feeder rebuild and upgrade and the automation investment. The result has been a predominant focus on maximizing the value of the feeder rebuild, thus limiting the opportunities for installation of automation. Through this separation of activities and also by working more closely with the Company's substation group, the Grid Modernization program manager believes they can increase the deployment of cost effective feeder automation. It is also an advantage to separate the program activities because the process of evaluating the prudence of each type of investment is different.

Staff of the Grid Modernization and Wood Pole Management Programs also continue to review their strategy and process for coordinating both programs. This is particularly useful in maximizing efficiencies in how the work is performed under each program in cases where funding levels might vary substantially from year to year.

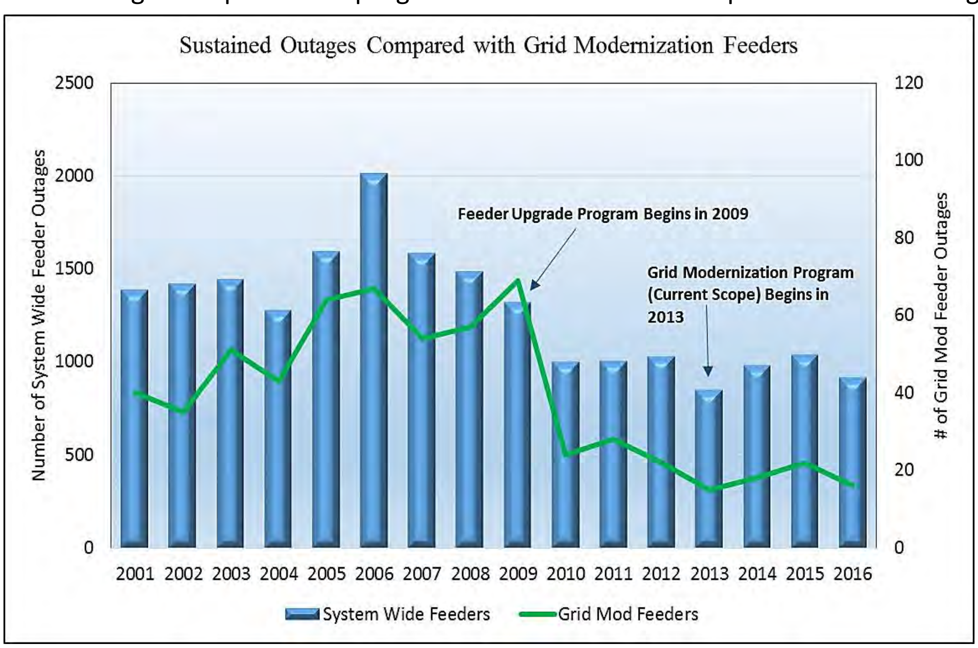


Figure 38. Grid Mod Sustained Outages

Historic and Planned Program Investments - Program spending for the period 2012 – 2016 is provided below in Table 13. The financial values include the initial budget request made by Grid Modernization staff for each year of the then-current five-year planning cycle. The beginning budget reflects the amount that was initially approved by the Company's Capital Planning Group (CPG) for the five-year plan, and the ending budget is the amount that was finally approved by the planning group for each year. The Company's planned level of capital investment for the current period 2017 – 2021 is also provided in the table below (see footnote[72]):

Year	Initial Funding Request	CPG Initial Approved Budget	CPG Revised Final Budget	Actual Investment	Planned Circuit Miles Addressed *	Actual Circuit Miles Addressed *
2012	$9,000,000	$7,370,690	$6,452,937	$7,362,925		73
2013	$8,000,000	$7,313,766	$7,254,084	$7,312,362		54
2014	$22,500,000	$9,700,019	$9,586,000	$10,140,626		88.8
2015	$11,000,000	$11,000,015	$12,310,000	$12,060,958		100
2016	$12,000,000	$7,000,894	$10,850,000	$10,883,805		97.59
2017	$17,500,000	$13,699,503			120	
2018	$17,500,000	$14,000,000			118	
2019	$19,500,000	$14,500,000			124	
2020	$21,500,000	$15,000,000			182	
2021	$22,500,000	$15,500,000			146	

Table 14. Grid Modernization Budgets and Actuals **See Footnote 72*

Distribution Grid Modernization represents a comprehensive approach to infrastructure management from its data and engineering-driven analysis and evaluation to the way it serves as a platform to better integrate a portion of the capital investments we make each year in our electric distribution system. Through Grid Modernization, the Company knows it is targeting work on the right infrastructure at the right time, and in a priority that allows us to optimize the customer value of every investment made under the program, as well as to optimize the value of other programs, as explained above.

Due in part to the need to balance priority infrastructure investments across the Company, however, Avista has not yet funded the Grid Modernization program at the level required to achieve the desired 60-year cycle interval. As a result, wood pole inspections and replacements that would have been completed under this program are shifted to the wood pole management program and failed plant. This results in lower work efficiency, which increases our capital and expenses and impacts customer value. The other areas of cost effective value delivered by the Grid Modernization program are foregone. The benefits of Grid Modernization are described in detail in Appendix C.

[72] Units of Work are in Circuit Miles Addressed. Note that in 2012 the budget was cut but the investments had already been made.

Distribution Device Management Program

Avista relies on a range of distribution management devices installed on its system to perform operations that enable our distribution grid to be more reliable and energy efficient. These specialized devices include reclosers, voltage regulators, capacitors, and automatic transfer switches. The Distribution Device Management Program performs equipment inspections, routine maintenance, data collection, and battery replacement on a three year systematic schedule for these devices. In addition to maintenance, as devices reach their end-of-life and are prone to failure, they are programmatically replaced to insure the safe and reliable operation of our system.

> **Automation Successes**
>
> ***In the first eighteen months of this Program:***
>
> - **16 Automated Restorations**
> - **9 Dispatcher Remote Restorations**
> - **1.75 Million Avoided Customer Outage Minutes**

A major consideration of this program is public and worker safety. A safety risk is created when these devices fail or function improperly, especially during storm outage restoration efforts. Crews working on the distribution grid have safe guards in place to protect them against devices not functioning properly; however proactively caring for each device helps reduce any safety risk for our employees as well as to the general public.

Program History - Management of Avista's reclosers and other equipment was previously performed by employees in Avista's Operations and Substation groups. In 2013, the Company recognized the need for a more proactive and systematic approach for maintaining and replacing its reclosers and other automated devices. There are now over 500 automated devices included in this program, which brings all of this equipment under the same management and maintenance practices, optimizing inspections and replacements throughout the lifecycle of the devices.

Avista's Distribution Device Management Program is based on a set of optimized inspection, data collection, and full device replacement practices. Its goal is to maximize the effectiveness of personnel resources, capture device data for Avista's enterprise asset management system (Maximo), obtain outage data, help identify outage causes, and improve safety and operations effectiveness by proactively managing and maintaining these devices.

Since the Program is in its initiation phase, its scope is being evaluated to determine if other devices will be added to the program and whether to adjust the amount of data collected and the frequency of data collection. However, the success of the program is already apparent, as can be seen in the text box above.[73]

Using a "hot stick" to work on energized lines

[73] "Avista's Smart Grid Technology," John Z. Gibson, https://www.nrel.gov/esif/assets/pdfs/agct_day1_gibson.pdf

These components represent a considerable investment in our company and our ability to enhance reliability and system performance for our customers. The current five year budget for this Program is shown in Table 15. As the scope of the program becomes finalized, the budget will be refined to reflect a best estimate.

Distribution Device Management Program	2017	2018	2019	2020	2021
Capital	$0	$0	$0	$0	$0
O&M	$20,000	$40,000	$40,000	$40,000	$40,000

Table 15. Distribution Automated Devices Maintenance Budget

Replacing Transformers Containing PCBs

Between 1929 and 1979, a family of synthetic organic compounds known as Polychlorinated Biphenyls (PCBs) were commonly used in the oil that fills electrical transformers due to their high dielectric strength[74] and resistance to fire. Studies conducted in the 1960s and 70s revealed, however, that these compounds are also toxic, carcinogenic and highly resistant to biodegradation in the environment. Their production was banned in the United States in 1979.[75] In the prior decade, Avista monitored a number of local, regional, and national initiatives focused on the elimination of PCBs and similar contaminants. In 2010, the U.S. Environmental Protection Agency (EPA) issued an Advanced Notice of Proposed Rulemaking on new PCB regulations. In addition to these developments, Avista faced the possibility of citizen-filed lawsuits related to PCB contamination in the Spokane River watershed. As a result of this elevated concern, and our experience with the risk of aging transformers leaking or breaking open when striking the ground as a result of damage to the feeder, Avista began to formally analyze alternatives to deal with its distribution transformers containing PCBs.

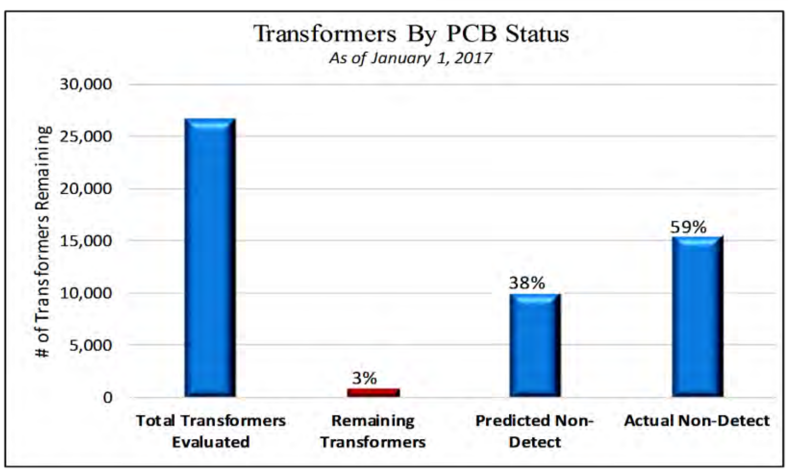


Figure 39. Transformer Replacement Status

[74] Dielectric strength refers to the ability of a material to resist carrying an electrical current, which is a measure of its potential to insulate against electric short circuit or fault.
[75] "PCBs Questions & Answers," United States Environmental Protection Agency, https://www3.epa.gov/region9/pcbs/faq.html.

In 2010 the Company conducted a detailed assessment of its distribution transformer population, and the following year initiated a systematic and prioritized replacement of its transformers known or suspected to contain PCBs. When the program began in 2011, Avista targeted over 12,000 transformers for replacement. Because most of these transformers were already 30 years of age and older, the program, irrespective of eliminating PCBs, is predominantly based on replacements for asset age and condition.

The program was initially slated for completion in 2016, but this timeline was extended to accommodate the Company's overall capital demand, and to increase the efficiency by having our line crews engaged in other work on a feeder also perform these transformer change-outs. Currently, about 900 of the 12,000 targeted transformers remain in the system, as shown in Figure 39. Under the current plan, all transformers with PCB concentrations exceeding 1 part per million should be removed from our system by year 2019. In year 2020 and beyond, the remainder of the pre-1981 transformers in our system will be removed and replaced as part of the Wood Pole Management and Grid Modernization Programs. A significant benefit of the program is the energy savings captured by removing old and inefficient transformers from the system and replacing them with new energy efficient units.

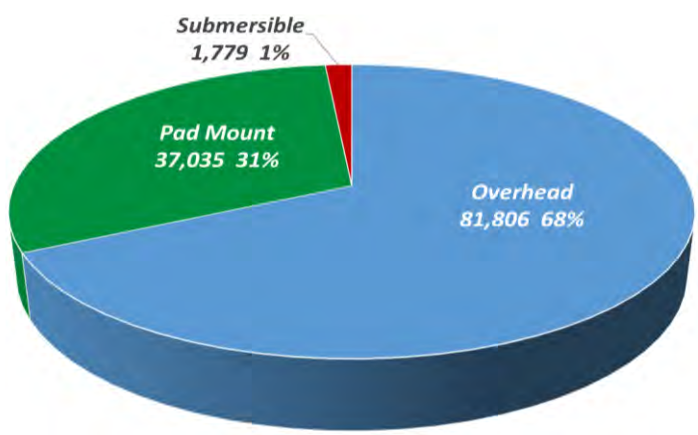
Requested, approved, and actual capital investments for the PCB Transformer Change-Out Program are shown below in Table 16:

Year	Initial Funding Request	CPG Initial Approved Budget	CPG Revised Final Budget	Actual Investment	Planned Replacements	Actual Replacements
2012	$7,000,000	$2,912,403	$6,000,000	$3,871,624	2,687	4008
2013	$6,000,000	$2,414,015	$2,924,015	$2,846,360	2,555	2,625
2014	$5,800,000	$4,700,001	$3,944,000	$3,747,953	2,930	2721
2015	$6,900,000	$4,700,001	$3,750,000	$3,285,614	2,335	2,919
2016	$5,800,000	$2,200,001	$3,750,000	$3,552,069	1,530	2310
2017	$3,000,000	$3,000,001			1,419	

Table 16. Transformer Replacement Program Requested & Actuals

Managing Avista's Transformer Assets - Avista has approximately 82,000 overhead transformers, 37,000 pad mount transformers, and about 1,800 submersible transformers across our system. Overhead transformers are the most common type of distribution transformer on our system; they

Working on an Overhead Transformer



provide the final voltage transformation required to serve customers, typically less than 200 kVA[76] and serve an average of 2.72 customers per unit. Pad mount transformers are typically larger (for commercial and industrial applications, for example) and commonly range between 100 to 2,000 kVA. Submersible transformers are typically located below the street level in vaults, where they are exposed to a variety of weather conditions and potential flooding. They come in a variety of sizes, from 10 to over 4,000 kVA.

Flooding in the Downtown Network underground system after a rainstorm

Above: Pad Mount Transformers awaiting installation
Below: Submersible Transformers

If a distribution transformer is operated under ANSI / IEEE basic loading conditions[77], it has a normal life expectancy of about 20 to 30 years assuming it is not subjected to extreme weather conditions or overloading on a regular basis.[78] At Avista, our submersible and pad mount transformers have a typical lifespan of 44 to 46 years, and overhead transformers last an average of 60 years based upon average age at failure. An extended lifespan is not unexpected if the units are properly serviced, have enough capacity to handle the expected loads, and are set up with the proper specifications to meet the application (i.e. residential load versus industrial load, liquid-filled or dry type).[79]

Placing a Pad Mount Transformer

As previously described, Avista has three programs involved in inspecting and replacing distribution transformers: the Wood Pole Management Program, Grid Modernization Program, and PCB Transformer Change-Out Program. Inspectors check for leaks, proper sizing, acceptable clearances, identify potential safety issues, ensure adequate grounding of the unit, and make certain labeling is correct.

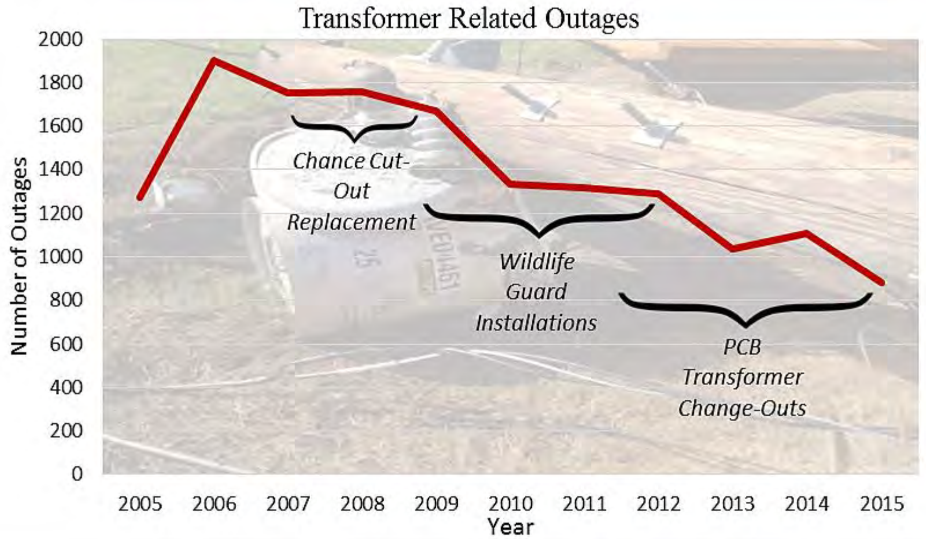
Avista Transformer Life Expectancy

Transformer Type	*Years*
Overhead	60.4
Pad Mount	46
Submersible	44

[76] A kVA is 1,000 volt amps – a volt measures electrical pressure, an amp measures electrical current. A unit of kVA measures "apparent power" versus a watt, which measures "real power." Apparent power is the maximum possible power attainable when the current and voltage are in phase, that is, how much power a supply can deliver, versus real power or watts, which is the amount of power that does the actual work. Only part of the kVA is available to do real work, the rest is excess current.
[77] "Guidelines for Transformer Application Designs," Robert B. Moran, May 1, 1999, http://www.ecmweb.com/content/guidelines-transformer-application-designs and http://members.questline.com/Article.aspx?articleID=12304&accountID=1874&nl=13764
[78] "Electric Power Distribution Engineering, Third Edition," Turan Gonen, 2014, p.114, https://books.google.com/books?id=JIDSBQAAQBAJ&pg=PA114&lpg=PA114&dq=average+life+expectancy+of+an+electric+distribution+overhead+transformer&source=bl&ots=LBfDVJz4Gd&sig=aWbuSECTpyeFjDdc76FhI-1pO-o&hl=en&sa=X&ved=0ahUKEwjAu5fX3v_UAhUi0oMKHdMZBTYQ6AEISTAE#v=onepage&q=average%20life%20expectancy%20of%20an%20electric%20distribution%20overhead%20transformer&f=false
[79] 79 "Guidelines for Transformer Application Designs," Robert B. Moran, May 1, 1999, http://www.ecmweb.com/content/guidelines-transformer-application-designs

In addition to managing the transformers themselves, these programs also replaced failed equipment such as chance cutouts and they install wildlife guards on applicable feeders.

Through these three projects, the company has replaced the great majority of its oldest transformers (i.e. beyond their useful life), which has markedly reduced the number of transformer-related outages, as shown in Figure 41. Less than 1% of our overhead and pad mount transformers and less than 5% of our submersible transformers are beyond their expected lifespan (by Avista standards – 60, 44, and 46 years), as can be seen in Figure 42.



Failed Transformer

Figure 41. Transformer Related Outages

The reliability benefits resulting from reduced transformer failures are often more substantial than one would anticipate. The average Avista overhead transformer serves 2.72 customers on average but when it fails, it can have a domino effect along the feeder, tripping up to ten neighboring transformers and impacting all the customers they serve. "Cascading" failures in a system of interconnected parts is not uncommon, as nearby components are often required to compensate for a failed unit, which may cause unexpected overloading and demand spikes across a number of nodes in the system, rather like the ripples in a pond. The Company is aware of this potential and is endeavoring to insure, during our inspection process, that our transformers are sized appropriately to reduce the potential occurrence of such multiple outages.

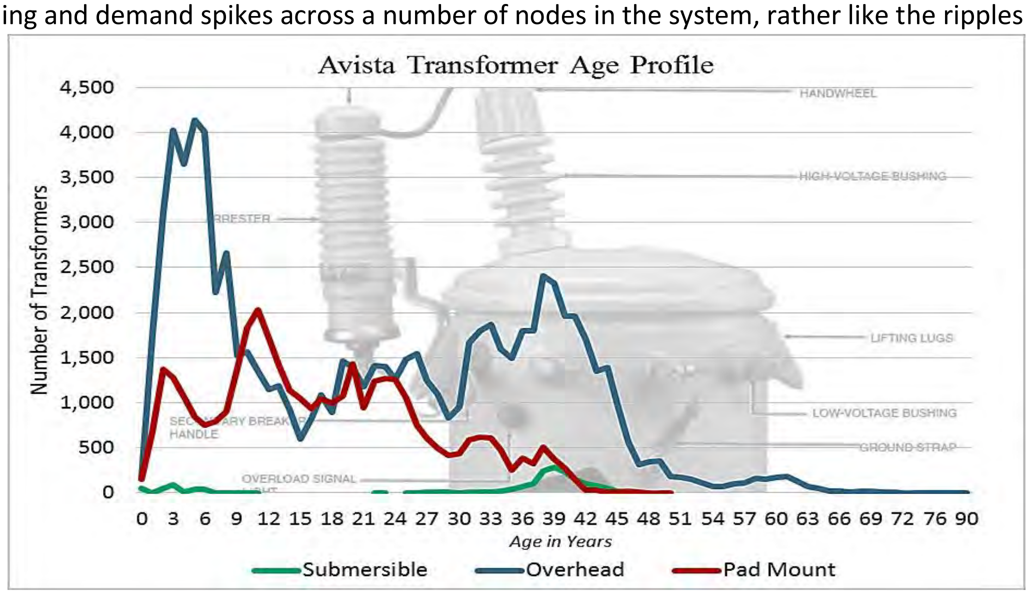


Figure 42. Avista's Distribution Transformer Inventory Age Profile

Underground Cable Replacement

"FIRST GENERATION" UNDERGROUND CABLE ISSUES

- Lack of adequate insulation, resulting in numerous faults
- Splicing (a routine operation) results in weakness and premature failure
- Excessive corrosion on the neutral strands cause voltage levels to drop unexpectedly or complete cable malfunction
- Water penetration of the exterior insulation causes voltage surges and faults
- Lack of protection against dig-ins, animal and vegetation incursions as well as flooding and lightning damage

Underground Residential District Cable (underground cable or URD) has been used by the utility industry since the 1930s, though Avista did not begin installing the cable until the late 1960s. During the 1990s it became apparent that the cable manufactured prior to the 1990s had numerous problems, as highlighted in the text box.[80]

Prior to the underground cable problems becoming apparent to the industry, Avista had installed over 6,000,000 feet of this type of cable.[81] By the mid-1990s, customers served by this cable began to experience more prevalent outages that were increasing with time as the cable aged and continued to deteriorate at an accelerated rate. Though the Company had initiated a program to systematically replace this cable, it became apparent that the effort was insufficient to address the accelerating problem. Avista estimated that by 2016 the annual number of outages per 10 miles of cable would exceed 30 under that initial program, as shown in Figure 43.

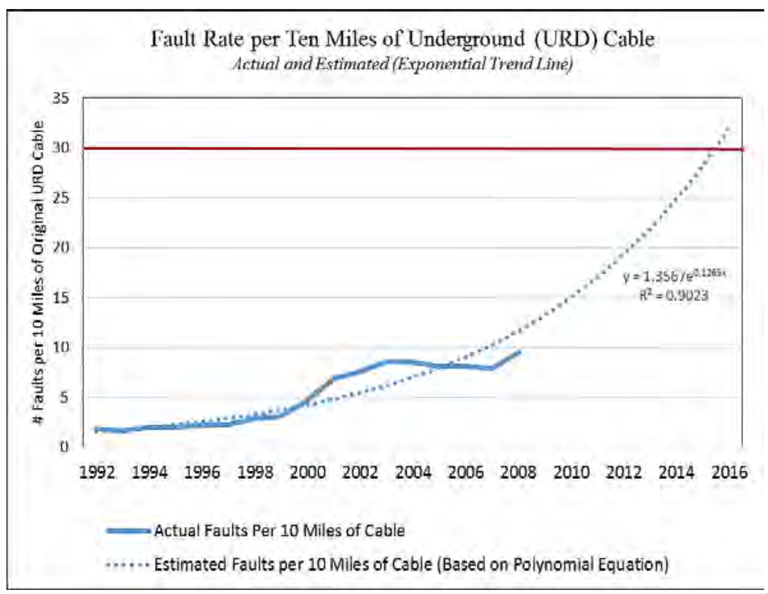


Figure 43. Projected Underground Cable Failures

Avista's asset management group analyzed options for accelerating the replacement schedule from ten years to a four year program. The analysis, which was based on savings from avoiding unplanned outages, estimated that the four-year program would save customers approximately $7.3 million in capital

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[80] "Medium Voltage Underground Cable White Paper," Nuclear Energy Institute 06-05, April 2006, https://www.nrc.gov/docs/ML0612/ML061220137.pdf
[81] Madden, Glenn and Rodney Pickett, "Asset Management 5 Year Plan and Budget Summary," 2010

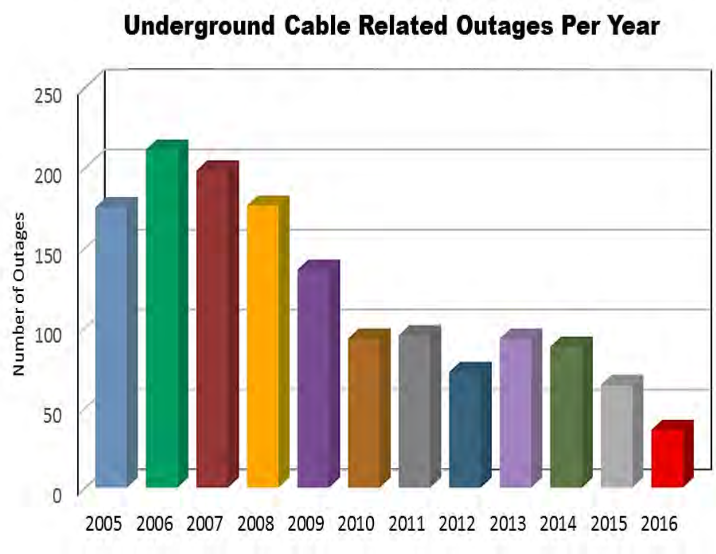


Figure 44. Actual Underground Cable Related Outages

installation, expenses, and failure consequences.[82] With the majority of the known vintage cable replaced by 2013, the program was ramped down to an annual investment of approximately one million dollars, which provides for the removal and replacement of this vintage cable as we find it on the system (usually through responding to an underground fault). The substantial reliability benefits of the program for our customers are shown in Figure 44.

Avista's budgeted and actual capital invested for underground cable replacement from 2005 – 2016, and forecasted through year 2021 is shown in Figure 45.

This year the Company is conducting a detailed inventory to identify all remaining first generation cable throughout our underground distribution system. When this study is complete we will have a better understanding of the locations and footage of this cable remaining, which will allow us to optimize our approach to its removal, as well as forecasting the future investment need.

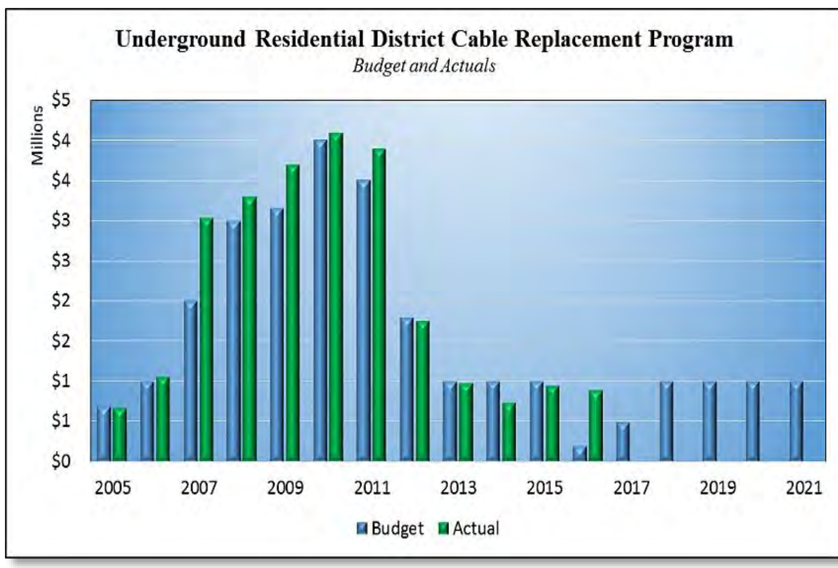


Figure 45. Underground Cable Replacement Program

Though this program is centered on replacing the cable based on asset condition (i.e. it has reached or is nearing the end of its useful service life), our progress has had a measurable impact on the incidence of cable-related outages on our system, as shown in Figure 44.[83]

Undergrounding feeders and service lines is often cited as the answer for increasing system reliability, but the cost effectiveness of each application must be evaluated in this decision. The initial cost of undergrounding can be much more than constructing overhead distribution lines. Life cycle costs of underground lines can also be higher due to a shorter useful life and higher repair and replacement costs. In

[82] Savings are based on the outages forecast to occur without the replacement program, minus the actual outages, multiplied by the average cost of responding to an average cable outage.
[83] This data on cable failures was collected from outages recorded on the Company's outage management system, which became operational in 2005.

addition, outages associated with these lines are harder to locate and repair.[84] Avista takes all of these factors into consideration when deciding whether it is in our customers' best interests to install underground systems.

Requested, approved, and actual capital expenditures for this program are shown in Table 17. (Note: CPG is the Capital Planning Group.)

Year	Initial Funding Request	CPG Initial Approved Budget	CPG Revised Final Budget	Actual Investment	Planned Replacements (in Feet of Cable)	Actual Replacements (in Feet of Cable)
2005		$699,308		$672,080		36,982
2006		$1,000,007		$1,059,350		93,416
2007		$2,000,006		$3,031,836		178,868
2008		$3,000,007		$3,296,006		136,342
2009		$3,156,003		$3,686,950	178,000	211,059
2010		$4,000,006		$4,092,425	178,000	217,883
2011		$3,500,003		$3,888,899	178,000	223,291
2012	$2,292,000	$1,792,006	$1,792,000	$1,746,583	178,000	118,427
2013	$1,000,000	$1,000,007	$1,000,000	$982,815		28,443
2014	$1,000,000	$1,000,009	$750,000	$737,639		36,465
2015	$1,000,000	$1,000,004	$1,000,000	$952,136		20,824
2016	$1,000,000	$200,010	$1,000,000	$894,584		112,861
2017	$1,000,000	$500,009				

Table 17. Underground Cable Replacement Program Requested & Actuals

Underground Inspection Pilot Program

Avista has over 37,000 pad mount transformers and over 12,700 junction enclosures[85] throughout our electric distribution system. Our placement and operation of this equipment is subject to a range of laws, standards, and codes that are intended to provide for the safety and security of our customers and employees. Over time the identification markings, condition and operability of these assets will naturally deteriorate and the Company must take steps to ensure they are properly maintained or replaced as needed to guarantee our compliance with applicable rules and the safe and reliable operation of our electric system.


Underground equipment now in a bog


Once upon a time this was a safety decal

Over the past few years Avista staff have anecdotally reported that much of our underground equipment was missing proper marking decals or that those decals were so deteriorated as to be unreadable. In other cases, homeowners had added aesthetic elements that block access for our workers. Some equipment had also been damaged or its function and reliability were compromised by age, weather, or local conditions. Based

[84] "Power outages often spur questions around burying power lines", U.S. Energy Information Administration, Today in Energy, July 25, 2012, https://www.eia.gov/todayinenergy/detail.php?id=7250
[85] A junction enclosure is a usually small underground vault where the Company has joined underground electric cables or installed various line devices.

on these reports, the Company determined it should develop a consistent, comprehensive plan to inspect all Company underground equipment and make any necessary improvements needed for compliance and safe operation.

Left: Transformer Covered by Shrubbery

Below: Vines Growing Inside a Transformer Box

To determine the needs and scope of this inspection program, the Company conducted a pilot inspection of 474 transformers and 120 junction enclosures over a four week period. This short-term pilot study found that 96% of the equipment examined had improper identification decals - the decals were either outdated or no longer valid, were destroyed by age or weather, were missing or illegible, or had been removed by property owners. In addition, over a third of the units were overgrown with vegetation or had walls, rocks or decorations installed within the required clearance zone. Other concerns included the potential for unauthorized access, the failure of paint and protective coatings,[86] problems related to rust, and equipment that had settled 'out of level,' creating the potential to leak oil.

Legal Requirements for Underground Equipment

- ✓ Washington State WAC 296-24-95605 provides direction for exterior marking
- ✓ IEEE C57 requires specifics for enclosure integrity (to prevent unauthorized access)
- ✓ Washington State WAC 468-34-130 350 contains codes related to locating equipment along roadways
- ✓ Washington State WAC 296-24-95605 directs that the area around pad mount equipment be kept free of obstruction
- ✓ National Electric Safety Code NESC C2-2007 contains grounding requirements

Left: Landscaping features block Avista access to equipment

Below: Paint failure can lead to rust-through of cover

These findings demonstrated the significant need to systematically inspect and remediate these types of issues, particularly those that would pose a safety threat to our customers and citizens (as most of these units are easily accessible in yards, playgrounds, and other public places).

Based on the pilot program results, a model was developed to determine the optimum inspection cycle based on a comparison of risk, resource needs, and financial impacts. That work supported development of an inspection program based on a cycle interval in the range of 8 years, and with an annual capital investment starting at $1.6 million dollars for the replacement of equipment at or past its useful life, plus $800,000 in O&M expenditures to conduct the inspections. Avista believes this approach effectively balances the program costs with our obligation to meet

86 Avista studies estimate that 2% of paint failures will result in a Pad Mounted Transformer failing and requiring replacement.

compliance requirements, our commitment to public, customer and employee safety, and the reliability of our system.

Avista's inspection protocol is designed to identify damaged, obscured, or missing safety decals, equipment not accessible due to vegetation, impeding landscaping or structures, and to examine the general physical integrity of these assets. To maximize the efficiency of the inspections, teams will be equipped with the proper materials and tools to take immediate corrective actions, which will include removal of vegetation, installation of new locks and labels, cleaning and insuring the integrity of the structures, and to repair the pads. Taking these corrective actions will allow us be more cost effective and to quickly reduce any potential safety risks. More complex issues will be reported, tracked and systematically repaired in follow-up work.

Pilot Program Results

- 96% Improper Decals
- 35% Clearance Issues
- 3% Transformer Not Level
- 8% Failed Tamper-Resistant Bolts
- 8% Paint Failure

This program will allow us to achieve compliance with all applicable codes and regulations**,** decrease our risk of safety issues and equipment failures, and to positively impact our system reliability by replacing failing or failed equipment on a planned basis. Expected expenditures are shown in Table 18.

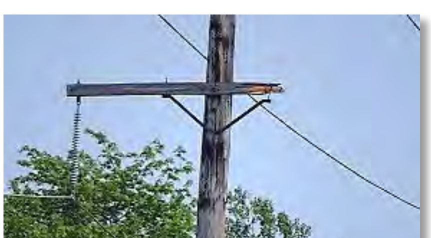
Underground Equipment Inspection Program	*2017*	*2018*	*2019*	*2020*	*2021*
Capital	$1,600,000	$1,600,000	$1,600,000	$1,600,000	$1,600,000
O&M	$800,000	$800,000	$800,000	$800,000	$800,000

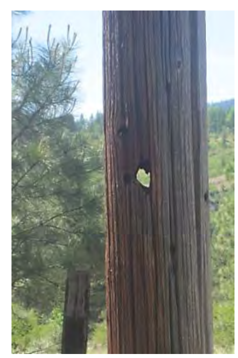
Table 18. Underground Equipment Inspection Expenditures

Worst Feeders

As noted in the electric system reliability section above, the Company evaluates the opportunity to modify certain segments of its feeders of greatest reliability concern, which are implemented through investments based on the asset condition of the feeder. Because of the many infrastructure demands we currently face, the Company has substantially reduced the funding allocated to this program, currently planned for 2017 alone.[87]

Above: Fire damaged pole
Below: Broken crossarm





The annual planned capital investments for each of the asset condition programs described above are presented in Table 19:

[87] In addition, the funding for worst feeders has been moved into the Grid Modernization Program.

	2017	2018	2019	2020	2021
Wood Pole Management	$9,000,000	$9,500,001	$9,500,000	$9,000,000	$12,000,000
Distribution Grid Modernization	$12,900,000	$13,900,000	$13,295,050	$13,753,500	$14,211,950
Underground Cable Replacement	$500,000	$1,000,004	$1,000,004	$1,000,004	$1,000,004
PCB Transformer Replacement	$3,000,000	$1,200,000	$1,200,000	$1,200,000	$0
Total	***$25,400,000***	***$25,600,005***	***$24,995,054***	***$24,953,504***	***$27,211,954***

Table 19. Planned Distribution Investments: Wood Pole, Grid Mod, Underground, PCB Replacement

Failed Plant and Operations Investments

The replacement and capital repair of equipment failures constitute "*requirements to replace assets that have failed and which must be replaced in order to provide continuity and adequacy of service to our customers (e.g. capital repair of storm-damaged facilities)*." While large-scale outages such as the windstorm of November 2015 are vividly remembered by both Avista employees and our customers, the Company responds to thousands of outage events each year that occur almost every day of the year. The replacement of assets due to equipment failure or outage events, however, is only one component of the investments required to operate our electric system. In addition to outage response, Avista's nominal operations involve reconfiguration and replacement of electric facilities under a variety of circumstances. For example, electric distribution systems are protected by a network of fused devices. Changes in customer demand and load additions often require revisions to the system of 'coordinated fusing' in order to adequately protect for line faults. These projects may also involve ancillary activities not directly attributable to the end-use customer, but necessary to maintain the safe and reliable operation of our electric distribution system, including adding voltage regulators or reclosing equipment, or replacing a pole, cross arms, or transformers in poor condition. Avista monitors circuit loading and often shifts load from one circuit to another during winter or summer peak usage, which often involves extending overhead or underground primary wires and cables.

Above: A pole rots and fails
Below: Replacing old pole with new (significantly straighter) pole
Top Right: Pole hit by a truck
Bottom Right: Wind storm causes a pole to split

Failed Plant

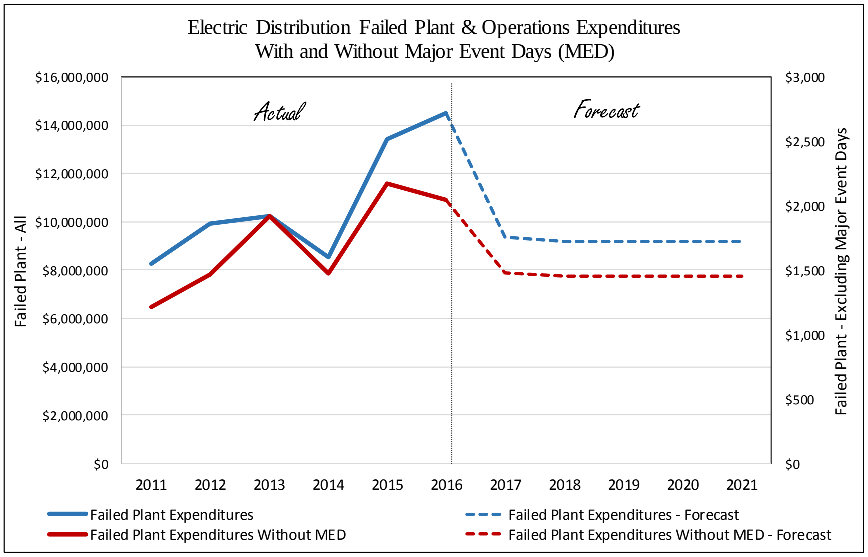


Figure 46. Failed Plant & Operations Expenditures

Avista responds to various types of equipment failures each year resulting from a range of factors, some of which result in service outages for our customers. The required investments for replacing this plant are included in the program titled "Distribution Minor Rebuild."

The vast majority of customer outages occur on the overhead electric distribution system. In 2016, there were 7,083 outages on the distribution grid compared to only 53 failures related to substations and 61 associated with transmission lines. The majority of these outages are related to weather (e.g. lightning, wind, rain and snow), downed trees, animals (e.g. squirrels and birds), and equipment failure. Repairs to the system often require the installation of poles, transformers or crossarms, and may include the installation of overhead conductors. Other failures include third-party damage to electric cables, as well as the unanticipated failure of assets due to a range of factors including age and condition. Figure 46 shows the actual and forecasted costs of failed plant and operations for Avista's electric distribution system.

"Car Hit Pole" Situations

Emergency Storm Response

Avista tracks the costs of these major events through our Emergency Storm Response program. Figure 48 shows the actual and forecast level of spend on major storms since 2011. The emergency storm spending for this period is dominated by results for 2014 and 2015, which resulted from only four individual storm events. In August 2014, Avista suffered three significant windstorms, which resulted in 20,000 to 50,000 customers losing their electric service during each event. The November windstorm of 2015 was the largest single day, resulting in a loss

Lineman in Davenport restoring service in a snowstorm.
Courtesy of Infinity Rose Photography

of service for over 168,400 Avista electric customers.[88] The majority of the outages were the result of hurricane force winds that severely impacted the Spokane area.

For the forecast of the current five-year period, we have used a more 'typical' level of investment related to major storms, with an annual value of approximately $2.2 million.

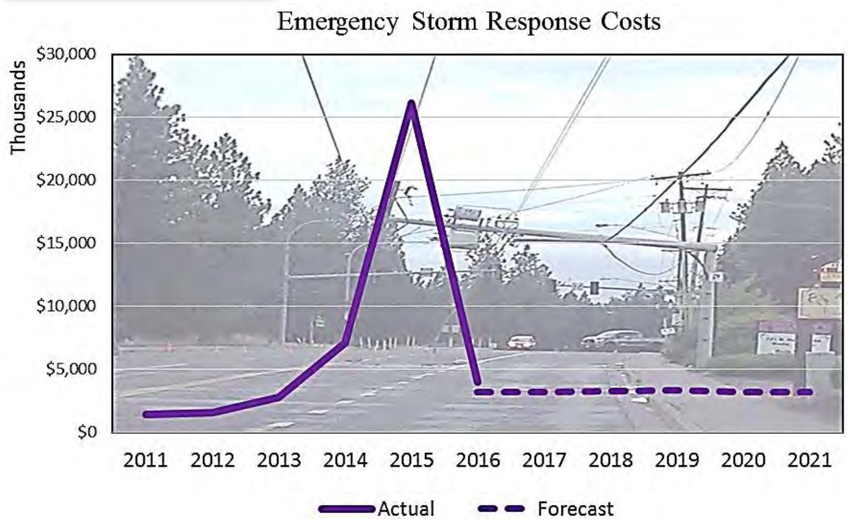


Figure 47. Storm Response Costs

Windstorm 2015 by the Numbers:

- 180,000 Avista customers without service at peak
- 369,000 Total Avista customers
- 500 Linemen from contractors or other utilities assisting in the restoration (the PG&E crew traveled 873 miles)
- 26 severed gas lines found in one 12-hour shift
- 54% of homes and businesses in North Idaho and Eastern Washington experienced an outage
- 62 intersections in Spokane without stoplights
- Over 3,700 tons of debris

Operations Capital

In addition to replacing assets that have failed, Avista's operations staff performs a wide range of limited capital infrastructure work that does not rise to the level of a project or program. The investments described in this section are included in the distribution minor rebuild program. This work includes the need to reconfigure, replace, repair and upgrade electric facilities for a variety of reasons, including:

- *Investments that are associated with customer requests for new or modified services*
- *Replacement of equipment based on asset condition*
- *Remedying capacity deficiencies*

As noted under customer requested investments, direct costs associated with extending feeder and service wires and cables to provide requested service to a customer are subject to cost sharing between that customer and Avista. As the number of customers on a feeder grows over time, however, the Company may have to replace or upgrade the capacity of trunk line feeders or laterals. The investments needed for this work, which are included under the operations capital, are paid for by all customers because they are required to provide reliable service to everyone on our system. Examples of this type of work are shown in the text box below.

[88] "Windstorm Pummels Spokane, Killing Two People and Causing Widespread Blackouts," The Spokesman Review, November 17, 2015, http://www.spokesman.com/stories/2015/nov/17/windstorm-pummels-spokane-killing-two-people-and-c/

Spokane Electric Network

Avista operates an underground electric distribution system in the core business district of downtown Spokane. This distribution "network" is configured as a fully redundant distribution grid that includes cables encased in concrete reinforced duct lines and major equipment such as underground transformers in concrete vault structures. Most mid-size to large cities operate such a network including Seattle, Portland and Tacoma. The Spokane network system dates back to the early 1900's, with some vaults carrying a date stamp as early as 1910. Major expansion of the system occurred between 1940 and 1960 with significant modifications made to accommodate the World's Fair in 1976. The expected annual cost of maintaining the network for the 2017-2021 time period is approximately $2.3 million per year.[89]

Working below the streets in the Downtown Network

Capital investments associated with the Spokane electric network include customer requested load additions, replacements of assets based on condition, as well as replacement of equipment and infrastructure that fails.

Downtown network crew beginning the process of filling cable with lead to create a solid splice; this type of work is considered an art

Spokane's system is relatively small, including 100,000 feet of underground feeder cable and 125,000 feet of service cable connecting submersible, vault-type transformers. The Downtown Network feeder lines are separated into four sub-networks, each of which is capable of sustaining the loss of one trunk line without losing any customer load. The network requires specialized material, equipment, tooling, and manpower to perform maintenance, repairs, planned replacements, and capacity growth projects. The pace of annual investments for replacements and additions include approximately 7,500 feet of primary feeder cable (15,000 volts), 7,500 feet of service cable (600 volts), 6 to 8 manholes, 2 to 4 vaults and/or vault roofs and the replacement of 10 street lights.

Typical Operations Activities

- Repair broken or damaged equipment and fixtures whether or not they are related to a customer outage.
- Adding additional phase (overhead conductor or underground cable) to support customer loads requiring three-phase service.
- Replace undersized conductor or cables as needed to provide adequate service.
- Reconfigure overhead feeder conductors to meet the clearance requirements for joint use facilities, such as telecom fiber attached to Avista's poles.
- Load balancing among the phases on a feeder to reduce the return current on the neutral wire.
- Modifications or line additions to protect birds and animals.
- Repair or replacement of equipment damaged by vandalism or theft (e.g. copper wire theft.)
- Replacement of failed customer demand meters.

[89] Direct Testimony of Heather L. Rosentrater, February 2016, UE-160228, pg. 41, https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=323&year=2016&docketNumber=160229

Today, Riverfront Park is being renovated as part of an effort to redevelop and reinvigorate the core of downtown Spokane. In 2015, the Spokane Grand Hotel was added to the skyline in response to the expansion of the Spokane Convention Center. Efforts are underway to develop all-electric bus routes through the heart of Spokane extending to the Gonzaga and Spokane Community College Campuses. Downtown Spokane is growing and Avista continues to meet the challenges associated with that growth.

Table 20 provides the expected level of capital investment for each of the program budgets discussed above for each year of the current planning period.

	2017	2018	2019	2020	2021
Major Storms	$3,182,700	$3,278,181	$3,376,526	$3,168,822	$3,200,000
Distribution Minor Blanket	$8,867,270	$8,900,000	$8,900,000	$8,900,000	$8,900,000
Meter Minor Blanket	$505,000	$300,000	$300,000	$300,000	$300,000
Spokane Electric Network	$2,300,000	$2,300,000	$2,300,000	$2,300,000	$2,300,000
Total	***$14,854,970***	***$14,778,181***	***$14,876,526***	***$14,668,822***	***$14,700,000***

Table 20. Planned Distribution Program Investments

Conclusion

As described and documented in this report, the increasing investments made by the Company over the prior decade reflect a demonstrated need for new investment in electric distribution infrastructure. The information provided in this report, and which is supported by more-detailed analysis and documentation, supports these prior-period investments as necessary and prudently incurred. The year-over-year growth in our prior investments is not at all unusual in our industry. Compared with our peers across the industry, our capital investments on a per-customer basis are reasonably consistent with the industry average over time, though our cumulative spend over the prior 20 years is slightly below the industry average. These investments have allowed the Company to achieve a level of electric system reliability that we believe is satisfactory to our customers and represents a cost effective value.

Our individual infrastructure programs are responsive to investment demands that are beyond the control of the Company, such as the case for customer requests for service, mandatory and compliance issues, and failed plant, or they respond to needs that are necessary and immediate or that are cost effective for our customers. Our asset management programs have been thoughtfully developed, thoroughly analyzed and optimized, and re-analyzed and adjusted as appropriate to ensure that we deliver cost effective value for our customers.

Our LED Street and Area Lighting Program, which is 1.8% of our overall distribution investment, delivers greater safety and security to our customers, and saves them money through operations and energy efficiency savings, not counting the substantial grant received by Avista that further enhances the customer value. Likewise, the Company's deployment of advanced metering will allow us to cost effectively improve our service and reliability for customers as we build the foundation for the emerging energy services grid of the future. Our efforts to improve our base reliability through feeder automation accounts for less than 1% of our overall planned investment yet plays a significant role in helping the Company uphold and maintain the overall reliability of its system. LED lighting and feeder automation are the only programs in our primary distribution investments (not including customer meters) that are not directly tied to the need to repair or replace infrastructure, to remedy equipment overloading and safety issues, or to connect new electric customers to our system. These investment drivers and their associated portions of our overall plan in electric distribution are summarized in Figure 48.

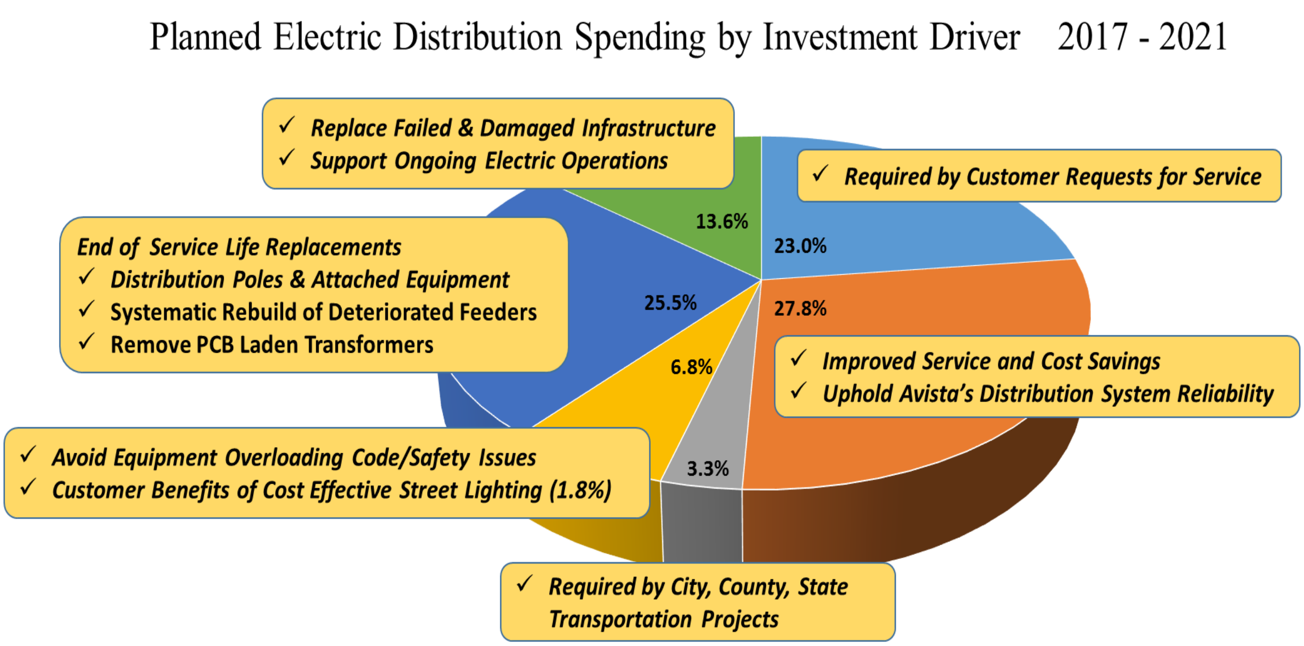
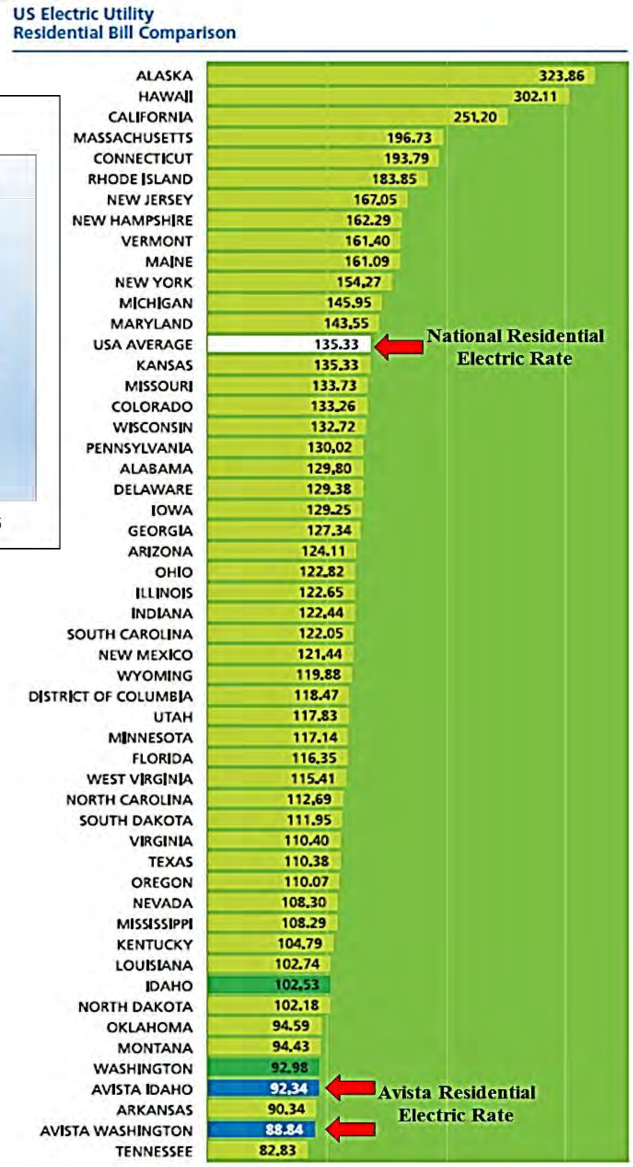
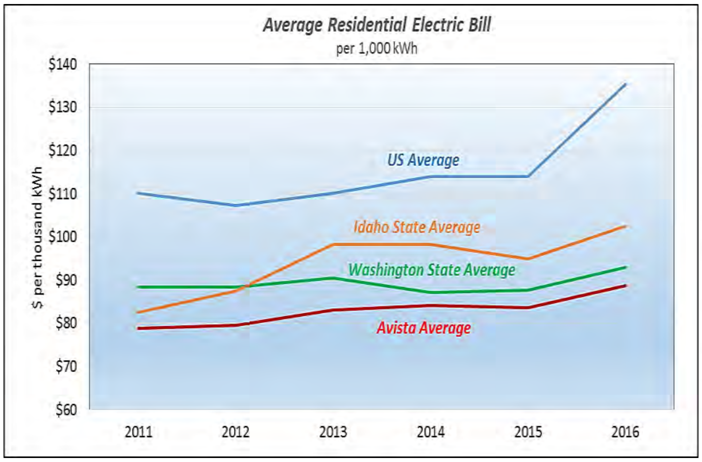
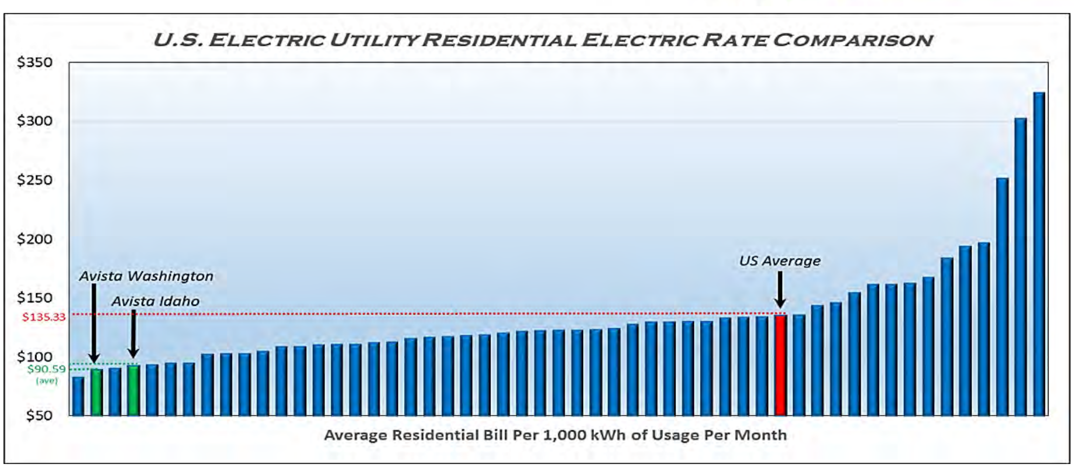


Figure 48. Distribution Spending by Investment Driver

Appendix A: Avista Customer Costs







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Appendix B: Customer Satisfaction

2016 Service Quality Report Card

Each year Avista measures how well we perform in meeting our goal to provide the best customer service possible. In line with that tradition, we established a set of Service Quality Measures in collaboration with the Washington Utilities and Transportation Commission (WUTC) and others. We will be providing this annual report card to customers showing how we are doing on meeting these goals. For more information, visit **www.avistautilities.com.**

Customer Service Measures	Benchmark	2016 Performance	Achieved
Percentage of customers satisfied with our Contact Center services	At least 90%	92.7%	✓
Percentage of customers satisfied with our field services	At least 90%	94.7%	✓
Number of complaints filed with the WUTC annually per 1,000 customers	Less than 0.40	0.25	✓
Percentage of calls answered live within 60 seconds by our Contact Center	At least 80%	81.7%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies	No more than 80 minutes	39.3 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies	No more than 55 minutes	48.4 Minutes	✓

Electric System Reliability	5-Year Average (2012-2016)	2016 Performance	Change in 5-Year Average
Number of non-major storm-related power outages annually per customer	1.04	.86	-0.05
Length of non-major storm-related power outages annually per customer	142 Minutes	133 Minutes	+3 Minutes

Customer Service Guarantees	Successful	Missed	$ Paid
Keep service appointments scheduled with our customers	1,477	10	$500
Restore service within 24 hours of a customer reporting an outage (excluding major storm events)	26,344	1	$50
Turn on power within a business day of receiving the request	3,380	3	$150
Provide a cost estimate for new electric or natural gas service within 10 business days of receiving the request	5,024	0	$0
Investigate and respond to a billing inquiry within 10 business days if unable to answer a question on first contact	1,760	0	$0
Investigate a reported meter problem or conduct a meter test and report the results within 20 business days	309	2	$100
Notify customers at least 24 hours in advance of a planned power outage lasting longer than 5 minutes	30,336	349	$17,450
Totals	**68,630**	**365**	**$18,250**

Appendix C: Grid Modernization Benefits

- ***Reliability Index Analysis***

Reliability indices are significant components of any utility's ability to measure long-term electric service performance, and are one indicator of system health or condition. The common reliability indices of CAIDI, SAIDI, SAIFI, and CEMI-3[90] are used by the Grid Modernization Program to analyze and illustrate the historical reliability performance of the feeders, as well as to assist in justifying any proposed circuit improvements or automation deployments. Each historically averaged reliability index for a feeder is compared to the Avista target value for that calendar year to determine the reliability performance of a feeder. The reliability index performance will also be monitored in future years to quantify the success and magnitude of the Program's work. Major Event Days (MEDs) is an industry standard used to evaluate major events, such as severe weather or storms, which can lead to unusually long outages in comparison to the distribution system's typical outage. The reliability indices that are being used do not include MEDs, as is standard in the industry and which is in line with what is requested by the Commission.

New pole being set with a crane

- ***Load Balancing***

Imbalanced load on a feeder has the ability to create or worsen numerous problems which contribute to inefficiency. Unbalanced load can unnecessarily burden one conductor, potentially causing the highest loaded phase conductor to be overloaded or approach its ampacity limit. This can in turn create voltage quality concerns with low voltage scenarios, which are amplified when loads are higher. The exercise of load balancing also promotes the switching of balanced load between feeders during switching scenarios, which mitigates the problem of overloading a particular phase on an adjacent feeder when load is transferred. Load will be approximately balanced on multi-phase laterals, between sectionalized switching devices or reclosers, and between strategic points on the feeder trunk. These balancing efforts commence towards the end(s) of the feeder and roll up to nearly balanced load on each phase at the substation breakers.

Installing underground cable

Using a helicopter to reach inaccessible areas

[90] CAIDI (average duration of outages/average restoration time) , SAIDI (outage duration), SAIFI (frequency of outages), and CEMI-3 (number of customers experiencing three or more outages), https://www.oeb.ca/oeb/_Documents/EB-2010-0249/OEB_Customer_Specific_Reliability_Metrics_Report.pdf and http://www.galvinpower.org/sites/default/files/Electricity_Reliability_031611.pdf

- ***Feeder Reconfiguration***

The Grid Modernization program supports the efforts to identify and relocate sections of the distribution feeder where the cost and benefits of greenfield construction outweigh the significant work required to rebuild the existing line in place to current standards. In addition, overhead facilities can be converted to underground when the benefits of rebuilding in place are not significant, the cost difference between overhead versus underground is comparable, or if notable reliability improvements can be achieved by removing sections of vulnerable overhead conductors. The ability to reconfigure and convert feeder for reliability and efficiency improvements is a characteristics that distinguishes Grid Modernization from other Programmatic or Capital work.

Feeder Reconfiguration

- ***Trunk Conductor Analysis***


Guy line issue

Primary trunk conductors have the ability to negatively affect the reliability and efficiency of a distribution circuit. Primary trunk conductors are analyzed to determine if they are in acceptable physical condition and modeled to assess if they are appropriately sized to serve peak loading demands, provide adequate voltage levels, and do not cause significant and unnecessary line losses. Primary trunk conductors that do not meet these criteria are replaced with the most appropriate standard conductor size to improve the feeder's operability, reliability, and energy efficiency.

- ***Lateral Conductor Analysis***

Lateral trunk conductors also have the ability to negatively affect the reliability and efficiency of a distribution circuit. Primary lateral conductors are analyzed to determine if they are in acceptable physical condition and modeled to assess if they are appropriately sized to serve peak loading demands, provide adequate voltage levels, and do not cause significant and unnecessary line losses. Lateral conductors that do not meet these criteria are replaced with the most appropriate standard conductor size to improve the feeder's operability, reliability, and energy efficiency.


Split Pole – old stub in background

- ***High Loss Conductors Replacement***

High loss conductors are inefficient conductors that result in line losses, especially where there is moderate to heavy loading. The Distribution Feeder Management Plan (DFMP) calls attention to higher loss conductors, with emphasis on replacing conductors that have a resistance greater than 5 ohms per mile. The Grid Modernization program analyzes all conductor sizes on a feeder to target and locate these higher

Old line on the left, new on the right

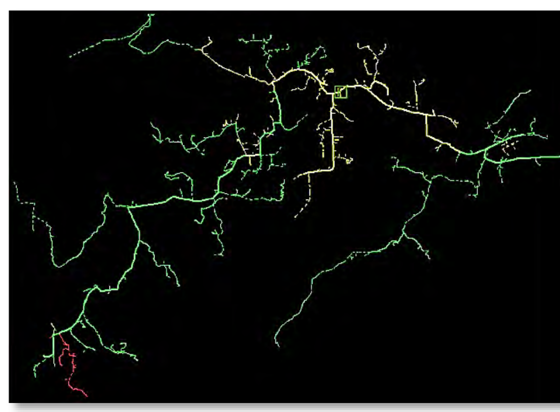
loss conductors. An engineering decision can immediately be made to replace the conductor based on loading, voltage drop, or line losses; however, a Designer may also determine that it is best to re-conductor based on the effects of pole conditions and classifications, the results from the Wood Pole Management inspection reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

- ***Feeder Tie Creations***

  A reduction in the duration of outages can be achieved through rebuilding existing feeder ties and establishing new feeder ties. Existing feeder ties can be improved by re-conductoring to higher ampacity conductors to increase capacity, as well as replacing existing manual switches to devices with communications that can either be controlled remotely or through a distribution management system (DMS). New feeder ties can be established for circuits without connections to adjacent feeders or where additional ties could provide improvements in reliability.

- ***Voltage Quality***

  Service voltage at the point of delivery between the utility and the customer should be consistent to allow the safe and reliable operation of electrical equipment. Over-voltage and under-voltage situations negatively affect the service voltage that is provided, and can also be associated with inefficient operation of the distribution circuit. The Grid Modernization Program analyzes feeders to identify sections of the feeder where the service voltage level fall outside of the allowable ANSI 84.1 Range A or B operating limits[91]. The feeders are modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. Improvements to voltage quality can first be addressed by balancing load on the phases between numerous strategic locations on the feeder to eliminate unnecessary overloading of phases that may worsen line losses due to loading. In addition, primary laterals and trunks are re-conductored with more efficient conductors to increase sagging voltage levels. In some scenarios, an additional conductor phase (or phases) may be installed to offload a heavily loaded phase and assist in supporting the voltage.



Modeled Voltage Levels at Peak Loading

- ***Voltage Regulator Settings***

  As a complement to the efforts of providing optimal voltage quality, the Grid Modernization Program analyzes and recalculates the substation and midline (outside the substation) voltage regulator

[91] ANSI C84.1 specifies the steady-state voltage tolerances for an electrical power system. The standard divides voltages into two ranges. Range A is the optimal voltage range. Range B is acceptable, but not optimal. http://www.powerqualityworld.com/2011/04/ansi-c84-1-voltage-ratings-60-hertz.html

settings. This is performed to reflect the changes to loading and the conductor characteristics that the Program is proposing as part of the holistic upgrade and rebuild of the circuit. Feeders are modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. The result of the analysis is the establishment of regulator settings that bring the voltage quality back into the permissible ANSI 84.1 ranges for all customers during the modeled scenarios, and eliminate over-voltage and under-voltage situations.

- ***Fuse Sizing and Coordination Study***

Incorrect fuse sizes can compromise the reliability of the feeder through mis-coordination of operation or being undersized. For example, if the fuses in series are not sized correctly, the device furthest downstream from the source of the outage (rather than the fuses closest to the problem) may operate first, meaning that all of the customers in between will be out of service. Also, fuses that are undersized and do not match the load being served can unexpectedly operate and create outages. A customized fuse protection and coordination scheme is determined for each distribution circuit to ensure that a consistent fusing philosophy is deployed and that all fuses are accurately sized. This efficiency helps reduce customer outages.

- ***Line Losses***

The distribution of electricity at medium voltage results in energy lost to resistance, which varies depending on the current magnitude, the resistive characteristic of the conductor(s), and the length of the conductor(s). The greater the line losses on a feeder, the higher the inefficiency. Line losses can be minimized by replacing higher loss conductors with more efficient conductors. Grid Modernization analyzes and sizes primary conductors appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and improve voltage levels on feeders. Line losses are generally first addressed by balancing load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. Line losses are then further minimized by replacing wire with more efficient conductor where conductor resistivity is high and/or where loading levels are moderate to high.

- ***Power Factor***

Power factor is defined as the ratio of the real power in a circuit to the apparent power. The difference between the two values is caused by the presence of reactance in the circuit and represents reactive power that does not perform useful work, which is a form of line losses. Power factor is a value that can fluctuate with variations in loading. The Grid Modernization Program analyzes the historical power factor scenario of over

GRID MODERNIZATION RESULTS:
- ❖ *Increased Reliability*
- ❖ *Reduced Energy Losses*
- ❖ *Reduced Maintenance Costs*

17,000 hourly data pars covering at least a 24 month span to calculate the apparent power and power factor. The result is a comprehensive tabular and graphical representations that detail and explain the power factor performance of the feeder, the percent occurrence of lagging and leading power factors, and the severity to which a circuit could be lagging and leading – both in terms of time and quantity.

Grid Modernization: A Snapshot

- ✓ 5 Years as a Program
- ✓ 9 Feeders Completed
- ✓ 8 Feeders Currently Under Construction
- ✓ 6 Feeders Currently in Design
- ✓ 414 Circuit Miles Upgraded
- ✓ $45 Million in Capital Investments Made
- ✓ 48 Automated Line Devices Installed
- ✓ 100% Quality Assurance Inspection
- ✓ 50% Contract Labor Augmentation

• *Power Factor Correction*

The power factor of a circuit can be corrected to offset the reactance in the system to a more optimal level and bring the circuit closer to unity. A unity power factor is desirable in a power system to reduce losses and improve voltage regulation. The Grid Modernization Program corrects the circuit power factor and lowers line losses from reduced reactive power flow by analyzing the historical power factor scenarios and enacting a solution. The historical raw watt and VAR data is reanalyzed with a variable VAR to adjust the resulting power factor with the known capacitors values. This exercise allows the ideal amount of capacitance to be modeled on the circuit for the loads in order to optimize the power factor at variable times. In scenarios with significant or unnecessary leading power factors, existing fixed capacitor banks are removed or reduced in size. In scenarios with significant or unnecessary lagging power factors, fixed capacitor banks are installed. In more severe situations, to raise the power factor to a reasonable base value, switched capacitor banks are installed to supplement the power factor when required by loading. This approach helps to optimize the correction of the power factor and reduces line losses. The establishment of power factor also incorporates the field verification of existing deployed capacitor sizes, as it is not uncommon to discover capacitor banks that are incorrectly represented in Avista's GIS and modeling software.

• *Distribution Automation*

The Grid Modernization program currently represents Avista's largest centralized program to fully automate and improve the operating functionality and efficiency of the distribution system through the installation of automated distribution line devices. Grid Modernization has been programmatically addressing the distribution automation needs of Avista since the end of 2013. The program focuses on installing air switches, reclosers, capacitor

banks, and voltage regulators with communications and remote operability. The reduction in the duration of outages can be achieved through the installation of devices with communications that can either be controlled remotely or through a distribution management system (DMS). In addition, the number of customers impacted by an outage and a reduction in the frequency of outages is achieved through the installation of devices with fault sensing and tripping capabilities. Time and cost savings are accomplished through the remote application of hot-line-holds. Fault detection, isolation, and restoration, conservation voltage reduction, and integrated volt/VAR control are also gained through Grid Modernization when the necessary substation equipment and components are in place.

- ***Open Wire Secondary Identification, Analysis and Replacement***

  Open wire secondary districts have the ability to negatively affect reliability due to the physical nature of construction and configuration. These districts are also predominantly located in areas with high vegetation growth and limited crew access. These factors have the ability to increase the number of outages and the duration of the outages. A circuit's reliability can be improved by strategically splitting the districts with dedicated transformers and replacing these districts with an appropriately sized dedicated neutral. Grid Modernization is also initiating a study to analyze and quantify the estimated amount of open wire districts on feeders, as well as the amount requiring replacement based off of the criteria of the Distribution Feeder Management Plan. This will assist in planning and budgeting appropriately to address the needs of the feeders.

Identified Open Wire Secondary District in Spokane

- ***Poles Analysis & Replacement***

  All components of an overhead distribution system rely on the integrity and health of poles to ensure that the system remains safe, reliable, and operational. The Grid Modernization program performs engineering and field examination of all of the poles and structures on a feeder to determine the removal, installation, replacement, or reinforcement based off of the criteria of the program (the Distribution Feeder Management Plan, discussed earlier on page 82). A pole inspection report is requested and conducted to obtain an explicit list of poles on the feeder. The pole information from the inspection report provides detailed information for Grid Modernization to leverage in the assessment and proposals. This information includes: number of poles, age of poles, number of poles past the Mean Time to Failure (optimized replacement age), yellow and red tag poles (those identified as needing replacement), and to illustrate the overall characteristics of the feeder in terms of average age and pole classification.

Poles at Mission Campus, waiting to be loaded and installed

- ***Transformers***

Core losses are an inherent characteristics of distribution transformers that negatively affect efficiency and do not change with fluctuation in loading. The Grid Modernization program analyzes the approximate energy savings that are achieved through the reduction in transformer core losses obtained when transformers are replaced with more efficient units – whether being replaced due to overloading or PCB levels. The estimated energy savings are achieved through the use of a unique algorithm that was created to: analyze each transformer on the feeder, determine the PCB/age replacement status, determine if the transformer is sized appropriately based on actual loading, make a recommendation on the appropriate size for the load, and then use historical core loss values to calculate the approximate energy savings that are achieved. All transformers on a feeder are identified for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. However all transformers are analyzed and sized to most accurately reflect customer loads per the Distribution Feeder Management Plan (DFMP), incorporating flicker and voltage drop analysis.

Baby Red Tail Hawk in a nest on a transformer

- ***Underground Cable Identification & Analysis***

Improvement in the number of underground primary cable outages has been achieved by strategically replacing cable that has a known susceptibility to faulting. This includes the targeted replacement of all pre-1982 non-jacketed primary cable, which Avista's historical data (and industry-wide experience) suggests has the highest failure rate of underground cable. In addition, the Program replaces any primary cable section that has multiple documented failures for either jacketed or non-jacketed primary cable.

Installing Underground in Coeur d'Alene

- ***Vegetation Management***

Vegetation can pose serious reliability and safety problems for distribution feeders when not properly maintained. Trees can grow into overhead distribution lines as they mature, which creates access issues, public safety concerns, and the possibility for trees or limbs to fall through the conductors or to create electrical faults through physical contact. Proper vegetation maintenance along feeder corridors removes many of these concerns while improving safety and system reliability. This includes along easements where feeder re-conductoring is being performed and where appropriate clearances need to be reestablished between vegetation and Avista's primary and secondary conductors. Grid Modernization's work is optimized when performed in coordination with Vegetation Management efforts.

Vegetation Management Issue

Appendix D: Automated Equipment

A recloser or autorecloser is a circuit breaker equipped with a mechanism that can detect and automatically close and re-energize a line after it is tripped. Since the majority of faults are temporary and transient (such as those caused by lightning, tree limbs brushing against overhead conductors, wind or birds), using reclosers can significantly improve reliability, quickly restoring normal service for our customers. Typically, reclosers are designed to have three open-close operations followed by a final lock-out. Up to 95% of faults can be cleared with this type of recloser operation.[92] Avista has about 330 midline (outside the substation, thus belonging to Distribution) reclosers on our system, and the Company is adding more every year.

Voltage regulators are also included in this program. All electrical equipment is designed to operate within narrow limits; poor voltage conditions can result in flickering lights, burned out motors or other damage to electrical equipment. Voltage irregularities are one of the most critical power quality issues facing utilities today.[93] One of Avista's core responsibilities is to deliver voltage to customers within a suitable range. Minimizing variations and maintaining the voltage at an acceptable level that is tolerated by electrical machines is achieved using voltage regulators.

RECLOSER MAINTENANCE PROGRAM

- Semi-Annual Visual Checklist Inspections of all Breaker Reclosers, Midline Voltage Regulators, and Midline Capacitor Banks
- Monthly to Semi-Annual Data Readings for all Voltage Regulators
- Recloser Replacement at 30 years
- Monthly Inspections of Reclosers and Batteries at Substations
- Battery Replacement at 36 Months
- 3 Year Battery Replacement Cycle For Any Smart or Non-Smart Device Utilizing a 40 Amp-Hour Battery
- SCADA Distribution battery replacement with major alarm for existing DMS reclosers

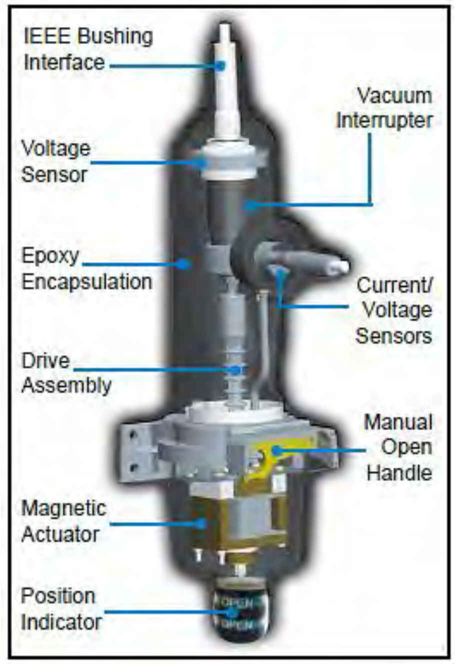


Diagram of a Recloser

Voltage Regulators

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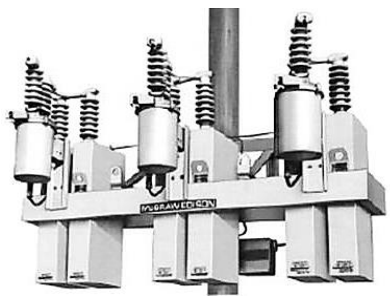
[92] "Improving Network Reliability with Reclosers," Scott Ware, FECA Meeting, June 11, 2012, http://studylib.net/doc/18121185/recloser and "Distribution System Protection", University of Western Ontario, May 2008, http://www.eng.uwo.ca/people/tsidhu/Documents/ES586B-Hesam%20Hosseinzadeh-250441131.pdf

[93] "Voltage Irregularities," Hershey Energy Systems, http://www.hersheyenergy.com/voltage_irregularities.html

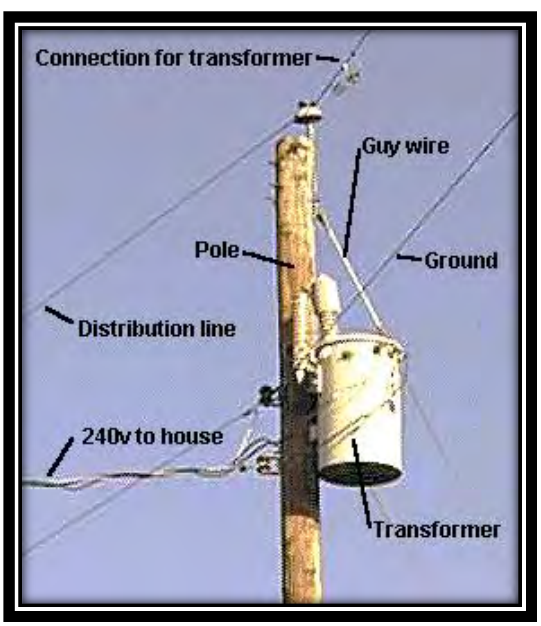
Another key piece of equipment in distribution operations is a device called a capacitor, which can maintain voltage at a specific level as needed. Capacitors store energy which can be used to offset fluctuations and improve a circuit's power factor (the efficiency of the load current being converted to actual useful work output.) By installing suitably sized capacitors and maintaining the correct power factor, energy waste (line loss) is minimized, voltage is maintained at the correct levels, efficiency is created at the power plant level, more energy is available for consumption, and customers ultimately save money by only paying for the power they actually use.[94]

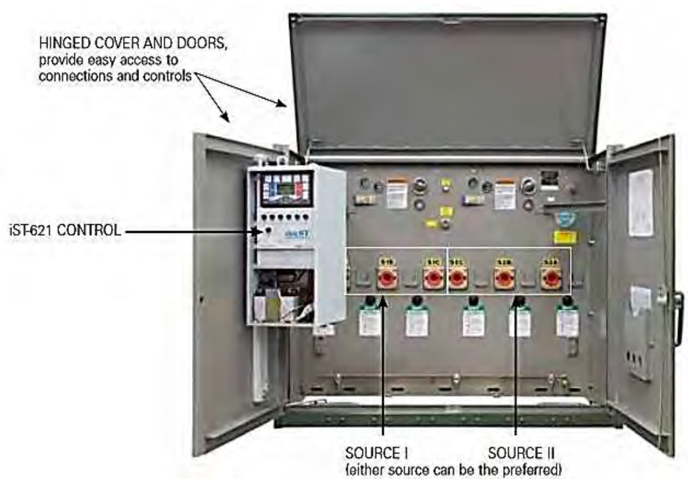
Above and Below: Capacitors



Viper Reclosers

Automatic Transfer Switches (ATS) are installed at customer's request due to commercial loads with high reliability requirements. Specifically, the ATS provides the customers load with access to two separate feeder sources, creating a redundant supply of power. Examples of such customers are airports, waste water treatment plants, manufacturing facilities, and biotech labs. ATS devices, while not many in number, are also included in Avista's Device Program.





Above: Automatic Transfer Switch

94 "What is Power Factor?" kW Saving, AJM Energy, http://www.kwsaving.co.uk/Business/pfc/pfc-simple.htm