DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL FOR
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851
DAVID.MEYER@AVISTACORP.COM

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-21-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-21-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	EXHIBIT NO. 11
NATURAL GAS SERVICE TO ELECTRIC	)	
AND NATURAL GAS CUSTOMERS IN THE	)	HEATHER L. ROSENTRATER
STATE OF IDAHO	)	
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

Avista Utilities

Distribution Infrastructure Plan

2020

Exhibit No. 11
Case Nos. AVU-E-21-01 & AVU-G-21-01
H. Rosentrater, Avista
Schedule 1, Page 1 of 28

Table of Contents

Table of Figures

Table of Tables

Executive Summary

Avista's Distribution business unit is experiencing the need for increasing investments as they work to replace, upgrade, and repair aging infrastructure across the service territory. This never-ceasing work has been increased significantly by the addition of providing new technologies to benefit customers such as energy efficient LED (light emitting diode) street lighting and advanced metering infrastructure. All of this has the aim of providing a level of service reliability that is satisfactory to customers at a price that is fair and reasonable. Some individual infrastructure programs are responsive to investment demands that are beyond the control of the Company, such as the customer requests for service or mandatory and compliance projects. Other programs respond to needs that are necessary and immediate such as failed equipment or storm damage. Others are put in place to benefit reliability and customer service such as adding devices to reduce the number of customers impacted by an outage.

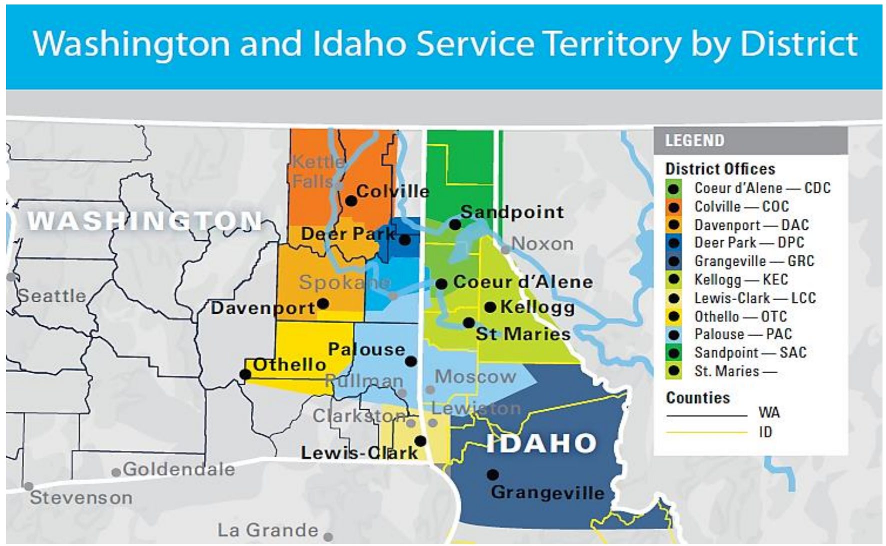
Over time these investments change, programs come to an end, or new programs are introduced based on need. This team stays on top of issues and technology applications that can bring value to customer service as well benefitting system stability, reliability, and resiliency. An example of this foresight is the revamp of the Segment Reconductor and Feeder Tie business case, which is being enhanced to provide additional value as described in the text below. Another example is the implementation of a padmount transformer inspection program which was recommended by the Company's insurance carrier. The Company leveraged this opportunity to create a robust program that emphasizes public safety and quality of service. Another creative and beneficial program being developed by the team this year is the Wildfire Resiliency Program. Recognizing the increasing risk of utility-caused fires, Avista is developing a comprehensive program to safeguard customers and Company assets. This program includes enhanced vegetation management practices, transmission and distribution system digital data collection to monitor both vegetation and line/structure/equipment condition, development of appropriate power line corridors, public outreach, and partnering with associated state and local agencies to address fire issues. Further details on these new programs are included later in this report.

Avista's Distribution team is continually challenged by a variety of circumstances, from budget constraints to aging equipment to changing technologies and customer expectations. Through the programs and tactics described in this report, they successfully navigate these changes and provide a proven level of service in keeping the lights on. In fact, based on the Company's outage data, the average Avista customer had service 99.999741% of the time in 2019.[1]

[1] The total outage duration for 2019, spread across every individual customer, was 2.27 hours per customer (SAIDI = 2.27) / 8760 hours in a year = 0.000259 or 99.999741%

Introduction

Avista owns and operates nearly 19,000 miles of electric distribution lines serving nearly 380,000 retail electric customers in Washington and Northern Idaho, providing energy to over 1.6 million people.[2] This infrastructure, designed, built, operated and maintained by the Company, includes both overhead wire (conductor), underground electric lines (cable), secondary transformers, service lines (feeders), and customers' electric meters. This system is interconnected with 176 related substations.[3] Avista must continually make new investments in this system in order to continue providing customers with safe and reliable electric service, at a reasonable cost, and with service levels that meet customer's expectations for quality and satisfaction.



In order to meet all of these requirements, the Company develops specific capital programs. These programs are developed through planning and engineering studies and analyses, as well as scheduled upgrades or replacements identified in the operations districts and within engineering groups. These projects undergo internal review by multiple stakeholders who help ensure all system needs and alternatives have been identified and addressed. If proposed projects are initially approved, they go through a formal review process referred to as the Engineering Roundtable, a diverse group of engineering leaders[4] who track project requests, prioritize them, and establish committed construction package dates and required in-service dates for projects. Once a project has passed this phase of evaluation, it moves to the Capital Planning Group.

The Capital Planning Group (CPG) is a group of Avista Directors that represent capital intensive areas of the Company. Committee members are directors from a variety of business units to add a depth of perspective, though their role is to consider capital decisions from the perspective of overall Company operations and strategic goals as well as spending guidance set by senior management and approved by the Finance Committee of the Board of Directors. They develop a final budget that represents a reasonable balance among competing needs required to maintain the performance of Avista's systems, as well as prudent management of the overall enterprise in the best interest of customers.

[2] Avista Quick Facts, https://investor.avistacorp.com/static-files/a7342b27-72cc-44d4-b9a7-b62903e999df

[3] This includes 13 generation (step-up) substations, 22 transmission and switching substations, 31 transmission with distribution substations, 110 distribution only substations, and two substations that are owned by other utilities but contain Avista equipment.

[4] Eleven representatives are included in this group from: Transmission and Distribution Planning, Transmission, Distribution, and Substation Design, System Protection, System Operations, Asset Management, Communications and Generation Engineering, and Transmission Services.

This report provides a summary overview of the Company's recent historic, current, and planned infrastructure investments in the electric distribution system for the period 2020-2024. For the purposes of this report, discussions of "infrastructure investments" are confined to the physical energy delivery facilities used to link electric substations with each customer's meter. Operations and maintenance (O&M) programs such as Vegetation Management are also included because they play a key role in helping 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 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. All of this is subject to what is known about the business today, including a range of precision in future cost estimates, applicable laws, regulatory requirements, and the capabilities of current technologies.

Avista has experienced relatively flat customer growth over the past few years, about 1% per year, as shown in Figure 1. Between 2005 and 2019, the Company has responded to an average of over 4,600 requests for a new residential electric service connection each year. For the current five-year planning period, Avista expects customer growth to continue at about 1% per year based on regional economic and population forecasts. On the commercial side, the Company connected an average of over 1,000 new commercial customers per year between 2005 and 2019, peaking in 2007 with nearly 1600 new commercial customers. Today we are expecting growth rates more in the range of 700 new commercial connects per year.

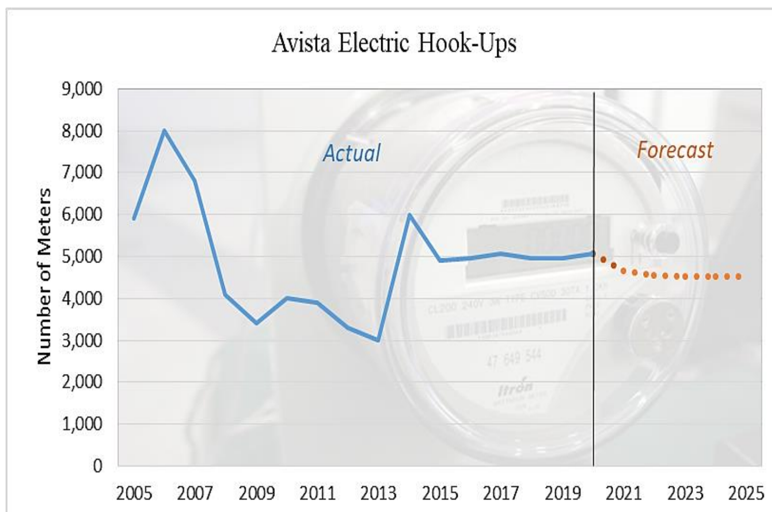


Figure 1. Electric Customer Growth

The programs put forward by the Distribution business unit encompass a broad spectrum of the utility's business needs including such things as infrastructure needed for new subdivisions or businesses, mandatory work required when a county or a city relocate a roadway, dealing with failed equipment or storm damage, replacing aging critical assets such as transformers and underground cable, inspecting and replacing wood poles, installing new and customer-beneficial technologies such as energy efficient lights and automated meters, and more. The current programs and their associated expenditures are described in the following pages.

Avista's Distribution Capital Investments

Classification of Infrastructure Need by Investment Drivers

As a way to create more transparency around the particular needs being addressed with each capital investment as well as simplify the organization and understanding of overall project plans, the Company has developed "investment drivers" to classify its capital projects. These drivers are broad categories that attempt to sort projects by the need they are addressing, as described below:

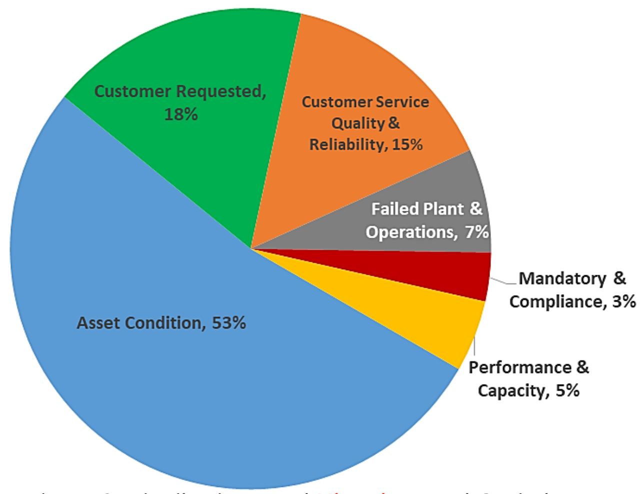


*Figure 2. Distribution Total **Historic** Actual Capital Spending by Investment Driver: 2010-2019*

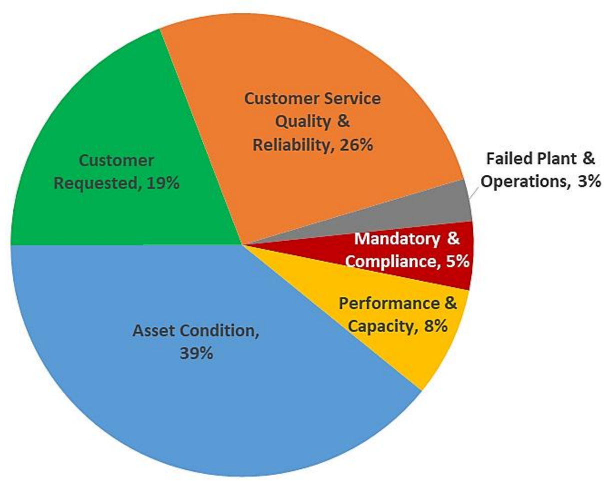


*Figure 3. Projected Five Year **Budget** for Distribution Capital Expenditures by Investment Driver: 2020-2024*

1. ***Customer Requested*** – This category is set aside primarily for connecting new customers or enhancing their service as requested. Typical projects include installing or extending electric service to new subdivisions or commercial developments.

2. ***Mandatory & Compliance*** – This category of capital spending includes investments driven by compliance with laws, regulations, and contract requirements. 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 and largely outside of the Company's control. The types of electric distribution investments that fall into this driver include the obligation to relocate facilities to accommodate state, county and municipal infrastructure projects (frequently transportation related) and compliance with environmental regulations.

3. ***Failed Plant & Operations*** – This category of spending replaces failed equipment, typically related to storm damage or other unexpected failures of capital assets. While large-scale outages such as windstorms or ice storms are vividly remembered by both Avista employees and its customers, the Company responds to thousands of outage events each year that occur almost daily. Cars hit poles, ice overloads and breaks lines,

trees fall or grow into circuits, animals get into the equipment and create faults, and more. Company crews manage issues like this on a daily basis to keep the power flowing to customers.

4. ***Asset Condition*** – This driver is focused on replacing assets at the end of their useful service life. Avista uses an analytical approach to asset replacement which includes asset criticality, inspections, and optimization of life cycle costs. For example, the Company is actively replacing failure-prone underground cable and transformers containing PCBs, and has a robust inspection program for wood poles to identify issues before failure. Some non-critical assets are allowed to fail to maximize their lifespans and minimize costs. Some are so critical to providing service that they cannot be allowed to fail and must be replaced as they reach end-of-life.

5. ***Customer Service Quality & Reliability*** – This category of spending helps Avista meet customers' expectations for quality of service and electric system reliability. Programs in this category include the Washington and Idaho advanced meter infrastructure (AMI) programs to enhance customer and Company access to information. Another program in this category is the replacement of old style streetlights with energy-efficient LED lights to save money for customers.

6. ***Performance & Capacity*** – This driver helps ensure that the Company's assets satisfy business needs and meet performance and safety standards. Avista develops and maintains multiple standards related to operating their electric facilities safely as well as following the National Electric Safety Code, which impacts nearly all of the Company's programs and projects. This category also includes investments designed to improve the performance of the distribution system, such as reconductoring feeders to remedy overloading problems and balancing the load on feeders across the system to maximize asset performance and lifespan.

Currently Planned Capital Investments in Distribution 2020 – 2024

For the next five-year planning horizon, Avista expects to spend nearly $463 million in capital dollars for the Distribution side of the business, allocated across the six investment drivers described above. These programs are summarized below.

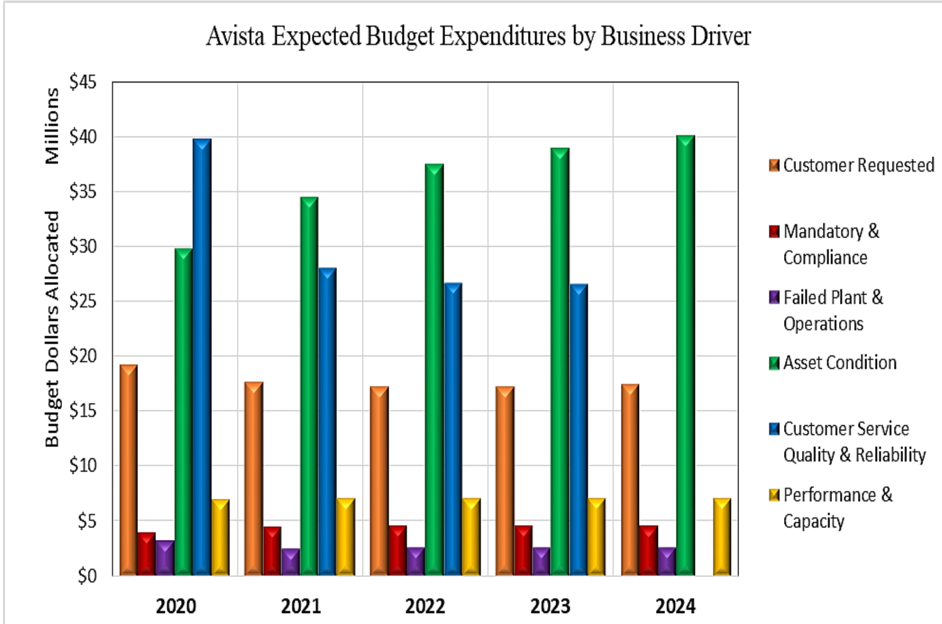


Figure 4. Capital Budget by Investment Driver

Project	Business Driver	2020	2021	2022	2023	2024	5-Year Total	5-Year Average
New Revenue - Growth	Customer Requested	$19,272,425	$17,662,805	$17,264,366	$17,218,924	$17,523,576	$88,942,096	$17,788,419
Elec Relocation and Replacement Program	Mandatory & Compliance	$2,470,000	$3,000,000	$3,100,000	$3,100,000	$3,100,000	$14,770,000	$2,954,000
Joint Use	Mandatory & Compliance	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$7,500,000	$1,500,000
Electric Storm	Failed Plant & Operations	$3,000,000	$2,340,000	$2,432,000	$2,450,000	$2,450,000	$12,672,000	$2,534,400
Meter Minor Blanket	Failed Plant & Operations	$200,000	$200,000	$200,000	$200,000	$200,000	$1,000,000	$200,000
Distribution Grid Modernization	Asset Condition	$8,000,000	$10,000,000	$12,000,000	$12,200,000	$13,000,000	$55,200,000	$11,040,000
Distribution Minor Rebuild	Asset Condition	$8,768,500	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$48,768,500	$9,753,700
Distribution Transformer Change Out Program	Asset Condition	$541,000	$600,000	$0	$0	$0	$1,141,000	$228,200
Downtown Network - Asset Condition	Asset Condition	$1,539,000	$1,600,000	$2,800,000	$2,800,000	$2,800,000	$11,539,000	$2,307,800
LED Change-Out Program	Asset Condition	$500,000	$585,000	$500,000	$500,000	$500,000	$2,585,000	$517,000
Primary URD Cable Replacement	Asset Condition	$0	$750,000	$750,000	$750,000	$750,000	$3,000,000	$600,000
Wood Pole Management	Asset Condition	$10,500,000	$11,000,000	$11,500,000	$12,730,000	$13,111,900	$58,841,900	$11,768,380
Idaho Advanced Metering Infrastructure	Customer Service Quality & Reliability	$2,500,000	$26,700,000	$26,700,000	$26,600,000	$0	$82,500,000	$16,500,000
Washington Advanced Metering Infrastructure	Customer Service Quality & Reliability	$37,292,537	$1,357,245	$0	$0	$0	$38,649,782	$7,729,956
Segment Reconductor and Feeder Tie	Performance & Capacity	$6,000,000	$6,000,000	$6,000,000	$6,000,000	$6,000,000	$30,000,000	$6,000,000
Downtown Network - Performance & Capacity	Performance & Capacity	$1,012,500	$1,125,000	$1,125,000	$1,125,000	$1,125,000	$5,512,500	$1,102,500
	Total	*$103,095,962*	*$94,420,050*	*$95,871,366*	*$97,173,924*	*$72,060,476*	*$462,621,778*	*$92,524,356*

Table 1. Distribution Capital Budget by Program 2020 - 2024

Business Driver	2020	2021	2022	2023	2024
Customer Requested	$19,272,425	$17,662,805	$17,264,366	$17,218,924	$17,523,576
Mandatory & Compliance	$3,970,000	$4,500,000	$4,600,000	$4,600,000	$4,600,000
Failed Plant & Operations	$3,200,000	$2,540,000	$2,632,000	$2,650,000	$2,650,000
Asset Condition	$29,848,500	$34,535,000	$37,550,000	$38,980,000	$40,161,900
Customer Service Quality & Reliability	$39,792,537	$28,057,245	$26,700,000	$26,600,000	$0
Performance & Capacity	$7,012,500	$7,125,000	$7,125,000	$7,125,000	$7,125,000
Grand Total	***$103,095,962***	***$94,420,050***	***$95,871,366***	***$97,173,924***	***$72,060,476***

Table 2. Planned Capital Budget by Driver 2020 - 2024

Customer Requested

Growth often refers to new service connections, as in growth in the number of customers, however, these investments are primarily 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 customer requests for service is a requirement of providing utility service. 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 Avista's system.

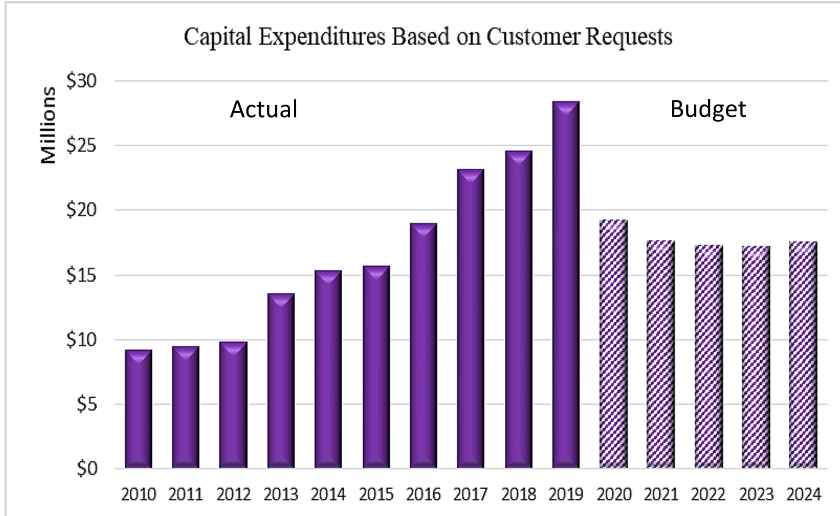


Figure 5. Capital Actual & Budget Expenditures Based on Customer Requests / Growth

Customer Requested	2020	2021	2022	2023	2024	5-Year Total	5-Year Average
New Revenue - Growth	$19,272,425	$17,662,805	$17,264,366	$17,218,924	$17,523,576	$88,942,096	$17,788,419

Table 3. Customer Requested / Growth Capital Budget

Mandatory & Compliance

Avista operates within a complex regulatory and business framework and is required to comply with laws and regulations from the local to the federal level. The types of investments that fall into this driver include compliance with safety and environmental regulations and contractual work such as joint projects with other utilities and relocating facilities as requested by state, county, or local

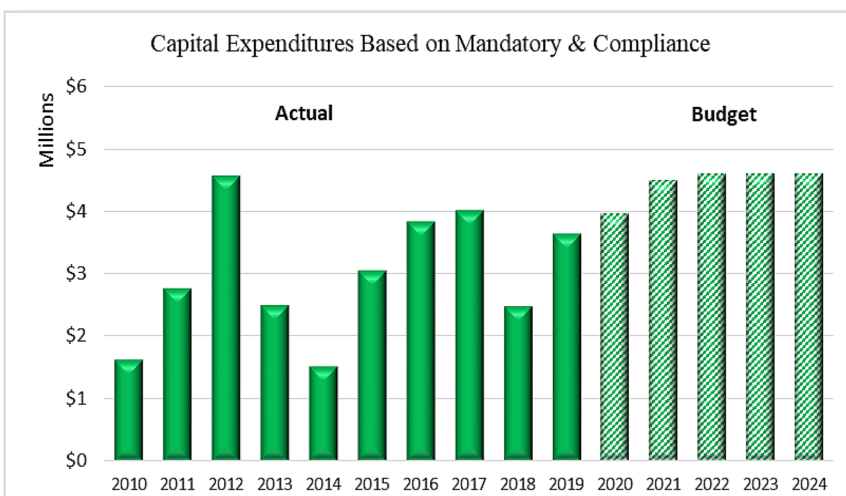


Figure 6. Capital Actual & Budget Expenditures Based on Mandatory & Compliance

jurisdictions. Distribution has two primary programs in this category: the Relocation and Replacement Program and a Joint Use Program. Both will be described below.

Mandatory & Compliance	2020	2021	2022	2023	2024	5-Year Total	5-Year Average
Elec Relocation and Replacement Program	$2,470,000	$3,000,000	$3,100,000	$3,100,000	$3,100,000	$14,770,000	$2,954,000
Joint Use	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$7,500,000	$1,500,000
Total	$3,970,000	$4,500,000	$4,600,000	$4,600,000	$4,600,000	$22,270,000	$4,454,000

Table 4. Mandatory & Compliance Capital Budget

Electric Relocation & Replacement Program

Avista is required to move its electric distribution infrastructure in response to municipalities, counties and state-level agency projects, often related to rebuilding or realigning roads, streets and highways. 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 as requested and paying all of the associated costs. Avista works with the Departments of Transportation in both Washington and Idaho to renew and maintain crossing and encroachment permits, which often requires the Company to move its distribution infrastructure at its own expense. 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. These costs are increasing over time as jurisdictions in which Avista must perform the work are becoming more and more demanding in their requirements, including calling for additional work as a condition of construction such as extensive landscaping or hiring additional flaggers, all of which increase costs. As shown in Figure 7, these costs are also highly variable from year to year and difficult to predict.

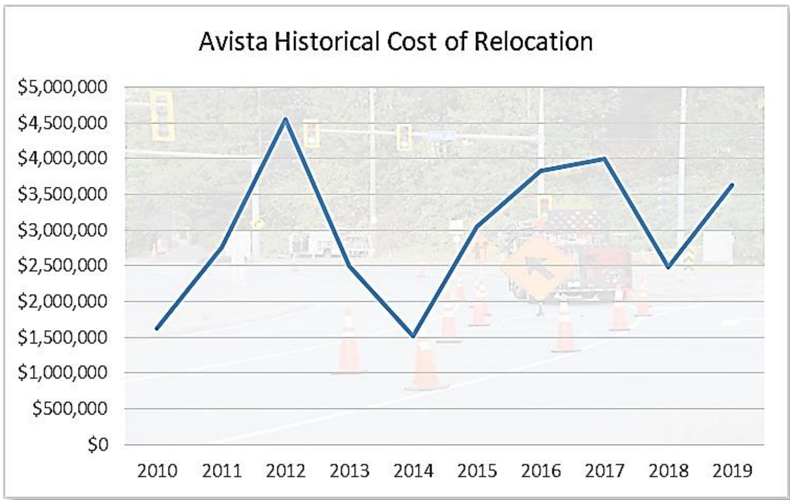


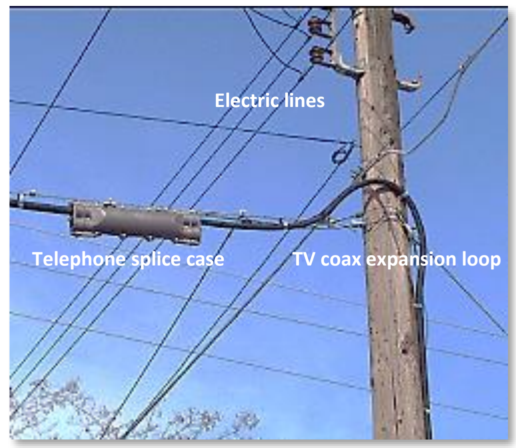
Figure 7. Facilities Relocation Capital Expenditures

Joint Use Program

Joint use occurs when one or more utilities share space on the same pole. Avista currently has over 74 joint use and licensee partners in Idaho and Washington, including those related to telephone, telecommunications, cable television, etc. On average, Avista has at least two joint use cables on about

half of its utility poles across the service territory (about 150,000 structures). Sharing poles is completely routine and makes sense for all parties, as there is a logical maximum to the number of utility poles that can exist in an area, and having multiple wires from several independent sources can create safety and maintenance hazards. The joint use concept creates a more organized system for managing the diverse needs for poles. Avista provides fair and non-discriminatory access to Company distribution poles and coordinates the work involved in attaching to Avista's structures to ensure that the attachments have the proper clearance, the poles have the required strength, and that there is adequate climbing space for line work.

Capital expenditures in this category may include putting in a taller pole or more robust pole anchors to handle the additional weight, rearranging poles, or installing additional grounding. If a joint use pole is failing, Avista may replace it by agreement with the associated party to ensure continued service for Avista customers. The Company is typically reimbursed for customer-requested work or requests for work made by other utilities but provides a capital budget for work on the Company's own shared structures.



Typical joint use situation

Failed Plant & Operations

This business driver is designed to fund replacement of assets that have failed and which must be replaced, including customer meters. A portion of Company assets fail each year as a result of damage from storms, fires, vehicle accidents, third-party dig-ins, etc. When this happens, the Company must quickly respond to replace the failed infrastructure in order to ensure the continuity of service to customers.

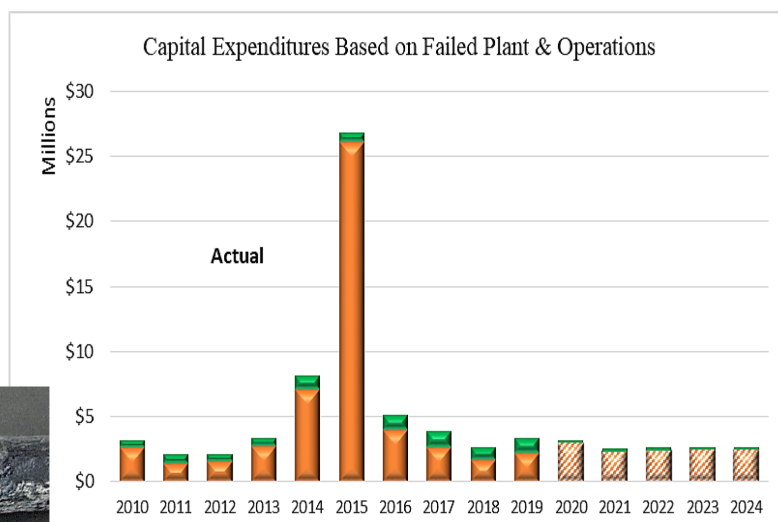


Figure 8. Capital Actual & Budget Expenditures Based on Failed Plant & Operations

Failed Plant & Operations	2020	2021	2022	2023	2024	5-Year Total	5-Year Average
Electric Storm	$3,000,000	$2,340,000	$2,432,000	$2,450,000	$2,450,000	$12,672,000	$2,534,400
Meter Minor Blanket	$200,000	$200,000	$200,000	$200,000	$200,000	$1,000,000	$200,000
Total	$3,200,000	$2,540,000	$2,632,000	$2,650,000	$2,650,000	$13,672,000	$2,734,400

Table 5. Failed Plant & Operations Capital Budget

Electric Storm Budget

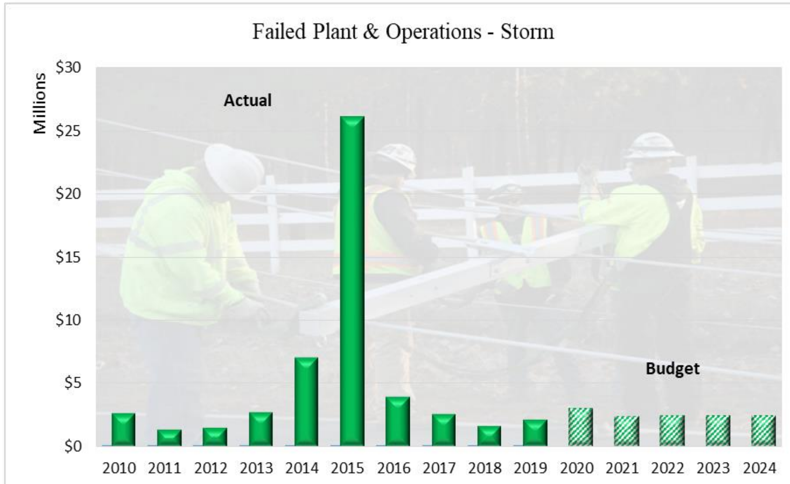


Figure 9. Capital Actual & Budget Expenditures: Storms

During this budget cycle the Company expects to spend about $2.7 million on distribution storm repairs but, as can be imagined, this amount could vary substantially. As shown in Figure 9, one major event can have drastic impacts on Avista's capital budget. For example, in 2015 a historic 100 year wind storm event rolled through the area. Hurricane force winds caused the greatest level of damage to Avista's system ever experienced. At the peak of this storm, more than 180,000 Avista customers were without power, some for up to two weeks. It took nearly a year for the Company to complete permanent repairs on its infrastructure. This event cost nearly $23 million in damage to equipment and facilities. Though this situation is not typical, such unexpected expenditures are always possible.

Meter Minor Blanket

Part of the routine work the Company experiences are meters and/or metering equipment failures. Meters are a critical component to supplying customers with electricity and to accurately measuring their energy consumption. When meters fail, immediate action must be taken to repair or replace the meter. A failed meter will not provide accurate consumption data, requiring the customer's usage to be estimated, which has been shown to cause customer dissatisfaction. In determining the best course of action in dealing with failed meters, the Company looked at three options (shown in the box above) and determined that the most cost effective course was to replace a failed meter with a new meter. The expenses associated with replacing meters are allocated to the Failed Plant & Operations budget category.

Failed Meter Options	Cost	Installation Labor	Total Cost
Refurbish Meter	$37.26	$35.76	$73.02
Return to Manufacturer		$35.76	
Removal Cost	$9.31		
Shipping Cost	$7.17		
Repair Cost	$30.00		$82.24
Install New Meter	$20.43	$35.76	$56.19

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 as well as the safety of the public and Avista employees. 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 by the Company each year.

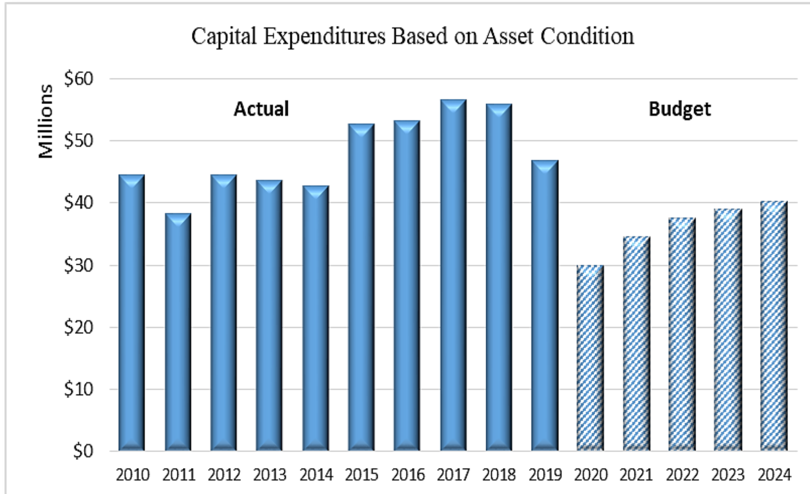


Figure 10. Capital Actual & Budget Expenditures Based on Asset Condition

At Avista, the goal is to manage assets in a manner that optimizes their overall value over the lifecycle of each particular asset class. 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 the Company to meet a variety of important performance objectives, such as public safety or the efficient use of employee crews. Because failure of critical assets is unacceptable, they must be replaced before the end of their useful life even if 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."

In Distribution, the Asset Condition business driver includes the Grid Modernization Program, replacing aging or PCB transformers, wood pole work, underground cable and street or area light replacement, upgrading the Downtown Network system, and performing system-wide repairs. Each of these programs is described in more detail below.

Asset Condition	2020	2021	2022	2023	2024	5-Year Total	5-Year Average
Distribution Grid Modernization	$8,000,000	$10,000,000	$12,000,000	$12,200,000	$13,000,000	$55,200,000	$11,040,000
Distribution Minor Rebuild	$8,768,500	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$48,768,500	$9,753,700
Distribution Transformer Change Out Program	$541,000	$600,000	$0	$0	$0	$1,141,000	$228,200
Downtown Network - Asset Condition	$1,539,000	$1,600,000	$2,800,000	$2,800,000	$2,800,000	$11,539,000	$2,307,800
LED Change-Out Program	$500,000	$585,000	$500,000	$500,000	$500,000	$2,585,000	$517,000
Primary URD Cable Replacement	$0	$750,000	$750,000	$750,000	$750,000	$3,000,000	$600,000
Wood Pole Management	$10,500,000	$11,000,000	$11,500,000	$12,730,000	$13,111,900	$58,841,900	$11,768,380
Total	*$29,848,500*	*$34,535,000*	*$37,550,000*	*$38,980,000*	*$40,161,900*	*$181,075,400*	*$36,215,080*

Table 6. Asset Condition Capital Budget

Distribution Grid Modernization Program

Avista is systematically rebuilding and upgrading its electric distribution feeders and, where cost effective, is installing feeder automation 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. The program also replaces pre-1981 distribution transformers with energy efficient units that meet current standards. This program also replaces underground cables that have uninsulated neutrals, which pose a system reliability risk.

This Program not only focuses on rebuilding feeders that are at or nearing the end of their useful life, but also evaluates the potential benefits of a range of physical reconfigurations of the feeders, taking into account opportunities to improve voltage settings, fuse coordination, line losses, transformer losses, power factors, and 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 actions that will be applied to the feeders, identifying the investment requirements and the cumulative estimated benefits.

The Grid Modernization Program is the only program at the Company that provides a holistic approach to each feeder by addressing asset condition, transformer change outs, efficiency improvements, improved reliability, real estate encroachments, highway clear-zone issues, avian and animal protection, environmental permits, and other unique considerations that are specific to each feeder all at the same time. This increases crew efficiency and minimizes the number of outages and instances that crews will be deployed to affected communities. Rather than multiple outages that address each of these issues as they arise, one planned outage is taken to address all relevant issues.

GRID MOD FOCUS AREAS

- Undersized or deteriorating conductor
- Failed poles, crossarms, fuses, insulators, guy wires, arrestors, cutouts, street lights
- Avian protection
- Accessibility issues
- Right-of-way concerns
- Potential for undergrounding
- Coordinating joint use facilities
- Clear Zone compliance
- Safety Issues

Minor Rebuild Program

In addition to outage response, Avista's routine operations include reconfiguration and replacement of electric facilities under a variety of circumstances. This spending category allows the Company to address small unplanned asset failures or customer requested modifications to their electrical service that don't rise to the level of requiring their own capital program. Even though relatively small in cost, these are projects that impact the reliability of the distribution system, customer service, or the safety of the public or employees and must be addressed. Typically these projects are related to meeting safety codes, inoperable equipment such as failed poles or broken crossarms, or unpredictable circumstances such as when vehicles hit poles.

At times equipment must be modified or upgraded to handle changing customer load conditions such as installing a system of fuses that protect the system from line faults, adding voltage regulators or reclosing equipment, or replacing a pole, cross arm, or transformer in poor condition. Avista monitors circuit loading and may shift load from one circuit to another during winter or summer peak usage, which often involves extending overhead or underground primary wires and cables. These types of capital infrastructure work do not qualify as a project or program on their own but must have funding, so are handled through the Minor Rebuild general budget account. Occasionally larger projects are constructed under this category if there is an urgent need and a short timeframe for implementation, but that is not typical.

Typical Minor Rebuild Work

- Repair broken or damaged equipment and fixtures whether or not they are related to a customer outage.
- Add an 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.

Transformer Change-Out Program

The Transformer Change-Out Program has three primary drivers. The program initially focused on replacing pre-1981 transformers to increase the reliability and availability of the electric system and ensure that transformers potentially containing polychlorinated biphenyls are removed from Avista's distribution system.

Polychlorinated Biphenyls (PCBs) were commonly used in the oil of electrical transformers in past decades due to their high dielectric strength[5] and resistance to fire. Studies conducted in the 1960s and 1970s 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[6] and Avista has been programmatically replacing these transformers. There were about 12,000 such transformers on Avista's system when this program started. In 2020 there were less than 300 remaining PCB transformers.

[5] 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.
[6] "PCBs Questions & Answers," United States Environmental Protection Agency, https://www3.epa.gov/region9/pcbs/faq.html.

Downtown Network – Asset Condition Program

The Downtown Network has funding set aside under both the Performance and Capacity and the Asset Condition investment drivers. Most of the Network's equipment is located in underground vaults, manholes and hand-holes in Downtown Spokane. With ongoing growth in Spokane, the downtown area is in a continual state of construction, requiring the Company to upgrade old equipment, relocate assets due to road work or construction, or respond to city, county, or customer requests that are fairly random every year, yet make up a large portion of the Downtown Network operations.

Above & Below: Downtown Network Vaults

The majority of the Network's structural assets (such as manholes, vaults, and ducts) have exceeded their expected life and must be programmatically replaced in order to continue service. When this equipment fails, it can have a significant impact on downtown businesses as well as pose safety hazards for the public. The Company is in a state of constantly replacing old structural and electrical equipment while at the same time addressing requests from the city, county, and customers for service changes in addition to mitigating construction impacts on Company facilities and operations. These projects fall under the Asset Condition investment driver for the Downtown Network.

LED Change-Out Program

Avista operates approximately 35,000 street lights across the service territory as well as area lights requested and paid for by individual customers. Avista manages street lights for many local and state government entities by installing and replacing street lights per their request. In 2013, in response to the superior safety and efficiency performance of Light-Emitting Diode (LED) lighting, the energy savings potential, and the opportunity to reduce long-term energy costs, Avista evaluated the benefit of converting from High Pressure Sodium (HPS) to LED fixtures and, based on significant savings opportunities, developed a replacement program. LED bulbs are six to seven times more efficient than traditional bulbs, cutting energy use by up to 80%. In addition, they can operate more than 25 times longer than conventional bulbs.[7] This program

[7] "How Energy-Efficient Light Bulbs Compare with Traditional Incandescent," U.S. Department of Energy, https://www.energy.gov/energysaver/save-electricity-and-fuel/lighting-choices-save-you-money/how-energy-efficient-light

also helps the Company be in compliance with Washington State Initiative 937 (or the "Clean Energy Initiative"),[8] part of which required that Washington utilities undertake all cost-effective energy conservation measures. LED streetlight technology is part of this energy conservation work.

Primary URD Cable Replacement Program

Underground Residential District Cable (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 1982 had numerous problems, primarily a lack of insulation that allowed water penetration and corrosion. It also had a lack of protection from dig-ins, animals, vegetation and lightning all leading to numerous faults and failures. Prior to the underground cable problems becoming apparent to the industry, Avista had installed over 6,000,000 feet of this type of cable.

By the mid-1990s, customers served by this cable began to experience outages that were increasing in number as the cable aged and continued to deteriorate. Repairing these failures is particularly expensive (about $3000 per event) due to the complexity involved in locating the fault, digging up the cable, and splicing in new sections. The Company initiated a program to systematically replace pre-1990 cable about 15 years ago. Unfortunately, unmapped sections of this old cable are being continually found, typically when the cable has failed, thus this program will be ongoing into the near future.

Wood Pole Management Program

Avista Wood Pole Inspection

Avista has 347 overhead electric feeders that are supported by approximately 230,000 poles. These poles are predominantly wood (about 99%). The attached equipment includes crossarms, transformers, cutouts, insulators and pins, wildlife guards, lightning arresters, guy lines, and pole grounding. Avista's wood pole population is inspected on a 20-year cycle interval, which means about 11,500 poles, crossarms, and associated equipment are inspected on average each year.

Stubbed Pole

Avista's distribution wood poles have an average lifespan of approximately 70 years as they are managed in the system today.[9] A key part of maintaining the wood pole population is Avista's robust inspection program. The condition of each pole is assessed during this inspection to determine whether any issues

[8] https://www.commerce.wa.gov/growing-the-economy/energy/energy-independence-act/
[9] This lifespan can be increased by stubbing and chemically treating the wood poles.

need to be addressed, rather than relying only upon only 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 issues such as a broken guy wire, grounding, or soil concerns. Decay is the most common reason for pole failure and is detectable with proper inspection. Inspectors also assess components including transformers, ground, and guy wires. The capital investments made under this program cover the needed repair and replacement of poles and attached equipment that is identified during the inspections.

Types of Pole Inspection Issues Identified in Inspections

Customer Service Quality & Reliability

This category of spending helps Avista meet customers' expectations for quality of service and electric system reliability. The programs in this category are the Washington and Idaho advanced meter infrastructure (AMI) programs. Traditionally, utility customers have had few tools to effectively understand and manage their energy use because conventional meters are not equipped to provide near real-time information on energy consumption. AMI offers a variety of benefits for customers including providing them with the framework for new technology options, increased information availability, and a measure of control over their energy usage and expenditures. It allows customers the ability to integrate new "smart" devices into their homes, and provides the ability to offer customers technology products and services into the future. From the Company's perspective, Avista will see general savings (which ultimately benefit customers) via voltage reductions, reduced theft and unbilled usage, consistency and simplicity in metering applications, remote service connectivity, and outage management.

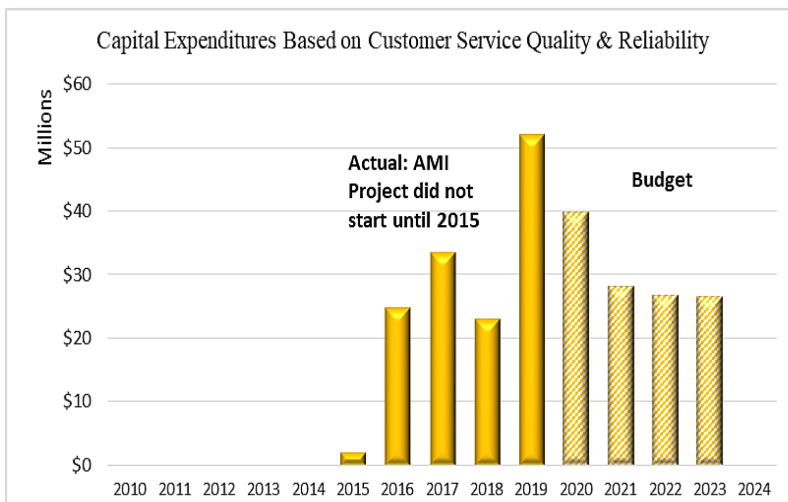


Figure 11. Capital Actual & Budget Expenditures Based on Customer Service Quality & Reliability

Customer Service Quality & Reliability	2020	2021	2022	2023	2024	5-Year Total	5-Year Average
Idaho Advanced Metering Infrastructure	$2,500,000	$26,700,000	$26,700,000	$26,600,000	$0	$82,500,000	$16,500,000
Washington Advanced Metering Infrastructure	$37,292,537	$1,357,245	$0	$0	$0	$38,649,782	$7,729,956
Total	***$39,792,537***	***$28,057,245***	***$26,700,000***	***$26,600,000***	***$0***	***$121,149,782***	***$24,229,956***

Table 7. Customer Service Quality & Reliability Capital Budget

Washington Advanced Metering Infrastructure

The Washington Advanced Metering Infrastructure (AMI) program encompasses Avista's Washington service territories. Also popularly known as "smart meters," this effort keeps pace with the evolving metering standard of the industry and will deliver a range of cost-effective benefits to customers as shown in the blue text box on the right. This project will take approximately six years and will deploy advanced meters to approximately 253,000 electric customers and 155,000 gas customers. Avista is planning to replace all of its existing Washington electric meters, the majority of which are conventional electro-mechanical meters, with a new advanced meter. The existing natural gas meter will not be replaced but will be upgraded with a new digital communications module. Since most gas meters are mechanical devices, installation of AMI technologies use a radio device attached to the existing gas meter to communicate the amount of gas used.

Idaho Advanced Metering Infrastructure

The Idaho AMI Project will install an advanced metering system to include meters, the communication network and data repository. Advanced meters will be deployed to approximately 136,000 electric customers and 87,000 gas customers starting in 2020. All existing Idaho digital electric meters will be replaced with a new advanced meter. As was the case in Washington, existing natural gas meters will be upgraded with a new digital communicating module; the natural gas meter itself will not be replaced. Idaho AMI customers will be integrated into Avista's current hardware/software system for Washington AMI customers, reducing duplication of resources.

ADVANCED METERING INFRASTRUCTURE BENEFITS

- Customer access to interval energy usage data
- Customer tools to help them manage their energy use
- Enables smart home options
- Energy alerts for customers when their bill reaches a predetermined level
- Customer property privacy
- Migration away from manual meter reading
- Remote and rapid disconnect / connect / reconnect
- Outage management
- Energy efficiency - more efficient feeder operation
- Energy theft and unbilled energy usage detection
- Billing accuracy
- Data for utility system studies
- Improved utility employee safety
- Variable rate options
- Enhanced data analytics
- Support for micro grids and smart cities
- Foundation for distributed generation

Performance & Capacity

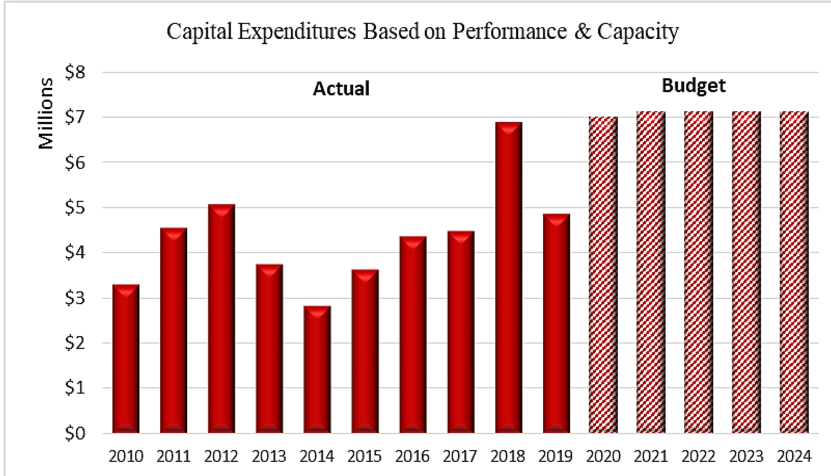


Figure 12. Capital Actual & Budget Expenditures Based on Performance & Capacity

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 based on a demonstrated need. Avista is also attentive to investment opportunities to improve the performance of the distribution system when supported by a study or analysis that demonstrates the cost-effectiveness of the benefits achieved for customers.

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. When the Company determines its operations no longer meet a given standard, infrastructure needs must be assessed in order to make the timely capital investments necessary to remain within the limits of the standard. A common example is the objective to operate within established thermal limits for electrical equipment. During this budget cycle, two primary programs fall into this category. These programs are described below.

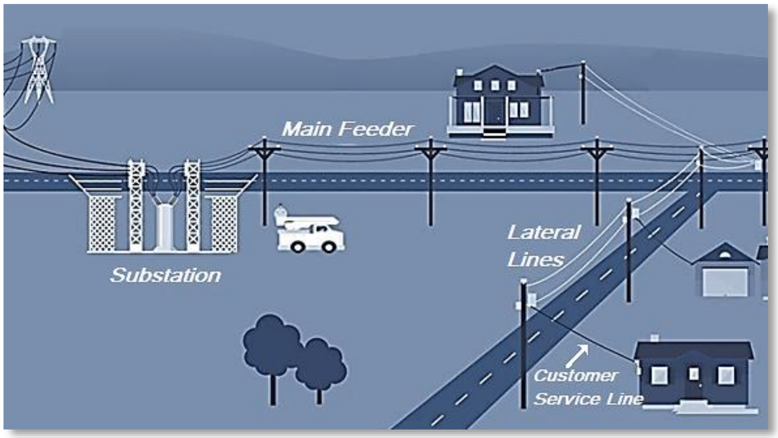
Performance & Capacity	*2020*	*2021*	*2022*	*2023*	*2024*	*5-Year Total*	*5-Year Average*
Segment Reconductor and Feeder Tie	$6,000,000	$6,000,000	$6,000,000	$6,000,000	$6,000,000	$30,000,000	$6,000,000
Downtown Network - Performance & Capacity	$1,012,500	$1,125,000	$1,125,000	$1,125,000	$1,125,000	$5,512,500	$1,102,500
Total	***$7,012,500***	***$7,125,000***	***$7,125,000***	***$7,125,000***	***$7,125,000***	***$35,512,500***	***$7,102,500***

Table 8. Performance & Capacity Capital Expenditures

Segment Reconductor and Feeder Tie

This program is designed to remedy the overloading of electric equipment and cable, as well as the conductor sag 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.

Avista's distribution system follows the industry standard of using relatively short sections of main feeder 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 and field tested to verify whether a problem exists. Resolving these overloading issues involves a combination of two strategies known as "load shifting" and "segment reconductoring."



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 capture additional value from the existing infrastructure. *Segment 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 also optimize the overall distribution system.

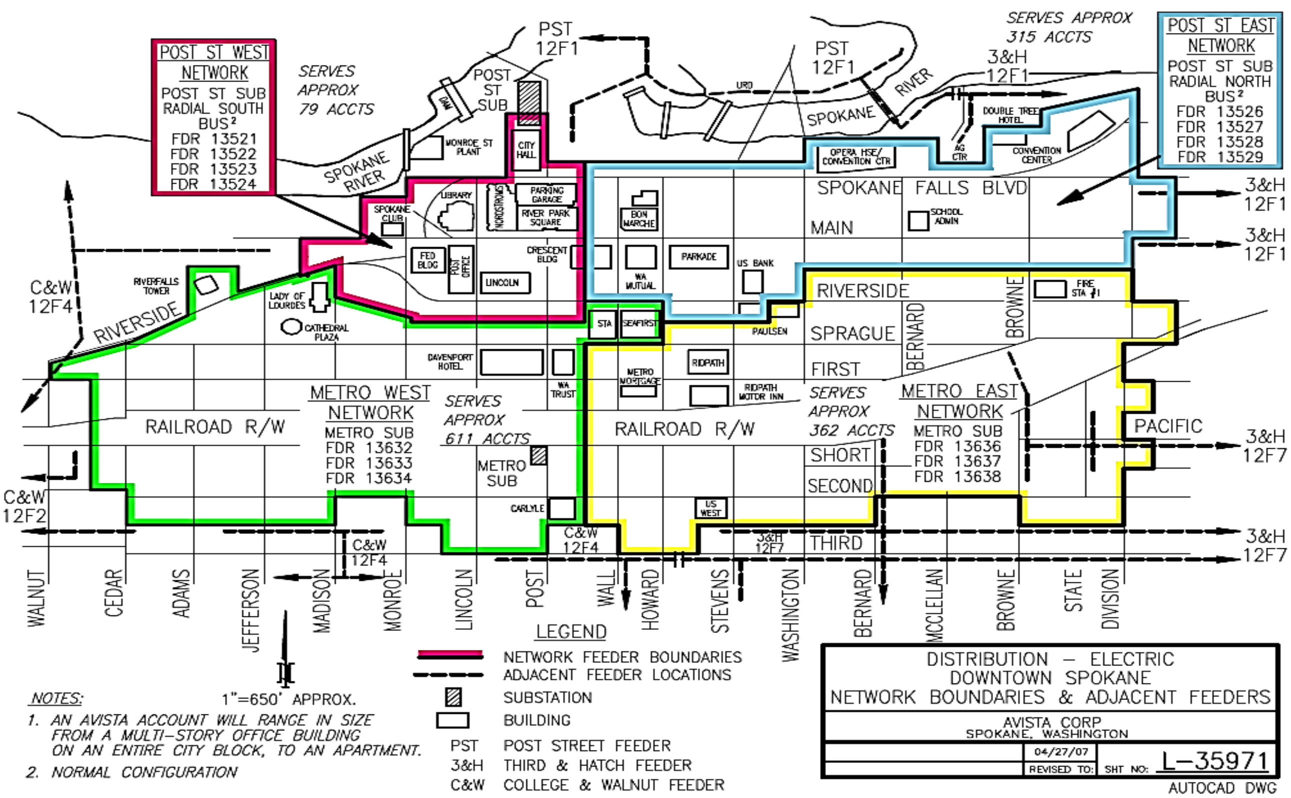
Currently the Company is facing an increasing number of new large spot loads, typically ranging anywhere from one to five megawatts. The size of these new loads increases the need for unplanned reconductoring of distribution feeder segments. In turn, this unplanned work is hindering the ability to complete planned and preventative work and creates unanticipated budget pressures, creating a situation in which work is becoming more and more reactive in nature and necessary maintenance and repair work begins to fall behind. In an effort to address these circumstances in a proactive way, the Distribution team is updating the Segment Reconductor and Feeder Tie business case. This business case will be renamed "Distribution System Enhancements," and in the future will encompass more of the work that is being done to maintain and improve the distribution system.

This business case will become the main budget source for the Avista Area Engineers. These specialized employees are responsible for continually monitoring, analyzing and evaluating the overall health of the distribution system. They act upon issues such as conductor or equipment overloading due to customer growth, power quality issues caused by voltage or current harmonics, power quality issues caused by over or under voltage, and reliability issues that can be improved with the installation of new equipment or new sections of power lines. These issues will all be addressed under the new Distribution Systems Enhancement business case.

Downtown Network Performance & Capacity

Downtown Network vault

Avista owns and maintains an underground electric network that serves the core business, financial, and city government district of downtown Spokane. This network encompasses over a thousand underground manholes, hand-holes, and vaults. There are two investment drivers associated with the Downtown Network: Asset Condition, and Performance & Capacity. Under the Performance and Capacity investment driver, the Downtown Network provides funding to address load growth at the system level, network grid expansion, as well as crew and public safety issues. A key focus area is to add the ability to remotely observe the actual flow on the secondary networks and equipment to provide the status of the network protectors. Increasing loads due to the growth in Downtown Spokane are beginning to overload the network, requiring additional line and/or transformer capacity. It is critical for the Company to track the load status to ensure that equipment is not overloaded and to identify where additional capacity is needed. In addition, safety equipment such as operable customer disconnects are required. Currently roughly 10-15% of the Network is at a high safety risk level for faults, fire, or electrical shock. Measures must be taken to mitigate this risk to the public, Avista employees, and contract crews. Those types of expenditures fall under this investment driver.



Avista's Distribution O&M Investments

Avista monitors the distribution system very closely to guarantee that critical equipment remains functional and the system is fully intact. O&M expenditures allow the Company to maintain and operate the electric system in the most safe, reliable, and efficient way possible. These expenditures permit the Company to respond when damage occurs from weather or accidents and a host of other issues that arise in this complex system, all in service of keeping the power flowing safely and efficiently to customers.

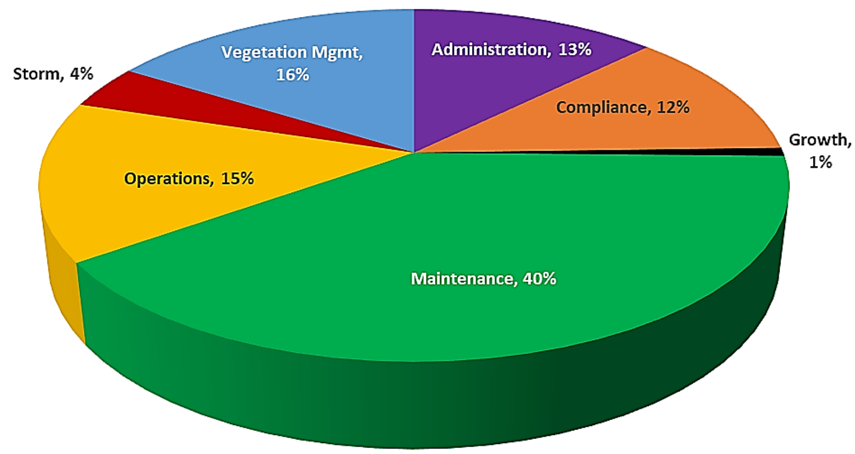


Figure 13. Distribution O&M Expenditures 2009-2019

O&M expenditures are a part of every maintenance project, as these projects all require manpower, administration, and supplies and equipment that don't rise to the level of capital items. As shown in Figure 13, both planned and failed asset maintenance comprise a large percent of the Company's required expenditures. Compliance is another important area, and includes obligations such as joint use project work, environmental requirements, contractual work, required training, relocation request work, and the like. Other factors include customer growth requirements, repairing storm and weather damage, and operating this complex system.

Vegetation Management

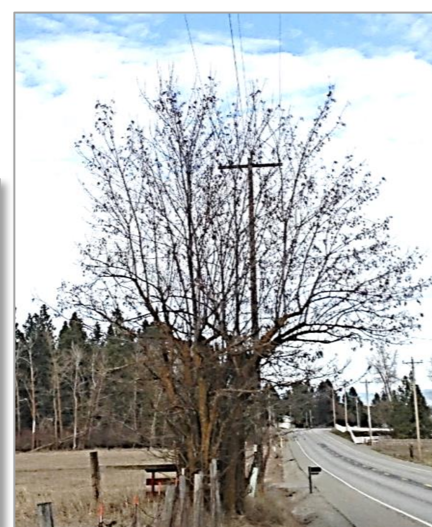
Vegetation is a significant source of outages for utilities. At Avista, typically about 8% of outages result from trees, tree limbs, or other vegetation falling or growing into power lines, and the resulting impact is significant. Since 2001, vegetation issues have led to over 1.3 million hours of customer outages. In 2019 alone vegetation caused the loss of 109,000 customer service hours. Recent years have shown that vegetation issues also create potentially explosive wildfire situations. Avista takes this issue very seriously and has developed a robust vegetation management program in response.

The Company manages vegetation across the rights-of way of 19,000 miles of overhead electric distribution lines and 2,770 miles of 115 kV and 230 kV transmission corridors.[10] In recent years the Transmission Vegetation

[10] From Avista Quick Facts, https://investor.avistacorp.com/static-files/a7342b27-72cc-44d4-b9a7-b62903e999df

Management Program was rolled into the Distribution Vegetation Management Program, so there is now a single program under one business unit. This program utilizes a three-pronged proactive approach to try to identify and address potential vegetation-related issues before they result in outages for our customers:

- **Routine Cycle Maintenance** is planned on a five year cycle and is focused on trimming practices that are tailored to the type of landscape and species of trees along our rights of way, identifying "problem trees" that require the most attention. This 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 power lines. 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.
- **Risk Tree Mitigation** 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 typically identified by certified utility foresters or by others on the ground who spot dead, diseased and dying trees as they perform work in the field. Once identified, the health of these individual trees is tracked to determine 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.
- **Right of Way Clearing** 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 area as needed. 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.



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

Distribution Upcoming Programs

Padmount Inspection Program

The Padmount Distribution Facilities Inspection Program provides a ten-year physical inspection of padmount transformers and junction enclosures associated with Avista's underground distribution system. Avista has approximately 36,000 padmount transformers and 12,500 junction enclosures system wide. This program was initiated in response to a request from Avista's insurance provider, AEGIS, to programmatically inspect underground distribution enclosures/cabinets to ensure correct labeling. Building upon this basic request, the Company developed a robust inspection program that will examine all of the padmount transformers and junction enclosures across the system in order to gain an initial assessment and determination of work to be done, followed by formal inspections on a ten year cycle. The initial inspection will begin in the first quarter of 2020. This program will address three primary concerns with these units: proper labeling, physical integrity/security and age. It is important to note that these transformers are readily accessible to the public, with many located in yards, playgrounds, commercial parking lots, on sidewalks, and other public places. Thus public safety is a significant concern.

	Illegible / Missing Decals	Clearance Violations	Failed Pads	Failed Tamper Resistance Bolt	Paint Failure
Failure Percentage	**96%**	**35%**	**3%**	**8%**	**8%**

Figure 14. Padmount Transformer Issues Identified

Correct labeling and markings of padmount transformers is required by law and by internal Company standards.[11] In 2013 the Company sampled 474 transformers and 120 junction enclosures and found significant failures in several areas especially in decals, as shown in Figure 14.

The second focus of this program is the physical security and integrity of the cabinets and associated mountings. Clearance violations such as the boulders shown in the photo on the left limit accessibility, especially in an emergency situation, but also for routine maintenance activities. These units sit on concrete pads to keep them off

This program addresses required labeling such as the transformer decal above and access issues such as the boulders blocking access to the transformer on the left.

[11] WAC 296-24-95605 (http://lawfilesext.leg.wa.gov/law/wsr/2012/16/12-16-064.htm) provides direction for marking the exterior of padmount transformers used in underground distribution applications. These warning markings are prescribed for the safety of the general public as well as utility crews who will be working with the equipment. This code also provides direction for ensuring that the area around the padmount equipment is kept free from obstruction so that the equipment can be accessed for maintenance or replacement. Additional markings are defined by Avista Utilities construction standards to aid in location and identification of equipment by service crews.

Padmount Transformers

the ground and out of the elements as well as to keep them level to prevent oil leakage. The survey found many of the pads had settled over time and cracked or even broken open. Tamper-resistant bolts are used to secure the box cover in place and to prevent unauthorized access. The survey found that many of these bolts were either stripped, broken off, or missing. Paint condition is also a concern, as degradation to the paint can create rust and corrosion, giving public or animals access to the electrical equipment inside the enclosure and creating a potential safety risk for both the equipment and the public.

The third element addressed by this program is the transformer age. About 4% of the padmount transformers are 40 years of age or older, thus past their expected service life. But nearly 20% are 30 or more years of age, thus rapidly approaching end of life.

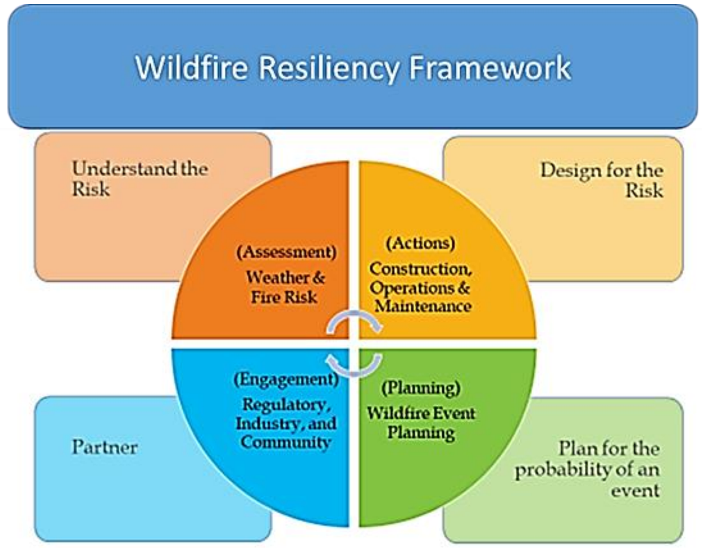
Wildfire Resiliency Program

Wildfire represents a significant risk for western utilities. Avista is developing a comprehensive wildfire resiliency plan to address this risk and to support three strategic goals: enhancing emergency operations, promoting public safety, and safeguarding Company assets. To achieve these significant goals, the Company is focusing on three primary areas:

1) Protect lives and property
2) Ensure emergency preparedness & align operating practices with fire threat conditions
3) Protect Avista's energy delivery infrastructure

The primary elements of this plan include:

- Enhanced Vegetation Management to reduce the likelihood of wildfire events through fuel reduction treatments as well as including extensive associated data collection, identifying high risk areas in Avista's system. Also includes partnering with associated state and local entities, widening transmission rights-of-way, and public outreach to encourage removal of high risk trees.



- Situational Awareness to provide more information about the status of the system including adding specialized communications capability (SCADA) to every substation to monitor and control powerlines, developing a web-based fire weather dashboard, and adding distribution protection technology.
- Grid Hardening and Dry Land Mode which adds a non-reclosing protection mechanism during dry weather high-fire-danger conditions that prevents lines that trip out of service from reclosing without specific intervention. It also includes putting eyes on a potentially dangerous situation to make sure it is safe to place a line back in service, either with servicemen dispatched to the situation or with SCADA information.[12] First responders count on Avista's ability to de-energize electric lines during fire events, making this technology even more crucial to public safety. This element also includes adding a specialized fire retardant mesh to transmission wood poles in high risk areas, more in-depth aerial inspections, conversion of wood transmission poles to steel in high risk areas, and replacing equipment in the distribution system associated with spark-ignition potential.
- Operations and Emergency Response to combine the current programs related to wildfire into a comprehensive and overarching effort with associated metrics and analytics. This piece will include a more comprehensive Company focus on wildfire events and risk, provide specialized training for first responders both inside and outside the Company, and agreements with external fire personnel to investigate transmission line faults during fire season.

This comprehensive wildfire program is scheduled to take place over the next ten years and will require new equipment such as the SCADA equipment mentioned earlier, software monitoring and tracking systems, and extensive inspections of the entire system to identify vegetation related trouble spots. It is estimated that this program will cost $242 million in capital, $43 million in O&M over the next ten years. This investment will also include funds Avista provides to local efforts. The Company will be partnering with fire districts, the U.S. Forest Service, the Bureau of Land Management, and other related agencies as they work to protect infrastructure in their jurisdictions. This investment should provide immense benefits in risk reduction and protection for Avista, its customers and equipment.

[12] Currently 33 of Avista's 176 substations operate without SCADA and thus have no remote sensing, monitoring, or equipment control systems.

Wrap Up

Avista takes the service and safety of customers and employees very seriously. The Company's Distribution Team designs Capital and O&M programs that are robust, proactive, and designed to ensure that the distribution system is as safe as it can possibly be while providing a level of service and cost effectiveness that customers and regulators expect. As depicted in this report, each of these programs has a specific goal and purpose in serving customers safely and successfully, including inspecting and protecting existing infrastructure, thoughtful, measured replacement of end-of-life assets, adding equipment to allow additional monitoring and control, providing additional service to customers as requested, maintaining full compliance with all legal and regulatory standards, and reacting to damage or repair as needed. These programs balance all of these needs while providing a critical service to customers in a reliable, cost effective manner.

Avista Utilities

Substation Infrastructure Plan

2020

Table of Contents

Table of Figures

Executive Summary

The Substations group is heavily impacted by the same factors driving investments in all of the other areas of the Company as well as utilities across the nation: continually increasing regulations from the federal to the local level, aging infrastructure, increasing customer demands for reliability, changing technology, and increasingly complex siting issues and construction permitting to name a few.

Substations and their associated equipment are critical to the integrity of the grid. The Federal Energy Regulatory Commission (FERC)[1] and the North American Electric Reliability Corporation (NERC)[2] are well aware of this and have a strong focus on regulating almost every detail of substation operating, maintenance, processes, and planning procedures as well as equipment operation and protection, all in the service of preserving the integrity of the interconnected system. Their mandates are heavily enforced, backed by significant fines for non-compliance.

In addition to federal regulating bodies, the electric power industry must comply with literally hundreds of national, state and local regulations. For example, utilities are governed by laws related to federal lands or affecting unique interests, such as culturally significant sites, environmental issues, or endangered species. The National Electrical Safety Code defines the rules for installation of electrical gear, electrical protection, methods and materials and even communications for all electric utilities. The Occupational Safety and Health Administration (OSHA) regulates safety standards. State and local authorities and regulators focus on facility siting and zoning, safety regulations, environmental considerations, and more; state regulatory commissions determine revenue requirements, allocate costs, set service quality standards and oversee the financial responsibilities of the utility. All of these regulators and regulations have developed over time to ensure that people and equipment stay safe and that the lights stay on.

These mandatory standards heavily inform Avista's decision-making processes and behaviors. They also help to ensure that the Company's system is reliable, resilient, and secure. However, decisions that were once based on qualitative risk assessment under a voluntary framework are now made based on deterministic criteria within standards required by law, with non-compliance resulting in substantial financial penalties. This has resulted in changes which influence the Company's capital spending decisions and operating practices to a significant degree.

[1] The Federal Energy Regulatory Commission (FERC) oversees all electricity transmission and wholesale marketing in the United States. FERC has regulatory authority over both the reliability of Avista's system and the commercial aspects of Avista's wholesale uses of its transmission.
[2] FERC has assigned reliability standard development and enforcement to the North American Electric Reliability Corporation (NERC). Its purpose is to regulate, enforce, monitor and manage the physical and logical security of systems that manage the electrical power grids.

At the same time, across the nation and specifically at Avista, thousands of assets are well past their expected lifespans, including transformers, reactors, capacitors, conductor, and poles. The Company is replacing these assets over time and as funding allows, but concurrently the traditional utility business is undergoing significant changes that make this work even more pressing and challenging. Customers are increasingly demanding "perfect power," meaning zero service interruptions, due to the sensitive nature of their technology systems and changing perceptions of inconvenience and disruption. This in part drives the need for new devices to detect and automatically manage outages.

Burke Substation

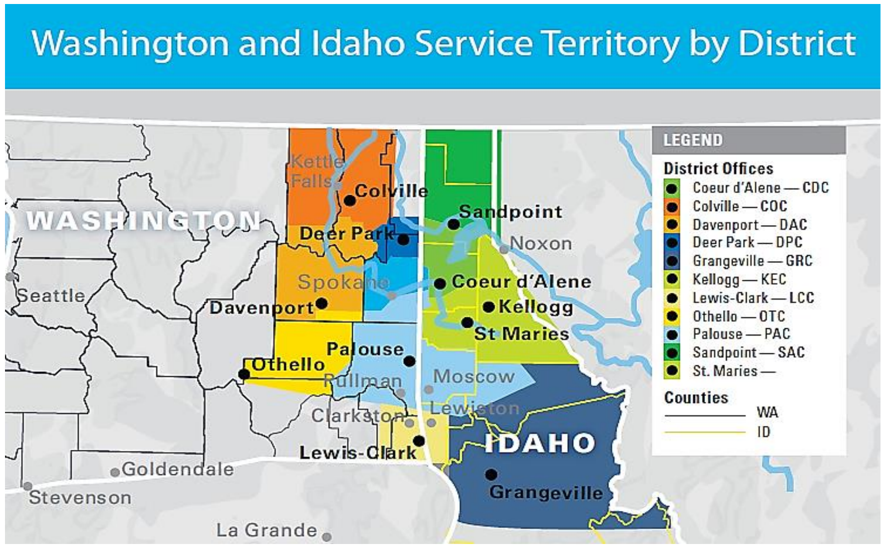
To add even more complexity to this mix, power system requirements are changing in directions never anticipated when the system was built, most of it in the 1950s and 1960s. Interconnections to private parties for integration of new variable energy resources particularly wind and solar, distributed generation, electric vehicles, smart grid technology, customer-requested technologies, and more require significant capital investment to extend or reinforce the electric system in order to provide for these non-traditional uses of the power grid. The Substations team is right at the heart of these efforts. This report describes the capital programs that impact the Substations group, put in place to try to address these diverse needs in the most effective, cost-conscious way possible while achieving the multiple objectives described above.

Cabinet Sub

Metro Sub

INTRODUCTION

Avista Utilities serves nearly 400,000 electric customers in Washington and Idaho over an extensive electric system that is designed, built, operated and maintained by the Company. This infrastructure system consists of nearly 19,000 miles of electric distribution lines, approximately 2,750 miles of high voltage transmission lines[3] along with 176 substations and their associated equipment crossing 30,000 square miles and bringing electric power to over 1.6 million people in Washington and Northern Idaho.[4] Avista currently has 176 substations, including 13 generation (step-up) substations, 21 transmission and switching substations, 31 transmission with distribution substations, 109 distribution only (step-down) substations, and two substations that are owned by other utilities but which contain Avista equipment.



All of the various kinds of substations are designed to handle different tasks. Generation substations take the energy from the power plant and step it up to transmission level for long distance travel to other substations. Transmission switching stations do not reduce the power level to distribution level, instead the lines come in and go out at high voltage, the electricity is just rerouted in different directions, split onto other lines, or stepped up or down in voltage, for example from 230 kilovolt (kV) to 115 kV. Transmission with distribution subs transform high voltage (transmission) into distribution (sub-transmission) level voltage and send it out onto distribution feeders. Distribution-only subs may route distribution-level power to various feeders or transform sub-transmission to different power levels to suit different customer needs. Each type of substation serves a particular purpose in serving customers.

Number of Substations	
Distribution	109
Foreign	2
Generation	13
Switching	13
Transmission	8
Transmission w/Dist.	31
	176

Substation Count by Voltage	
13 kV	4
24 kV	1
34 kV	1
115 kV	142
230 kV	14
Generation	14
	176

Location of Substations	
Coeur d'Alene	19
Colville	12
Davenport	13
Kellogg-St. Maries	13
Lewiston-Clarkston	22
Othello	12
Palouse	26
Sandpoint	13
Spokane	45
Coyote Springs	1
	176

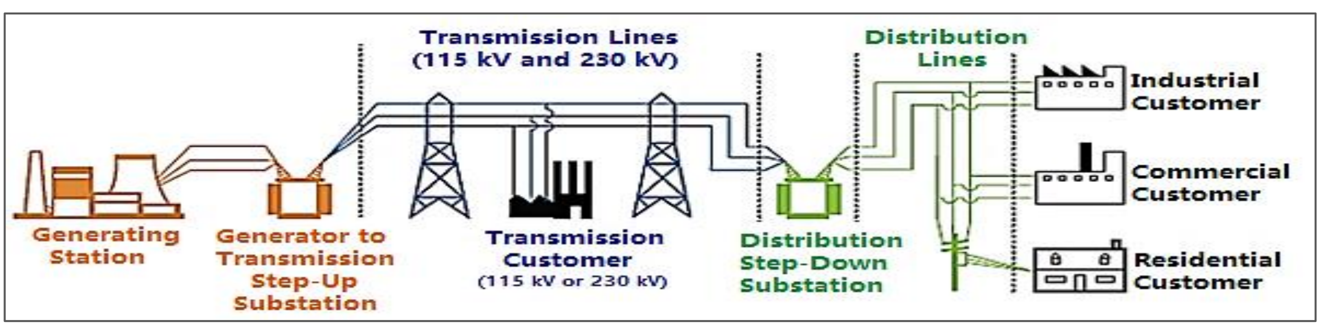
[3] This includes 700 miles of 230 kV, 1550 miles of 115 kV, and 500 miles of co-owned (Colstrip) 500 kV lines.
[4] Avista Quick Facts, https://investor.avistacorp.com/static-files/a7342b27-72cc-44d4-b9a7-b62903e999df

Avista must continually make new investments in this system in order to continue providing customers with safe and reliable electric service, at a reasonable cost, with service levels that meet customer's expectations for quality and satisfaction, and that meet stringent national, regional, state, and local regulatory requirements.

In order to meet all of these requirements, the Company develops specific capital programs. These programs are developed through planning and engineering studies and analyses, as well as scheduled upgrades or replacements identified in the operations districts and within engineering groups or to replace equipment that has been damaged or failed. Capital projects undergo internal review by multiple stakeholders who help ensure all system needs and alternatives have been identified and addressed. If proposed projects are initially approved, they go through a formal review process referred to as the Engineering Roundtable, a diverse group of engineering leaders[5] who track project requests, prioritize them, and establish committed construction package dates and required in-service dates for projects. Once a project has passed this phase of evaluation, it moves to the Capital Planning Group.

The Capital Planning Group (CPG) is a group of Avista Directors that represent capital intensive areas of the Company. Committee members are directors from a variety of business units to add a depth of perspective, though their role is to consider capital decisions from the perspective of overall Company operations and strategic goals as well as spending guidance set by senior management and approved by the Finance Committee of the Board of Directors. They develop a final budget that represents a reasonable balance among competing needs required to maintain the performance of Avista's systems, as well as prudent management of the overall enterprise in the best interest of customers.

Though all of Avista's assets play a role in providing the electricity that ultimately reaches consumers, in this report this discussion is confined specifically to substation facilities. All of us have passed by substations many times in the course of our travels, filled with complicated-looking electrical equipment and surrounded by high fences and barbed wire. They are easy to overlook and ignore, but they touch our lives every day, playing a critical role in providing the electricity we all depend upon. Substations play the primary role in the safe and reliable operation of the electric system, in essence providing the physical locations to monitor and manage the grid.



[5] Eleven representatives are included in this group from: Transmission and Distribution Planning, Transmission, Distribution, and Substation Design, System Protection, System Operations, Asset Management, Communications and Generation Engineering, and Transmission Services.

SUBSTATION FUNCTIONS

- *Changing voltage from one level to another*
- *Controlling the flow of electricity in various directions and onto various lines; splits the electricity out onto various feeders*
- *Providing circuit breakers to protect the system from faults*
- *Protecting the transmission system by insuring proper voltage levels and frequency*
- *Regulating voltage to compensate for changes due to fluctuating load, unexpected equipment failures, etc.*
- *Switching transmission and distribution circuits into and out of the grid system for maintenance or to meet other system conditions*
- *Measuring the electric power quantities flowing in the circuits*
- *Connecting communication signals to the circuits*
- *Eliminating surges from the system caused by lightning or other electrical conditions*
- *Connecting electric generation plants to the grid*
- *Correcting reactive power flows to insure voltage is stable*
- *Creating interconnections and controlling the electricity flow between electric systems of more than one utility*
- *Data transmission and communications*
- *General control and protection*
- *Fault analysis and pinpointing the location of a fault*
- *Providing the ability to shed load in a controlled fashion if demand exceeds power supply*

Before electricity can travel into your home, it must first pass through a substation. Substations are, in fact, the very heart of the electrical system, performing the critical functions necessary to get electricity from a generator to the customer. They are the center of protection and control of the electrical system, monitoring the voltage levels and frequency of the grid to insure they are sufficient, providing breakers to isolate faults, routing the power to where it is needed, and switching transmission and distribution lines in and out of service for maintenance and to serve customer loads.

Substations are also connection points. One of the most important and obvious connections is between the generator and the customer. Electricity is created at the generator, which passes it to a transmission substation where it is stepped-up to the high voltage level required for it to be conveyed long distance on transmission lines to the load source. This high-voltage electricity cannot be used in most homes and businesses. Voltage is like pressure, and high-voltage electricity has too much pressure to run everyday things. A residential customer's voltage need is only 120 volts. The voltage level of a transmission line is typically 115,000 volts or more to minimize line losses. This level is unusable for most end-use applications. Trying to use power at that level for all but extremely high-level industrial customers would be like trying to fill water glass with a fire hose. To deal with this challenge, the transmission line carries the electricity to a substation. The substation takes the electricity provided by the line and steps it down to the distribution level using a transformer. After converting the electricity to a usable level, the substation transfers the lower voltage electricity to the distribution system. Thus, the substation is vital to the functionality of the entire power system as the means by which power can be delivered to the customer in a form they can use.

Another substation function is splitting the power off in different directions, sending it onto different transmission or distribution lines for delivery to where it is needed.

Substations also provide a place for interconnections between different utilities in the grid, enabling them to buy and sell power to or from one another.

Substations are designed to provide switching, which is the connecting and disconnecting of transmission and distribution lines or other components to and from the system. An example of this function is switching the electricity from a line that is de-energized to another line or lines to keep the power flowing to customers, which helps maintain system reliability. Switching is used if a line needs to be de-energized for maintenance, due to a fault, to move power to a different location, or for new construction.

One of the highest priorities in a substation is to detect and isolate failures in the transmission system as quickly as possible. Short circuits or overloaded currents on a transmission line feeding a large substation can leave thousands of people without electricity. To protect against such an event, substations have specialized equipment to monitor, manage and protect the transmission system so the power can continue to flow. Substation equipment can isolate a faulted area so the rest of the system continues to function normally.

This report provides a summary overview of Avista's substations and the way the Company manages and invests in these critical assets and their associated equipment. Collectively these historic, current, and planned investments allow Avista to effectively respond to customer needs and expectations, provide service enhancements, meet regulatory and other mandatory obligations, replace equipment that is damaged or fails, support electric operations, address system performance and capacity issues, support the interconnected grid, and replace infrastructure at the end of its useful life based on asset condition. The investments described in this plan are based on what we know about the business today, including a range of precision in future cost estimates, applicable laws, regulatory requirements, and the capabilities of current technologies.

For more information about substations, their associated equipment, functions, and a glossary of terms, please see the 2019 Electric Substation Infrastructure Plan located on the Company's internal website[6] or as a hardcopy available upon request.

Above: Work at Cabinet Sub
Left: Inside Post Street Sub

[6] On the Avenue under "Tools and Resources" then "Avista Infrastructure Plans."

Classification of Infrastructure Need by Investment Drivers

As a way to create more transparency around the particular needs being addressed with each capital investment as well as simplify the organization and understanding of overall project plans, the Company has developed "investment drivers" to classify its capital projects. These drivers are broad categories that attempt to sort projects by the need they are addressing, as described below:

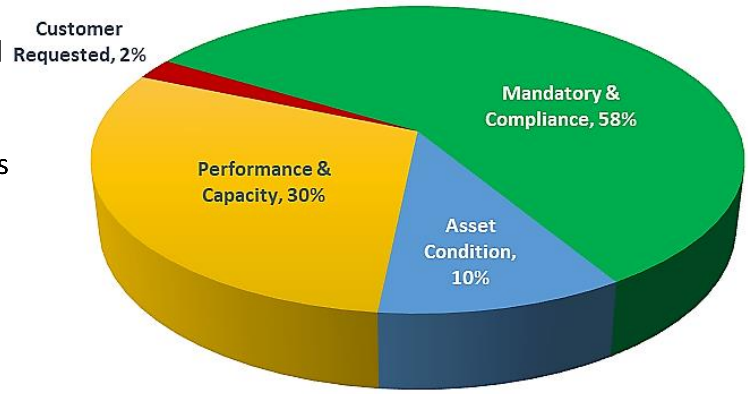
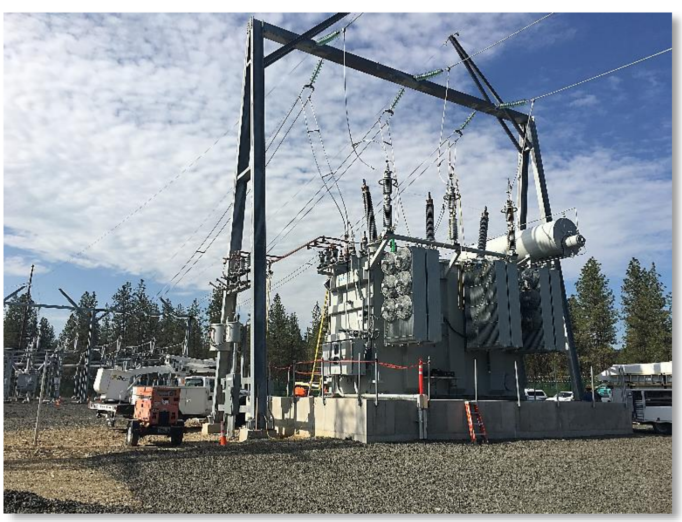


Figure 1. Total Substation Planned Capital Expenditures by Investment Driver

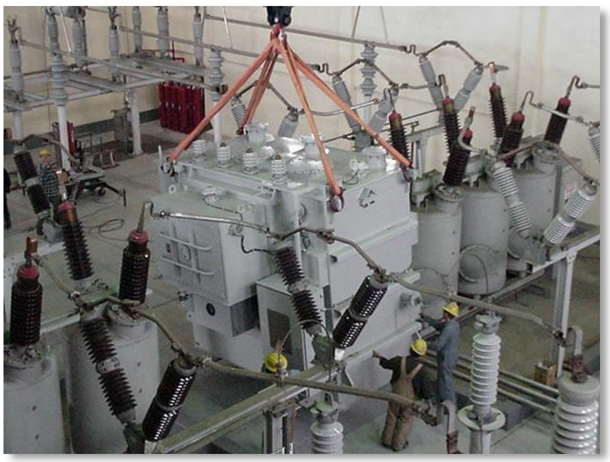
1. ***Customer Requested*** – This category is primarily related to customer growth, but also provides funding to enhance customer service as requested. The Company must build new or upgrade existing substations in response to changes in load or consumption patterns. This category also includes funding related to requested interconnections of third party resource developers such as the Lind Solar Project and the Rattlesnake Flat Wind Project.

2. ***Mandatory & Compliance*** – The Company makes a large number of business decisions as a direct result of compliance with laws, mandatory standards, safety codes, contracts, and agreements. An example is control equipment required by NERC to preserve and monitor the reliability of the interconnected grid or to replace equipment that is exceeding thermal limits, as substations are a key part of maintaining system reliability. Projects in this category are primarily driven by external requirements that are largely beyond the Company's control, such as building the Saddle Mountain Substation, required to meet NERC grid stability requirements, as well as construction of the West Plains Substation and the reinforcement of the Ninth and Central and Westside Substations, again required by NERC related to remediating system reliability issues.


Installation of new autotransformer at Westside Sub

3. ***Failed Plant & Operations*** – This category sets aside funds which allow the Company to replace failed equipment and support ongoing utility operations as assets are damaged or no longer provide adequate functionality. Often these expenditures are the result of storm damage, but they can also be required by other unexpected equipment failures, animal or human-caused damage, and the like. In Substations, Failed Plant and Operations dollars are combined with funds for planned and unplanned failed plant in the Substations Rebuilds Business Case, which is held under the Asset Condition business driver.

Animal-caused damage at Deer Park Substation



Post Street Sub receives a new transformer to replace one that reached end-of-life

4. ***Asset Condition*** – All assets have a defined useful service life. This category provides funding to replace equipment as needed so the system can continue to function effectively. This may include replacing parts as they wear out or when items can no longer meet their required purpose, as systems become obsolete and replacement parts are no longer available, to remedy safety or environmental issues, or if the condition of an asset is such that it is no longer optimizing its own performance or customer value. The Company also proactively replaces critical equipment to mitigate the risk of failure.

5. **Customer Service Quality & Reliability** – This category is for costs related to meeting customers' expectations for quality of service and electric system reliability. Substations does not have any specific dollars set aside under this category, as this is primarily a function of Distribution. An example of this type of expenditure is Distribution's programs to replace old style streetlights with energy-efficient LED lights. Another example is Avista's installation of smart meters to provide customers the ability to manage their energy usage, among many other benefits.[7]

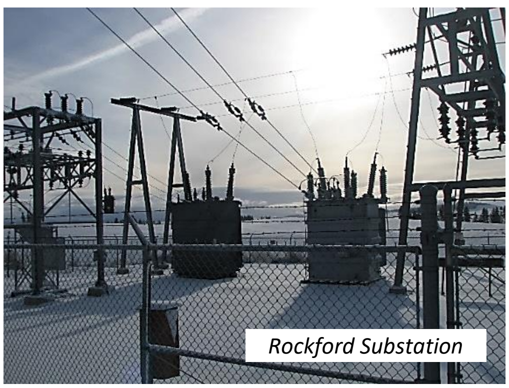
6. ***Performance & Capacity*** – Programs in this category ensure that the Company's assets satisfy business needs and meet performance standards, typically defined by Company experts or in line with industry expectations. Some examples include adding redundant distribution feeders to reduce the impact of outages on customers, replacing equipment that is not functioning at nominal levels, or adding monitoring capability to enable viewing critical equipment in real time. This category is also used to add new substations or upgrade existing stations to manage customer

[7] Customer benefits include providing customers access to their energy usage to allow managing it and controlling costs, energy alerts, billing accuracy, support for customer "smart home" technology, and more.

load growth/change. During this budgeting cycle, funding has been set aside to add new transmission lines to the Mead, Colbert, and Milan substations for service redundancy and the resulting improvement in customer reliability.[8]

Building the Opportunity Substation in Spokane to manage customer growth

Note that not all investment driver categories are utilized in all Avista's business units. For example, electric Distribution includes budgets in all six categories listed above; however, investments planned for Substations during the upcoming five-year planning cycle do not include any specific projects in the category of Customer Service Quality & Reliability or Failed Plant & Operations. It is also important to note that some projects may resolve issues under more than one investment driver category.



Rockford Substation

While projects are categorized by a *principal* investment driver, a project that resolves multiple issues may be prioritized differently than it would be if it fell fully under a single investment driver category. For example, investments in Substations related directly to service reliability for all customers are generally driven by mandatory compliance requirements, so they can be found in the "Mandatory & Compliance" driver even though the project may also provide more dependable customer service. Though the Substations team implements the T&D projects that impact substations and associated apparatus, these expenditures are typically dictated by Transmission and Distribution projects, thus many of the Substation business cases are the same ones listed in those reports.

Business Driver	2020	2021	2022	2023	2024	Five Year Total	Five Year Ave.
Customer Requested	$2,225,000	$0	$0	$0	$0	$2,225,000	$445,000
Mandatory & Compliance	$10,000,000	$15,900,000	$5,300,000	$1,650,000	$24,000,000	$56,850,000	$11,370,000
Asset Condition	$2,450,000	$1,670,000	$1,600,000	$2,900,000	$1,550,000	$10,170,000	$2,034,000
Performance & Capacity	$500,000	$1,800,000	$1,000,000	$11,900,000	$14,150,000	$29,350,000	$5,870,000
Total	**$15,175,000**	**$19,370,000**	**$7,900,000**	**$16,450,000**	**$39,700,000**	**$98,595,000**	**$19,719,000**

Figure 2. Substation Planned Capital Budget by Business Driver 2020 – 2024

[8] These projects are under the "Transmission New Construction" subcategory of Performance and Capacity and are share with the Transmission Group.

Overview of Currently Planned Capital Investments in Substations 2020 – 2024

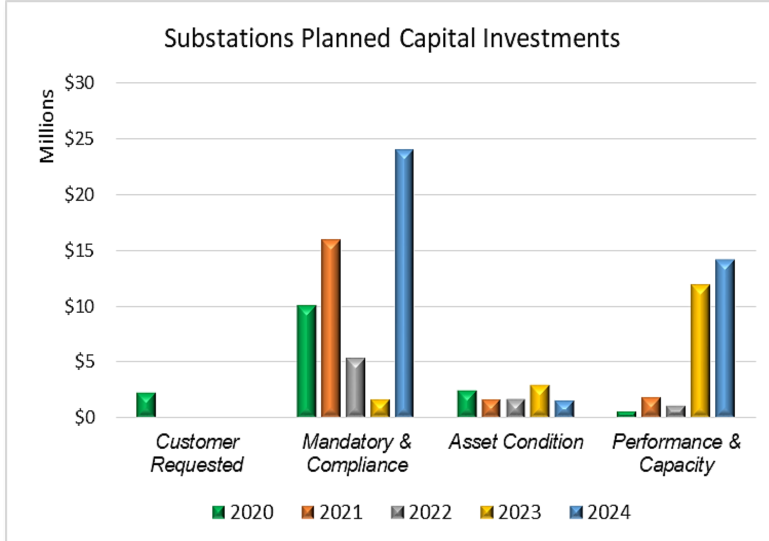


Figure 3. Planned Capital Substation-Related Expenditures by Investment Driver 2020-2024

Substation construction and maintenance activities are heavily regulated by state, regional and federal agencies that implement compliance standards, safety requirements, work activities, thermal limits, and the like. These rules govern when equipment must be replaced, how it must be monitored and maintained, operating characteristics and limits, and even cyber and physical security. Compliance with these mandatory standards is not optional and drives a number of the Company's investment decisions. This is clearly reflected in the expenditures the Substations team expects during the upcoming budget cycle and into the future.

This focus on compliance makes sense, as substations are the key to a utility's ability to serve customers. Equipment must be replaced or upgraded as loads grow or load patterns change, when equipment wears out or no longer functions to prescribed levels, to address potential outage or safety issues, to deal with equipment that is exceeding its tolerances, and to maintain the high level of reliability the Company and its customers expect. In addition, customers can request service that may require a new substation or adding capacity to an existing station, such as a wind project, a new subdivision, or a new manufacturing facility that require new or more robust substations.

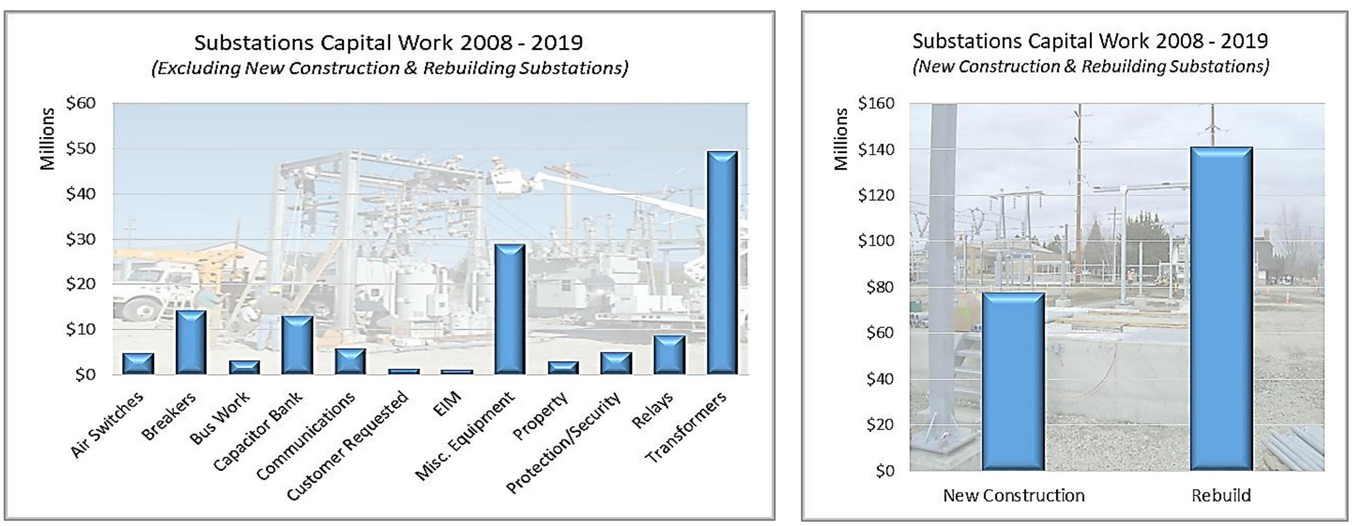


Figure 4. Historic Substation Capital Expenditures 2008 – 2019 [9]

[9] Misc. Equipment includes batteries, reclosers, fuses, switches, metering, voltage regulators, and technology equipment.

The Substations group is in the middle of all of these mandates and requirements, constantly monitoring the health and effectiveness of their equipment, rebuilding old substations to meet current standards or needs, constructing new substations as needed to manage loads and system stability, and adding equipment or replacing it as necessary. These crews also manage the substation property, insuring fences and gates are secure, installing security systems, and maintaining the associated substation yard and buildings. This team also installs and manages system protection and communication equipment, ensuring it is kept in working order so the Company can keep an eye on the operation of the system as well as detect equipment performance issues or be alerted to unauthorized intrusion.

Above: Break-in at Garden Springs Sub
Left: Security at Northeast Substation

As can be seen in Figure 4 above, rebuilding old substations (some built in the early 1900s) to replace aging equipment has been a major driver in Substation expenditures. This is required in order to handle growing demands as well as to stay in compliance with increasing numbers of stringent federal regulations, which include requirements for more monitoring, control and security measures, as well as replacing aging or undersized transformers to maintain reliability. These three requirements dominate Substations capital expenditures.[10]

Transient issues at the 3rd & Hatch Substation

Over the current five-year planning horizon, Avista expects to spend nearly $100 million for substation-related capital investments. Note that this figure includes some Transmission projects, as these projects are planned by Transmission but implemented by Substations.[11]

Salvaging the old transformer at Benewah in 2010

[10] Note in Figure 5 the "Misc. Equipment" category includes batteries, communications equipment, fuses, grounds, meters, reclosers, regulators, relays, and switches.

[11] The sister Transmission Infrastructure to this report can be found on the Company's internal website, the Avenue, under "Tools & Resources" in 'Avista Infrastructure Plans" for more information about Transmission capital expenditures.

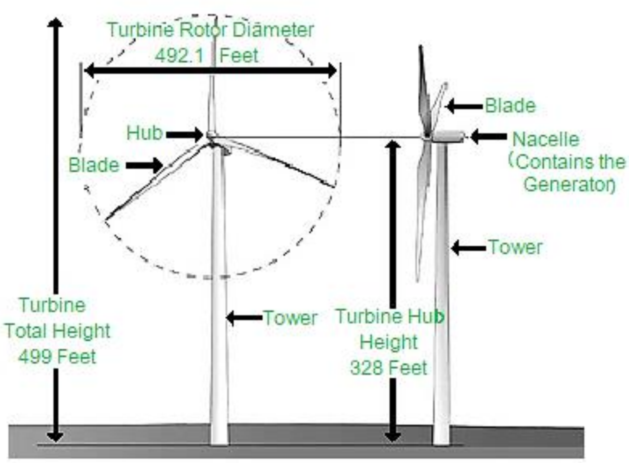
Planned Capital Investments

Customer Requested

Responding quickly to customer requests is a requirement of providing utility service. 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. The Company must also upgrade existing substations or build new ones in response to customer growth or at the request of generation resource developers such as the one described below.[12]

Rattlesnake Flat Wind Project

Avista issued a request for proposal in June 2018 for additional renewable energy. An external company, Clearway Energy Group, was selected to provide this resource. Clearway is developing a wind power facility known as Rattlesnake Flat Wind, which is projected to provide Avista with approximately 50 average megawatts of renewable energy, or as much as 144 megawatts of nameplate wind capacity, under a 20-year power purchase agreement with deliveries beginning in 2020. This project, including 90 wind turbines and associated facilities, is located on approximately 23,000 acres in Adams County, Washington. This project requires significant upgrades to Avista's existing infrastructure in order to allow this new generation to be added to the power grid. The required work includes rebuilding nearly 27 miles of 115 kV transmission including distribution underbuild and optical ground wire. It also necessitates a new substation (Neilson) with adequate protection, control and communications equipment, as well as upgrades to three existing substations[13] to handle the increased system demands this project will create. *This business case is part of the same Transmission business case.*



Rattlesnake Flat Wind Turbine Design

Building the new Neilson Substation to add the Rattlesnake Flat Wind generation to the power grid

[12] Purchasing qualifying output from independent power producers and providing the transmission, substations, and other necessary equipment to allow this projects to connect to the grid is required by law. http://app.leg.wa.gov/WAC/default.aspx?dispo=true&cite=480-107

[13] The substations requiring capacity upgrades include Lind, Warden, and the Othello Switching Station as well as replacement of the circuit switcher at Roxboro. The developer is responsible for a portion of the cost of this project.

Mandatory & Compliance

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 which drive much of the Company's capital spending requirements as mentioned earlier. Compliance with these laws and rules, as well as with contracts and settlement agreements, represent obligations that are generally outside of Avista's control. The types of investments that fall into this driver include the obligation to relocate facilities to accommodate state, county and municipal infrastructure projects (frequently transportation related) and compliance with environmental regulations. FERC and NERC requirements for grid stability have a significant impact on the Substations group workload and budgets as described below.

Saddle Mountain 230/115 kV Station

Avista's System Planning group and related outside entity studies determined that the western portion of the Avista's existing system is not meeting NERC performance requirements during heavy load scenarios. The Saddle Mountain project, undertaken in two phases, will allow Avista to continue serving Company load in the Big Bend Area near Othello while eliminating the pressure Avista's load is putting on the Grant County Public Utility District system. This issue will be solved by constructing a new 230/115 kV substation where the Walla Walla – Wanapum 230 kV and the Benton – Othello 115 kV transmission lines cross. This new sub will consist of a three-terminal 230 kV double bus double breaker configuration,[14] a 250 MVA 230/115 kV auto-transformer,[15] four 115 kV breakers, rebuilding existing aging 115 kV transmission lines, and building ten miles of new 115 kV transmission. This project will greatly improve the reliability of transmission in the area and rem n existing single point of failure situation which could create widespread outages in case of a fault. It also mitigates potential thermal overloading and voltage issues in this area. *This business case is part of the same Transmission business case.*


Saddle Mountain Substation under construction

[14] A double bus double breaker bus configuration consists of two main buses, each normally energized and electrically connected to each other so that if one is removed from service by a fault or for maintenance, the other breaker continues to function so there is no interruption to service.
[15] An auto-transformer is used to adjust line voltages or hold them constant, and can step up or step down voltages in the 115 kV and 230 kV range, for example, providing a 115 kV tap from a 230 kV line.

Spokane Valley Transmission Reinforcement

This project reinforces transmission in the Spokane Valley area, spurred by load growth in the region as well as compliance with the NERC TPL-001-4 Reliability Standard[16] which requires each utility to ensure that their system is robust enough to operate reliably over a broad spectrum of system conditions and under a wide range of possible contingencies. Avista system studies identified this area as requiring additional reinforcement in order to be in compliance with the NERC standard about ten years ago, and the Company has been working on it since that time. This long term project required the construction of a new switching substation (Irvin) off of Trent Avenue. It also includes rebuilding 4.4 miles of the Beacon-Boulder #2 115 kV transmission line, building 1.75 miles of transmission for the new Irvin-Opportunity 115 kV tap, construction 2.2 miles of 115 kV transmission from the new Irvin sub to the existing Millwood sub, and installing circuit breakers to handle the upgrades changes at the Opportunity Sub. These changes will not only address compliance issues, but will make the transmission system in this urban area more stable and reliable, specifically for serving large industrial customers. *This business case is part of the same Transmission business case.*

Site of new Irvin Substation in Spokane Valley

West Plains New 230 kV Substation

Planning studies of the Spokane area transmission system revealed specific transmission performance issues which will occur within the next five to ten years, including an inadequate number of transformers. These performance issues have a significant potential to exceed NERC reliability standards, designed to prevent cascading outages and ensure the integrity of the interconnected system especially around thermal or voltage limit issues.[17] System studies identified at least seven NERC thermal or voltage limit violations including:

- Inadequate 230/115 kV transformation provided by the four existing substations in the area, especially in the case of system events. Existing transformers are reaching maximum thermal capacity now and in time will exceed it.
- Related 115 kV transmission lines are running at 96% to 135% of their rated capacity during specific contingency scenarios.[18]

[16] NERC Standard TPL-001-4: http://www.nerc.com/files/tpl-001-4.pdf requires the Company to avoid load loss and have circuit breakers with sufficient interrupting capability for faults.
[17] NERC Reliability Guidelines, September 2018, https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_Methods_for_Establishing_IROLs.pdf. Non-compliance with NERC directives can lead to fines of up to $1 million per day until the violation is rectified.
[18] This includes the Northwest-Westside 115 kV, the Bell-Northeast Waikiki Tap 115 kV lines, and the lines from the Beacon and Westside substations.

These issues are expected to intensify with projected growth in this region. In addition, some of the transmission lines in the Spokane area are radial lines, requiring manual intervention in order to restore service to customers after a fault, with a total customer exposure of up to 31 miles. In order to manage this situation and remain in compliance with NERC directives, the Company is planning to construct a new 230 kV substation in the West Plains area. The Company selected this property at the convergence of two major transmission lines to provide maximum value for this new substation. No new transmission lines will need to be built; the existing lines along with this new substation will address the transmission performance issues. This location also provides an opportunity to interconnect with a 230 kV line owned by Bonneville Power Administration, strengthening Avista's grid and adding additional operating flexibility. The West Plains Substation is designed to mitigate all of the identified system deficiencies, including adding 500 MVA of transformer capability and redundancy to the transmission system in this area. *This business case is part of the same Transmission business case.*

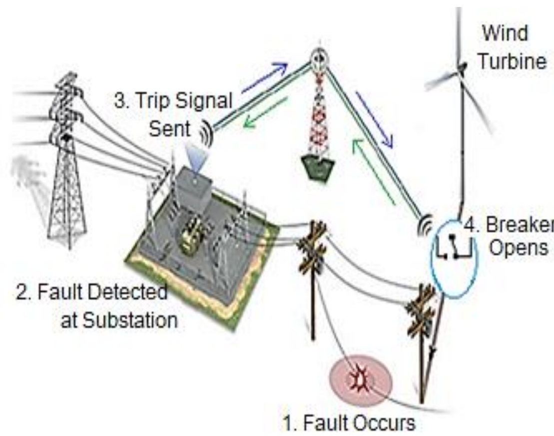
Ninth & Central 230 kV Station & Transmission

The Spokane area transmission system is heavily dependent upon the Beacon Substation, which is networked to the Bell Substation as well as eight 115 kV transmission lines. In order to reduce this dependency, create redundancy, enhance customer reliability, and remain in compliance with mandatory standards, Avista is planning on upgrading the infrastructure of the Ninth & Central Substation to provide a more robust and dependable infrastructure for the Spokane area. The Company is adding new 230 kV infrastructure to accommodate a 230/115 kV auto-transformer and associated circuit breakers, and putting in place additional transformer capacity for the Spokane transmission system. This project will also build eight miles of new transmission lines, utilizing existing 115 kV corridors in a double circuit configuration in order to fortify the Spokane area transmission system without increasing the transmission footprint through the area. This project significantly strengthens the electric system in the Spokane area, especially in the South Hill region. *This business case is part of the same Transmission business case.*

Work on the Ninth & Central Substation

Ninth & Central transmission line

Protection System Upgrade



NERC Reliability Standard PRC-002-2[19] defines the disturbance monitoring and reporting requirements for Bulk Electric System elements.[20] This Standard requires collecting and recording data needed to analyze disturbances. The Standard requires 50% compliance with these data requirements by 2020 and 100% compliance by 2022. To achieve compliance, Avista is required to upgrade fault recording capability at several substations including: Beacon, Boulder, Rathdrum, Cabinet Gorge, North Lewiston, Lolo, Pine Creek, Shawnee and Westside. This project will be ongoing until 2022.

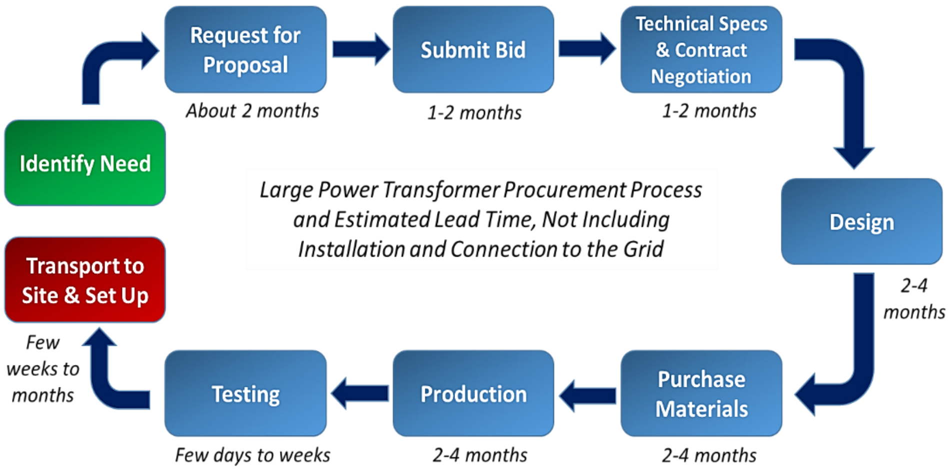
Westside 230/115 kV Substation "Brownfield Rebuild"[21]

The Westside 230 kV Substation Rebuild is a major project made necessary because the existing Westside #1 230/115 kV transformer exceeded its applicable facility rating during heavy summer loads, resulting in the cascading failure of the Westside #2 230/115 kV transformer. This situation created a compliance risk with NERC TPL-001-4, a standard which has very specific requirements around equipment failure that could result in shedding customer load.[22]

New Westside #1 230/115 kV transformer being put into place

Engineers determined that the existing old transformers (one was manufactured in 1976 and one in 1958) were underrated for their use and not up to current design standards. These transformers will be replaced with 250 MVA[23] rated transformers designed for current performance and safety standards. Importantly, this replacement will meet stringent NERC requirements related to critical equipment being operated beyond its ratings and failing, which could ultimately impact the interconnected system.[24] These types of transformers are highly specialized, must be custom-ordered, and can take months to arrive. They weigh approximately 170 tons (making transportation an issue) and have prices tags of approximately

[19] NERC PRC-002-2 "Disturbance Monitoring & Reporting Requirements," http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-002-2&title=Disturbance%20Monitoring%20and%20Reporting%20Requirements&jurisdiction=United%20States
[20] NERC defines the Bulk Electric System as any transmission element operated at 100 kV or higher that has the potential to impact the grid.
[21] A "Brownfield" project refers to a project that takes place on land that has been occupied by a "permanent" structure at some point, requiring demolishing or renovating a prior structure, versus a "Greenfield" project that will be built in a place where nothing had been built before.
[22] NERC TPL-001-4, http://www.nerc.com/files/tpl-001-4.pdf
[23] MVA refers to the amount of power output a transformer is capable of delivering at a specified voltage under normal operating conditions without exceeding internal temperature limitations. A 250 MVA transformer is a very large transformer.
[24] "System Operating Limit Definition and Exceedance Clarification," NERC, https://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/2014_03_third_posting_white_paper_sol_exceedance_20141001_clean.pdf



$2,000,000[25] so entail a great deal of planning and preparation as well as installation time, making this a multi-year project.

Along with the transformer change-outs, numerous other equipment replacements are required to have the capacity needed from this station. To maximize the value the construction time, failing air switches and breakers at this substation will be replaced, the end-of-life protection equipment will be updated and upgraded, oil containment provisions will be made, and site security issues will be addressed. The 230 kV and 115 kV buses at the substation will be upgraded to a double bus double breaker configuration to provide adequate redundancy. This project, started in 2016, should be completed during the current budget cycle. *This business case is part of the same Transmission business case.*

Failed Plant & Operations

While large-scale outages are vividly remembered by both Avista employees and 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 the electric system. In addition to outage response, Avista's nominal operations involve reconfiguration and replacement of electric facilities under a variety of circumstances. Causes of damage to the system include weather events, lightning, fire, snow and ice, downed trees/vegetation, wildfires, human or animal caused damage, and equipment failure. Other failures include the unanticipated loss of assets due to a range of factors including age and condition. Funding in this category is split between Transmission and Distribution, but often it is the Substations group that performs many of the repairs, replacements, and upgrades.

Above: Warden Switching Station failed PT
Left: Circuit switch failure at Gifford Sub

[25] U.S. Department of Energy, "Large Power Transformers and the U.S. Electric Grid," 2012, https://www.wecc.biz/Reliability/2014_TEPPC_Transmission_CapCost_Report_B+V.pdf, page 7.

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 continuation of service. 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, 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 meeting a variety of important performance objectives, such as electric system reliability or the efficient use of employee crews.

Switchyard equipment failure at Little Falls

Post Street Substation Wall

Because failure of some critical assets is unacceptable, they must be replaced near the end of their useful life even if they are still providing reliable service to proactively prevent outages. In other instances it may be reasonable and economical to wait until an asset fails before it is replaced, a strategy known as “run to failure.” The Company sets aside funding to provide for swapping out old substation equipment as it reaches the end of its useful life, no longer meets performance requirements, becomes a safety hazard, is creating outages, or is so critical to operations that it must be replaced prior to failure. The Asset Condition category is a major focus for the Substations group, as they are continuously rebuilding, replacing, upgrading and repairing equipment to keep the system operating at optimal performance levels. Some of their specific programs in this category are described below.

Failed cable at Moscow City Sub

South Othello circuit switch interrupter failure

Substations Rebuild Program

Work on the Lee & Reynolds Substation in 2018

Investments in this program include updating old equipment to meet new safety and construction standards, installing communications systems (often in response to NERC directives), and replacing or upgrading other equipment such as circuit breakers, reclosers, switches, capacitor banks, transformers, and regulators. In addition, supporting equipment like relays, meters, batteries, panel housing, and fences must be replaced or rebuilt periodically to ensure the full functionality and safety of Avista's substations. Other projects in this category include rebuilding some of the Company's older wood substations, replacing or improving equipment at others, or increasing the capabilities of a substation due to growth or load changes in the area. *Please note that capital allocated for this program is shared between Transmission, Substations, and Distribution though Transmission creates and manages this program.*

Performance & Capacity

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 analysis. Substations projects in this category are typically related to system reliability, as substations are the primary provider of system protection. Projects may include replacing circuit breakers that are not performing to optimum protection levels or adding automation that instantly responds to and mitigates system issues. Other projects include adding redundancy to transmission and distribution lines to provide substations with the ability to switch lines to continue service when a fault occurs. In addition, this category incorporates customer growth-required substation equipment and upgrades.

Cabinet Gorge 230 kV Add Bus Isolating Breakers

The existing circuit breaker arrangement at the Cabinet Gorge substation causes a fault to trip off all four of the hydro units (about 260 megawatts), as well as trip both 230 kV lines and the primary 115 kV transmission line into Sandpoint. In the past this type of fault was an unusual occurrence so resolving the problem was not a high priority, but recently the number of these outages has increased, resulting in seven NERC Event Reports so far and driving the need to resolve this reliability issue as quickly as possible. The Company plans to install two breakers to separate the 230 kV bus at Cabinet from the generation step-up transformers to isolate the impact of faults across the bus and reduce the large scale impact currently experienced. Relay protection will also be added. *This business case is part of the same Transmission business case.*

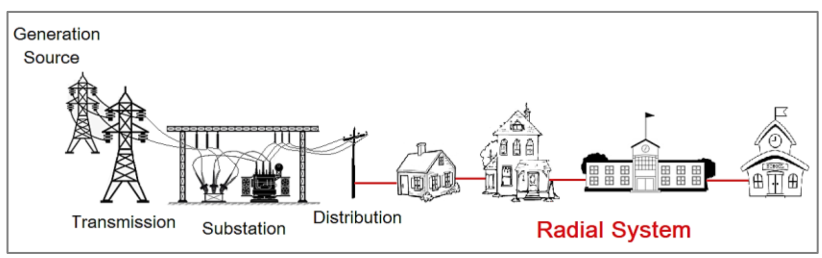
Cabinet Gorge 230 kV Substation breakers

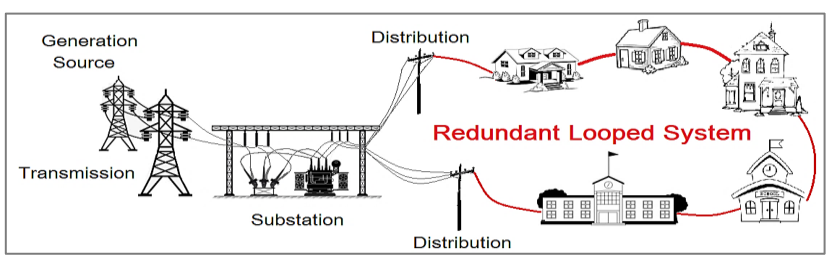
Substation – New Distribution Station Capacity

Adding new substations for load growth and reliability is critical to the long term safe, dependable, and cost-effective operation of the system. As load demands change and increase and customer expectations related to reliability also continue to increase, incremental substation capacity is required to serve those demands. Funding under this category is based on the historical experience of needing to add approximately two new substations to the system per year or to rebuild/upgrade existing substations to ensure that the system is growing at an adequate pace to maintain the expected level of service and reliability.

During the upcoming five year budget cycle, this program will fund upgrades to Spokane area substations to handle the increased load growth and add needed redundancy to the distribution system there. These changes will improve operational flexibility, allowing loads to be shifted to other lines in case of a fault or maintenance, maintaining continuous customer service through these types of events. *The capital allocated to this program is shared between Transmission, Substations, and Distribution.*

Transmission New Construction





Investments made under this program support the addition of new substations due to load growth in a particular area or to reinforce existing substations with new transmission required for increased performance, system stability, or customer service reliability. Funding in this category is also used to provide redundant feeds to radially-fed substations, reducing the potential for customer outages. *This program is managed through the joint efforts of Avista's Transmission Design & Engineering, Substations, Operations, and Transmission Planning groups, from which the requests for upgrades or additions are initiated.*

Operations & Maintenance Expenditures

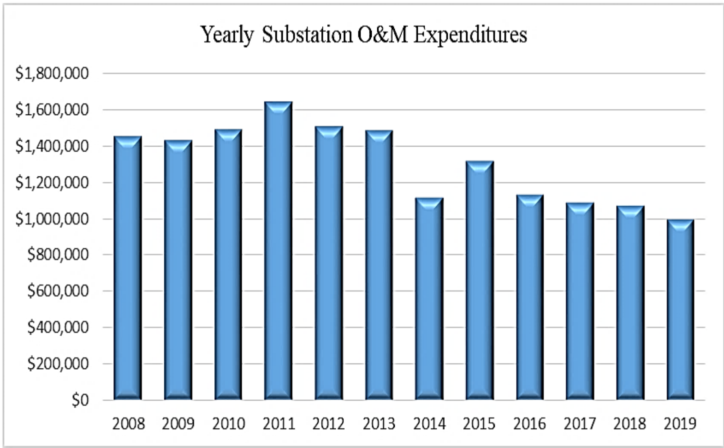


Figure 5. Substation O&M Expenditures 2008-2019

Avista's Substations employees are responsible for maintenance activities that involve Generation, Distribution, and Transmission assets. These employees are crucial to maintaining the integral equipment that transfers electricity to the end customer. Over the past decade, Substations has typically spent about $1.3 million per year[26] on a huge variety of operations and maintenance related tasks including servicing power lines, transformers, breakers, regulators and even the fences and grounds under and around their substations. The highly specialized and sophisticated equipment they maintain, repair, and install requires continual upkeep – checking the oil levels and quality, ensuring that breakers work when they are needed, repairing damaged equipment, and replacing blown fuses and dead batteries to name a few.

As an example, transformers are critical to grid operations and reliable power supply. Their failure can pose a variety of unsafe conditions, lead to extended outages for customers, and impose extraordinarily high costs on the utility for replacement. Therefore routine maintenance, diagnostic testing, and insuring proper operation of this equipment is of paramount importance. Equipment must be kept cool, leaks must be repaired, and equipment must be cleaned to protect against arcing. As can be seen in Figure 6, there is a great deal of work to be done in maintaining the substations portion of the power system.

Even beyond the major projects shown in Figure 6, there are constant small projects that must be managed. Substation buildings contain critical equipment that must be kept cool in hot summer months (fans and HVAC systems), wildlife guards are installed to reduce the number of outages caused by birds and squirrels, weeds must be kept at a minimum to avoid arcing. This group also utilizes specialized equipment to monitor and test equipment. One of the many ways they do this is with infrared imaging to identify hot spots in transformers. All of this work is in the service of preventing outages and maintaining system stability.

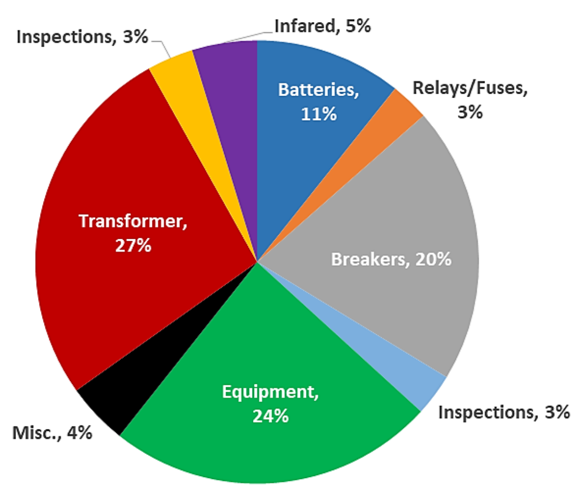


Figure 6. Primary Substation O&M Expenditures 2008 - 2019

[26] This average has dropped to approximately a million dollars per year over the past five years as the Company reduces O&M expenditures. Note that the required work does not go away, but is only postponed when budgets are reduced.

Summary

Avista's substations are the very heart of Avista's electrical system, performing the essential functions needed to provide power to customers. They serve a number of vital purposes. They are the focal point for protection and control of the electrical system. They contain highly technical and specialized equipment that monitors and maintains the voltage levels and frequency of the interconnected grid, provide breakers to isolate faults, route power to where it is needed, switch transmission and distribution lines in and out of service to serve loads or to perform maintenance, and transform power to required voltage levels. Substations are the backbone of power stability and quality. They play the primary role in the safe and reliable operation of the entire grid and are the means of getting power to the customer.

As discussed throughout this report, substations are filled with complex and sophisticated equipment, enabling the utility to monitor and manage the electric system. Avista has over 176 substations across a 30,000 square mile service territory, each fulfilling a particular purpose. Whether it is to step up the power from the power plant to high voltage transmission level, re-route power lines, manage power quality, connect to neighboring utilities, or step down the power to distribution level, all of the Company's substations play a central role in protecting and maintaining the electrical system and getting the power to customers.

The Substations group is responsible for some of the most important equipment in the Company, both for customer service and in protecting the integrity of the interconnected grid. They are intensely focused on insuring that this equipment continues to perform reliably into the future. Avista's Substation Engineering team, in collaboration with the Generation Production and Substation shops, oversees the design, testing, maintenance, repairs, rebuilds, and monitoring of all of the Company's substations and associated equipment. These critical connection points must be carefully managed to preserve not only reliable electrical service to customers and to maintain compliance with national regulations, but also to manage costs and provide safety for the public, employees, and the entire Western Interconnection. At Avista, substation failure could potentially lead to a local or even regional outage, with the very real possibility of costing millions of dollars and impacting millions of lives. The Substation team takes on these responsibilities while managing to fixed capital budgets and limited operations and maintenance allowances. About two Avista substations are built or rebuilt each year to meet customer growth and system needs, but the future indicates that even more work will be required. Changing customer reliability expectations, increasing state and federal regulations, cybersecurity concerns, aging infrastructure, and limited manpower are having an impact already and are likely to change the landscape of Avista's substation management and required expenditures into the future.

Appendix A: Avista's Substations

Coeur d'Alene Substations

Appleway 115kV
Avondale 115kV
Blue Creek 115kV
CD'A 15th St 115kV
Dalton 115kV
Huetter 115kV
Idaho Road 115kV
Lakeview 230/13kV
Pleasant View 115kV
Post Falls 115kV
Prairie 115 kV
Ramsey Rd. 115kV SS
Rathdrum 230kV
Spirit Lake 115kV

Lewiston-Clarkston Substations

Clearwater 115kV
Cottonwood 115kV
Craigmont 115kV
Critchfield 115kV
DryCreek 230kV
Dry Gulch 115kV
Grangeville 115kV
Holbrook 115kV
Kamiah 115kV
Kooskia 115kV
Kooskia 34kV
Lewiston Mill Rd. 115kV
Lolo 230kV
Nez Perce 115kV
N. Lewiston 230kV
Orofino 115kV
Pound Lane 115kV
S. Lewiston 115kV
Sweetwater 115kV
Tenth & Stewart 115kV
Weippe 115kV
Wickes 115kV

Colville Substations

Addy 115kV (BPA)
Arden 115kV
Chewelah 115kV
Colville 115kV
Gifford 115kV
Greenwood 115kV
Kettle Falls 115kV
Orin 115kV
Spirit 115kV
Valley 115kV

Davenport Substations

Davenport 115kV
Devil's Gap 115kV SS
Ford 115kV
Harrington 115kV
Little Falls 115kV
Long Lake 115kV
Long Lake 115kV SS*
Odessa 115kV
Reardan 115kV
Stratford 115kV SS
Wilbur 115kV

Othello Substations

Lee & Reynolds 115kV
Lind 115kV
Marengo 115kV
Othello 115kV
Othello 115kV SS
Ritzville 115kV
Roxboro 115kV
South Othello 115kV
Sprague 115kV
Warden 115kV SS
Wanapum 230kV (GCPUD)
Washtucna 115kV

Spokane Substations

Airway Heights 115kV
Barker 115kV
Beacon 230kV
Boulder 230kV
Boulder Park 115 kV
Chester 115kV
Colbert 115kV
College & Walnut 115kV
Deer Park 115kV
East Farms 115kV
Fort Wright 115kV
Francis & Cedar 115kV
Garden Springs 115kV SS
Glenrose 115kV
Greenacres 115kV
Hallett & White 115kV
Indian Trail 115kV
Inland Empire Paper 115kV
Liberty Lake 115kV
Loon Lake 115kV
Lyons & Standard 115kV
Mead 115kV
Metro 115kV
Milan 115kV
Millwood 115kV
Nine Mile 115kV SS
Ninth & Central 115kV
Northeast 115kV
Northwest 115kV
Opportunity 115kV
Otis Orchards 115kV SS
Post St. 115kV
Ross Park 115kV
Silver Lake 115kV
Southeast 115kV
Spokane Ind. Park 115kV
Sunset 115kV
Third & Hatch 115kV
Waikiki 115kV
Westside 230kV

Sandpoint Substations

Blanchard 115kV
Bronx 115kV SS
Cabinet Const. 115kV
Cabinet 230kV
Clark Fork 115 kV
Noxon 230kV SS
Noxon Const. 230/13kV
Noxon 230 kV Reactor
Oden 115kV
Oldtown 115kV
Priest River 115kV
Sagle 115kV
Sandpoint 115kV

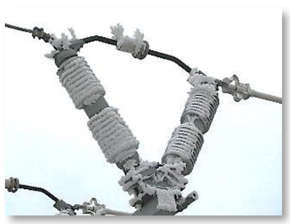
Palouse Substations

Benewah 230kV
Deary 115kV
Diamond 115kV
E. Colfax 115kV
Ewan 115kV
Garfield 115kV
Juliaetta 115kV
Latah Jct. 115kV
Leon Jct. 115kV
Moscow 230 kV
Moscow City 115kV
N. Moscow 115kV
Palouse 115kV
Potlatch 115kV
Rockford 115kV
Rosalia 115kV
Shawnee 230kV
South Pullman 115kV
Spangle 115kV
St. John 24kV
Tekoa 115kV
Terre View 115kV
Thornton 230kV SS
Turner 115kV
WSU 13kV
WSU - E. Campus 13kV

Generation Substations

Noxon Rapids HED
Cabinet Gorge HED
Post Falls HED
Upper Falls HED
Monroe St. HED
Nine Mile HED
Long Lake HED
Little Falls HED
Kettle Falls GS
Kettle Falls CT
Northeast CT
Boulder Park GS
Rathdrum CT
Coyote Springs 2

Control room at Beacon Sub



Lightning arresters at Lakeview Substation

Fire retardant at Avondale Sub

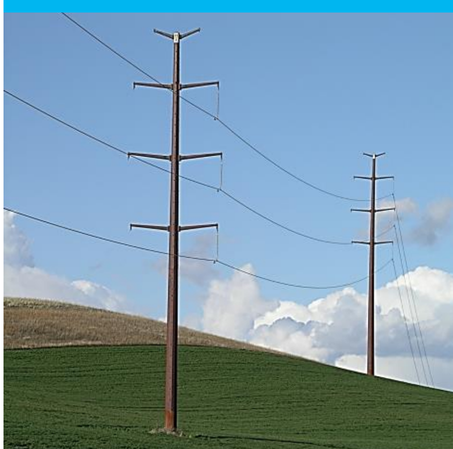
Post Street Sub

Upgrade work at Westside

Avista Utilities

Transmission Infrastructure Plan

2020



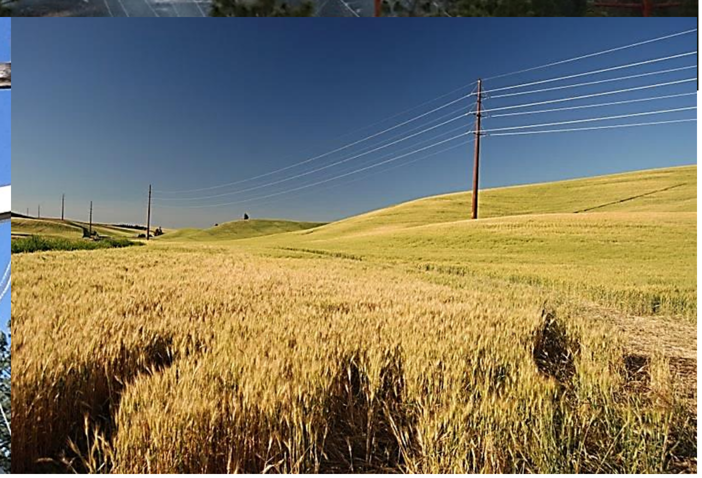


Table of Contents

Table of Figures

Table of Tables

Executive Summary

Our nation's electric utilities are facing times of unprecedented challenge when it comes to the forces driving the need for new investment in transmission infrastructure, and Avista is no different. This growing demand for new investment has significantly impacted the ability to fund all of the high-priority needs for electric transmission which include:

- **Aging Infrastructure**. Thousands of transformers, reactors, capacitors, conductors, poles and structures are well past their expected lifespans.[1] Avista has transmission lines that are over 110 years old. Though the Avista transmission group is replacing these lines as funding is available and changing out wood structures with more resilient steel, the need continues to outpace the ability and funding to complete all the work that must be done.

- **Increasing Need for Capacity**. Much of the U.S. power grid was built in the 1950s and 1960s with a 50-year life expectancy, and, to add further tension, the more than 640,000 miles of high-voltage transmission lines in the lower 48 states are at full capacity now while demand for use continues to grow.[2] Much of Avista's system was built during the same time frame. This already strained system is being significantly impacted by shifts in the loads served by the transmission system, including transmission interconnections to private parties for integration of new variable energy resources, particularly wind and solar. These types of interconnections require significant capital investment to extend or reinforce the system in order to provide for these non-traditional uses of the power system and add additional strain to an already constrained transmission grid.

- **Growing Numbers of Federal and State Regulations.** Power markets, already weakened by flat to declining demand growth, are often caught in the middle of a conflict between federal and state policies. Many states have pursued public policy goals with respect to renewable energy options, energy efficiency and CO_2 abatement. On the flip side, federal policy such as tax credits and the Public Utility Regulatory Policies Act (PURPA) have led to a growing amount of zero and negative marginal cost power being injected into power markets already suffering sluggish load growth. In addition, allowed return on equity (ROE) has been consistently dropping throughout the industry since the 1980s, although the need for capital investment is increasing, creating tremendous tension. Though regulators maintain close scrutiny over rates, they are "freely encouraging the development of renewables and greater customer access to the grid, distribution channels, and equipment through emerging technologies."[3] These technologies require expensive investments and infrastructure. The cost of new infrastructure is continually increasing, so any significant new construction means higher

[1] Robert Walton, "Aging Grids Drive $51B in Annual Utility Distribution Spending," UtilityDive, July 25, 2018, https://www.utilitydive.com/news/aging-grids-drive-51b-in-annual-utility-distribution-spending/528531/ and Energy.gov, https://www.energy.gov/articles/infographic-understanding-grid. The U.S. Department of Energy (DOE) estimates that, nationwide, 70% of transformers are 25 years old or older, 60% of high voltage circuit breakers are more than 30 years old, and 70% of transmission lines are 25 years old or older and approaching or at the end of their useful life.
[2] American Society of Civil Engineers, "2017 Infrastructure Report Card," https://www.infrastructurereportcard.org/wp-content/uploads/2017/01/Energy-Final.pdf
[3] Earl Simpkins, Leslie Hoard, Suva Chakraborty, Daniel Wilderotter, "Utilities Preparing for Growth: Navigating Disruption By Linking Capabilities," November 20, 2015, https://www.strategyand.pwc.com/reports/utilities-preparing-for-growth

rates for consumers. Utilities face significant risk of not recovering all their costs, much less an adequate return, for new infrastructure investment, the need for which is beyond their control.[4]

- **Siting, permitting and construction.** Building required transmission lines has become more complex, time-consuming and expensive due in part to increasing environmental and property requirements. Landowners, public and private, seek more compensation for rights-of-way and access agreements than in the past. Local, state, and federal permitting requirements cover issues such as endangered species, historical and cultural resources, water quality, wildlife and more. Permitting can extend over several years and typically includes conditions that limit how utilities construct or maintain these assets as well as stringent requirements for site restoration. These requirements considerably constrain the siting, construction and operation of new grid facilities.[5]

- **Changing Issues and Technology.** In addition to feeling its age, the integrated grid, designed to accommodate very steady, very stable traditional resources, is now required to integrate non-traditional and often unpredictable resources such as solar, wind, and distributed generation sources. Smart grid technology including wide-area monitoring, protection, automation and control is also predicted to have a significant impact on grid operations – and spending.[6] At the same time, the grid is facing cyber threats never imagined back in the 1950s and 1960s when most of the system was built. According to a variety of studies across the United States including the Department of Energy, the viability of the century old bulk power grid has been declining and is "nearing the end of its useful life."[7] They note that depreciation is exceeding new investment, even with all of the large projects being built nationwide. The grid is facing increasing digitization and other technologies that require adapting and upgrading the existing system. Customers are requiring new services, increased levels of reliability, flexibility, and choice that are beyond the experience of traditional power companies, demands that not only create uncertainty, but add cost, demand, and complexity.

When it comes to the impact for customers, who must ultimately pay for these requirements and investments, an exacerbating factor is Avista's relatively stagnant load growth due to both declining use per customer and lackluster economic growth in most of the region.[8] This translates into nearly flat revenues, which means that new capital investments must be covered by higher customer rates. Historically, annual increases in customer loads produced new revenues that were often sufficient to cover the costs for new investment and inflation without the need to increase customer rates. Now utilities are pulled to economize and pushed to innovate, dealing with decreasing revenues and, at the same time, expensive and revolutionary new technologies such as distributed generation, battery storage technology, customer-requested technologies, and integrating intermittent renewable resources. This report intends to illustrate the way Avista's Transmission group is dealing with these challenges.

[4] Earl Simpkins, Leslie Hoard, Suva Chakraborty, Daniel Wilderotter, "Utilities Preparing for Growth: Navigating Disruption By Linking Capabilities," November 20, 2015, https://www.strategyand.pwc.com/reports/utilities-preparing-for-growth

[5] To illustrate this point, a transmission line proposed into Las Vegas was on hold for twenty years due to continuous siting opposition, including protecting the habitat of two endangered species that were not considered endangered when the project was proposed. Holland & Hart, "Transmission Siting in the Western United States," page 10, https://www.hollandhart.com/articles/Transmission_Siting_White_Paper_Final.pdf

[6] Julio Romero Aguero, "What Does the Future Hold for Utilities?" February 24, 2015, T&D World, https://www.tdworld.com/grid-innovations/distribution/article/20965183/what-does-the-future-hold-for-utilities

[7] U.S. Department of Energy, Energy Advisory Committee, "Keeping the Lights On In a New World," https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/adequacy_report_01-09-09.pdf

[8] Avista's service territory is experiencing about 1% growth, a rate that economists predict will continue for the next several years.

Introduction

Avista Utilities serves approximately 380,000 electric customers in Washington and Idaho over an extensive electric transmission system that is designed, built, operated and maintained by the Company. This infrastructure system consists of approximately 2,750 miles of high voltage transmission lines[9] crossing 30,000 square miles and bringing electric power to over 1.6 million people in Washington and Northern Idaho.[10] Avista must continually make new investments in this system in order to continue providing customers with safe and reliable electric service at a reasonable cost with service levels that meet customer's expectations for quality and satisfaction, and, at the same time, meet stringent national, regional, state, and local regulatory requirements.

In order to meet all of these requirements, the Company creates specific capital programs. These programs are developed through planning and engineering studies and analyses, as well as scheduled upgrades or replacements identified in the operations districts, within engineering groups, or based upon need. These projects undergo internal review by multiple stakeholders who help ensure that all system needs and alternatives have been identified and addressed. If proposed projects are initially approved, they go through a formal review process referred to as the Engineering Roundtable, a diverse group of engineering leaders[11] who track project requests, prioritize them, and establish committed construction package dates and required in-service dates for projects. Once a project has passed this phase of evaluation, it moves to the Capital Planning Group.

The Capital Planning Group (CPG) is a group of Avista Directors that represent capital intensive areas of the Company. Committee members are directors from a variety of business units to add a depth of perspective, though their role is to consider capital decisions from the perspective of overall Company operations and strategic goals as well as spending guidance set by senior management and approved by the Finance Committee of the Board of Directors. They develop a final budget that represents a reasonable balance among competing needs in order to maintain the performance of Avista's systems, as well as prudent management of the overall enterprise in the best interest of customers.

The purpose of this report is to provide a comprehensive overview of the approved transmission system programs, as well describe the need for capital investment, operations, and maintenance funding. But more importantly, the goal is to explain the many forces that are driving these expenditures and how Avista is attempting to balance these complex and competing needs.

[9] This includes 700 miles of 230 kV, 1550 miles of 115 kV, and 500 miles of co-owned (Colstrip) 500 kV lines.
[10] Statistics from "2018 Avista Quick Facts," https://investor.avistacorp.com/static-files/a7342b27-72cc-44d4-b9a7-b62903e999df
[11] Eleven representatives are included in this group from: Transmission and Distribution Planning, Transmission, Distribution, and Substation Design, System Protection, System Operations, Asset Management, Communications and Generation Engineering, and Transmission Services.

Avista's Transmission Capital Investments

Classification of Infrastructure Need by Investment Drivers

As a way to create more clarity around the particular needs being addressed with each capital investment as well as simplifying the organization and understanding of Avista's overall project plans, the Company has organized all capital infrastructure investments by the classification of need or "Investment Driver." The investments associated with each investment driver are briefly defined below, and in greater detail later in this report.

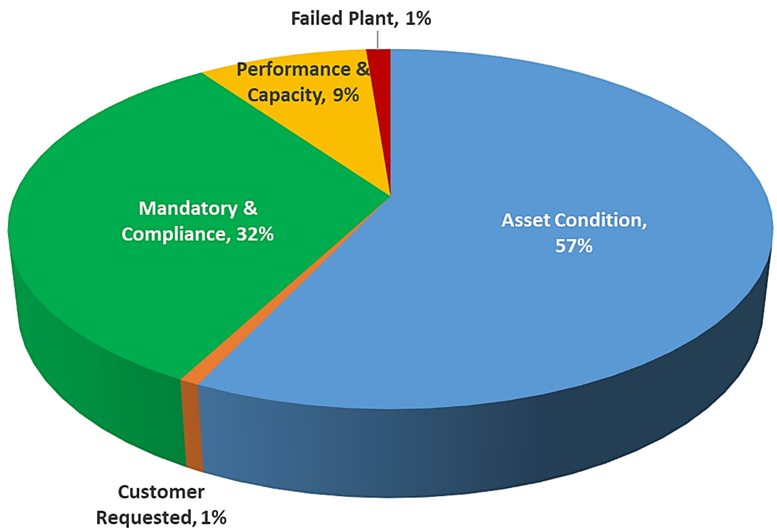


Figure 1. Total Planned Capital Expenditures by Investment Driver 2020-2024

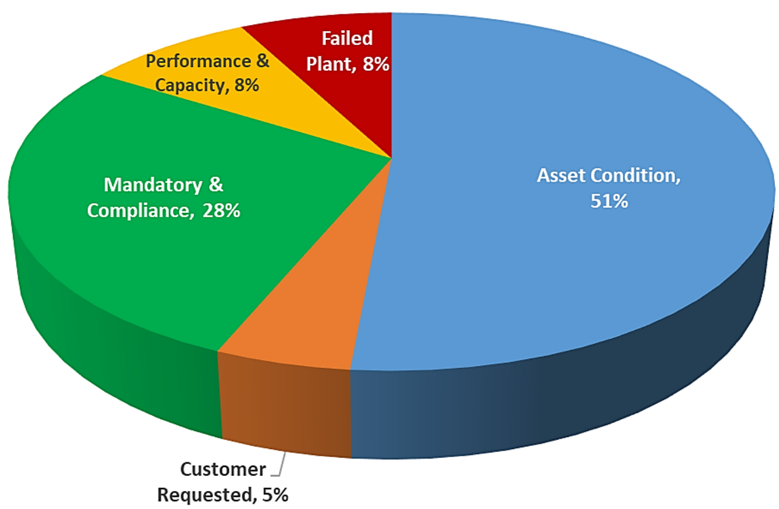


Figure 2. Historic Capital Expenditures by Investment Driver 2010-2019

Customer Requested – In the Transmission business unit, this category is primarily related to building new facilities for connecting large transmission-direct customers or to enhance their service as requested. This category is used, for example, to provide for expenses related to the requested interconnection of solar or wind projects, which are typically owned by an independent developer requesting interconnection with the Company's transmission system.

Mandatory & Compliance – The Company makes a large number of business decisions as a direct result of compliance with laws, mandatory standards, safety codes, contracts, and agreements. Examples include transmission reinforcement projects or control equipment required by NERC to preserve the reliability of the interconnected grid or contract-required work on the Colstrip transmission system that Avista co-owns with other utilities. These decisions are primarily driven by external requirements that are largely beyond the Company's control.

Failed Plant & Operations – This category sets aside funds to replace failed equipment as well as support ongoing utility operations. Typically these expenditures are the result of storm damage but are also the result of damage from vehicles accidents, animals, trees, etc.

Asset Condition – All assets have a defined useful service life. This category provides funding to replace equipment as needed so the system can continue to function effectively. This may include replacing parts as they wear out or when items can no longer meet their required purpose, as systems become obsolete and replacement parts are no longer available, to remedy safety or environmental issues, or if the condition of an asset is such that it is no longer optimizing its own performance or customer value. The Company also replaces critical equipment prior to failure in order to mitigate the risk of failure and the resulting customer impacts.

Customer Service Quality & Reliability – This category is for expenses related to meeting customer expectations for quality of service and reliability. Transmission does not have any dollars set aside under this category, as it does not typically directly impact customers.

Performance & Capacity – Programs in this category ensure that assets satisfy business needs and meet performance standards, typically defined by Company experts or in line with industry standards. Some examples include adding new substations or transmission lines to meet customer growth or to provide redundancy to reduce the potential for customer outages.

All of Avista's capital expenditures are categorized into one of these drivers, though not all of the investment driver categories are represented for each business unit. For example, investments planned for electric transmission during the upcoming five year planning cycle do not include any projects in the category of Customer Service Quality and Reliability. This is fairly common, since very few of Avista's customers receive direct transmission service. In addition, investments in electric transmission related directly to service reliability for all customers are generally driven by mandatory compliance requirements so can be found in the "Mandatory & Compliance" Driver. Note that not all of the investment drivers will be used in all of Avista's primary asset categories in every budgeting cycle, yet they remain an efficient and effective way of categorizing expenditures in a clear and transparent fashion that promotes better understanding of how and why the Company makes business decisions.

Currently Planned Capital Investments in Transmission 2020 – 2024

For the next five-year planning horizon, Avista expects to spend about $143 million in capital dollars for the Transmission side of the business, allocated across five of the investment drivers described above. These programs are summarized by investment driver below. Note that Transmission and Substations are connected by physical locations and voltage and thus share several business cases, which is noted in the text below.

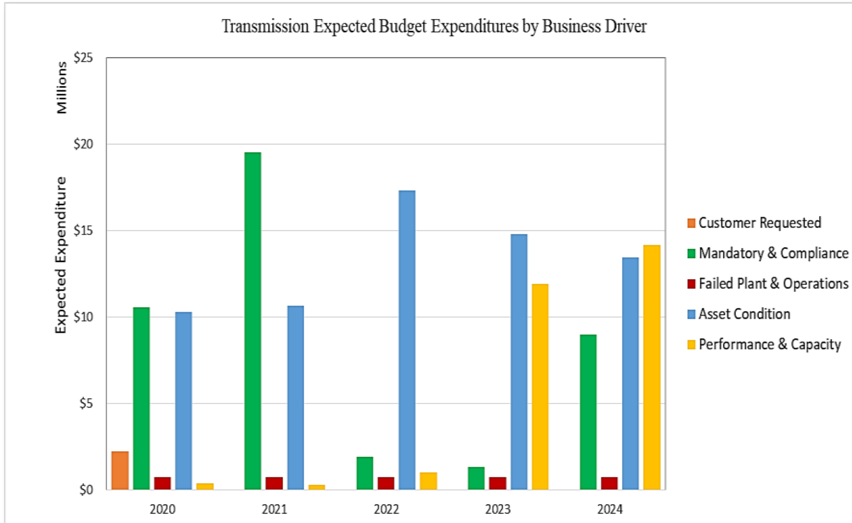


Figure 3. Capital Budget by Investment Driver

Business Driver	2020	2021	2022	2023	2024	5 Year Total	5 Year Average
Customer Requested	$2,225,000	$0	$0	$0	$0	$2,225,000	$445,000
Mandatory & Compliance	$10,550,000	$19,500,000	$1,900,000	$1,350,000	$9,000,000	$42,300,000	$8,460,000
Failed Plant & Operations	$750,000	$750,000	$750,000	$750,000	$750,000	$3,750,000	$750,000
Asset Condition	$10,309,120	$10,659,120	$17,309,120	$14,793,420	$13,443,420	$66,514,200	$13,302,840
Performance & Capacity	$400,000	$300,000	$1,000,000	$11,900,000	$14,150,000	$27,750,000	$5,550,000
	$24,234,120	*$31,209,120*	*$20,959,120*	*$28,793,420*	*$37,343,420*	*$142,539,200*	*$28,507,840*

Table 1. Planned Capital Budget by Investment Driver

Increasing Capital Investments for Infrastructure Needs

In recent years Avista has experienced an increasing demand for new and upgraded infrastructure investment. The pattern of investments made by the Company during this time period are similar to that of the industry, as shown in Figure 4. Utilities across the nation are responding to the same issues mentioned earlier: the demand to replace an increasing amount of infrastructure that has reached the end of its useful life, ever increasing regulatory compliance requirements, and the need for reliability and technology investments necessary to build the integrated energy services grid of the future. Avista's investments in electric

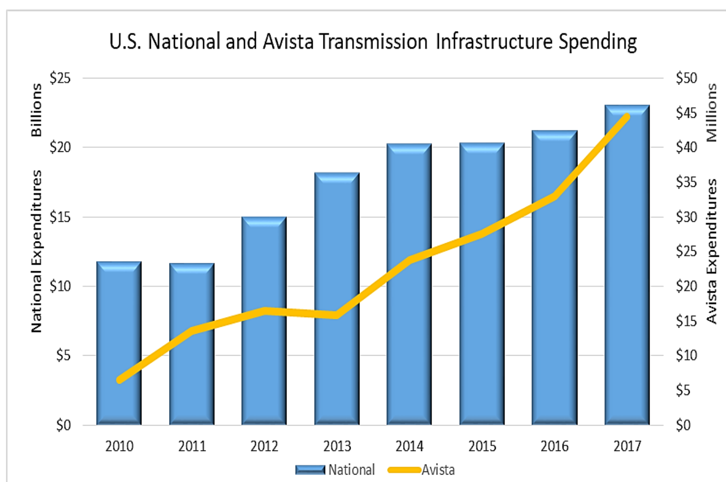


Figure 4. Avista's Transmission Spending Compared to National Levels [12]

[12] National data obtained from EEI: https://www.eia.gov/todayinenergy/detail.php?id=34892 (only available through 2017)

transmission also reflect the Company's adoption of asset management-based approaches for assessing infrastructure needs and developing strategies and programs to optimize the lifecycle value of the Company's transmission system.

Customer Requested

Customer requested projects are triggered by non-Company applications for new transmission-level connections, line extensions, transmission capacity, or system reinforcements. For example, the Company may be obligated to construct a distribution substation with an associated transmission line extension in order to meet the requested new load requirements of an industrial or large commercial customer, large subdivision or business park. Other situations may involve a requested transmission interconnection with a neighboring utility or a customer-owned generation project. In the current five year budget period, this category includes an interconnection required to integrate Rattlesnake Flat Wind Project, being built by an independent developer.

Customer Requested	*2020*	*2021*	*2022*	*2023*	*2024*	*5 Year Total*
Rattlesnake Flat Wind Integration	$2,225,000	$0	$0	$0	$0	$2,225,000

Table 2. Planned Capital Budget for Customer Requested

Rattlesnake Flat Wind Integration

Avista issued a request for proposal in June 2018 for additional renewable energy. An external company, Clearway Energy Group, was selected to provide that energy. They are developing a wind power facility known as Rattlesnake Flat Wind, which is projected to provide Avista with approximately 50 average megawatts of renewable energy, or as much as 144 megawatts of nameplate wind capacity, under a 20-year power purchase agreement with deliveries beginning in 2020. This project, including 90 wind turbines and associated facilities, is located on approximately 23,000 acres in Adams County, Washington. This project requires significant upgrades to Avista's existing infrastructure, including transmission line rebuilds, an additional new switching station, and existing substation upgrades in order to handle the new generation. This new energy resource benefits Avista customers in two primary ways: providing customers with additional renewable energy and the required transmission upgrades enhance the strength and resiliency of the existing infrastructure. *This business case is part of the same Substations business case.*

Mandatory & Compliance

The investments in transmission infrastructure made under this category are investments driven typically by compliance with laws, rules, and contract requirements that are external to the Company and outside of Avista's control. Many of these are the result of NERC Reliability Standards related to planning and operations, where failure to comply may result in monetary penalties of up to $1 million per day per infraction. In addition, imbedded within every transmission construction project are environmental compliance costs. Other examples in this category include leases on tribal lands, contractual obligations, and expenditures related to implementing safety standards. Other examples in the current budget cycle of projects required by NERC mandates include the new Saddle Mountain and West Plains Reinforcement Plan and upgrades to the Ninth and Central Substation, described below.

Mandatory & Compliance	2020	2021	2022	2023	2024	5 Year Total	5 Year Average
Saddle Mountain 230/115kV Station (New) Phase 1	$3,300,000	$0	$0	$0	$0	$3,300,000	$660,000
Saddle Mountain 230/115kV Station (New) Phase 2	$300,000	$10,700,000	$0	$0	$0	$11,000,000	$2,200,000
Spokane Valley Transmission Reinforcement	$300,000	$2,250,000	$0	$0	$0	$2,550,000	$510,000
Transmission Construction - Compliance	$2,850,000	$3,500,000	$0	$1,200,000	$0	$7,550,000	$1,510,000
Transmission NERC Low-Risk Priority Lines Mitigation	$2,800,000	$2,700,000	$1,000,000	$0	$0	$6,500,000	$1,300,000
West Plains New 230kV Substation	$0	$100,000	$500,000	$0	$0	$600,000	$120,000
Ninth & Central Sub - New 230kV Transformation	$0	$0	$150,000	$150,000	$9,000,000	$9,300,000	$1,860,000
Westside 230/115kV Station "Brownfield Rebuild"	$500,000	$250,000	$250,000	$0	$0	$1,000,000	$200,000
Road Relocations	$500,000	*TBD*	*TBD*	*TBD*	*TBD*	$500,000	$500,000
	$10,550,000	*$19,500,000*	*$1,900,000*	*$1,350,000*	*$9,000,000*	*$41,800,000*	*$8,460,000*

Table 3. Planned Capital Budget for Mandatory & Compliance

Saddle Mountain 230/115 kV Station


Saddle Mountain Substation under construction

Avista System Planning and related outside entity studies determined that the western portion of the Avista's existing system is not meeting NERC performance requirements during heavy load scenarios. The Saddle Mountain project, undertaken in two phases, will allow Avista to continue serving Company load in the Big Bend Area near Othello while eliminating pressure on the Grant County Public Utility District system. This problem will be solved by constructing a new 230/115 kV substation where the Walla Walla–Wanapum 230 kV and the Benton–Othello 115 kV transmission lines cross. This new sub will consist of a three-terminal 230 kV double bus double breaker configuration, a 250 MVA[13] 230/115 kV auto-transformer, four 115 kV terminals, rebuilding the existing associated aging 115 kV transmission lines, and building ten miles of new 115 kV transmission. This project will greatly improve the reliability of transmission in the area and

[13] MVA refers to the amount of power output a transformer is capable of delivering at a specified voltage under normal operating conditions without exceeding internal temperature limitations. A 250 MVA transformer is a very large transformer.

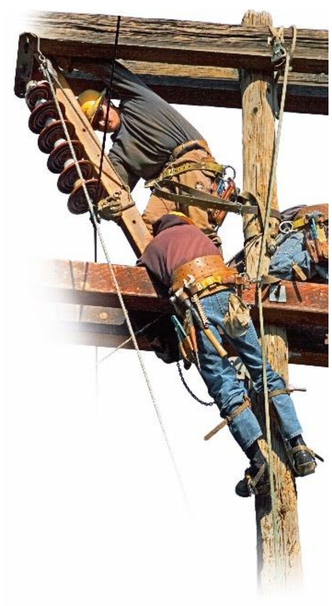
remove the current single point of failure situation which could create widespread outages. It also mitigates potential thermal overloading and voltage issues in this area. *This business case is part of the same Substations business case.*

Spokane Valley Transmission Reinforcement

Site of new Irvin Substation in Spokane Valley

This project reinforces transmission in the Spokane Valley area, spurred by load growth in the region as well as compliance with the NERC TPL-001-4 Reliability Standard[14] which requires each utility to ensure that their system is robust enough to operate reliably over a broad spectrum of system conditions and under a wide range of possible contingencies. Avista system studies identified this area as requiring additional reinforcement in order to be in compliance with the NERC standard about ten years ago, and the Company has been working on it since that time. This long term project requires the construction of a new switching substation (Irvin) off of Trent Avenue. It also includes rebuilding 4.4 miles of the Beacon-Boulder #2 115 kV transmission line, building 1.75 miles of transmission for the new Irvin-Opportunity 115 kV tap, constructing 2.2 miles of 115 kV transmission from the new Irvin sub to the existing Millwood sub, and installing circuit breakers to handle the changes at the existing Opportunity Sub. This work will not only address compliance issues, but will make the transmission system in this urban area more stable and reliable, specifically for serving large industrial customers. *This business case is part of the same Substations business case.*

Transmission Construction - Compliance



This program covers the transmission rebuild work, line reconductoring, and new construction outlined in the Corrective Action Plan developed under NERC Reliability Standard TPL-001-4.[15] It has 8 requirements and 57 sub-requirements related to planning and analysis, including the requirement for robust system models to determine system stability, voltage levels and system performance under various scenarios. This Standard also contains spare equipment regulations, load loss requirements and mitigation, a number of system protection requirements, and more. In addition, when Avista's system planning studies indicate any kind of problem that could arise in the transmission system, it must be remedied within specific timeframes. The Transmission Construction - Compliance Program provides funding to mitigate any identified reliability issues in order to remain in compliance with NERC requirements.

[14] NERC Standard TPL-001-4: http://www.nerc.com/files/tpl-001-4.pdf requires the Company to avoid load loss and have circuit breakers with sufficient interrupting capability for faults.
[15] NERC TPL-001-4: https://www.nerc.com/pa/Stand/TPL0014RD/Implementation%20Plan%20for%202010-11_TPL-001-4.pdf and http://www.oasis.oati.com/PPW/PPWdocs/PacifiCorp"s_NERC_TPL-001-4_Standard_Overview_R1.pdf

Transmission – NERC Low Risk Priority Lines Mitigation

Placing conductor using a helicopter (left) and by hand (right)

This program addresses mitigation required on Avista's "Low Risk" 115 kV transmission lines and brings these lines into compliance with NERC requirements[16] and National Electric Safety Code (NESC) minimum transmission line clearance values.[17] These code minimums have also been adopted into the State of Washington's Administrative Code (WAC).[18] "Low risk" lines are those ***not*** connecting Avista generation to primary load. Investments made under this program provide funding to reconfigure insulator attachments, rebuild existing transmission line structures, or remove earth from beneath transmission lines to mitigate ratings/sag discrepancies found between the line designs and actual field conditions in order to provide minimum clearance requirements for worker and public safety.

West Plains New 230 kV Substation

Planning studies of the Spokane area transmission system revealed specific transmission performance issues which will occur within the next five to ten years. Note that these performance issues have a significant potential to exceed NERC reliability standards, designed to prevent cascading outages and ensure the integrity of the interconnected system.[19] System studies identified at least seven NERC thermal or voltage limit violations including:

- Inadequate 230/115 kV transformation provided by the four existing substations in the area, especially in the case of system events. In addition, the existing transformers are reaching maximum thermal capacity now and in time will exceed it.
- Related 115 kV transmission lines are running at 96% to 135% of their rated capacity during specific contingency scenarios.[20]

These issues are expected to intensify with projected growth in this region. In addition, some of the transmission lines in the Spokane area are radial lines, requiring manual intervention in order to restore

[16] North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings," http://www.nerc.com/pa/rrm/bpsa/Pages/Facility-Ratings-Alert.aspx
[17] National Electric Safety Code Electrical Safety Requirements, https://www.usbr.gov/ssle/safety/RSHS/sec12.pdf
[18] Washington State Legislature WAC 296-46B-010: https://apps.leg.wa.gov/wac/default.aspx?cite=296-46B-010
[19] NERC Reliability Guidelines, September 2018, https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_Methods_for_Establishing_IROLs.pdf
[20] This includes the Northwest-Westside 115 kV, the Bell-Northeast Waikiki Tap 115 kV lines, and the lines from the Beacon and Westside substations.

service to customers after a fault, with a total customer exposure of up to 31 miles. In order to manage this situation and remain in compliance with NERC directives, the Company is constructing a new 230 kV substation in the West Plains area. This location provides also an opportunity to interconnect with Bonneville Power Administration (BPA) to strengthen Avista's grid and add additional operating flexibility. The West Plains Substation is designed to mitigate all of the identified system deficiencies, including adding 500 MVA of transformer capability and redundancy to the transmission system in this area. *This business case is part of the same Substations business case.*

Ninth & Central 230 kV Station & Transmission

The Spokane area transmission system is heavily dependent upon the Beacon Substation, which is networked to the Bell Substation as well as eight 115 kV transmission lines. In order to reduce this dependency, create redundancy, enhance customer reliability, and remain in compliance with mandatory standards, Avista is upgrading the infrastructure of the Ninth & Central Substation to take on more of this load. The Company is adding new 230 kV infrastructure to accommodate a 230/115 kV auto-transformer and associated circuit breakers, and putting in place additional transformer capacity for the Spokane transmission system. This project will also build eight miles of new transmission lines, utilizing existing 115 kV corridors in a double circuit configuration in order to fortify the Spokane area transmission system. This project significantly strengthens and adds resiliency to the electric system. It is scheduled to begin in 2022. *This business case is part of the same Substations business case.*

Westside 230/115 kV Substation "Brownfield Rebuild"[21]

The Westside 230 kV Substation Rebuild is major project made necessary because the existing Westside #1 230/115 kV transformer exceeded its applicable facility rating during heavy summer loads, which led to the cascading failure of the Westside #2 230/115 kV transformer. This situation created a compliance risk with NERC TPL-001-4, a standard which defines system planning performance and has very specific requirements around equipment exceeding ratings as well as shedding customer load.[22] The previous transformers were underrated for their use and not up to current design standards. In addition, air switches and breakers at this substation had begun to fail, the protection equipment needed to be updated and upgraded, oil containment provisions needed to be made, and site security issues had to be addressed.

New Westside #1 230/115 kV transformer being placed

[21] A "Brownfield" project refers to a project that takes place on land that has been occupied by a "permanent" structure at some point, requiring demolishing or renovating a prior structure, versus a "Greenfield" project that will be built in a place where nothing had been built before.
[22] NERC TPL-001-4, http://www.nerc.com/files/tpl-001-4.pdf

Engineers determined that the existing old transformers (one was manufactured in 1976 and one in 1958) must be replaced with 250 MVA rated transformers that meet current performance, efficiency, and safety standards. In addition, the 230 kV and 115 kV buses at the substation will be upgraded to a double bus double breaker configuration to provide adequate redundancy. Along with the transformer change-outs, numerous other equipment replacements are required to have the capacity needed from this station. This project, started in 2016, should be completed during the current budget cycle. *This business case is part of the same Substations business case.*

Road Relocations

Avista is required to move its infrastructure in response to municipalities, counties, and state-level agency projects to rebuild or realign roads, streets and highways, as well as other state, county, and city infrastructure projects. This work must be performed at the Company's expense.

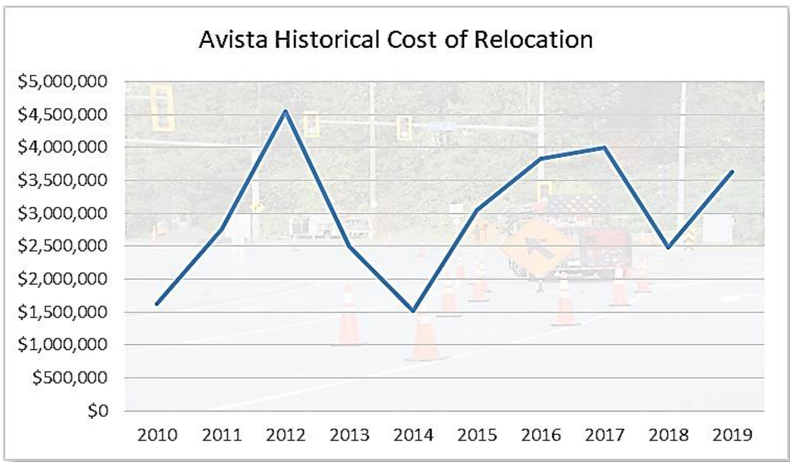
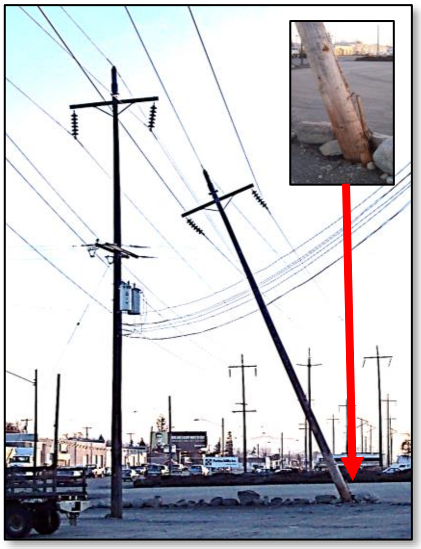


Figure 5. Facilities Relocation Capital Expenditures

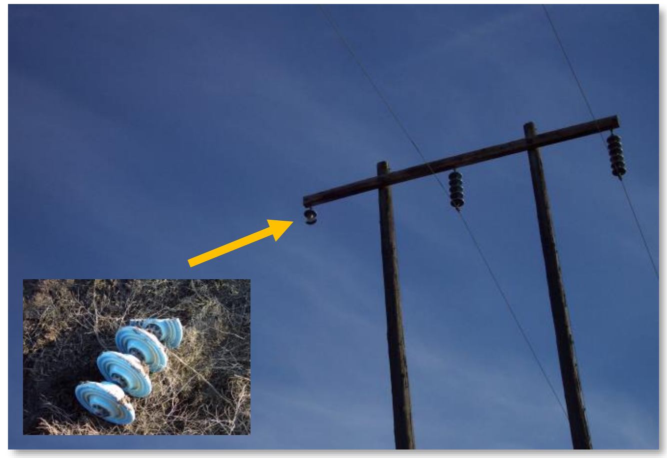
While Avista may have some latitude to negotiate the timing of the construction, it has no choice with regard to removing and relocating its infrastructure and paying all of the associated costs. Avista also works with the Departments of Transportation in both states to renew and maintain crossing and encroachment permits, which at times also necessitates the Company moving its infrastructure at its own expense. 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, and overhead conductors. These costs are increasing over time as jurisdictions in which Avista must perform the work are becoming more and more demanding in their requirements, including calling for additional work as a condition of construction such as extensive landscaping, which increases costs. As shown in Figure 5, these costs are also highly variable from year to year and difficult to predict.

Failed Plant & Operations

Transmission investments in this category are primarily the result of storm damage to the Company's transmission system or the funding needed for failed or damaged equipment. When this happens, the Company must quickly respond to replace the infrastructure in order to ensure



the continuity of service to customers. Common causes of damage to the system include major wind events, lightning, fire, snow and ice, downed trees/vegetation, wildfires, human or animal caused damage (left), and equipment failure (above). Other failures include the unanticipated loss of assets due to a range of factors including age and condition. *Planned pending for this category is shared between Distribution, Substations, and Transmission.* Transmission's share of this spending is shown in Table 4.



Failed Plant & Operations	2020	2021	2022	2023	2024
Transmission - Minor Rebuild: Storm	$750,000	$750,000	$750,000	$750,000	$750,000

Table 4. Planned Capital Budget for Failed Plant & Operations

Asset Condition

Investments in transmission infrastructure related to Asset Condition are required to replace assets based on established asset management principles and strategies adopted by the Company, which are designed to optimize the overall lifecycle value of the investment for customers. This category includes rebuilds related to aging or end-of-life assets and upgrades related to design, safety, or construction standards. It also includes specific technology upgrades related to interconnected system reliability and cybersecurity. The Company closely monitors outages and replaces equipment that is either impacting customer service or is likely to do so. Some equipment is so critical that it cannot be allowed to fail. When this equipment reaches an age when it is close to or at the end of its useful life, the Company preventively replaces it to maintain reliability and acceptable levels of service.

Asset Condition	2020	2021	2022	2023	2024	Five Year Total	Five Year Average
SCADA - SOO and BuCC	$2,100,000	$920,000	$700,000	$700,000	$700,000	$5,120,000	$1,024,000
Substation Rebuild Program	$18,750,000	$18,250,000	$24,950,000	$25,050,000	$25,125,000	$112,125,000	$22,425,000
Transmission Major Rebuild - Asset Condition	$7,550,000	$7,500,000	$14,000,000	$10,000,000	$10,000,000	$49,050,000	$9,810,000
Transmission - Minor Rebuild: Non-Storm	$909,120	$1,659,120	$1,659,120	$1,843,420	$1,843,420	$7,914,200	$1,582,840
	$29,309,120	***$28,329,120***	***$41,309,120***	***$37,593,420***	***$37,668,420***	***$174,209,200***	***$34,841,840***

Table 5. Planned Capital Budget Based on Asset Condition

SCADA – SOO and BuCC

Above: Post Street control panels
Right: Rathdrum Substation panel house

Supervisory Control and Data Acquisition (SCADA) and the System Operations Office and Backup Control Center (BuCC) provide the capabilities required to achieve compliance with numerous reliability standards and requirements.[23] This business case replaces and upgrades existing control center telecommunications and computing systems for these systems as they reach the end of their useful lives, require increased capacity, cannot be upgraded due to outdated technology, or are necessitated by other requirements, including NERC reliability standards, system growth, and external projects (e.g. Smart Grid). This type of work includes hardware, software, and operating system replacement and upgrades. These control systems provide real-time visibility, situational awareness, and control of Avista's electric and gas systems and are critical to Company operations. These expenditures prevent the degradation of these capabilities due to lack of capacity, capability, or aging systems that would present increased safety and significant compliance risk. These specialized systems are critical in ensuring continued operation and customer service. *This business case is shared and is part of the same Substations business case.*

Substations Rebuild Program

Work at the Kooskia Substation

Replacing and upgrading major substation apparatus and equipment as it approaches end-of-life or becomes obsolete is a routine part of Avista's maintenance strategy. Replacing this equipment before it fails is necessary to maintain the safe and reliable operations of the transmission and distribution systems, and substations are at the heart of these interconnected systems. Investments in this program include updating old equipment to meet new safety and construction standards, installing communications systems, and replacing or upgrading other equipment such as

[23] For the electrical system these include NERC standards BAL, COM, CIP, EOP, INT, PER, PRC, TOP, and VAR. BAL = Balancing Authority Control, COM = Interpersonal Communications among business units within a utility, CIP = Critical Infrastructure Protection, EOP = Emergency Preparedness & Operations, INT = Interchange Scheduling & Coordination, PER = Personnel Training Requirements, PRC = Protection & Control Systems, TOP = Transmission Operations Requirements, and VAR = Voltage and Reactive capabilities. For more information about any of these requirements, please see: https://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx

circuit breakers, reclosers, switches, capacitor banks, transformers, and regulators. In addition, supporting equipment like relays, meters, batteries, panel housing, and fences must be replaced periodically to ensure the full functionality and safety of Avista's substations. *Please note that capital allocated for this program is shared between Transmission, Substations, and Distribution but the entire amount is shown here as the Transmission function creates and manages this program.*

Transmission Major Rebuild – Asset Condition

Investments made under this program rebuild existing transmission lines based on overall asset condition. "Condition" is measured by useful life or the number of condition-related outages. Factors such as operational issues, ease of access during outages, and need to add automation or communications equipment may be included in the type of spending in this category. Replacing old and worn-out poles and cross-arms and other associated transmission equipment, help guard against increasing risk for more failures and outages. Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations. It is split between the 115 kV system and the 230 kV system.

Working on the Benewah – Moscow 230 kV line

Transmission Minor Rebuild – Non-Storm

Expenditures under this business case typically cover work found during wood pole and aerial patrol inspections as well as replacement of air switches that have malfunctioned, failed, or reached end-of-life. During inspections, various issues are discovered regarding the condition of assets. This can include rotten poles, broken or split crossarms, broken conductor, guy or ground wire missing or damaged, encroachments, and the like. At times these issues are discovered based on outages. Transmission engineers evaluate each situation and prioritize them based on customer impact, safety and fire risks to allocate funding in this category.

Failed Conductor

Performance & Capacity

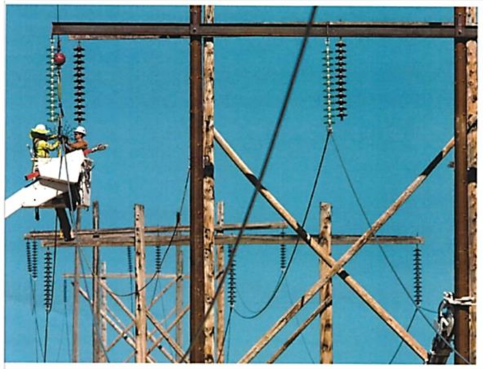
These investments support additions of new substations or reinforcement of existing substations that require supporting transmission upgrades or additions. Investments are typically requested by Transmission Planning or Operations. Funding in this category can be used to increase reliability to existing substations by providing redundant transmission feeds to radially-fed substations, reducing the potential for customer outages. Another common example is an identified operational or equipment issue that is leading to increasing outages or safety concerns. The issue that hits the "capacity" aspect of this driver is customer load growth or load changes. Currently there are two Transmission programs in the Performance and Capacity category in the upcoming budget cycle which will be described below.

Performance & Capacity	*2020*	*2021*	*2022*	*2023*	*2024*	*Five Year Total*	*Five Year Average*
Cabinet Gorge 230kV Add Bus Isolating Breakers	$100,000	$1,500,000	$0	$0	$0	$1,600,000	$320,000
Transmission New Construction	$0	$0	$400,000	$11,250,000	$12,900,000	$24,550,000	$4,910,000
	$100,000	*$1,500,000*	*$400,000*	*$11,250,000*	*$12,900,000*	*$26,150,000*	*$5,230,000*

Table 6. Planned Capital Budget Based on Performance & Capacity

Transmission New Construction

Investments made under this program support the addition of new substations due to load growth in a particular area or to reinforce existing substations which require new transmission. Funding in this category is typically related to increased performance, system stability, customer load growth, or service reliability. Funding in this category is also used to provide redundant transmission feeds to radially-fed substations, reducing the potential for customer outages. This program is managed through the joint efforts of Avista's Transmission Design & Engineering, Substations, Operations, and Transmission Planning groups, from which the requests for upgrades or additions are initiated.



Transmission O&M Expenditures

Avista typically spends about $13 million annually in operations and maintenance work required to sustain its electric transmission system. Unexpected expenses are always a possibility, but the Company has routine maintenance programs in place to insure that those occurrences are as few as possible. All of Transmission's O&M programs play a role in ensuring reliable service. Programs such as aerial and ground patrols to identify potential problems, fire retardant to protect poles from wildfire, foundation work to maintain the integrity of structures, and vegetation management around lines and on associated roads and trails to allow access for maintenance and repair all work to help prevent outages.

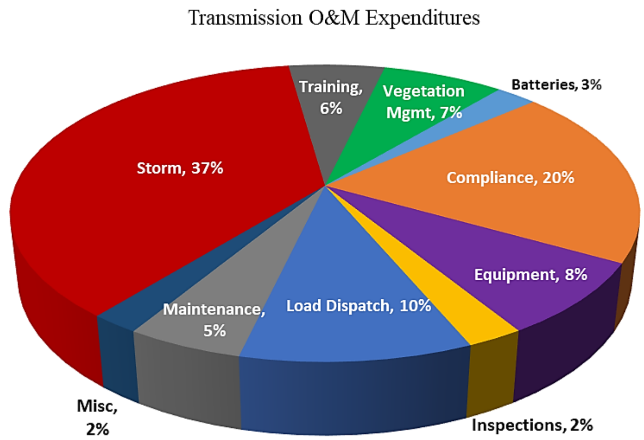


Figure 6. Typical Transmission O&M Expenditures

As can be seen in Figure 6, storms take a significant toll on transmission equipment, though these expenditures can vary widely from year to year. Compliance related expenditures are also a major factor. Compliance category requirements can include interconnection work with neighboring utilities, Columbia Grid and Western Electricity Coordinating Council (WECC) regulations, and meeting requirements from the North American Electric Reliability Corporation (NERC) that impact equipment maintenance requirements, security measures, training, and planning among other elements. Compliance also includes work related to the Colstrip transmission system as required by Avista's contract with the other line owners. Other Transmission O&M expenditures include performing aerial and ground inspections of Avista's transmission system, ensuring adequate vegetation management in all transmission rights-of-way, installing, replacing, and maintaining air switches and other system control devices, and providing the manpower and equipment for System Operations, System Planning, the Supervisory Control and Data Acquisition (SCADA) and Energy Management Systems (EMS), System Protection, Reliability, and Distribution Operations.

The Transmission group is closely involved with the Substation and Generation groups, as transmission structures and equipment directly connect with both generating sources and the substations which direct the power around the system. Thus some of the projects listed in this report are shared with other business units within the Company (as noted where each business case is described above).

More details about the Transmission team, their work, equipment used, regulations, and a glossary of terms are all available in the 2018 Transmission Infrastructure Report located on the Company's intercompany website[24] or upon request.

[24] Avista Avenue, "Tools & Resources" tab, "Avista Infrastructure Plans" heading as "Transmission Plan."

Conclusion

Avista's transmission infrastructure programs are thoughtfully developed, analyzed, optimized, adjusted, and re-analyzed as appropriate to ensure that Avista delivers cost effective value for customers while meeting all legal and mandatory requirements. As the Company moves forward with new programs such as Wildfire Resiliency, many of Transmission's programs will be impacted. For example, it is likely that new technology including LIDAR,[25] infrared imaging, drones, and virtual inspections will create significant change for the current inspection practices and may increase costs, but will also provide a far more robust picture of the state of Avista's transmission system. The Wildfire Resiliency project is also driving a change to the Company's wood pole fire protection programs, which have used an effective fire resistant paint for poles until now, but which will migrate toward a fire-resistant mesh system that lasts far longer.

Avista's Transmission is facing other long-term issues being felt by utilities across the nation. Aging structures and equipment create increasing risk of failure and resulting impacts to customer reliability, just as customers are demanding higher and higher levels of service. Determining the priority of replacement is also a challenge, as Transmission competes for limited funding with other Company business units facing their own aging equipment challenges and requirements. State and federal regulations increase every year; sometimes hundreds of new regulations are introduced within a short span of time, and compliance is required; it is not an option. Most of these new regulations have an impact on the bottom line in one way or another, and add ever-increasing levels of complexity to the way the Company operates.

The Transmission team is dedicated to facing all of these challenges in the most efficient, cost-effective, and thoughtful way possible, as demonstrated by the programs described here. As these programs change and adapt to whatever comes next, be it new regulations, state policies, failed equipment, or even a pandemic, the focus of this group will remain unchanged. They will continue to operate and manage Avista's grid successfully and in the long-term best interests of customers.

[25] LIDAR is a surveying system that uses a laser to create 3-D images of landscapes, making it invaluable for identifying vegetation management issues.

Avista Utilities

Natural Gas Infrastructure Plan

2020

AVISTA

Table of Contents

Table of Figures

Table of Tables

Executive Summary

The Natural Gas group is facing a lot of changes in the next few years, many related to processes and requirements, and many outside of the Company's control. All of these changes will create direct budget impacts.

This sector faces heavy scrutiny across a wide spectrum of environmental issues including air and water quality and greenhouse gas emissions from the Environmental Protection Agency, the Federal Energy Regulatory Commission, state agencies, state legislatures, and the public at large.

Safety and operations regulations are also evolving at the state and federal level. The United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) establishes national policy, sets and enforces standards, educates, and conducts research to prevent incidents. Currently there are discussions underway at both the PHMSA and at the Washington Utilities and Transportation Commission to clarify the definition of transmission versus distribution level pipelines. Today transmission high pressure supply lines are designated as those operating above 20% yield strength.[1] Under this definition, Avista has 76 miles of transmission pipe (the Kettle Falls system) and 270 miles of high pressure distribution (supply) pipe in Washington. If this classification is changed, all 346 miles of the Company's natural gas pipeline would have to be operated as transmission. Transmission pipelines require a significantly higher level of maintenance, integrity management, and inspections to operate. Thus this change would impact Avista's Capital and O&M budgets and have a significant impact on technical and field resources as well. The Company is awaiting a decision on this issue.

Clearwater Paper Gas Service

As another example, Avista is required to relocate facilities to accommodate state, county and municipal infrastructure projects, often transportation related, and which must be done at the Company's expense. The schedules for these moves are not always provided with enough notice to be included in Avista's budgets. In addition, there are increasing restoration requirements. In Oregon, for example, specialized fill is required for trenches, and the entire roadway must sometimes be resurfaced rather than restoring the asphalt directly over the trench itself as we do in most other districts. Extensive

[1] Yield strength is an indication of the minimum level of internal stress a pipeline can experience and maintain integrity. https://sciencing.com/calculate-smys-5332072.html

landscaping, new sidewalks, a large number of traffic control measures, and the like are becoming more commonplace when these requests are made, all of which hit Avista's Natural Gas budget, often unexpectedly, and without Avista's choice or control.

Adding additional complexity, the gas business has been particularly hard hit by workforce issues. The industry is experiencing challenges in attracting and retaining the experienced workforce needed for

gas construction work. As mentioned, this business requires very specialized skills. Over the past few years, lower gas prices led to the layoff of thousands of employees who have moved on to other industries.[2] Qualified workers are hard to come by across the industry. Avista and its contractors are facing this problem as well. Not only is it difficult to attract workers to this business, it is difficult to keep them, and the cost of doing so continues to rise. Increasing competency requirements and regulatory obligations are also causing workers to move to other types of construction activities where these requirements don't exist and the work is easier.

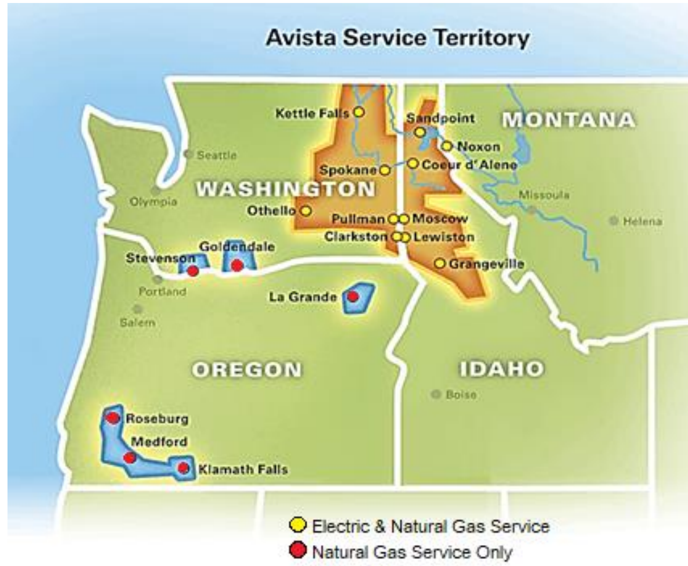
This report attempts to document the business investments that are known and why they are important to serving customers and providing safe, reliable natural gas service and infrastructure. It describes Avista's work to manage through these issues by developing Capital and O&M programs that meet customer and regulatory requirements while attempting to be as cost effective and efficient as possible. The primary focus is always safety, as there is nothing more important to the gas industry, and to Avista, than the safety of customers, employees, and the communities served.

For more information about Avista's natural gas business, the issues facing the natural gas industry, the Company's natural gas safety and public outreach programs, and a glossary of terms, please see the Avista's Natural Gas Infrastructure Plan 2019, available on the Company's internal website[3] or by request.

[2] Since 2014 more than 440,000 jobs were lost in the oil and gas industry. Irina Slav, "Recovery? The Oil and Gas Industry is Hiring Again," USA Today, November 2, 2017, https://www.usatoday.com/story/money/energy/2017/11/02/recovery-oil-and-gas-industry-hiring-again/819773001/

[3] Go to the Avenue, Tools and Resources tab, under "Avista Infrastructure Plans"

Introduction



Avista owns and operates nearly 8,000 miles of natural gas distribution mains serving about 350,000 customers across Washington, Idaho, and Oregon.[4] The natural gas Avista purchases can be transported via six connected pipelines on which the Company holds first contractual transportation rights, with access to both U.S. and Canadian supplies.[5] In 2019 the Company delivered about 345 million therms of retail natural gas and over 504 million therms of wholesale natural gas, generating revenues of approximately $288 million dollars.[6] Avista's electric generation mix is also heavily dependent upon natural gas as a fuel. In a typical year, the Company's electricity portfolio is comprised of about 49% hydro, 35% natural gas-fired, 9.5% coal, 4.5% wind, and 2% biomass generation.[7] Natural gas is a significant part of Avista's business on both the electric and the gas side, allowing us to serve customers energy needs in diverse and cost effective ways.

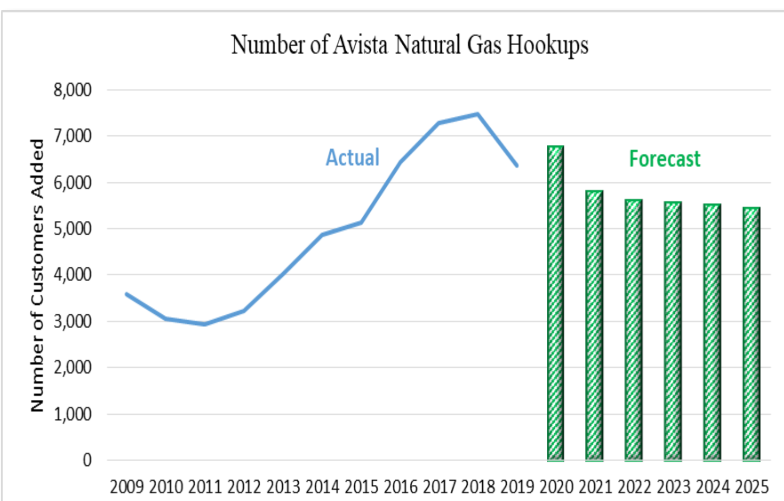


Figure 1. Avista Natural Gas Hookups

The Company has experienced steady growth in natural gas customers, though hookups were down in 2019 due to the expiration of the Washington Line Excess Allowance Program (LEAP). This program helped customers receive an allowance to help pay for connecting to Avista's natural gas system. The forecast over this budgeting period indicates an average of approximately 5,800 hookups per year going forward.

[4] 2019 Avista Quick Facts, https://www.myavista.com/about-us/our-company/quick-facts
[5] Oregon Public Utility Commission UG-325, Direct Testimony of Scott L. Morris, page 3, https://edocs.puc.state.or.us/efdocs/HTB/ug325htb154322.pdf. Note that typically approximately 25% of the Company's supply comes from the U.S. with the remaining 75% coming from Canadian sources.
[6] From Avista's 2019 Quick Facts. Note that electric revenues were approximately $800 million during the same time period.
[7] Avista 2017 Electric IRP (the most current as of this printing), https://www.myavista.com/about-us/our-company/integrated-resource-planning, select "Electric Integrated Resource Plan (PDF)," page 4-1. For more information about Avista's natural gas generating resources, please see Appendix A.

Avista's Natural Gas Capital Investments

Classification of Infrastructure Need by Investment Drivers

As a way to create more clarity around the particular needs being addressed with each capital investment, as well as simplifying the organization and understanding of Avista's capital spending, the Company has organized its capital infrastructure investments by the classification of need or "Investment Driver." The need for investments associated with each investment driver is briefly defined below. Please note that all dollar figures shown in this report represent expenditures on a system wide basis.

1. ***Customer Requested*** – This category is set aside primarily for connecting new customers or enhancing their service as requested. Typical projects include installing gas facilities in new housing or commercial developments or moving equipment at a customer's request, for instance if they are building a deck or addition that conflicts with the current location of their gas meter.

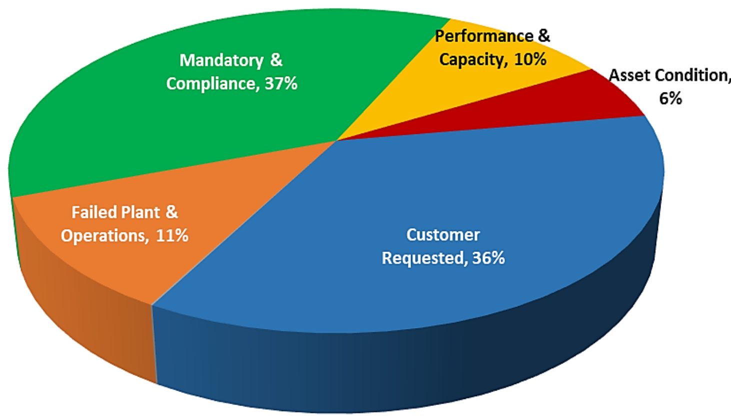


Figure 2. Avista Total Historic Actual Capital Spending by Investment Driver

2. ***Mandatory & Compliance*** – This is a driver related directly to compliance with laws, regulations and agreements, areas for which the Company has little or no discretion in spending. This category also applies to national safety codes and regulations. Projects in the Mandatory and Compliance category may include the obligation to relocate facilities based on road construction projects, environmental compliance, and replacement of pipeline protection systems based on national code requirements. Compliance expenditures are often related to safety. The Gas group's laser focus on safety and compliance leads this to be a primary spending category.

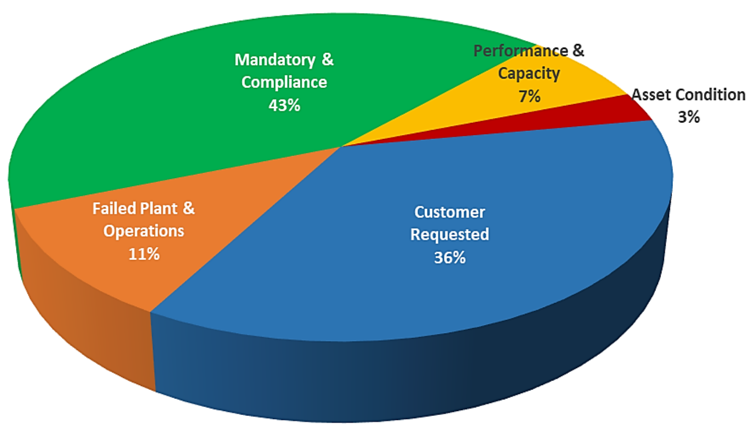


Figure 3. Avista Projected Five Year Budget for Gas Capital Expenditures by Investment Driver

3. ***Failed Plant & Operations*** – This category of spending replaces failed equipment, typically related to storm damage or the unexpected failures of capital assets. In Gas, this funding is under a program called Non-Revenue, which tends to be reactionary (unplanned) work such as responding to leaks, damaged equipment, dig-ins, etc. The forecasted budget levels for this category are based on historical spend.

4. ***Asset Condition*** – This driver is focused on replacing assets at the end of their useful service life. Avista uses an analytical approach to asset replacement which includes asset criticality, inspections, and optimization of life cycle costs. Gas pipeline condition (and associated equipment) is directly related to customer and employee safety, so the equipment is carefully monitored and replaced as necessary. Laws and regulations are also a factor. For example, regulator stations are required by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) to be kept in very specific condition.[8] Federal Code also requires that Avista maintain an active program related to asset condition, including evaluating risk related to gas facilities and mitigating any such risks, such as unconventional or obsolete pipe, deteriorated pipe and associated equipment, or corrosion issues.

5. ***Customer Service Quality & Reliability*** – This category of spending helps Avista meet customers' expectations for quality of service and reliability. Programs in this category include the Washington and Idaho advanced meter infrastructure (AMI) in the Distribution business unit budget or customer facing technology programs implemented by Enterprise Technology. There are no specific funds set aside in the gas business unit for this category in the current budget cycle.

6. ***Performance & Capacity*** – This driver helps ensure that assets satisfy business needs and meet performance and reliability standards. In the gas business, many of the projects in this category are related to reinforcing gas service as customer loads grow and change. The goal of these programs is to ensure that customers have an adequate supply of natural gas to keep them warm on the coldest days through effectively managing the gas delivery system. This category also includes technology that allows monitoring and controlling the system more proficiently for safety and reliability.

Star Road City Gate

[8] DOT Code of Federal Regulations Title 49 Transportation 192.739, https://www.gpo.gov/fdsys/pkg/CFR-2017-title49-vol3/xml/CFR-2017-title49-vol3-sec192-739.xml

Currently Planned Capital Investments in Natural Gas 2020 – 2024

For the next five-year planning horizon, Avista expects to spend nearly $385 million in capital dollars for the Natural Gas business, allocated across five of the six investment drivers described above. Avista's programs for gas infrastructure investments are summarized by investment driver below.

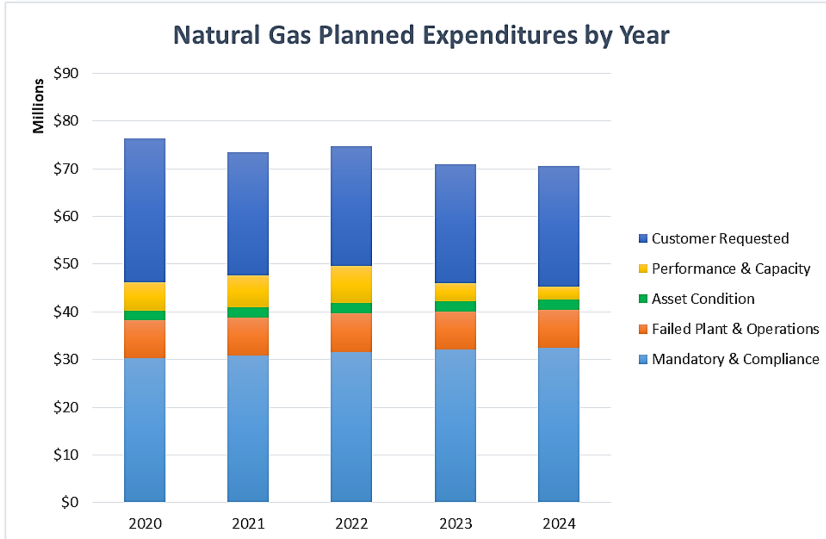


Figure 4. Avista Gas Capital Budget by Investment Driver

Business Driver	2020	2021	2022	2023	2024	5 Year Total
Customer Requested	$30,123,307	$25,855,402	$25,177,121	$25,009,773	$25,260,975	**$131,426,578**
Mandatory & Compliance	$30,233,892	$30,758,892	$31,639,816	$32,068,645	$32,425,648	**$157,126,893**
Failed Plant & Operations	$8,000,000	$8,000,000	$8,000,000	$8,000,000	$8,000,000	**$40,000,000**
Asset Condition	$2,000,000	$2,200,000	$2,210,000	$2,220,000	$2,230,000	**$10,860,000**
Performance & Capacity	$5,960,000	$6,650,000	$7,700,000	$3,700,000	$2,700,000	**$26,710,000**
Total	**$76,317,199**	**$73,464,294**	**$74,726,937**	**$70,998,418**	**$70,616,623**	$366,123,471

Table 1. Avista Natural Gas Planned Capital Expenditures by Driver

Customer Requested

Growth often refers to new service connections, as in growth in the number of customers, however, these investments are primarily 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 customer requests is a requirement of providing utility service. This kind of work may include hooking up

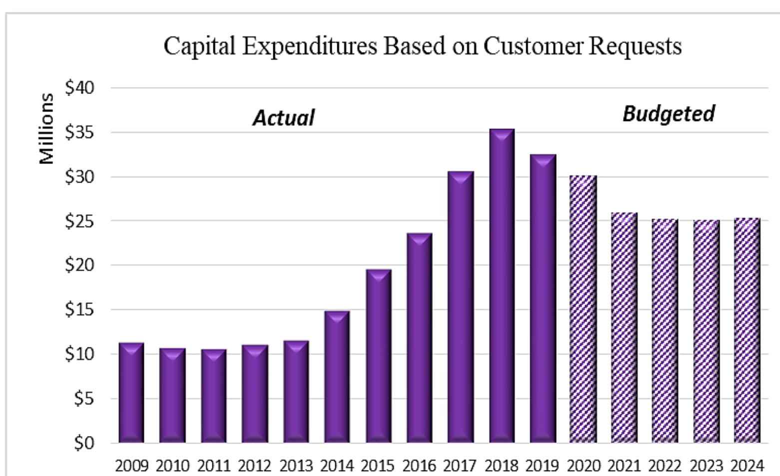


Figure 5. Avista Gas Capital Expenditures Based on Customer Requests & Growth [9]

[9] In 2018 these expenditures jumped due to the Company's Advanced Metering Infrastructure (AMI) gas meter installations in Washington.

new customers or adding meters, regulators, and/or electronic transmitting devices to read meters. The Gas Revenue classification specifically covers the addition of new customers.

Customer Requested	2020	2021	2022	2023	2024
Gas ERT Minor Blanket	$863,119	$812,907	$829,275	$851,543	$874,735
Gas Meters Minor Blanket	$1,224,583	$1,078,078	$1,091,969	$1,118,911	$1,147,112
Gas Regulators Minor Blanket	$483,208	$450,535	$450,184	$454,826	$459,891
Gas Revenue	$27,552,397	$23,513,882	$22,805,693	$22,584,493	$22,779,238
Total	**$30,123,307**	**$25,855,402**	**$25,177,121**	**$25,009,773**	**$25,260,976**

Table 2. Avista Natural Gas Customer Requested / Growth Capital Expenditures

Mandatory & Compliance

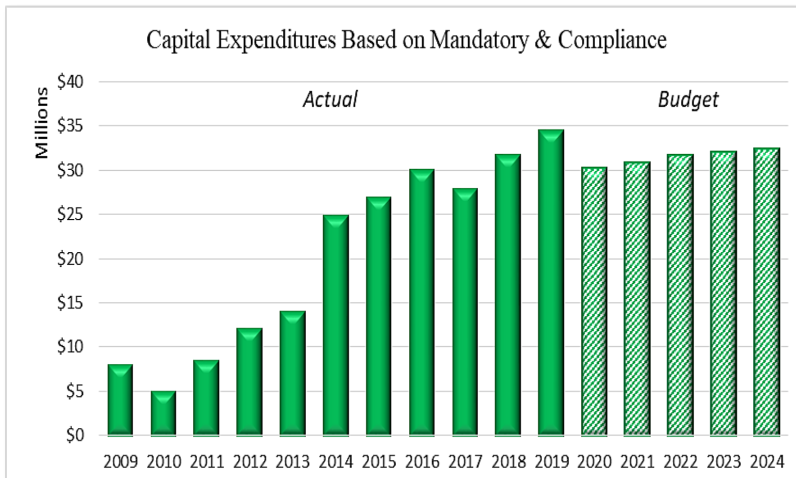


Figure 6. Avista Gas Capital Expenditures Based on Mandatory & Compliance

Avista operates within a complex regulatory and business framework and must adhere to state and federal laws, agency rules and regulations, and county, city, and municipal ordinances. Compliance with these rules, as well as contracts and settlement agreements, represent obligations that are generally required by others and largely outside of Avista's control. The types of gas investments that fall into this driver include the obligation to relocate facilities to accommodate state, county and municipal infrastructure projects (frequently transportation related) and compliance with pipeline safety and environmental regulations. Regulations are increasing and becoming progressively more expensive to implement,[10] as indicated by the increasing budget for this category.

In the natural gas business, the PHMSA requires pipeline operators to identify and document as well as have adequate cathodic protection in place for pipelines to protect against corrosion. Pipeline operators are also required to identify and mitigate the highest risk areas of their natural gas distribution systems[11] and to remove any customer-

[10] The jurisdictions in which Avista must perform the work are becoming increasingly demanding in their requirements, including calling for additional work as a condition of construction, requiring excessive and extensive re-paving and/or landscaping, and even hiring additional flaggers, all of which increase costs in both capital and O&M budgets.
[11] For Avista, a high risk is the bending stress that occurs on Aldyl-A service pipe where it connects to a steel main pipe.

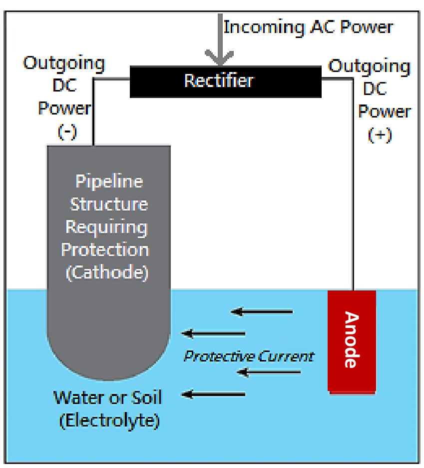
installed encroachments over pipelines. In addition, the Gas group must test meters to make sure they are performing correctly and replace them if they do not. Another capital cost results from local authority requests to relocate equipment residing on public easements, which must be done at the Company's expense. Note that a primary driver for gas related mandatory and compliance expenditures is safety, as indicated by the projects below.

Mandatory & Compliance	2020	2021	2022	2023	2024
Cathodic Protection Program	$715,000	$715,000	$715,000	$700,000	$700,000
Gas Facility Replacement Program (GFRP) Aldyl-A Pipe Replacement	$23,318,892	$24,043,892	$24,624,816	$25,218,645	$25,825,648
Isolated Steel Replacement Program	$1,400,000	$1,400,000	$1,600,000	$1,600,000	$1,600,000
Overbuilt Pipe Replacement Program	$400,000	$400,000	$400,000	$250,000	$0
Planned Meter Change Out Program	$1,400,000	$1,200,000	$1,300,000	$1,300,000	$1,300,000
Replacement Street and Highway Program	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000
Total	**$30,233,892**	**$30,758,892**	**$31,639,816**	**$32,068,645**	**$32,425,648**

Table 3. Avista Natural Gas Mandatory & Compliance Capital Expenditures

Cathodic Protection Program

The purpose of the Cathodic Protection (CP) program is to protect Avista's buried steel pipe from the effects of natural corrosion. Corrosion is the result of an electro-chemical reaction of a metal surface to its environment (such as the air or water) which causes a loss of metal from the surface, reducing the integrity of the pipeline. This can be seen as rust. The mechanism of cathodic protection is to make the pipeline part of an electric circuit by energizing the pipe with direct current, often provided by a device called a rectifier. The rectifier transforms the voltage level from the alternating current that it receives from the incoming power line into direct current (DC) that is used to electrify the pipe. The DC current is connected via a cable to a "sacrificial" metal anode that is easier to corrode than the pipe itself. This forced electrochemical process directs the corrosion process to the sacrificial metal, which protects the pipeline itself from corroding. In most cases the pipe also has a high-dielectric strength special coating in conjunction with the use of a CP system.



For this process to be effective, the circuit and power source must be properly maintained. The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration requires that gas pipelines installed after July of 1971 must have CP systems in place and that the performance must be closely monitored and tested at least once a year. If a rectifier is used, it must be checked six times a year.[12] Failure of these systems is especially difficult to predict or determine because most of the pipelines are buried underground so deterioration is not immediately visible. Some of Avista's CP systems have already exceeded their useful life and thus have increasing risk of failure. These old systems must be replaced. Besides compromising the corrosive protection for Avista's infrastructure, these aged systems create the potential for the Company to be at risk of non-compliance as well as increase safety concerns for employees and the public.

Gas Facility Replacement Program (GFRP) Aldyl-A Pipe Replacement

The PHMSA requires pipeline operators to identify and mitigate the highest risks in their gas distribution systems. Over time the industry discovered that the certain resins used in Aldyl-A pipe may become brittle, causing leaking and failure.[13] It is the Company's position that this issue creates unacceptable risk. Even above the mandatory requirements, this program is designed to protect public safety and property by proactively replacing all of this type of pipe existing within Avista's service territory.

The Gas Facility Replacement Program Aldyl-A Pipe Replacement replaces at-risk pipe sections over a 20 year time period starting with the highest risk areas. This work is done via a program endorsed by the Washington Utilities and Transportation Commission.[14] The Company identified approximately 737 miles of priority Aldyl-A main pipe (1¼" through 4" in size) manufactured prior to 1985 and about6,000 transition tees which need to be replaced. Transition tees connect the service lines to the main lines. The Company used a risk consequence model to try to predict where leaks are most likely to occur, then folded in information on customer density in these areas, specifically focusing on areas of congregation such as schools, hospitals, and apartment complexes.

The replacement program began in 2012 and is estimated to be completed within twenty years. It costs about $69 to $110 per foot depending upon conditions.[15] For example, replacing pipeline under a roadway requires mitigation such as repaving the street and replacing associated infrastructure like

[12] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, Cathodic Protection Requirements, https://primis.phmsa.dot.gov/comm/FactSheets/FSCathodicProtection.htm
[13] Aldyl-A pipe is a polyethylene pipe made by DuPont before 1984 and widely used throughout the gas industry. Over time it was discovered that this pipe can become brittle and prone to leaking, which can create safety risks.
[14] WUTC UG-14089 https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=256&year=2014&docketNumber=140189
[15] Before the Washington Utilities and Transportation Commission, Testimony of Don Kopczynski, page 12, https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=258&year=2014&docketNumber=14nk0189

trees and sidewalks, which is more expensive than work in a rural area. The Company makes every attempt to minimize the impact of this work on the public and public infrastructure.[16]

Isolated Steel Replacement Program

The program identifies and documents cathodically isolated steel pipe sections, including cathodically isolated steel risers,[17] installed after July 31, 1971 with the goal of ensuring they are either adequately protected against corrosion or are replaced.[18]

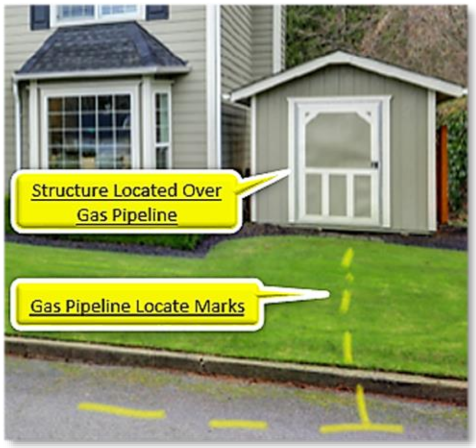
Avista protects all of the buried steel pipes in the system from corrosion using cathodic protection with large, strategically placed anode beds. In order to protect the pipeline, this system relies on all of the steel pipe in a section to be continuously connected together (electrically) to form one big electrical circuit directly connected to the anode bed. Unfortunately some of these circuits of steel pipe have been broken up with plastic pipe as pipelines have been replaced over time. A section of steel pipe that is not directly connected (electrically) to the larger system is considered 'isolated.' The anodes cannot protect this pipe because they aren't electrically connected to it anymore, so it is no longer adequately protected from corrosion. Federal and state regulations require at least 10% of the Company's isolated steel sections of pipeline be inspected each year. If these sections are not cathodically protected and are thus at risk of corrosion, they must be replaced. With this program, the Company is replacing 10% of the isolated steel risers and short sections of isolated steel main within one year of their discovery. This work is stipulated in an agreement between Avista and the Washington Commission.[19] Since the company has agreed this is prudent in the Washington jurisdiction, we have also extended this plan into our Idaho and Oregon jurisdictions.

Overbuilt Pipe Replacement Program

The Federal Code of Regulations[20] requires utilities to remove customer-installed encroachments or "overbuilds" that interfere with or prohibit the ability to safely operate the gas system. Typically an overbuild situation occurs when a structure is erected over the top of preexisting natural gas facilities. These structures or barriers prevent mandatory maintenance such as leak surveys, which

[16] For a great summary of this program, see Michael B. Whitby and Dan Gigler, "Gas Facility Replacement Program," https://www.utc.wa.gov/regulatedIndustries/transportation/TransportationDocuments/Avista%20-%20Aldyl%20A%20Replacement%20Program.pdf
[17] Risers are the part of the pipe that transitions the pipe from underground to the surface and, in some cases, from plastic to steel.
[18] 49 CFR 192.455 and 49 CFR 192.457 - External corrosion control for buried or submerged pipelines per United States Code. https://www.gpo.gov/fdsys/granule/CFR-2010-title49-vol3/CFR-2010-title49-vol3-sec192-455 and https://www.gpo.gov/fdsys/pkg/CFR-2017-title49-vol3/pdf/CFR-2017-title49-vol3-sec192-457.pdf
[19] "Isolated Steel Settlement Agreement Report, Docket PG-100049, https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=66&year=2010&docketNumber=100049
[20] This part of the Federal Code of Regulations prescribes minimum safety requirements for pipeline facilities and the transportation of natural gas. US DOT 49 CFR, Part 192. https://www.law.cornell.edu/cfr/text/49/part-192

are typically performed by walking directly above the gas pipeline while operating the leak detection equipment. Overbuilds also increase the Company's operating costs due to the need to return to the overbuild location multiple times to complete leak surveys and perform other maintenance tasks.



Buildings over a pipeline that are not properly vented also create the possibility of natural gas leaking and accumulating inside the structure, which creates additional safety hazards. Avista's Overbuilt Pipe Replacement Program is designed to identify and remediate these kinds of issues. The work tends to be focused on overbuilds in mobile home parks. Due to the dynamic nature of these parks, they represent areas of high risk because the dwellings can be easily sited over buried facilities. Mobile homes are not the only structures built over pipelines. Sheds, patios, and more can cause problems. When these situations arise, the Company handles them on a case-by-case basis to protect the interests of both Avista and other involved parties. This program funds the capital costs of relocating facilities to ensure adequate access to the pipeline and to preserve customer safety.

Planned Meter Change Out (PMC) Program

Accuracy in measuring customer usage is critical to both the customer and the Company. To ensure that meters are functioning correctly, Avista performs statistical meter sample testing based on

manufactured year, meter model and size. If analytics determine that a "meter family" is no longer taking precise measurements, the entire group of meters within that category are replaced. Conversely, if the analytics determine that the meters are testing well, the sample size for that group is reduced. This analytics-based methodology makes certain that problematic meters are identified and replaced quickly while maximizing the efficiency and cost effectiveness of the sampling process.[21]

Gas Line Relocated for Road Work

Replacement Street and Highway Program

Virtually all of Avista's pipelines are located in public utility easements which are controlled by local jurisdictional franchise agreements. When local authorities request relocation, Avista is mandated to do so and usually at the Company's expense. Unfortunately the expenditures in

[21] This program ensures that the Company is in compliance with Oregon's OAC 860-023-0015 "Testing Gas and Electric Meters" Tariff Rule #18 https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=221169 and Idaho's IDAPA 31.31.01.151 through .157 "Standards for Service" https://adminrules.idaho.gov/rules/current/31/313101.pdf and Washington's WAC Chapter 480-90-333 through -348 "Gas companies – Operations" Tariff Rule #170 http://apps.leg.wa.gov/wac/default.aspx?cite=480-90

this category are difficult to predict. Most often the impacted utilities (natural gas, electric, phone, cable, etc.) are notified of projects requiring relocation in the spring after local budgets are developed. Avista typically utilizes historical expenditures to estimate what might be required in this spending category.

Failed Plant & Operations

Non-Revenue Program

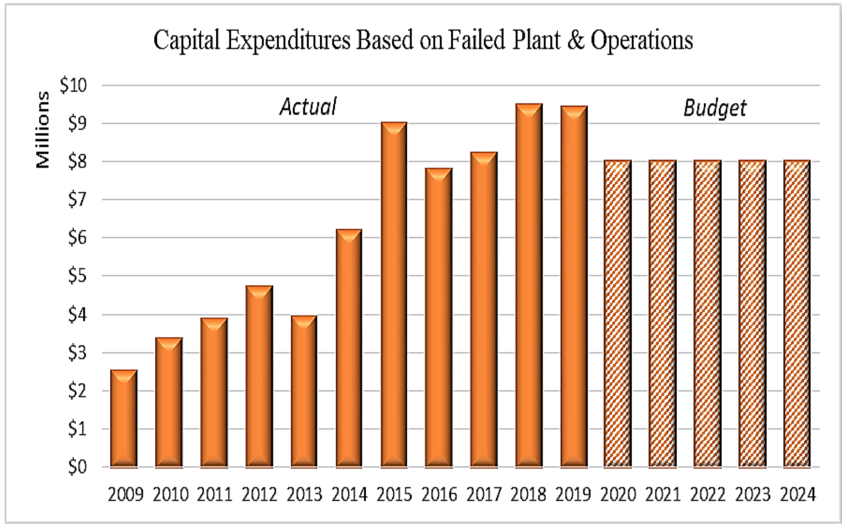


Figure 7. Capital Expenditures Based on Failed Plant & Operations

This program covers assets that have failed and/or which must be exchanged in order to provide continuity and adequacy of service to customers. In addition to outage response, typical work may involve repair and replacement of facilities under a variety of circumstances such as dig-ins, damage repair or other unplanned work that comes up. This funding, called the Non-Revenue Program, has approximately $8 million in funds set aside to cover this type of situation.

Funding for this type of work is very hard to predict, as it tends to be reactionary, such as relocations requested by customers (other than roadway relocations), leak repairs, pipeline that is found to be too shallow, or other such issues. If the work is large enough to warrant significant capital expenditures, it is prioritized and ranked against other Company capital projects, but smaller projects are funded through this program.

Gas Meter Barrier

Note that if customers request relocation of gas facilities, Avista is bound by tariff language to do so at the customer's expense. However, if the Company sees such a relocation as the chance to improve or update the gas system at the same time, the additional costs are charged to this category. Another common expenditure under this program is the reduction in the number of single-service taps off the supply main to serve a small group of customers versus a full distribution tap. By reducing the number of stations,

maintenance costs are lowered.[22] Meter barricades also fall under this category. These are installed if vehicles may get too close to existing meters in order to protect them from damage.[23] This program essentially covers unforeseen work the Company performs to satisfy customers and maintain the safety, reliability and integrity of the system.

Failed Plant & Operations	2020	2021	2022	2023	2024
Non-Revenue Program	$8,000,000	$8,000,000	$8,000,000	$8,000,000	$8,000,000

Table 4. Avista Natural Gas Failed Plant & Operations Capital Expenditures

Asset Condition

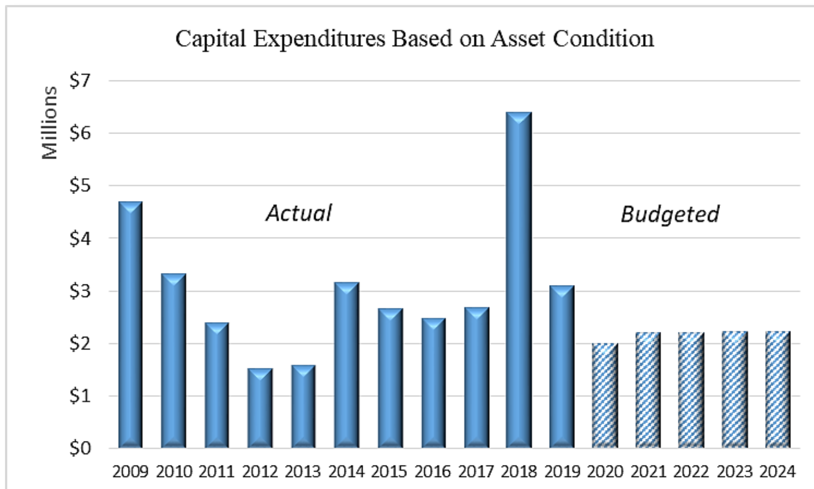


Figure 8. Avista Gas Capital Expenditures Based on Asset Condition [23]

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 as well as the safety of the public and Avista employees. 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, the goal is to manage assets in a manner that optimizes their overall value over the lifecycle of each particular asset class. 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 the Company to

meet a variety of important performance objectives, such as public safety or the efficient use of employee crews. Because failure of critical assets is unacceptable, they must be replaced before the end of their useful life even though they are still providing reliable service. In other instances it may be reasonable to

[22] These small taps are called Single Service Farm Taps (SSFT), and many of Avista's SSFTs are reaching the end of their service life at this time.
[23] These barricades are required by federal mandates and greatly improve the safety of the system.
[24] The large expenditures in 2018 are due to the installation of Advanced Metering Infrastructure (AMI) gas infrastructure in Washington.

wait until an asset fails before it is replaced, a strategy known as "run to failure." The Natural Gas group programs in the Asset Condition driver category have the goal of replacing deteriorated steel pipe, meters, and regulators as described below.

Asset Condition	2020	2021	2022	2023	2024
Deteriorated Steel Pipe Replacement Program	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000
ERT Replacement Program	$200,000	$200,000	$210,000	$220,000	$230,000
Regulator Station Replacement Program	$800,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000
Total	**$2,000,000**	**$2,200,000**	**$2,210,000**	**$2,220,000**	**$2,230,000**

Table 5. Avista Natural Gas Asset Condition Capital Expenditures

Deteriorated Steel Pipe Replacement Program

Multiple factors impact risk and the replacement of facilities including things like material failures, environmental impacts, increased leak frequency, unconventional/obsolete pipe sizes, no protective coating (bare steel) and/or problems with protective coating on pipe. This program is intended to address and remedy these issues. Pipe is regularly inspected across the service territory. When deteriorated pipe is identified, it is ranked by risk factor. The Company believes that replacing deteriorated pipe prior to failure in a planned manner will not only increase the safety of the system and customers but is also more cost effective than responding to unplanned emergency situations. The Deteriorated Steel Pipe Replacement Program is designed to specifically target and prioritize pipelines that may affect safety and system reliability. Avista believes that systematically replacing facilities on a planned basis reduces risk and increases the efficiency and effectiveness of expenditures over time.

Encoder Receiver Transmitter (ERT) Replacement Program

An ERT or Encoder Receiver Transmitter is a device that automatically records gas usage then sends the data to a remote data collector. These devices contain batteries. When these batteries fail, the customer's usage is not sent to the collector and on to the Company, so it is estimated and entered manually. Customers do not like to have their usage estimated due to the potential for billing errors and subsequent true-up bills. Billing estimates often result in a high number of customer complaints.

Itron's Natural Gas Encoder Receiver Transmitter Device

The Company currently has about 106,000 ERT units in Oregon, meaning there are a lot of batteries out there. The batteries are sealed inside the ERT for protection against weather and other environmental elements. It has been found to be more cost effective to replace the entire ERT rather than try to open them, replace the battery, and adequately reseal them. The average battery life is 16 years. The Company proposed a measured and levelized approach to this battery issue, developing a systematic replacement program of 7,000 ERTs per year beginning with the oldest units. This program will be primarily focused in Oregon, as the replacement of the ERTs in Washington and Idaho will take place under the Advanced Metering Infrastructure (AMI) program.

Regulator Station Replacement Program

Natural Gas Regulator Station

Regulator stations reduce and regulate the pressure in gas pipes. These stations and their associated equipment are critical to the successful operation of the gas system and must be replaced when they no longer meet standards or have reached the end of their service life. At times they are at an age where replacement equipment is no longer available. The maintenance and operation of these stations is regulated by the Federal Code of Regulations.[25] Avista's program is in full compliance with this Code and further is designed to improve system operating performance, enhance safety, replace inadequate or antiquated equipment that is no longer supported, and ensure the reliable operation of metering and regulating equipment. The goal of this program is to replace the highest priority projects every year, though new ones are being continually added.

Performance & Capacity

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 based on a demonstrated need. Avista is also attentive to investment opportunities to

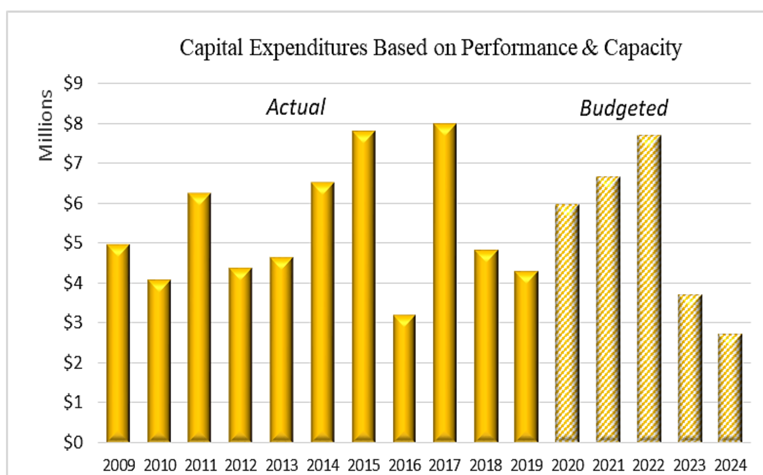


Figure 9. Capital Expenditures Based on Performance & Capacity [25]

[25] 49 CFR 192.739 - Pressure limiting and regulating stations: Inspection and testing https://www.law.cornell.edu/cfr/text/49/192.739
[26] Note that the increase in 2021 is due to the high pressure reinforcement program in Warden, described in this report on page 18.

improve the performance of the gas distribution system when supported by a study or analysis that demonstrates the cost-effectiveness of the benefits achieved for customers.

Natural Gas has many projects related to Performance and Capacity, all of them are related to reinforcing the existing natural gas system due to load growth or age-required replacement. During this budget cycle, these types of reinforcements will likely occur in the Washington cities of Cheney, Airway Heights, Pullman, and Warden, and in the Sandpoint, Idaho area. This investment driver also funds the placement of monitoring equipment at gate and regulator stations to allow the Company to monitor what is happening in the gas system in real-time.

The Gas Planning department routinely runs load studies on Avista's gas distribution system to identify areas of the system with insufficient capacity to serve existing firm customer loads based on "design conditions," which refers to the projected system demand for a "coldest day on record" weather event. Avista attempts to ensure that the natural gas system is adequate to serve customer load in extreme weather conditions when customers need service the most. Identified deficient areas are given a priority level based on the severity of the risk associated with insufficient system capacity. Below is more information about the Natural Gas programs that fall into the Performance and Capacity category, most of them are related to upgrading the system to ensure that customers have adequate service.

Performance & Capacity	2020	2021	2022	2023	2024
Airway Heights HP Reinforcement Project	$50,000	$1,950,000	$0	$0	$0
Cheney HP Reinforcement	$4,710,000	$3,100,000	$0	$0	$0
Intermediate Pressure Reinforcement Program	$1,000,000	$1,300,000	$1,500,000	$1,000,000	$1,000,000
Pullman HP Reinforcement Project	$0	$0	$100,000	$2,400,000	$0
Schweitzer Mtn Rd HP Reinforcement	$0	$0	$0	$100,000	$1,500,000
Telemetry Program	$200,000	$200,000	$200,000	$200,000	$200,000
Warden HP Reinforcement	$0	$100,000	$5,900,000	$0	$0
Total	**$5,960,000**	**$6,650,000**	**$7,700,000**	**$3,700,000**	**$2,700,000**

Table 6. Avista Natural Gas Performance & Capacity Capital Expenditures

Airway Heights High Pressure (HP) Reinforcement Project

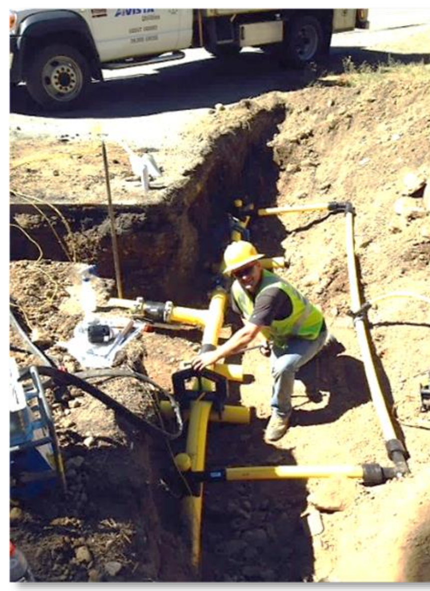
Airway Heights is the fastest growing area in Spokane County. The Company's capacity there is no longer sufficient to serve customers, primarily for space heating, during severely cold winter weather. This reinforcement project will install a new loop of approximately 20,000 feet of high pressure gas main to serve this area and reinforce the existing system.

Cheney High Pressure (HP) Reinforcement Project

The existing pipeline system that serves the town of Cheney is no longer adequate to serve customer demands on cold weather days. There are a couple of additional circumstances with this pipeline that must be noted. It was built between 1957 and 1965 so was not designed to support the current population of this area. In addition, a large industrial customer on this pipeline has submitted plans to increase their gas requirements beyond what the current system can provide. The Cheney High Pressure Reinforcement Project program will address these multiple concerns with one effective solution.

Intermediate Pressure Reinforcement Program

There are continual changes in customer growth and load patterns throughout Avista's intermediate pressure (≤60 psig) pipeline system as, for example, new subdivisions are built or businesses open, close, or expand. The Company has an obligation to serve firm customers by providing adequate capacity every day, including the coldest days of the year. In order to do this, the service territory and associated gas system is constantly monitored to identify areas where new customers are being added or where load patterns have changed. The Gas Intermediate Pressure Reinforcement Program focuses on maintaining adequate gas system capacity by upsizing existing gas mains, looping supply lines to provide back-up service capability, and other reinforcements or upgrades that may be needed to provide dependable, reliable service to customers across the service territory. Projects are evaluated and sorted by priority to maximize the value of the funding in this program.



Pullman High Pressure (HP) Reinforcement Project

Load growth in the Pullman area has exceeded the capacity of the existing Pullman Gate Station.[27] The contracted capacity at this gate is 786,000 cubic feet per hour but the projected need for design condition is 916,000 cubic feet per hour, which puts approximately 1,300 customers at risk of losing gas service when temperatures plunge. This project proposes installing a gas main between the Moscow Gate Station and the Pullman Gate Station (approximately 3 miles of pipeline) to balance the loads, create a more reliable looped system,[28] to allow for projected area load growth, and to make sure that no customers are at risk of losing gas service on cold winter days.

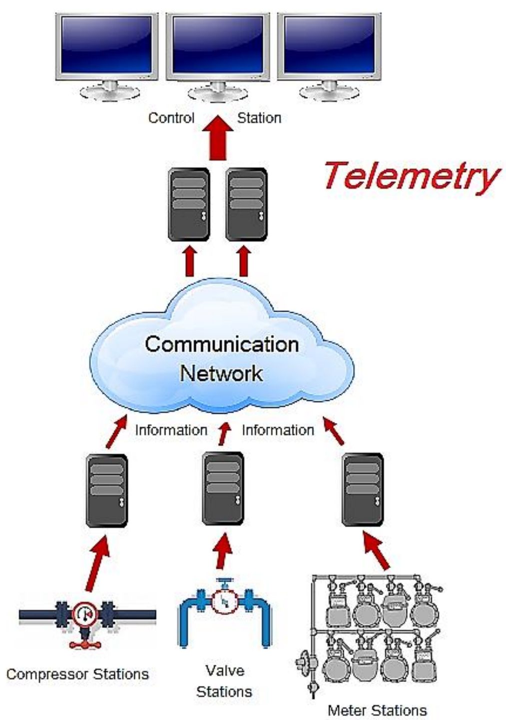
[27] A gate station is the supply point into Avista's system. It takes high pressure gas from a larger pipeline, reduces the pressure, and moves it onto a distribution pipeline.
[28] A looped system means that customers can be served from more than one pipeline so if a pipeline has a failure or is out of service for maintenance, customers can be served from a different pipeline without experiencing an outage.

Schweitzer Mountain Road High Pressure (HP) Reinforcement

Load growth in the Sandpoint area has exceeded the capacity of the existing gas distribution system, and it gets very cold in Sandpoint, which causes additional strain to the gas system. Avista plans to reinforce this system by installing 1.3 miles of 6" steel gas main pipeline and an associated regulator station on Schweitzer Mountain Road to alleviate this constraint.

Warden High Pressure Reinforcement

Warden, Washington, currently has two concerns associated with capacity. The first is that the town is supplied with gas from the fully-subscribed and capacity-constrained Moses Lake Lateral[29] (owned by Williams NWP). Secondly the high pressure supply line coming into town has reached its capacity. As a result of current capacity/supply constraints, industrial gas growth opportunities are hampered within the Port of Warden Industrial Park as well as other sites in the area. Grant County Economic Development Council and the Port of Warden have contacted Avista several times related to different commercial ventures interested in the Port site and are pressing for additional natural gas supply for the area. Schedule and timing are critical aspects of this project. To address this supply problem, the Company plans to install a new gate station and approximately 3.2 miles of 6" high pressure distribution pipeline.



Telemetry Program

Gas telemetry is equipment that remotely monitors system pressures, volumes, and flows across the gas pipeline system. It allows the Company to see what is happening at gate and regulator stations, monitor large industrial customer usage rates and interconnection points. Avista attempts to replace this equipment at the end of its useful life or as it fails. Another goal is to keep the technology current, as this equipment is critical in identifying problem areas in the pipeline such as a lack of pressure to serve customers or other abnormal situations that must be corrected in order to provide safe, reliable service. The current funding level adds about five new telemetry sites and upgrades or replaces an additional 15 sites per year based on the Company's experience and expectations.

[29] Lateral pipelines deliver natural gas to or from the mainline and are typically between 6 and 16 inches in diameter.

Avista's Natural Gas O & M Investments

Avista monitors the gas system very closely to guarantee that critical equipment remains functional and the system is fully intact. O&M expenditures allow the Company to maintain and operate the gas system in the most safe, reliable, and efficient way possible. These expenditures permit the Company to respond when damage occurs from weather, vehicles or dig-ins, maintain facilities, answer customer requests for locating underground pipelines, read meters, and a host of other issues that arise in this complex system, all for the purpose of keeping the natural gas safely and efficiently flowing to customers and to power plants.

As might be expected, the largest group of O&M expenditures are related to maintaining and repairing equipment. Assets are replaced because they are damaged by weather or storms, but that is only one component of the investments needed to keep the gas system operating safely, effectively, and efficiently. Equipment wears out or quits performing as intended and must be replaced. In the natural gas realm, equipment failures can have serious safety consequences. Adequate maintenance is critical. Equipment failure can also lead to loss of supply, leaving customers without heat and power plants without fuel to generate electricity. Leaking pipelines with a path of underground migration to structures can cause gas explosions and serious property damage or even loss of life. Maintenance of this system is even more important with older facilities, as is the case with much of Avista's system. Most of Avista's natural gas pipeline was laid in the 1950s and 1960s. The oldest pipe was installed in the 1930s.

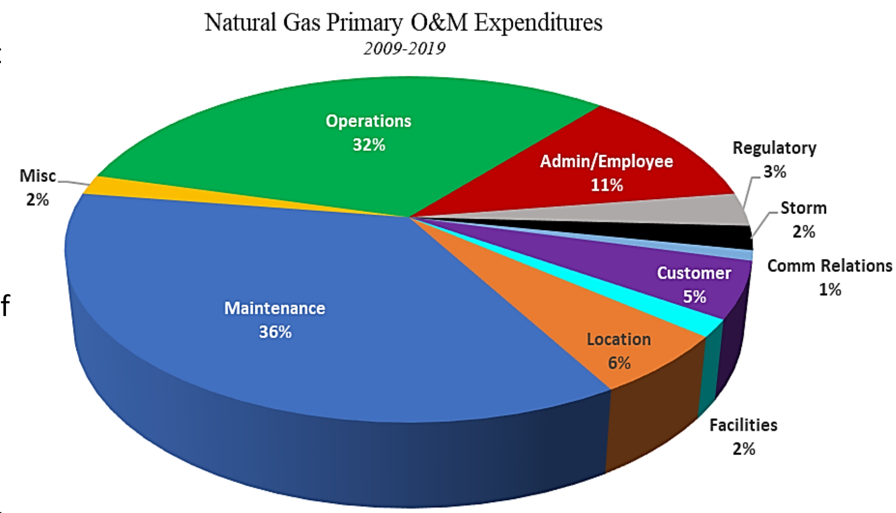


Figure 10. Historical Avista Gas Actual O&M Expenses 2009-2019

Pipeline Leak Detection

Avista performs preventative maintenance or repair of mains, regulators, meters and meter reading transmitters, regulator stations and gate stations. Maintenance work in the natural gas area also includes monitoring and adjusting pipeline pressure as needed to maintain reliability. It encompasses, cathodic protection and other infrastructure work, construction, dispatch, gas supply activities, truck and equipment expenses, and the field employees who perform the repairs and maintain the system.

Additional tasks included in the O&M category include sustaining the property related to natural gas equipment, maintaining the grounds around buildings and regulating stations, maintaining heating, cooling, and electrical systems, providing adequate security, and general supplies. Large repairs and maintenance tasks are performed by Company crews and are occasionally supplemented by contractors.

Avista's Natural Gas employee tasks are highly varied and involve everything from technical construction and maintenance activities to customer service. They perform a significant amount of regulatory-related work that necessitates a large amount of documentation required by the federal, state, local, and Commission governance over gas operations. Most importantly, their work is directly related to the safety of lives and property. Specialized training is required for these employees in order to perform their work, especially related to the protection of the public. They receive extensive education on gas system safety procedures, regulations, and legal requirements.

Avista employees are dispatched to customer homes and businesses to address safety concerns as well as being first responders to make safe and/or repair damaged or leaking gas facilities. Another operations function is leak-related work such as responding to gas odor reports, surveying the pipeline system to identify leaks, and performing the repairs needed to fix them. If anyone calls Avista to report that they smell gas, a gas serviceman is dispatched with a service order to investigate the concern. Strict standards are in place around the amount of time in which the Company must respond to these kinds of orders. If a leak is found, it is dealt with on a priority basis. The Company also responds to dig-ins related to natural gas pipelines and other damage to stations, pipelines, and equipment created by vehicles, earth movement, construction, etc.

Besides maintenance activities, customer service related expenditures are also a significant portion of gas operations. Gas employees perform customer-requested maintenance, read meters, handle general service calls, manage service turn off/on, and deal with collections when required. The gas group also manages customer concerns about equipment, even lighting pilot lights for people who need extra help. Avista's Gas employees are also very engaged in community relations and in educating the public about gas and safety.

Wrap Up

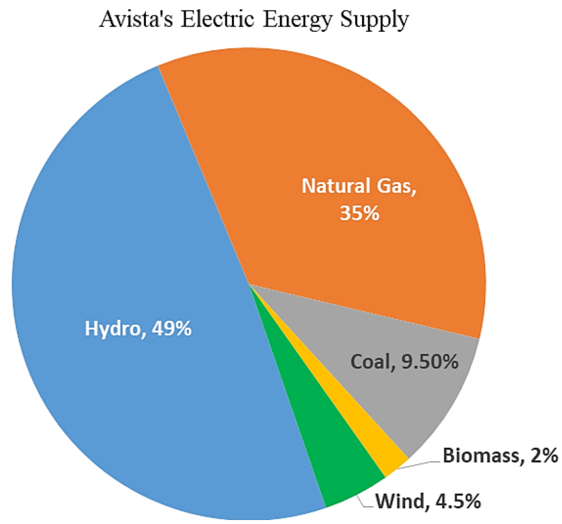
Avista takes the safety of customers and employees very seriously. The Company's Natural Gas business unit has a laser focus on this aspect of their work, and designs Capital and O&M programs that are robust, proactive, and designed to ensure that the natural gas system is as safe as it can possibly be while providing a level of service and cost effectiveness that customers and regulators expect. As depicted in this report, each of these programs has a specific goal and purpose in serving customers safely and effectively, inspecting and protecting the existing infrastructure, thoughtful, measured replacement of end-of-life assets, adding equipment to allow additional monitoring and control, providing additional service as requested, responding to location and relocation requests, and reacting to damage or repair as needed. These programs keep the Company in full regulatory compliance while balancing the need to provide service to customer even on the coldest days. The Company believes these natural gas programs have been, and will continue to be, extremely effective in providing the level of service customers request and expect.

For more information about Avista's natural gas business, the issues facing the natural gas industry, the Company's natural gas safety and public outreach programs, and a glossary of terms, please see the Avista's Natural Gas Infrastructure Plan 2019, available on the Company's internal website[30] or by request.

Installing natural gas pipeline across the Palouse

[30] Go to the Avenue, Tools and Resources tab, under "Avista Infrastructure Plans"

Appendix A: Natural Gas for Generation

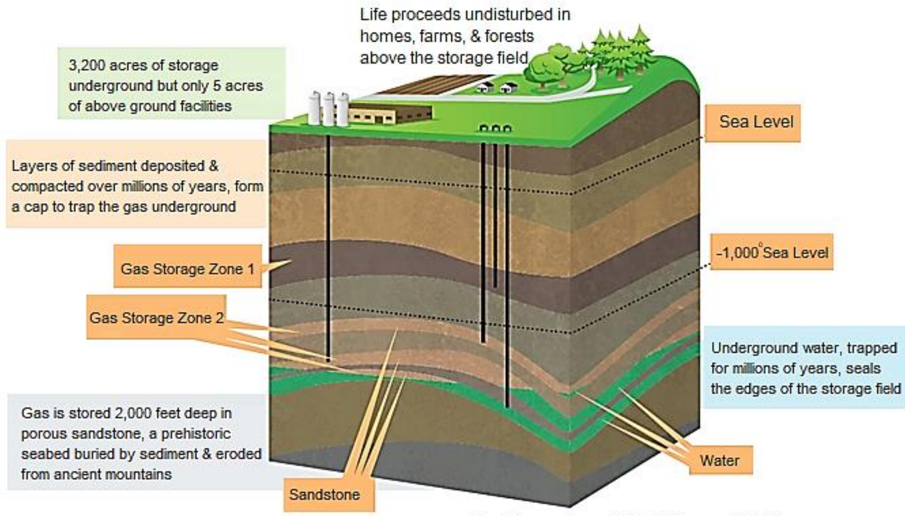


Besides directly serving natural gas customers across the service territory, Avista has capitalized on the opportunity to build power generation stations that utilize this resource. Gas-fired power plants tend to be less expensive to build than a comparable coal-fired or hydroelectric plant[31] and can be highly flexible in operations. Natural gas plants can be built for use in baseload, peaking or both, as they can be designed to come online and adjust their output quickly. Currently natural gas comprises about 35% of Avista's electric energy supply. The Company owns five natural gas power plants capable of generating up to 547 megawatts, one of which is a baseload power plant, Coyote Springs 2. The Company also has natural gas-fired plants specifically intended for peaking or reserve capability. These facilities can be brought online and synchronized quickly to the grid, providing the capability to make up the difference between base load and peak load as needed. Their generation can be varied to meet changing load or system conditions. These plants are also used to provide operating reserve margins,[32] allowing them to respond as needed to changing conditions on the grid, such as the unexpected loss of a generating unit or a transmission line. They are instrumental in integrating intermittent wind and solar facilities, as they can respond instantly to changes in the output from these resources.[33]

Project Name	Fuel Type	Plant Type	Location	Start Date	Summer Maximum Capacity (MW)	Winter Maximum Capacity (MW)
Rathdrum	Natural Gas	Peaking	Rathdrum, ID	1995	130.0	166.5
Northeast	Natural Gas	Peaking	Spokane, WA	1978	42.0	61.2
Boulder Park	Natural Gas	Peaking	Spokane Valley, WA	2002	24.6	24.6
Coyote Springs	Natural Gas	Baseload	Boardman, OR	2003	286.0	287.3
Kettle Falls CT	Natural Gas	Peaking	Kettle Falls, WA	2002	8.0	7.5
Total					**490.6**	**547.1**

31 Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=26532
32 Reserve margin is extra capacity set aside (such as running a generator below its maximum potential output or keeping a unit in "ready mode" on standby) in case of unexpected outages such as when a unit goes offline unexpectedly, a transmission line fails, loads differ from what was expected, etc.
33 For more details about Avista's generation, please see the 2019 Generation Infrastructure Plan, available on the internal website or upon request.

Appendix B: Jackson Prairie Storage Facility



Graphic courtesy of Black Diamond NOW

Avista owns 1/3 of the Jackson Prairie Storage Facility, which contains over 8.5 million dekatherms of working gas capacity. It has over 25 million cubic feet of storage capacity and is the largest natural gas storage site in the Pacific Northwest. Jackson Prairie holds 25% of the entire Northwest's peak-day supply.[34]

Jackson Prairie consists of a series of deep underground reservoirs, basically thick porous sandstone deposits that can hold large volumes of natural gas. It has 104 wells, 45 of which are used for injection or withdrawal. Natural gas is injected into pockets up to 2,000 feet deep, where layers of sediment and sand naturally cap the deposits and keep it underground. This storage facility is a tremendous financial benefit for Avista customers. Most utility customers receive their gas supply directly from a network of interstate pipelines and local gas lines and must pay the going rate for their usage. A storage facility such as Jackson Prairie allows Avista to purchase gas at the lowest price periods (typically summertime), store it, and utilize it during the times when gas usage is peaking and prices are highest.

Jackson Prairie supplements the interstate gas pipeline supply during customer peak times and ensures that there is adequate natural gas available to serve all customers at any time of day or year. It also helps stabilize energy prices by reducing the need to purchase gas supply during high cost times, reduces dependence upon a sometimes volatile gas market, and provides reliable, cost-effective natural gas to meet customer needs. The stored gas at this facility can also be used to alleviate load imbalances on associated pipelines that sometimes occur when there is a significant difference between the gas that flows into and the gas that flows out of the pipeline. Jackson Prairie allows the Company to occasionally take advantage of market conditions to sell gas stored at Jackson Prairie at a premium and then refill it when prices are down. All of these capabilities directly benefit customers by keeping gas prices low and relatively stable as well as directly offsetting expenses via profits made in the gas marketplace.

[34] For more information, see "Jackson Prairie Underground Natural Gas Storage Facility" from Puget Sound Energy, https://pse.com/aboutpse/PseNewsroom/MediaKit/052_Jackson_Prairie.pdf

Avista Utilities Asset Management

Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

May 2013

www.avistautilities.com

AVISTA®

Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Executive Summary

Avista Utilities (Avista) protocol for managing select Aldyl A pipe proposes a twenty-year program to systematically remove and replace select portions of the DuPont Aldyl A medium density polyethylene pipe in its natural gas distribution system in the States of Washington, Oregon and Idaho. None of the subject pipe is "high pressure main pipe," but rather, consists of distribution mains at maximum operating pressures of 60 psi and pipe diameters ranging from 1¼ to 4 inches. Further, Avista notes that while there have been concerns with the integrity of steel pipe in other parts of the country in recent years, the steel pipe in its system, including steel service risers, is being managed to protect its long-term reliability and performance and is outside the scope of this program.

In recent years, Avista experienced two incidents on its natural gas system that prompted the Washington Utilities and Transportation Commission and the Company to better understand the potential long-term reliability of Aldyl A pipe. Results of these investigations, which were aided by new tools developed for Avista's Distribution Integrity Management Plan, corroborated reports for similar Aldyl A piping around the country as supporting the development of a protocol for the management of this gas facility. The following report highlights the history of DuPont's Aldyl A natural gas pipe and summarizes DuPont and Federal Agency communications that are relevant to this proposed program. The report documents the Aldyl A pipe in Avista's natural gas system and describes the analysis of the types of failures observed in this pipe, and the evaluation of its expected long-term integrity. Finally, the report describes the results of Avista's work to establish the framework for the proposed protocol for the management of Aldyl A pipe in its natural gas system.

Table of Contents

Exhibit No. 11
Case Nos. AVU-E-21-01 & AVU-G-21-01
H. Rosentrater, Avista
Schedule 5, Page 3 of 35

History of DuPont Aldyl A Piping Systems

Modern polyethylene pipe products are corrosion-free, lightweight, cost-effective, highly-reliable, and can be installed quickly and efficiently. For these reasons, it has for decades been the 'standard for the industry' and is the predominant choice used in natural gas distribution systems. As with any revolutionary product line, polyethylene piping systems have undergone continuous and rigorous testing and product improvement. Such is the case with DuPont's Aldyl A piping systems, as very briefly summarized below.

DuPont Introduces Natural Gas Polyethylene Pipe – 1965

Along with other manufacturers, DuPont began to use polyethylene resin to produce plastic piping for a variety of purposes. The resin was produced from ethylene molecules combined together in repeating patterns to form larger molecules called 'polymers', hence the name 'polyethylene.' DuPont's product designed specifically for use in the natural gas industry was marketed under the name "Aldyl A." The initial resin used in production of Aldyl A pipe, Alathon 5040, was manufactured from 1965 to 1970. DuPont changed the resin in 1970 to improve Aldyl A's resistance to rupture during pressure testing. This improved formulation, known as Alathon 5043, was the primary resin used in DuPont's Aldyl A pipe from 1970 until 1984.

The Phenomenon of "Low Ductile Inner Wall"

Shortly after changing its polyethylene resin in 1970, DuPont detected a manufacturing issue highlighted during laboratory testing of Aldyl A pipe. DuPont learned that its manufacturing process was resulting in some of the pipe having a property described as "low ductile inner wall." "Ductility" is the ability of a material to withstand forces that alter its shape without it losing strength or breaking. A 'highly-ductile' material can be bent, flexed, pressed or stretched without cracking or losing strength because, unlike brittle materials, it can redistribute the forces of stress concentration. Low Ductile Inner Wall, or as it often appears "LDIW," results when the inner surface of the Aldyl A pipe becomes brittle, promoting the formation of cracks and premature failure. In early 1972, DuPont changed its manufacturing process to eliminate this phenomenon, but estimated that 30 – 40% of the pipe it produced in 1970, 1971 and early 1972 was affected, primarily in pipe diameters from 1¼ inches to 4 inches.

DuPont Communicates Potential Issues to Aldyl A Customers

1982 Letter

In 1982, DuPont sent a letter to its natural gas customers, noting that two of its gas utility customers had reported a low frequency of leaks in Aldyl A pipe manufactured prior to 1973. These leaks were reported as "slits" occurring where the pipe was in "point contact with rocks." DuPont noted these two utilities had increased the frequency of leak surveys where rock may have been part of the backfill around the pipe, and encouraged other Aldyl A customers to consider the same. This letter was the genesis of what would become a continuing focus on the pipe vintage known as "pre-1973 Aldyl A."

1986 Letter

DuPont's second letter to its Aldyl A pipe customers was sent in 1986, focusing again on pre-1973 Aldyl A pipe. The letter focused on results of newly-developed (elevated temperature) testing methods that allowed DuPont to more-accurately estimate the longevity of this vintage pipe, in diameters of 1¼ inches and larger. Test results showed that 'Aldyl A pipe manufactured prior to 1973 had certain limitations that were not previously-shown by then-available, state-of-the-art testing methods.' The limitations were described as a reduction in pipe service life caused by: 1) "rock impingement" or pressure from rock points directly on the pipe (as mentioned in their 1982 letter), and 2) the use of squeeze-off practices. The term "squeeze-off" refers to the current and long-standing construction practice of mechanically pressing in polyethylene pipe walls to temporarily stop the flow of gas during work on a line that is in service. DuPont further noted that average ground temperature surrounding the pipe, in the ranges of 60 to 70 degrees (F), had a major bearing on its ultimate expected service life. Finally, DuPont recommended that operators should reinforce the pipe, using clamps that surround the pipe at squeeze points, in order to extend the life of its Pre-1973 Aldyl A.

DuPont Substantially Improves Aldyl A Pipe

DuPont made a significant change to its Aldyl A resin formulation in 1984. The improved resin, known as Alathon 5046-C, was marketed as "Improved Aldyl A", and significantly improved the performance of Aldyl A pipe in its resistance to 'Slow Crack Growth' and overall long-term integrity. Slow Crack Growth, or as it's often abbreviated, SCG, describes the progression of a crack that begins with 'crack initiation' or the formation of a crack in the inner wall of the pipe. The crack then progresses through the pipe wall, usually over period of many years, until it finally breaks through the outer surface of the pipe, resulting in failure.

Again, in 1988, DuPont announced another advance in its Aldyl A pipe resin with the introduction of Alathon 5046-U. This change in resin formulation increased the resistance of the pipe to slow crack growth by another order of magnitude. In addition, because of the high 'molecular efficiency' of this new resin, its density was also reduced, which allowed for much greater ductility in the pipe. This product, the last of the DuPont Aldyl A materials that Avista would install, was also marketed as Improved Aldyl A. A summary of DuPont Aldyl A pipe produced between 1966 and 1992 is presented below in Table 1. Information includes the year of manufacture, resin formulation, relative resistance to slow crack growth (stress rupture testing at 80° C / 120 psig for accelerated life testing), and summary notes.

Table 1. DuPont Aldyl A Pipe 1965 - 1992

Years of Manufacture	Resin	Rupture Resistance*	Notes
1965 - 1970	Alathon 5040		Initial Product Marketed as "Aldyl A"
1970 - 1972	Alathon 5043	10 hours	Resin Improvement and Low Ductile Inner Wall
1970 - 1984	Alathon 5043	100 hours	Resin Improvement
1984 - 1988	Alathon 5046-C	1000 hours	Resin Improvement-- Sold as "Improved Aldyl A"
1988 - 1992	Alathon 5046-U	10,000 hours	Resin Improvement --"Improved Aldyl A"

*Illustrates the order of magnitude difference found from accelerated life testing of resins

Common Classifications of Aldyl A Pipe

Based on the characteristics of the different vintages of Aldyl A pipe, there would emerge over time, (from DuPont's 1982 letter going forward), three age-groupings recognized by the manufacturer, natural gas industry, and regulators as relevant in the reliability management of this pipe.

Pre-1973 Aldyl A – Pipe manufactured through 1972, from the first two resin formulations, and including pipe having low ductile inner wall.

Pre-1984 Aldyl A – Aldyl A pipe manufactured from Alathon 5043 resin, but only that pipe manufactured after 1972 and through 1983.

1984 and Later Aldyl A – Pipe manufactured from the improved Alathon 5046-C and 5046-U resins.

Aldyl A Service Pipe - Small-diameter (less than 1¼ inches) Aldyl A service piping is often treated or managed differently than larger-diameter Aldyl A pipe of the same vintage. This is because the small-diameter pipe has been assessed by industry experts as being more resistant to brittle-like cracking than larger-diameter pipe due to its greater flexibility. Further, small-diameter Aldyl A pipe has been confirmed as being free of the Low Ductile Inner Wall properties present in late 1970 through early 1972 vintage piping.

Federal Bulletins on Brittle-Like Cracking in Plastic Pipe

National Transportation Safety Board

In April 1998, twelve years after DuPont's second letter to customers, the National Transportation Safety Board (Board) published a comprehensive safety bulletin describing their investigation of natural gas pipeline accidents involving polyethylene pipe that had cracked in a "brittle-like" manner. The bulletin focused primarily on accidents related to an early plastic pipe manufactured by Century Utility Products (Century), produced from Union Carbide resin. In its review, findings, and in its Safety Recommendations, however, the Board concluded that in addition to the Century pipe, much of the polyethylene pipe produced for gas service from the 1960s through the early 1980s may be susceptible to brittle cracking and premature failure, further noting that vulnerability of this material to premature failure could represent a serious potential hazard to public safety.

The Board's bulletin represented a seminal work on the vulnerability of early plastic pipe to brittle-like cracking because it analyzed and integrated – for the first time – reports from the technical literature, manufacturers' communications, industry expert opinions, the experience of pipeline operators and regulators' accident reports. Because the bulletin provided a clear understanding of the drivers of failure in older polyethylene pipe, we have included a fairly detailed synopsis in this report.

Objectives of the Board's Investigation

Following the Board's investigation of over a dozen serious incidents, it undertook an effort to evaluate whether the existing pipeline accident data was sufficient for assessing the long-term performance of plastic piping. The office of Research and Special Programs Administration of the National Transportation Safety Board compiled the relevant accident data, but found it to be insufficient for this purpose. Lacking adequate data for the larger assessment, the Board instead focused on estimating the likely frequency of brittle-like cracking, focusing on published technical literature, industry expertise, and work with several gas system operators. From this review, the Board launched a special investigation with the objectives to address three safety issues related to polyethylene gas service pipe:

1. Vulnerability of plastic piping to brittle-like cracking
2. Adequacy of available guidance to pipeline operators regarding installation and protection of plastic pipe tapped to steel mains
3. Performance monitoring as a possible way to detect unacceptable performance in piping systems

Phenomenon of Premature Brittle-Like Cracking

The Board's survey suggested that early plastic piping may be "susceptible to premature brittle-like cracking under conditions of stress intensification." The term 'stress intensification' refers to localized pressure on the pipe wall created by such conditions as rock contact or significant bending of the pipe. The phenomenon of brittle-like cracking was characterized by the failure processes described above, beginning with the initiation of cracks on the inner wall of the pipe at the pressure or stress point, followed by slow crack growth that progressed under normal pipeline operating pressures (much lower than the pressure required to rupture the pipe). The process culminated with the crack reaching the outside wall of the pipe, showing up as a very tight, slit-like opening on the surface, running generally parallel with the length of the pipe. Premature brittle-like cracking was believed, at the time of the Board's safety bulletin, to require relatively high and localized stress on the pipe resulting from sharp or excessive bending, soil settling, rock "impingement" (point or contact pressure on the pipe) , improperly installed fittings, and dents or gouges to the pipe surface. The term 'brittle-like cracking' was used to describe this failure process because the pipe showed no signs of being bulged or deformed where the cracks occurred.

Board Findings on the Three Identified Safety Issues

Issue 1: Vulnerability of Plastic Piping to Brittle Cracking

Long-Term Strength of Early Pipe was Overrated - In the early 1960s the industry had very little long-term experience with plastic pipe, and consequently, developed laboratory testing procedures to forecast the expected service life of piping. Early testing results suggested that polyethylene pipe would exhibit a relatively constant, or 'straight line' gradual decline in strength over time. These tests and underlying assumptions were subsequently incorporated as standards for the industry and in related federal requirements.

As the industry gained experience, however, the straight-line assumptions of these early procedures began to be challenged through the development of new testing methods, where pipe strength was assessed under conditions of elevated temperature (such as the testing referenced in DuPont's 1986 letter to customers). Results of the elevated-temperature testing showed that the decline in strength of early plastic pipe was not gradual or linear as had been assumed, but instead, began to accelerate or drop below the straight line, especially after twelve years. The Board concluded that the early testing procedures may have overrated the strength and resistance to brittle-like cracking of the polyethylene pipe manufactured for the gas industry from the 1960s through the early 1980s.

Long-Term Ductility was Overrated - Another important assumption about early plastic pipe, based on short-term testing, was that it would retain its ductile properties long term. The assumption of long-term ductility had important safety ramifications since it allowed plastic pipe systems to be designed to withstand stresses generated primarily by internal pressure and to give less consideration to the impacts of external stresses such as bending. Unfortunately, the early testing methods did not properly identify the evidence of the "ductile to brittle" transition that was occurring early in the life of the pipe. Consequently, the tests did not distinguish pipe failures resulting from a loss in ductility. The Board noted that this loss of ductility was also observed in the older piping of several manufacturers, those other than Century Utility Products.

Pipeline Operators had Insufficient Notification - The Board noted that premature brittle-like cracking was a complex phenomenon that had not been systematically communicated to the industry, and hence, had not been fully-appreciated by pipeline operators. The Board recognized pipe manufacturers as commonly offering technical and safety assistance to operators, and occasionally, formal reports on their materials. But, because the information on the potential weakness of their products was also mixed with information publicizing its best performance characteristics, the message was not clear. The Board also noted that the Federal Government had not provided relevant information to gas system operators, and concluded that operators had insufficient notification that much of their early polyethylene pipe may have been susceptible to premature brittle-like cracking. Finally, the Board went on to recommend that the polyethylene pipe manufacturers' organization, the Plastics Pipe Institute, advise its members to notify pipeline operators if any of their materials indicate poor resistance to brittle-like failure.

Issue 2: Adequacy of Guidance for Connecting Plastic Pipe to Steel Mains

Critical Understanding of Stress on Pipe - The Board observed that the premature transition of plastic piping from a ductile to a brittle state appeared to have little observable adverse impact on the serviceability of plastic pipe, *except* where the pipe was subjected to external stresses, such as excessive bending, earth settlement, dents or gouges to the pipe surface, and improper installation of fittings, etc. Of those sources of stress, a key factor identified in the Board's bulletin was earth settlement, but particularly in cases where plastic piping was connected to more rigidly anchored fittings, such as steel main pipe. Because the physical properties of plastic and steel respond differently under the same conditions, such as to temperature change and ground settlement, the slight movements of each type of pipe in the ground will be different. This difference in movement can result in significant stress at the point of connection between the plastic and steel piping.

Much of the Guidance to Operators was Insufficient or Ambiguous - In addition to pipeline operators having insufficient guidance on the overall issue of the vulnerability of plastic pipe to brittle cracking, as noted above, the Board also observed that much of the available guidance to operators on how to limit stress on the pipe during installation was inadequate or ambiguous. This was particularly the case with the stress associated with the tapping of plastic service piping to steel mains, where the Board concluded that many of those connections may have been installed without adequate protection from external stress. The Board went on to identify several instances where safety requirements did not fully incorporate safety recommendations, resulting in ambiguity for pipeline installers and regulators. Other highlights of the Board's findings were the many cases where the applicable regulations applying to pipeline installation lacked any performance measurement criteria. Noting that the Office of Pipeline Safety considered many of its safety regulations to be performance-oriented requirements, the Board rebutted this in stating that “many are no more than general statements of required actions that do not establish any criteria against which the adequacy of the actions taken can be evaluated.” A particular example was the regulation that “requires gas service lines to be installed so as to minimize anticipated piping strain and external loading,” and yet it contained no performance measurement criteria for establishing compliance. Finally, the Board went on to note cases where the inadequacy of pipe manufacturers’ instructions also contributed to the lack of a clear understanding of methods to limit stress on plastic pipe during installation.

Issue 3: Monitoring of Plastic Pipe to Determine Unacceptable Performance

The Board’s final objective was focused on performance monitoring of pipeline systems as the key to effectively managing the vulnerable piping types identified in the bulletin. In this discussion, the Board focused on the accident in Waterloo, Iowa in 1994[1], in highlighting the very real challenges of designing effective pipeline monitoring programs. The Board stated that before the accident, the pipeline operator had developed a limited capability to monitor and analyze the condition of its system. It concluded however, that the systems the operator had developed for tracking, identifying, and statistically treating plastic piping failures did not permit an effective analysis of system failures and leak history, noting that their methods of handling of pipe data masked the high failure rates of the subject Century pipe. While the operator did re-evaluate its monitoring data after the accident, and subsequently identified the high failure rates of Century Pipe, the Board opined that the problem could have been detected earlier (before the accident) if the data had been properly analyzed in the first place. Finally, the Board concluded that an effective monitoring program would have allowed the operator to implement a pipe replacement program that might have prevented the accident.

In the second case, the Board noted that while the operator had added capabilities to its pipe-monitoring protocols, it had still not chosen parameters needed to provide adequate analysis of its plastic piping system failures and leak history. The bulletin went on to note examples of the many types of additional parameters needed to enable the effective tracking, identifying, and properly describing system failures and leak history.

The Board concluded that in light of the key findings in its bulletin, that gas system operators may need to be advised once again of the importance of complying with Federal requirements for piping system surveillance and analyses. Regarding the monitoring of older piping, the Board identified the necessity to analyze factors such as piping manufacturer, installation date, pipe diameter, operating pressure, leak history, geographical location, modes of failure, location of failure, etc. Finally, the Board noted that an effective monitoring program would require the evaluation of pipe material and installation practices to provide a basis for the planned and timely replacement of piping that indicates unacceptable performance.

[1] In October, 1994, a natural gas leak and explosion at Midwest Gas Company in Waterloo, Iowa, resulted in 6 fatalities and 7 injuries. The cause of the incident was identified as the failure of a ½ inch diameter service pipe cracking in a brittle-like manner at a connection to a steel main.

Pipeline and Hazardous Materials Safety Administration

1999 Bulletins

The first two of several advisory bulletins related to the Board's 1998 Safety Bulletin (above), were published by the Office of Pipeline Safety, now known as the Pipeline and Hazardous Materials Safety Administration (Administration), in March 1999. The bulletins, which were issued as advisories to pipeline owners and operators, provided an abstract of the findings of the Board's 1998 investigation and advised that much of the plastic pipe manufactured from the 1960s through the early 1980s may be susceptible to brittle-like cracking. The advisories concluded with the recommendation to owners and operators to identify all pre-1982 plastic pipe installations, analyze leak histories, evaluate potential stresses to pipe, and to develop appropriate remedial actions, including pipe replacement, to mitigate any risks to public safety.

2002 Bulletin

This bulletin, as with the prior advisories, reiterated to natural gas pipeline owners and operators the susceptibility of older plastic pipe to premature brittle-like cracking. But, for the first time, this advisory specifically named DuPont's pre-1973 Aldyl A pipe (low ductile inner wall) as being susceptible to brittle cracking. The bulletin also depicted several environmental and installation conditions that could lead to premature, brittle-like cracking failure of the subject pipe, and described recommended practices to aid operators in identifying and managing brittle-like cracking problems.

2007 Bulletin

This bulletin, again, served to review and recap the findings of the prior bulletins, advising natural gas system operators to review the earlier statements. In addition, the advisory recapped results of the ongoing effort of the American Gas Association to identify trends in the performance of older plastic pipe. The advisory reported that the data, at that point, could not assess failure rates of individual plastic pipe materials, but did support what was historically known about the susceptibility of older plastic piping to brittle-like failure, including the addition of specific materials to the list, such as Delrin insert tap tees.

2009 Distribution Integrity Management Program

The Administration published the final rule establishing integrity management requirements for gas distribution pipeline operators in December 2009. Though the effective date of the rule was February 2010, operators were given until August 2011 to write and implement their Distribution Integrity Management Plan (DIMP).

Objectives and Approach

Among other objectives, the program was intended to overcome two key weaknesses in pipeline safety management that were identified in the National Transportation Safety

Board's 1998 bulletin (above): 1) correct weaknesses in federal regulations, particularly in the Office of Pipeline Safety, by establishing true measurement criteria for establishing safety compliance, and 2) establish systematic protocols for pipeline data collection, analysis, and interpretation, that helps ensure accurate integrity assessment and appropriate remediation.

The concept of "Integrity Management" grew out of a demonstration project of the Office of Pipeline Safety designed to test whether allowing operators the flexibility to allocate safety resources through risk management was effective in improving pipeline safety and reliability. Integrity management requires operators, such as natural gas distribution companies, to write and implement Integrity Management Programs (IMPs) to assess, evaluate, repair and validate the integrity of pipeline segments. The program contains the following elements:

- Knowledge
- Identify Threats
- Evaluate and Rank Risks
- Identify and Implement Measures to Address Risks
- Measure Performance, Monitor Results, and Evaluate Effectiveness
- Periodically Evaluate and Improve Program
- Report Results

The Integrity Management approach uses historical leak data and other facility information, along with the input of subject-matter experts, to identify individual threats to a gas system. These threats are then analyzed to predict the likelihood and consequences of failure. Each threat is then ranked by priority, followed by the development of a plan to reduce or remove those risks as deemed necessary.

2011 Call to Action – Transportation Secretary LaHood

Finally, in April 2011, U.S. Transportation Secretary LaHood issued a Call to Action to all pipeline stakeholders in conjunction with the effective application of the Distribution Integrity Management Program. The Call to Action was aimed at the more than 2.5 million miles of liquid and gas pipelines of both federal and state jurisdiction, including transmission and distribution facilities, calling on owners and operators, the pipeline industry, utility regulators and state and federal partners to:

- Evaluate risks on pipeline systems;
- Take appropriate actions to address those risks, and
- Requalify subject pipeline systems as being fit for service.

The centerpiece of the Call to Action is the "Action Plan" of the Department of Transportation and the Pipeline and Hazardous Materials Safety Administration. The focus of the Action Plan is to accelerate the rehabilitation, repair, and replacement of high-risk pipeline infrastructure, calling on pipeline operators and owners to take "aggressive efforts… to review their pipelines and quickly repair and replace sections in poor condition." To buttress this Call to Action, Secretary LaHood has asked Congress to increase maximum civil penalties for pipeline violations, to close regulatory loopholes, strengthen risk-management requirements, add more inspectors, improve data reporting and help identify potential pipeline safety risks early.

Avista's Experience with DuPont Aldyl A Piping Systems

Avista has approximately 12,500 miles of natural gas piping in its service territories in the States of Washington, Oregon and Idaho. Like dozens of other gas utilities, Avista adopted plastic pipe as an excellent alternative to steel, and consequently, the broad majority of Avista's pipe is polyethylene (about 8,500 miles) of various types, ages and brands, including DuPont's Aldyl A.

Avista began installing DuPont Aldyl A in 1968 and discontinued its use in 1990 when DuPont sold their production to Uponor. Of the various vintages and formulations of Aldyl A pipe in its system, Avista has estimated quantities in the following amounts, in diameters of ½" to 4":

Pre-1973 Aldyl A (1965-1972 resins)	190 Miles
1973-1984 resins	960 Miles
1985-1990 resins	919 Miles

Avista noted the advisory bulletins of the Board and Administration in 1998, 1999 and 2002, but since it had no documented trends in the types of failures highlighted, continued to manage its Aldyl A pipe according to established monitoring standards for leak survey and sound operations practices.

Spokane and Odessa Incidents

In recent years, however, Avista experienced two natural gas incidents[2] resulting in injuries and property damage that signaled possible changes in leak patterns in its Aldyl A piping. The first incident occurred in 2005 at a commercial site in Spokane. This event involved the failure of 1976-vintage Aldyl A pipe caused by bending-stress resulting from poor soil compaction around the pipe that was performed by a non-Avista excavator in 1993. The post-incident investigation judged the resulting leak to be an anomaly that could have been prevented with proper care by that 3rd party excavator.

The second incident, at a residence in the town of Odessa, Washington, in late 2008, was determined to be the result of rock pressure on the 1981-vintage Aldyl A pipe that occurred during the initial installation. Avista signed a settlement agreement with staff of

[2] The Pipeline and Hazardous Materials Safety Administration defines a natural gas "incident" as a release of gas that results in any of the following: a fatality or personal injury that requires in-patient hospitalization; property damage of $50,000 or greater, or the loss of greater than 3 million cubic feet of gas.

the Washington Utilities and Transportation Commission as an outcome of the investigation of this incident. Under terms of the agreement, which was subsequently approved by the Commission, Avista increased the frequency of its residential leak survey on pre-1984 resin (pre-1987 installed) Aldyl A natural gas mains in its Washington jurisdiction, from once every five years to annually. In addition, whenever it is excavating in the vicinity of Aldyl A natural gas mains in Washington, Avista will also report on the soil conditions surrounding the pipe, and identify appropriate and reasonable remedial measures, as necessary. Avista retained the consulting services of Dr. Gene Palermo to help develop its approach for managing Aldyl A pipe, in relation to the soil conditions reported.

Expert-Recommended Protocol for Managing Aldyl A Pipe in Relation to Reported Soil Conditions

Dr. Palermo is a nationally-recognized expert on the plastic pipe used in natural gas systems, and in particular, Aldyl A piping. He has worked in the plastic pipe industry for over 35 years, which includes 19 years with the DuPont Corporation in its Aldyl A natural gas pipe division.

Dr. Palermo also served as the Technical Director for the Plastics Pipe Institute from 1996 through 2003 and served on the Institute's Hydrostatic Stress Board for over 20 years. Dr. Palermo has served on a variety of gas industry committees, has trained gas industry practitioners and regulators, and has received numerous awards of merit for his outstanding individual contribution to the natural gas plastic-piping industry. He is the only person to receive both the American Society of Testing and Materials - Award of Merit, and the American Gas Association - Platinum Award of Merit. Dr. Palermo is president of his consulting firm, Palermo Plastics Pipe Consulting.

Dr. Palermo reviewed the content of Avista's agreement with the Commission to become familiar with its requirements, specifically with regard to managing Aldyl A piping found in soils that would currently not meet standard criteria for bedding and backfill. Dr. Palermo's review and expertise provided the basis for his recommended protocol for management of Avista's Aldyl A piping found in rocky soils.

1. All Aldyl A pipe manufactured prior to 1984 should be evaluated for replacement in the following manner:
    a. If the pipe has Low Ductile Inner Wall properties, Avista should immediately begin a prioritized pipe replacement program.
    b. If the pipe is installed in soil with rocks larger than ¾ inch, Avista should immediately begin a prioritized pipe replacement program.
    c. If the pipe is installed in sandy soil or in soil with rocks up to ¾ inch in size, the pipe should remain in service and normal leak surveys per DOT Part 192 should be followed.

2. All Aldyl A pipe manufactured during or after 1984 should also be evaluated.

    a. If the pipe is installed in soil with rocks larger than ¾ inch in size, Avista should evaluate the pipe and consider replacing it if they begin to experience rock impingement failures, and should conduct leak surveys more frequently than required by DOT Part 192, until replacement.
    b. If this pipe is installed in sandy soil or in soil with rocks up to ¾" in size, the pipe should remain in service and normal leak surveys should be followed.

Evaluation of Leak Survey Records

Following the Odessa incident, Avista was also asked to review five years of leak survey records in Washington State to look for possible emerging patterns in the health of its Aldyl A piping system. Avista organized the leak survey information and then conducted several evaluations, which were organized under three general objectives, listed below.

1. Analyze the modes or observed types of failures in Aldyl A pipe;
2. Forecast the expected long-term integrity of Aldyl A piping;
3. Identify potential patterns in the overall health of this piping to aid in the design of a more-focused management protocol for Aldyl A pipe.

Avista used newly-available asset-management tools to conduct these assessments, including its recently-implemented Distribution Integrity Management Program (Integrity Management) approach for identifying and analyzing potential threats to its natural gas system. This approach is suited for just such an analysis, having the capability to determine potential patterns in the overall health of a piping system that might not have been otherwise evident through conventional data review. The analysis of the historic leak survey data, including the observation of several new Aldyl A material failures and leaks, did point to the development of a possible trend.

Pipe Replacement Projects in 2011

Another outcome of this heightened focus on Aldyl A leaks was Avista's decision to replace several thousand feet of its Aldyl A main in 2011. In Odessa, Avista increased the frequency of leak surveys on its gas system to once per quarter and mobilized a pipe replacement program that removed all of the pre-1984 Aldyl A main pipe from the gas system in the town. During that project, which was conducted from June to December 2011, nearly 32,000 feet of Aldyl A main pipe were replaced. Other Aldyl A replacement projects in 2011 removed an additional 7,000 feet of this priority pipe. Together, these projects had a capital cost of approximately $2.7 million.

Avista Distribution Integrity Management Program

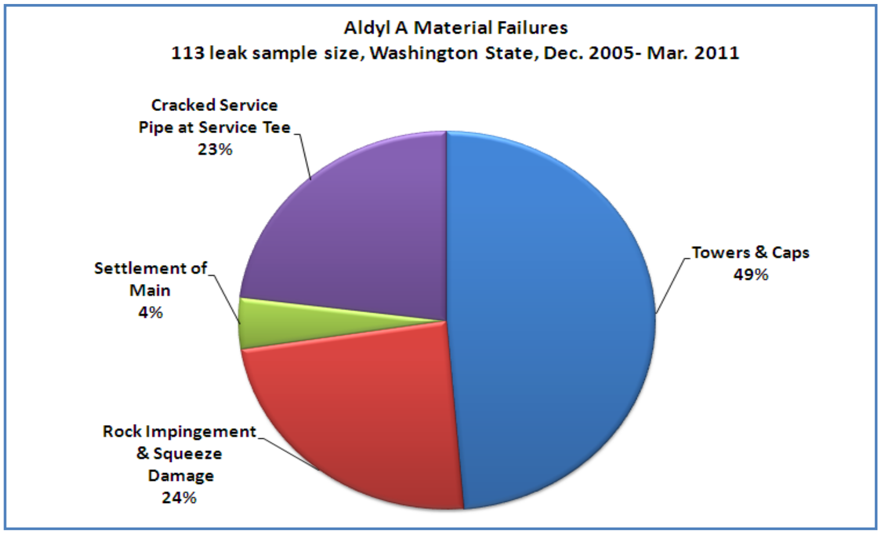
As described briefly above, the Integrity Management approach, now required by law, begins with the aggregation of historical leak-survey data and other facility information relevant to Avista's natural gas piping system. Then, in conjunction with the input of subject matter experts, individual threats to Avista's gas system are identified. These threats are analyzed to predict the likelihood and consequences of failure associated with each threat, based on the specific operating environment, system makeup, and history of Avista's natural gas system. Each threat is then ranked relative to all others to identify, by priority, those with the greatest hazard potential. From that priority list, measures are developed to reduce or remove those risks as deemed necessary. These mitigating measures are often referred to as "accelerated actions" because they may be above and beyond the minimum requirements of applicable federal and state codes. These accelerated actions can range from increased frequency of maintenance and leak surveys to full replacement programs for certain gas facilities. Finally, the mitigating measures will be reviewed to evaluate their effectiveness in reducing threats to the gas system, and the program will then be adjusted as necessary based on those outcomes.

Integrity Management requires the use of geographically-based analytical software to complete many of the required program elements. Like many utilities, Avista is using the Geographic Information System (GIS) platform developed and supported by Environmental Systems Research, Inc. (ESRI), as the geographic and analytical engine for conducting its gas system evaluations under the Integrity Management program. ESRI is a pioneer and world leader in developing and supporting geographic software products for a broad range of global business sectors, including utilities. Since Avista had already created a comprehensive GIS layer, or database, for its gas facilities, it made sense to add analytical capabilities to this platform in complying with the Integrity Management program requirements.

Analyzing Modes of Failure in Avista's Aldyl A Pipe

In tackling the first objective of the assessment of its Aldyl A piping, Avista aggregated the gas leaks resulting from Aldyl A material failures found in its gas system in Washington State from late 2005 through March 2011. The sample included 113 material failures that were evaluated and summarized by component to offer an understanding of the specific failure modes for Aldyl A pipe. The 'modes' or types of material failures categorized are shown below in Figure 1.

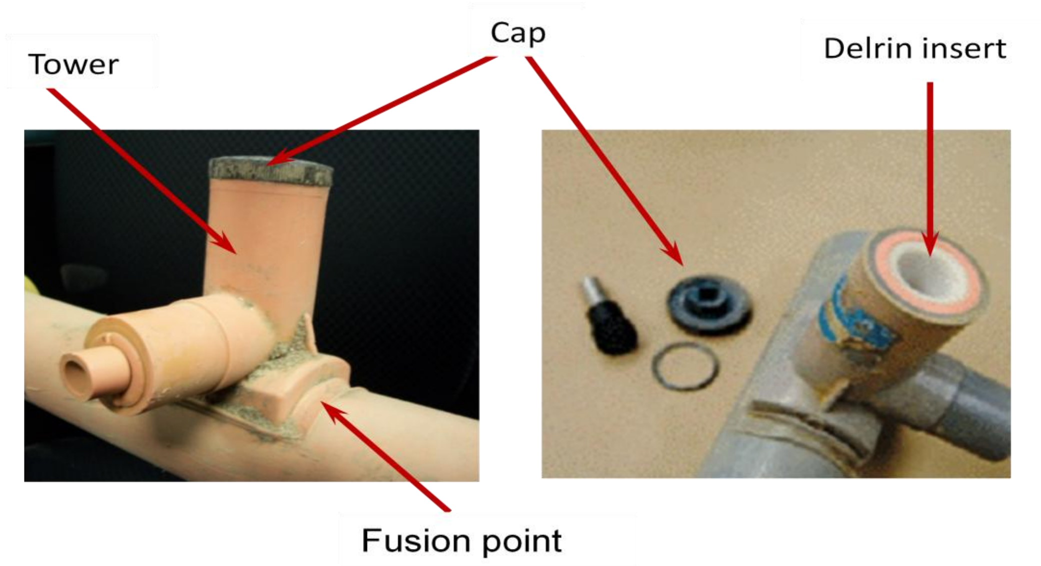
Figure 1. Modes or types of material failures documented in a sample of 113 leaks in Avista's Aldyl A piping in Washington State, December 2005 through March 2011.



Towers and Caps

The largest percentage of material failures in the sample occurred in Towers and Caps, referring to failure of the service tapping tee itself, shown below in Figure 2. In these cases, the pressure applied to the tee as the cap was tightened onto the body during initial installation has resulted in slow crack growth and failure of the tower body, the cap, or the Delrin® insert many years later. Additionally, the saddle fusion point of the tower to the main pipe is another frequent point of failure in this assembly. The unavoidable stresses created during standard installation (using factory recommended procedures) have led to brittle cracking in these components many years later. This phenomenon clearly demonstrates the susceptibility of certain resins of Aldyl A piping to tend to fail by brittle cracking due to the slow crack growth initiated during installation.

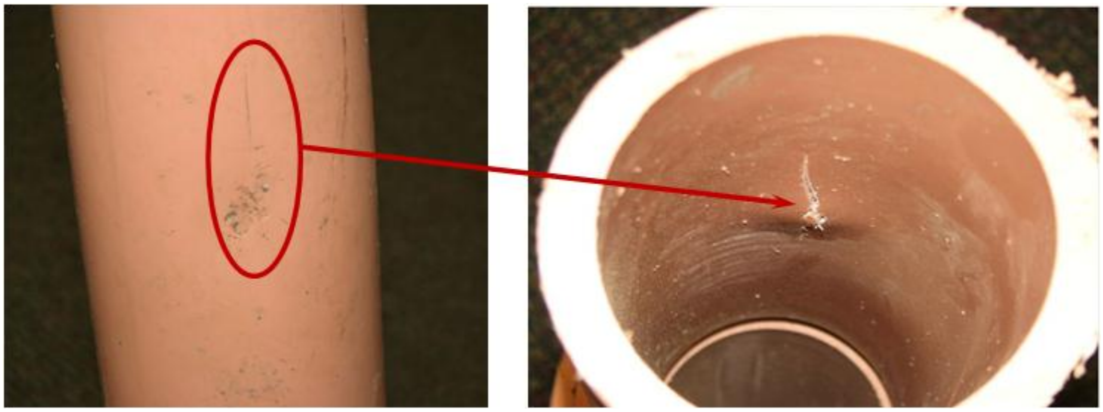
Figure 2. External features and internal components of a typical Aldyl A service tee, as fused to Aldyl A main pipe.



Rock Contact and Squeeze-Off

The second-most common material failure observed in Avista's Aldyl A pipe was due to localized, brittle cracking in Aldyl A mains that resulted from rock impingement – rock pressure directly on the pipe, or places where 'squeeze-off' was applied over the pipe's service life. These failures are very typical for certain resins of Aldyl A main pipe, having been consistently reported by other utilities since before the time of DuPont's 1986 letter. As described earlier, when these external stresses (rock impingement or squeeze-off) cause the pipe to fail, it always begins with crack initiation on the inside surface of the pipe wall, eventually resulting in slow crack growth that propagates toward the outer wall of the pipe, and finally, through-wall failure. These failures generally appear as short, tight cracks in the outer wall of the pipe that run either parallel, or slightly off-parallel with the length of the pipe. A typical failure in Aldyl A main pipe, showing a crack through the pipe wall as it appears on both the inner and outer surfaces, is shown below in Figure 3.

Figure 3. Typical brittle-like crack through the wall of Aldyl A pipe, resulting from rock contact directly on the pipe.



Although the duration of the stress caused by rock contact with the pipe is very different from that associated with squeeze-off, they both result the same pattern of crack initiation and slow crack growth leading to failure of the pipe. Other sources of external stress that can result in brittle failure of Aldyl A pipe, as mentioned earlier in the report, include bending of the pipe, soil settlement, dents or gouges to the pipe, and improper installation of fittings.

Services Tapped from Steel Mains

The third most-common failure in Avista's sample occurred where small diameter Aldyl A service pipe is tapped from steel main pipe. In this application, a steel service tee is welded to the steel main pipe and the small-diameter Aldyl A service pipe is then connected to a mechanical transition fitting on the tee, as pictured below in Figure 4.

Figure 4. Typical polyethylene service tapped from a steel main.

It is at this transition point, between the rigid steel fitting and the more-flexible Aldyl A service pipe, that brittle-like cracking has been observed. This failure mode in older plastic pipe is well understood, and was one of the three study objectives reported by the

National Transportation Safety Board in its 1998 bulletin, summarized earlier in this report.

Avista's Aldyl A Services

Avista believes its Aldyl A service piping (apart from cracking at the connection with the tee on steel main pipe) has no greater tendency to fail than its other polyethylene service piping , and at this point in time, should not be managed differently than other plastic service pipe (frequency of leak survey, etc.). Consequently, Avista is not planning to systematically replace Aldyl A service pipe as it replaces main pipe and rehabilitates service connections at steel tees. Avista is using the Integrity Management model, however, to track and analyze service leaks going forward to determine if the reliability of Aldyl A service piping changes in ways that warrant a different approach.

Understanding the Significance of Leaks in Aldyl A Pipe

Frequency and Potential Consequence

Analysis of the material failures of Aldyl A pipe provides the opportunity to put these leaks into perspective with other types of leaks on Avista's natural gas system. As part of the development of the Integrity Management Plan, five years of leak data were analyzed for Avista's three-state service territory. The data included nearly 17,000 individual leaks, which were categorized according to the underlying threats to the natural gas system as required under Integrity Management. As a point of comparison of the significance of leak types, the data included an excess of 2,000 leaks associated with the failure of gas system equipment, such as valves, fittings and meters. But only 153 leaks were identified as resulting from 'material failures' of Aldyl A piping in the three states. Looking simply at Aldyl A leaks as part of the aggregate of all system leaks, it could be easy to conclude that Aldyl A pipe failures pose a limited potential for hazard relative to the threat of other system leaks. In fact, while gas equipment leaks are more likely to occur, their potential consequence is often minimal. A thorough understanding of this difference is one of the most important requirements and outcomes of any effective Integrity Management Plan analysis.

Review of the leak-history data shows the vast majority of equipment leaks as occurring typically with shut-off valves and gas meters, located either above ground or in locations that allow free-venting of gas to the atmosphere. Consequently, these types of leaks have a low potential to result in an incident posing harm. Through public awareness programs, people have become familiar with the odor of venting gas and tend to quickly call Avista to make repairs; this is especially true if the venting gas can be associated with visible gas valves or meters. By contrast, Aldyl A failures and the associated leaks occur almost entirely underground, out of sight, often in populated areas, and occasionally in the proximity of buildings that are not actually connected to the natural gas system. Without visible facilities, natural gas may have an unexpected presence in the environment that allows people to dismiss slight gas odors. This reduced awareness allows gas from these undetected leaks to have the significant potential to migrate into buildings before it can be identified and reported. This is especially true in winter when the ground is saturated, frozen or snow covered, and in areas of full pavement and concrete finishes. Of the roughly 2,000 equipment leaks reported in the five years of data reviewed, none resulted in gas incidents. By comparison, two of the relatively-small number of Aldyl A material failures resulted in gas migrating into buildings undetected, and upon accidental ignition, resulted in harmful incidents.

The Complication of Brittle Cracking in Aldyl A Pipe

The common mode of failure for Aldyl A materials, brittle-like cracking, can also present special problems compared with leaks in other gas piping, such as corrosion in steel gas pipe. Corrosion leaks tend to begin with the failure of a very minute area in the pipe wall, which then begins to release a very minute amount of natural gas. These leaks then tend to progress very slowly and in a stable and somewhat predicable way over time. These types of leaks, while never positive, are more likely to be detected by modern gas-detection equipment when they are at a stage where the release of gas is relatively minor. By contrast, leaks in Aldyl A piping tend to first appear as substantial (high gas volume) leaks that appear in a very short time period. This is due to the nature of brittle cracking, where the crack can progress very slowly from the inner wall of the pipe toward the outer wall without any release of gas, until the pipe finally splits open, resulting in a substantial failure. Additionally, unlike the prevention or even suspension of corrosion problems in steel pipe through effective protection methods, there is no way to halt undetected progress of slow crack growth in brittle Aldyl A pipe.

Reliability Modeling of Avista's Aldyl A Piping

Avista's Asset Management Group performed reliability modeling for several classes of its natural gas pipe in order to assess the long-term performance of its Aldyl A piping, compared with steel pipe and newer-vintage plastic pipe. Reliability analysis comes from the discipline of 'reliability engineering' and is a foundational asset management tool that provides a forecast or prediction of the future performance of a piece of equipment (pipe, in this instance). The predicted asset performance then provides the basis for the application of other asset management tools, allowing the development of the ultimate maintenance or replacement strategies that optimize asset cost with any number of other factors, such as availability for service or risk avoidance.

Availability Workbench Software

Avista developed reliability forecasts for its Aldyl A and other piping using Availability Workbench™ software. This 'off the shelf software' was introduced by Isograph, Ltd., the world's leader in reliability analysis software. Availability Workbench was first introduced in 1988, and is used to support asset decision making in over 7,000 sites around the world and across a range of industries, including Aerospace, Automotive, Chemical, Defense, Electronics, Manufacturing, Mining, Oil and Gas, Power Generation, Railways, and Utilities. Avista's version of the model was released in 2009.

Reliability Forecasting

Availability Workbench has four modules, one of which, the Weibull module, is used to create reliability forecasts (curves) for an asset. Reliability curves for gas piping are generated from input data that include pipe inventory (type, brand, footage, location, soil conditions, etc.), current age of piping, historic and current failure information and repair data. Avista uses predominantly its own historical data for these inputs, but when they must be estimated, they are vetted by subject matter experts within the company. The model integrates pipe age and failure and repair data, and then by applying a conventional Weibull-curve mathematical model, it produces probability curves that represent the expected failure rates over time for each failure mode, such as the brittle-like cracking associated with Aldyl A services tapped to steel mains. The reliability curves represent how quickly the rest of the pipe is at risk of failing, shown as the percentage of failures expected each year over time.

Forecasting the Reliability of Aldyl A Piping

The objective of Avista's reliability modeling was to forecast expected failures for elements of Avista's Aldyl A piping system, compared with that of steel and latest-generation polyethylene pipe. The observed Aldyl A failure modes, discussed above, including leak data for other types of gas pipe in Avista's system, provided high-quality leak and age information for the reliability modeling. Forecasting was performed for the following pipe 'classes' in Avista's system.

a. Aldyl A Main pipe of Pre-1984 manufacture (Alathon 5040 and 5043 resins, including low ductile inner wall pipe)
b. Aldyl A Main pipe manufactured during 1984 and after (Alathon 5046-C and 5046-U resins)
c. Aldyl A Services Tapped to Steel Main (Bending Stress Services)
d. Steel Main pipe
e. Newer Polyethylene Main pipe (1990 and later)

To perform the modeling, the data for these pipe classes must be input as discrete elements, which are described as follows:

Main Pipe - Analyzed using 50-foot segments as discrete modeling elements.

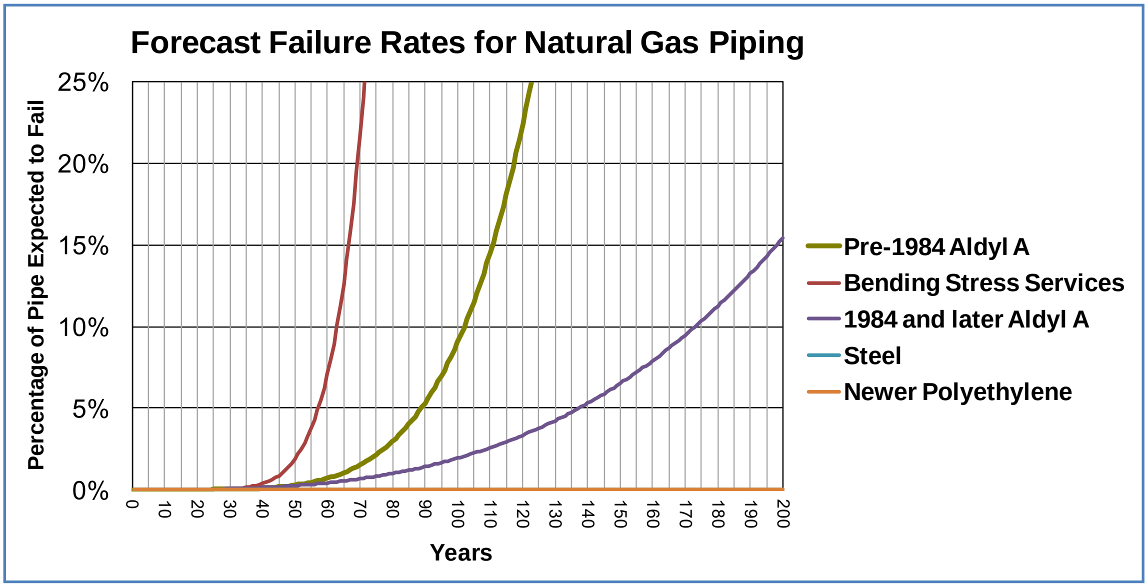
Services Tapped from Steel Mains - Avista identified 16,000 such services in its system, also referred to as 'bending stress tees.' For the reliability modeling, the individual service is the discrete element.

Forecasting Results

Forecast Piping Failures

Results of the forecast modeling, for the pipe classes evaluated, are represented as 'curves' showing the percentage of the amount of each pipe class that is projected to fail in each year of the forecast time period. The resulting reliability curves are shown in the graph below in Figure 5.

Figure 5. The expected failure rates for several classes of pipe in Avista's system, as forecast by Availability Workbench Modeling. The "Steel" curve is obscured by the "Newer Polyethylene" curve, both of which are essentially flat lines.



The failure curves show dramatic differences in the expected life for the pipe classes evaluated. The difference in expected life between the Aldyl A products as a group, compared with that of steel and newer-generation plastic pipe, is particularly evident. Striking also, are the expected performance differences among the classes of Aldyl A pipe evaluated, providing some clear trends useful in designing remediation strategies.

Dependability of Forecasting Future Failures

The reliability forecast is essentially a mathematical calculation of the 'chance' of future failure and decisions of significant risk and financial magnitude are based, at least in part, on that result. Importantly though, the forecast has a 'real numbers' foundation in the actual leak data, records of material failure and repair, and the relationship of those events with time. For Aldyl A pipe, the model is using observed endpoints in the life of the pipe resulting from a loss in ductility and slow crack growth, for example, and integrating that with other data to forecast future expected failures. Comparatively, the relatively rare observed failures in steel pipe and newer-generation plastic pipe are reflected in their nearly-flat cumulative failure curves. The value of using proven reliability forecasting approaches and widely-adopted software is derived from their ubiquitous application across reliability-critical industries, and their continuous testing, evaluation, and support. Finally, as Avista adds new data in coming years for pipe failures of all material classes, including Aldyl A, it serves to increase the statistical power of the forecast results.

Understanding the Significance of Cumulative Failure Curves

Although the failure curves for the different classes of pipe differ significantly over the long term, as mentioned, the failure rates also appear to be very close to zero for the first 40 years for Aldyl A services tapped to steel main, and for 75 years for Pre-1984 Aldyl A main pipe. Since the weighted average age for Aldyl A pipe in Avista's system is 32 years, it would appear that we might have ample time before the failure rate would start to rise substantially for Pre-1984 Aldyl A main pipe. The failure curve estimates that when the Pre-1984 Aldyl A main pipe is 80 years old that approximately three percent of it will fail in that single year. Given that Avista has 335 miles of this vintage pipe in Washington, that mileage equals about 35,000 discrete elements (50-ft sections) in the forecast model. The three percent failure, then, translates to 1,050 leaks in that 80th year. To put that failure rate into perspective, consider that Avista documented just 113 leaks over the past five years in Washington state, two of which resulted in injury and property incidents, and dozens more that were categorized as hazardous leaks[3], timely repaired. Since it is expected that the number of hazardous leaks and incidents would increase proportionally with the increase in total leaks, then it's easy to imagine just how unacceptable the pipe performance would be at an annual failure rate of three percent.

Prudent Failure Management

To carry this point further, if we "zoom-in" on the curves we can gauge the significance of the change in failure rate that is expected ten years from today. At that point the weighted average age of Aldyl A pipe in Avista's system will be 42 years, and the expected failure rate for that year is just over one-tenth of one percent (0.12%), or 42 leaks in that year. The failure rate in that year, then, will have nearly doubled over the average annual rate for the past five years (22.6). The critical point in this analysis is the understanding that failures in buried natural gas piping can be prudently managed only when they are occurring at very low rates. Otherwise new leaks in the system occur too frequently to be detected by even annual leak surveys of the entire system, resulting in an increase in the likelihood of hazardous leaks and the potential for harmful incidents.

[3] The Pipeline and Hazardous Materials Safety Administration defines a "hazardous leak" as an unintentional release of gas that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

Priority Aldyl A Piping

Every pipeline operator strives to install and maintain a safe, reliable and cost-effective system. While the goal is complete system integrity, it is impossible to avoid having any leaks, especially on large systems such as Avista's with over 12,000 miles of mains and several hundred thousand services. Regulators and the industry acknowledge this reality through the adoption of standardized leak-survey methodologies, and recognized pipe remediation practices.

But, while leaks are inherent on a system, there are circumstances where the expected reliability of a particular pipe begins to rise compared with that of other piping and industry norms. We have demonstrated that such is the case for portions of the Aldyl A pipe in Avista's system, and accordingly, we have determined these classes to be at-risk of quickly approaching a level of reliability that is unacceptable and in need of proactive remediation. It's for this reason that Avista refers to these pipe classes as "Priority Aldyl A piping."

Formulation of a Management Program for Priority Aldyl A Pipe

The timely application of Avista's Distribution Integrity Management approach to its recent and ongoing leak analysis and its reliability modeling results, including Dr. Palermo's review, and the experience gained in three priority pipe-replacement projects in 2011, has prompted Avista to formulate a protocol for systematically managing its Aldyl A pipe. The following categories are useful classifications for Avista's definition of "priority Aldyl A pipe"[4]:

1. Aldyl A gas services tapped to steel main pipe
2. Pre-1973 Aldyl A main pipe
3. Pre-1984 Aldyl A main pipe

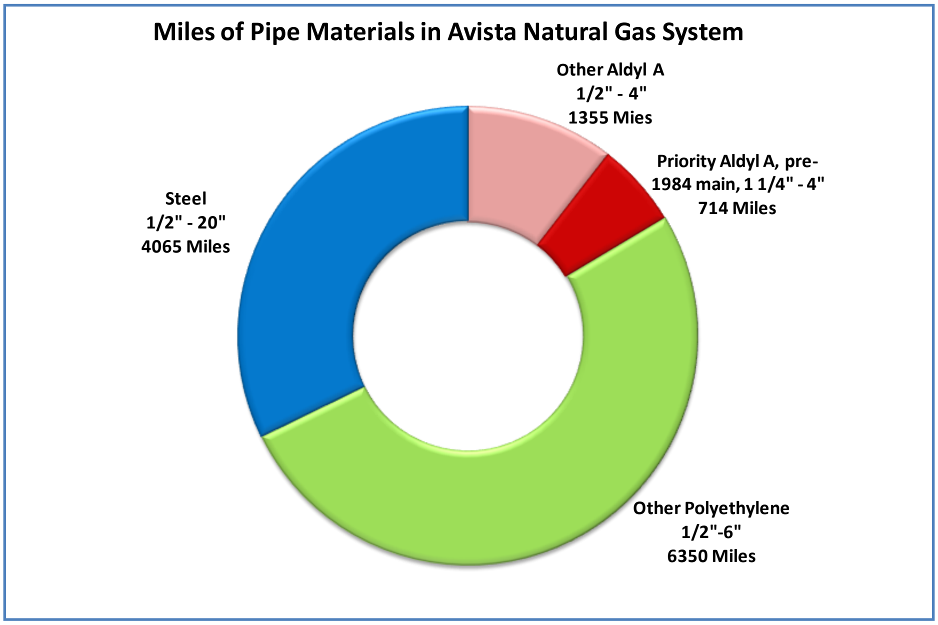
Avista has determined these classes of pipe are at risk of approaching unacceptable levels of reliability without prompt attention. Accordingly, Avista believes the decision to formulate a management program for its priority Aldyl A pipe is both timely and prudent, and is consistent with results of our leak investigations, Integrity Management principles and the recent Call to Action of Secretary LaHood. The decision is also consistent with the prior federal bulletins on this subject and with the decisions of other similarly-situated utilities that have implemented similar pipe-replacement programs. Finally, given the significant amounts of priority Aldyl A pipe on Avista's system, commencing a protocol now provides us greater opportunity to manage this facility in a prudent and cost-effective manner.

[4] Each class noted above is subject to material failures due to concentrated stresses such as rock impingement, bending stresses, squeeze off, and failures of service towers and caps.

Priority Aldyl A Piping in Avista's System

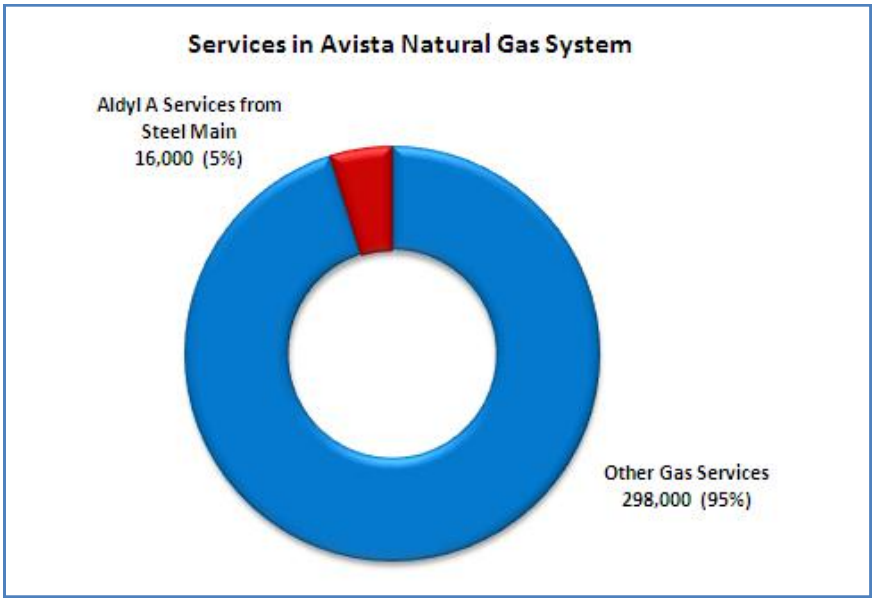
Main Pipe - Avista has approximately 12,500 miles of natural gas main pipe in its service territories in the States of Washington, Oregon and Idaho. Approximately seventeen percent of this total, or 2,000 miles, is Aldyl A pipe of all classes and sizes. Proportions of various classes of piping in Avista's system, including priority Aldyl A pipe (pre-1973 and pre-1984 mains) is shown below in Figure 6.

Figure 6. Avista's priority Aldyl A pipe, shown as a proportion of the different pipe classes in Avista's natural gas system (items 2 and 3 from the list above).



Gas Services - Avista has approximately 314,000 natural gas services, of which approximately 16,000, or five percent, are Aldyl service pipe tapped to steel main pipe, shown below in Figure 7 as priority Aldyl A services.

Figure 7. Avista's priority Aldyl A gas services (tapped from steel mains), shown as a proportion of Avista's total gas services.



Other Aldyl A Pipe Replacement Programs

Aldyl A Pipe in the Pacific Northwest

Through general conversation with our colleagues in western gas utilities, Avista believes it has a substantially greater proportion of Aldyl A pipe in its system than do our neighboring Pacific Northwest gas utilities. The proportions of Aldyl A in Avista's system (or of any other brand of early polyethylene pipe), however, is not a reflection of the unique purchasing practices of Avista, since plastic pipe quickly became the standard of the industry and the predominant pipe installed by utilities across the county. But, the proportions of early plastic pipe in a system do tend to track with the amount of system growth that gas utilities experienced during the 1970s and early 1980s. For Avista, this was a time of particularly rapid expansion of its natural gas system (from the Spokane metro area to outlying communities in its Washington and Idaho service territories), and consequently, the proportion of early Aldyl A pipe in our system reflects this period of expansion.

Established and Emerging Programs for Aldyl A Pipe Replacement

Two western utilities, Southwest Gas and Pacific Gas & Electric, have significant Aldyl A pipe management programs either well underway or anticipated, which are very briefly summarized below.

Southwest Gas – Responding to a fatality incident in the early 1990s, Southwest Gas entered into a settlement agreement with the Corporation Commission of Arizona to conduct additional leak monitoring and pipeline remediation. By the late 1990s, Southwest Gas had replaced 74 miles of Aldyl HD (high density) main pipe covered by the agreement, and had replaced another 648 miles of Aldyl A pipe based on its leak survey monitoring results. In 2005, Southwest Gas had another injury and property incident on their system involving Aldyl A pipe, and implemented an additional pipe replacement program in the vicinity of the incident. Southwest Gas has also worked closely with staff of the Public Utilities Commission of Nevada in the monitoring and replacement of what the Commission refers to as "aging" and "high risk" natural gas pipe, including Aldyl A pipe.

Pacific Gas & Electric - After some very high-profile natural gas incidents in 2011 that involved Aldyl A piping, Pacific Gas & Electric has announced plans to replace all the Pre-1973 Aldyl A pipe in its system. The utility reportedly has 7,907 miles of Aldyl A pipe of all classes in its system, which is about 19 percent of its gas system inventory. By comparison, Avista's Aldyl A pipe stock is about 16 percent of its system. Pacific Gas & Electric's planned replacement of its Pre-1973 Aldyl A pipe represents a massive effort because the utility plans to remove and replace the 1,231 miles of pipe in a proposed timeframe reported as in the range of three years, and at a cost said to exceed $1 billion, but that has not yet been formalized. There is some question regarding the selection of only pre-1973 Aldyl A for replacement in PG&E's system, since at least one recent high-profile incident was reported on newer vintage (still pre-1984) Aldyl A.

Developments of Interest

US Congresswoman Jackie Speier of California has been raising the awareness of Congress and Transportation Secretary, LaHood, in two separate actions. First, in May 2011, Speier sponsored House Resolution 22 entitled the "Pipeline Safety and Community Empowerment Act of 2011." The legislation provided for citizens being able to easily access pipeline maps and safety-related information from pipeline owners, prescribed certain changes in pipeline monitoring requirements, and called for the addition of physical safety devices to existing pipelines. The bill is currently under consideration by the House Committees on Transportation and Infrastructure, and Energy and Commerce.

In October 2011, Speier wrote to Secretary LaHood calling on him to direct the Pipeline and Hazardous Materials Safety Administration to "take immediate action to address the long-known safety risks associated with pre-1973 Aldyl-A plastic pipe manufactured by DuPont." She went on to advocate for the removal of this pipe from use in the U.S., and to commend Pacific Gas & Electric for its planned removal of all of its pre-1973 Aldyl A pipe. Citing the DuPont letters to customers, federal safety bulletins, and the Waterloo incident, she chided Congress for not taking action, and urged the Secretary to immediately do so.

Designing Avista's Replacement Protocol for its Priority Aldyl A Pipe

Avista modeled two different approaches to the replacement program, one that was systematic, based on an established timeframe and one that was responsive to problem areas as they were identified.

Systematic Replacement Program

Time Horizon

Determining the appropriate length of time over which to replace the Priority Aldyl A pipe involves the optimization of several factors, including: 1) the overall urgency from a reliability and safety perspective, both present and forecast; 2) potential consequences; 3) the impact of more intensive leak survey methods to better identify priority facilities in need of replacement and in helping reduce the potential for harmful incidents; 4) the ability to effectively prioritize specific projects to better ensure facilities in greatest need are addressed earliest; 5) the availability of equipment and labor resources needed to conduct the work, and the ability to coordinate the work with Avista's ongoing construction programs; 6) program efficiency, and 7) the degree of rate pressure placed on customers, both in absolute terms and in relation to other reliability and safety investments required across the natural gas and electric business. Ultimately, Avista must ensure that management and removal of its Aldyl A pipe is conducted in a way that shields our customers from imprudent risk, while at the same protecting them from the burden of unnecessary costs.

Prudent Management of Potential Risk

Avista believes it is important to establish for our customers and other stakeholders that while there can never be 'zero risk' associated with the program, the potential risk can be prudently managed. On one hand, a replacement program carried out over a very short timeframe cannot prevent the occurrence of all leaks forecast to occur over the course of the program. But at the other extreme, it's clear that setting a replacement timeline that's too lengthy would likely result in safety, reliability and financial consequences for our customers and our business that could be regarded as imprudent. Avista believes the timeline for the replacement program should optimize the factors mentioned above in a way that reduces the risk associated with Aldyl A pipe to the range of 'prudent risks' associated with the myriad other electric and gas facilities and practices that are used to serve the energy needs of utility customers. Said differently, there is no possible way to eliminate the risks associated with energy infrastructure, but there is a range of limited risk that's deemed prudent in the conduct of our business. Avista's treatment of its Aldyl A pipe will be managed to comport with these sound business practices.

Prioritizing the Work

As important as the replacement timeline in prudently managing the reliability of Avista's Aldyl A piping, is the ability of the Asset Management and Distribution Integrity Management staff to partner in effectively prioritizing the pipe-replacement activities in a way that minimizes the potential for hazardous leaks. Results of the Availability Workbench modeling provide some support in prioritization but do not take into account factors such as soil conditions or the proximity to buildings or people. Obviously, a leak occurring in a vacant field will have little, if any, consequence and will likely be detected and repaired during the next leak survey. By contrast, the potential hazard of a leak increases with its proximity to people and structures, so replacing pipe that has a high probability of leaking and is located in populated areas is first priority.

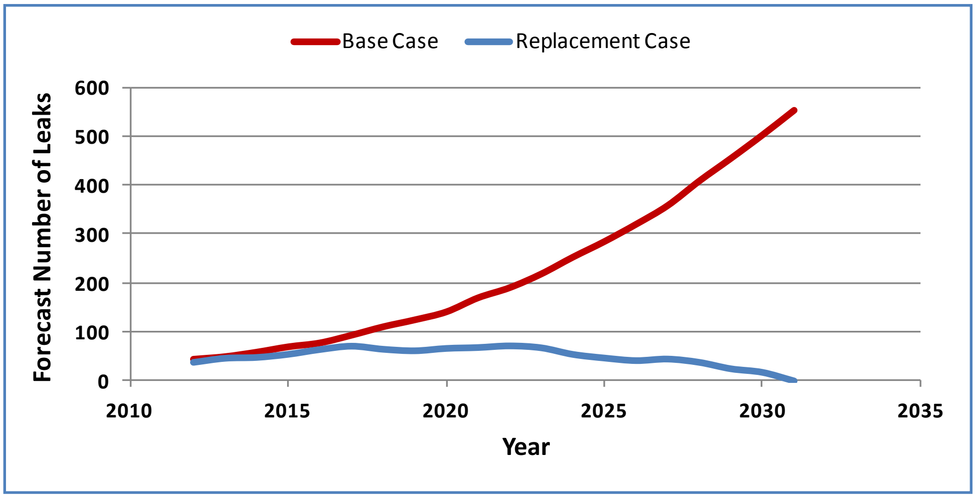
Avista's Integrity Management approach provides the analytical tools that integrate key knowledge and information needed to effectively prioritize replacement activities based on the potential hazard. In the prioritization process, each segment of Aldyl A pipe in Avista's system is assigned a relative risk ranking, based on its age, material, soil conditions, construction methods, and its maintenance and leak history. This information is then loaded into Avista's GIS database containing the gas system maps. These maps contain a "layer" of grid squares (50 feet per side) that correspond with sections of the Aldyl A pipe. Each square is known as a "raster" and each raster contains all of the risk-related information that was loaded into the GIS system, as associated with the Aldyl A pipe, at that precise geographic location.

Next, the software integrates the historic leak information for Aldyl A pipe on Avista's system with the risk data associated with each of the Aldyl A pipe segments, and predicts the geographic areas (via the risk rasters) where Aldyl A pipe failures are expected to be greatest. In the last step, the software integrates the results for expected failures with information for each risk raster that identifies the potential consequence of a leak on that segment (i.e. the proximity of that raster to buildings and people, and the population density/sensitivity of those structures). The end result is a color-coding of the rasters that provides a visual picture of where on the gas system that both the potential likelihood of a leak, and the potential consequence of a leak, are greatest. This approach provides Avista with a comprehensive and objective means of identifying Aldyl A pipe that has the highest priority for replacement.

Twenty-Year Proposal

Avista modeled various time horizons for the replacement program, up to a timeline of 30 years, and determined a replacement horizon in the range of twenty years to represent an optimum timeframe for removing and replacing its priority Aldyl A pipe. Shortening the timeline was found to have increasing cost impacts to customers but with little improvement in the numbers of expected facility failures. Lengthening the timeline past twenty years, however, was found to result in a substantial increase in the number of material failures expected. A replacement timeline of 25 years, for example, resulted in more than a doubling of the number of leaks expected when compared with the twenty year horizon. Under the twenty year replacement program, the number of material failures each year is expected to increase slightly until 2017, at which time the cumulative effect of priority piping replaced since 2012 begins to check the failure count and then drive it toward zero over the remaining course of the program (Figure 8).

Figure 8. Expected numbers of material failures in Avista's priority Aldyl A piping in two cases: Replacement Case - piping replaced over a twenty year horizon in the manner proposed by Avista in this report, and Base Case – assumed that priority piping was not remediated under any program.



Importantly, Avista is not saying that experiencing an increase in leaks on our system is "acceptable" per se, in particular, after having had two harmful incidents in the past few years. What we are saying, however, is that by using the Integrity Management model to prioritize work activities in the manner described above, Avista believes it can manage the forecast Aldyl A leaks in a way that significantly reduces their potential occurrence in areas that could result in harm. Under this approach, Avista believes it can prudently manage the replacement of priority Aldyl A pipe with the goal to avoid harmful incidents altogether, and at a reasonable rate impact for our customers.

Initial Optimization

Importantly, Avista's proposal for a 20-year replacement program represents an optimization based on the information we have available today. Any number of factors could change as the work proceeds over the first few years that could result in a 'new' optimum time horizon. Avista will be collecting new leak survey and other information each year, and will continue to use its Asset Management models to further refine expected trends and potential consequences, making program adjustments as appropriate.

Responsive Replacement Program

Avista also modeled a very-different pipe replacement strategy to provide a further measure of the efficacy of the systematic replacement program. This scenario, referred to as the Responsive Case, was essentially a reactive approach where pipe remediation and replacement activities would be driven by leak survey results and the magnitude of leak consequences. Under this case, it's expected that pipe replacement activity would commence at a lower level than in the systematic case, but would also vary significantly from year to year, depending on patterns of detected leaks and their consequences. Ultimately, however, the expected activity and spending levels would far exceed both the annual and cumulative costs of the systematic approach. This is because pipe segments are not replaced ahead of actual material failure (as happens in the structured case) and so the resulting work activity more-generally follows the geometrically-increasing numbers of material failures expected over time. This scenario was easily judged as failing to provide an appropriate measure of prudence, including system safety, reliability, cost-efficiency, or business risk. Without a prioritized replacement protocol in place Avista would be resigned to replacing pipe in response to serious leaks and potential incidents, after-the-fact, rather than with foresight. Such was the case with the Aldyl A replacements Avista completed in 2011.

From a practical standpoint, Avista believes that by managing the replacement of its priority Aldyl A pipe in a systematic way it can prudently manage potential risks and impacts to its customers and other stakeholders, plan for and use construction resources most efficiently, and plan more effectively for the capital and expense requirements necessary for the effort. This is clearly the case when compared with a responsive approach.

Dr. Palermo's Assessment of the Proposed Protocol for Managing Avista's Priority Aldyl A Piping

Following Avista's Integrity Management evaluations of failure trends in its Aldyl A piping, and the development of its proposed protocol, we invited Dr. Palermo to review the completed protocol and to judge, from his expert perspective, the overall effectiveness and adequacy of the program. Dr. Palermo completed his review in February 2012, and judged Avista's protocol to be highly responsive and appropriate to the management needs of the priority Aldyl A pipe in Avista's system. In particular, he noted his support for Avista's priority focus on pre-1973 Aldyl A pipe, and on the plan to remove and replace its pre-1984 Aldyl A mains. He further noted his agreement with Avista's priority for remediating Aldyl A services tapped to steel main pipe, and to the protocol of "managing in place" existing Aldyl A service piping between the mains and meters. Finally, Dr. Palermo agreed with the proposed twenty-year replacement time horizon for Avista's priority Aldyl A pipe, noting the reliability modeling results, and the effectiveness of Avista's increased leak survey and application of Integrity Management information, tools and analysis in prioritizing pipe replacement activities. Dr. Palermo reviewed and approved this affirmation prior to the finalization of this report.

Application of Avista's Washington State Study Results to Aldyl A Pipe in the States of Oregon and Idaho

Forty-six percent of Avista's Aldyl A main pipe is currently in service in the State of Washington, and coincidentally, so are 46% of Avista's Aldyl A services tapped to steel mains. Since Avista's leak survey study and subsequent modeling results are based on Washington State data, then it follows that the expected results are most applicable to this jurisdiction. The degree to which the reliability modeling results are applicable to Avista's Aldyl A pipe in the States of Oregon and Idaho depend on factors such as the age of the at-risk pipe and on the known similarity of conditions under which the pipe was installed, including method (trenching or plowing), backfill material, compaction and squeeze-off practices, soil conditions and ambient soil temperature, etc. Avista is aware of at least some general differences among state jurisdictions, including more favorable soil conditions in Oregon, newer pipe materials, and construction techniques potentially more favorable to low-ductility pipe. A contributing complication, too, is the relatively large amount of pipe of unknown age and material in services in Oregon. This territory was acquired by Avista from a utility that did not have a consistent practice of mapping services, and some existing maps were lost before the purchase. As a result, Avista is conservatively managing this 'unknown' pipe as if it was priority Aldyl A pipe, until the time that these segments are verified by records review and possible field verification.

Most important to this discussion, however, is the fact that Avista is using its Integrity Management model to integrate leak survey and other data to develop the priority pipe replacement activities for each year of the program. Since comparable leak survey data from priority Aldyl A pipe in Idaho and Oregon will be included in the prioritization analysis, then regardless of any differences that do affect the expected reliability of the Aldyl A pipe, that inherent reliability will be automatically integrated into the modeling, ensuring that Avista is systematically replacing the pipe at greatest risk, regardless of the jurisdiction. Finally, since the Medford and Grants Pass, Oregon, service territory offers a 12-month construction season, Avista will be able to continuously mitigate priority Aldyl A piping within that area when northern territories are effectively unable to continue working.

Resource Requirements and Expected Cost

Staffing

Avista's proposed Aldyl A pipe replacement project represents a major undertaking, even when spread over a twenty-year horizon. In addition to the scope of the effort, there's added complexity in efficiently managing the project, since Avista's territory extends from Bonners Ferry, Idaho to Ashland, Oregon, a distance of over 650 miles. Each year, the deployment of equipment and inspection and construction personnel will have to be adjusted across this service area in response to the sites identified for highest-priority pipe replacement in any given year. Avista is planning to coordinate with contractors to manage much of this construction, and since this project represents a long-term construction commitment, it is expected that the pool of contractors bidding for this work will be substantial, resulting in advantageous pricing and flexibility of field labor.

Though much of the physical construction will be accomplished through the use of contractors, there will still be a need to increase Avista's internal staffing to manage the flow of information, quality assurance, mapping, and related project documentation. Quality assurance is a critical project element that Avista will rigorously control. Effective remediation of Avista's priority Aldyl A pipe is a critically-important corporate objective, and we must continually ensure that sound inspection, training and auditing delivers the results we expect. Finally, the pipe replacement activities themselves will often have disruptive effects on our customers and others. Avista will carefully coordinate customer and community communications and notifications in an effort to minimize the effects of any disruptions.

Capital Costs

Avista's analysis and planning effort is projecting capital costs just over $10 million annually from the year 2013 – 2032. Actual costs will vary somewhat depending on the prioritization of piping to be replaced each year, among other factors, and the calculated amounts will also be subject to an estimated 2.3% annual inflation. Avista is planning to spend approximately $5 million in capital on this program in 2012, allowing for effective planning with contractors, hiring Avista staff, and developing a solid project management foundation for years 2013 and beyond.

Avista
Study of Aldyl-A Mainline Pipe Leaks
2018 Update

EMPOWER | EDUCATE | EQUIP

ISSUE DATE: April 2018

Report Prepared By:
Scott Gloyna

Report Approved for Issue By:
Gordon Mains

Executive Summary

The scope of this study was to review and update the analysis of Aldyl-A pipe conducted in 2013 based upon leaks and replacements through the end of 2017. The original study developed failure distributions that described the likelihood of leaks occurring on the Aldyl-A pipe installed by Avista for natural gas distribution and to evaluate multiple replacement scenarios. Based upon the original study and additional internal analyses, Avista selected the 20-year replacement program.

The original study identified rocky soil as the soil type most likely to have Aldyl-A mainline pipe leaks. Utilizing soil type specific Weibull distributions, and updated pipe information from the end of 2017 the number of leaks predicted when no proactive replacements are conducted over the next 70 years on Aldyl-A mainline pipe is 12,335 and the cumulative replacement costs is $3 billion.

After updating the model with leaks and replacements from 2013-2018 the expected number or leaks for the remaining period (2018-2088) reduced from 26,792 to 12,335 due to the large amount of the worst pipe already replaced. If the 20-year replacement program where all Aldyl-A pipe is removed continues there is a slight reduction in the expected number of leaks, 255 in the original study and 246 in the updated model.

According to the table below the baseline scenario remains more cost effective when compared to the replacement strategies, but it should be considered that current cost forecasts are based on cost of replacement and effects per leak. Safety risks were also incorporated into the study and while no individual segment of pipe exceeded the supplied thresholds in either scenario the cumulative risk was above the stated thresholds. This results in the projected number of catastrophic events drop from 258 to 5 events over the next 70 years by replacing the Aldyl-A pipe.

While Avista's 20-year structured replacement program has proven to reduce the highest risk in the early years of the program, the continuation of this structured replacement program is both necessary and prudent to mitigating the remaining risks within the system, and to achieving Avista's goal of operating and maintaining a safe and reliable natural gas distribution system.

Results of Aldyl-A Mainline Pipe Leak and Replacement Study

Scenario	Leaks from 2018 through 2088	IRR	Levelized Gr. Mar. Requirement*	Lev ROE*	NPV equity*
Baseline with effects – 2013	26792	9.21%	$16,417	$0	$0
20 Year Replacement with effects - 2013	255	6.04%	$23,229	$6,513	$93,490
Baseline with effects – 2018	12,335	18.04%	$10,785	$0	$0
20 Year Replacement with effects - 2018	246	3.87%	$36,147	$12,214	$177,848

*In Thousands

Contents

Disclaimer

Although every effort has been made by ARMS Reliability Engineers LLC to ensure the accuracy and completeness of this document and reported results, no warranty, express or implied is made by ARMS Reliability Engineers LLC as to the accuracy or completeness of the documentation or reported results. Any decisions made as a result of the information in this report are at the sole discretion of the reader

1 INTRODUCTION

This report has been developed to provide the results of an analysis carried out on the Aldyl-A pipe installed by Avista for natural gas distribution. The scope of the study was to review and update the failure distributions, leak rates and replacement costs originally developed in the original 2013 study.

2 METHOD

During the first phase of this study all available historical data on the Aldyl-A pipe was collected. This included GIS segment, installation year, soil type, leak history, replacement history, location, and length. The various sources of this data were combined in Excel and used to calculate the following:

- The age of the pipe when each of the leaks occurred
- The age of the pipe at capital replacement
- The length of pipe replaced
- The age of the pipe not yet replaced
- The length of the pipe not yet replaced

For the mainline Aldyl-A pipe the data was separated by GIS locations and imported into the Availability Workbench software where Weibull distributions could be developed. Each location had an associated age, soil type, and length. The Weibull distribution was selected, as it is able to provide risk predictions with small samples and can describe infant mortality, chance failure, and wear-out failure behaviors. For two soil types, Control Density Fill (CDF) and Concrete/Grout, a Weibayes distribution had to be used because the numbers of failure events was insufficient for a standard Weibull analysis. For these two soil types the shape factor was set to four to reflect a wear-out failure behavior.

Two models were run for the Mainline Aldyl-A replacement, a baseline scenario with no proactive pipe replacement and a model where all of the Aldyl-A pipe is replaced over a 20-year timeframe.

3 ASSUMPTIONS

The assumptions made during the study were as follows:

1. All models are simulated over a 75 year lifetime
2. A three foot section of pipe is replaced when a leak occurs. This number was included as the location quantity in AWB
3. Only 1.25" OD and greater pipe was considered
4. Soil Types of 0, unknown, or blank was assumed of rocky type
5. All Aldyl-A pipe installed between 1984 and 1987 was manufactured before 1984
6. Pipe of unknown install year was installed in 1970
7. All replacements that were done in 2011 and 2012 were in rocky soil
8. Call out time for corrective replacements includes 1.75 hours of travel time
9. All maintenance costs are included as equipment
10. The PF interval for leak inspections is zero
11. The shape factor, Beta of 4 was used for Concrete/Grout and CDF Soil types
12. Each Exposed Pipe Report for the Davenport and Talent replacement projects reports on an equal length of pipe.
13. Baseline models do not consider any planned capital replacement.
14. Planned replacement of Aldyl-A Mainline pipe costs $357 per three feet in Washington and Idaho and $360 per three feet in Oregon.
15. Unplanned replacement of Aldyl-A Mainline pipe costs $5,071 per three-foot section.
16. Consequences for a Catastrophic Event, Injury with lost time and injury without lost time are applied per Avista standard practice.
17. Safety thresholds were incorporated with the following severity levels
    a. Catastrophic Event: Once per 50 years
    b. Craft Injury, WITH Lost Time/Light Duty: Once per year
    c. Craft Injury, NO Lost Time: Four events per year
18. A different type of pipe is used to replace failed Aldyl-A pipe and as such a second failure of the same length cannot occur in the lifetime.
19. Cost escalations are 2.3% per year.
20. Effects escalation is 10% per year.
21. Revenue Requirement Calculation Assumptions
    a. 75 Year project life
    b. Capital Class 2 (Generation T & D)
    c. Gas: 20% ID, 35% OR, 45% WA

4 MAINLINE ALDYL-A PIPE

4.1 Analysis

As an example, the failure rate curve based on the Weibull distribution developed for Aldyl-A Mainline pipe installed in rocky soil is shown in Figure 1. This curve has the following parameters:

η = 2,548,000 hours or 290 years (63.2% of the installed pipe will generate a leak prior to reaching this age)

β = 3.945 (indicating a predictable end of life)

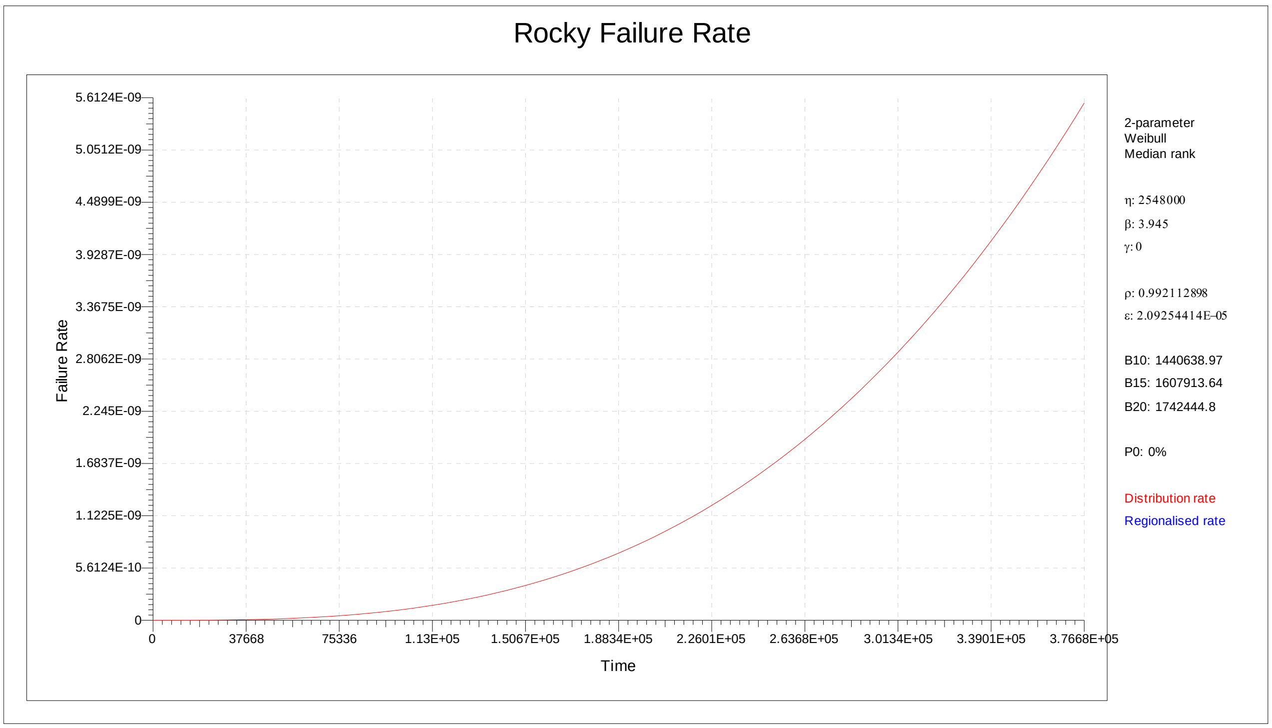


Figure 1: Failure rate curve for Aldyl-A Mainline pipe installed in rocky soil.

Table 1 below shows the change in the failure distributions when the leaks and proactive replacements from 2013 to the end of 2017 were incorporated. While Rocky soil still has the shortest life with an eta value of 290 years, the main change is that the eta values have increased while the beta values have decreased. The result is that on average, the pipe is lasting longer than the original model predicted, but there is less confidence on when it will fail. This is largely due to the large amount of pipe being replaced proactively. The proactive replacement both is removing the pipe with the worst failure rates and incorporates a large amount of un-failed pipe into the Weibull analysis.

Soil Type	Eta 2013 (Years)	Beta 2013	Eta 2018 (Years)	Beta 2018
Clay/Bentonite	473.52	3.40	627.85	3.18
Concrete/Grout	317.24	4	387.21	4
Control Density Fill (CDF)	308.68	4	347.49	4
Loam	311.53	3.95	425.91	3.55
Other	711.19	2.84	1,386.99	2.44
Rocky	221.92	4.36	290.87	3.95
Sand	274.89	4.32	340.98	4.02

Table 1: Weibull Parameters by Soil Type for 2013 study and 2018 study

Using the distribution shown in Figure 1, along with the distributions generated for the other soil types identified in the study and knowing the length of Aldyl-A pipe installed in each soil type that is yet to be replaced, the expected number of leaks in Aldyl-A if the replacement program is stopped was calculated over a ten-year period. The predicted number of leaks on Aldyl-A pipe for the next 10 years with no proactive replacement program is shown in Figure 2.

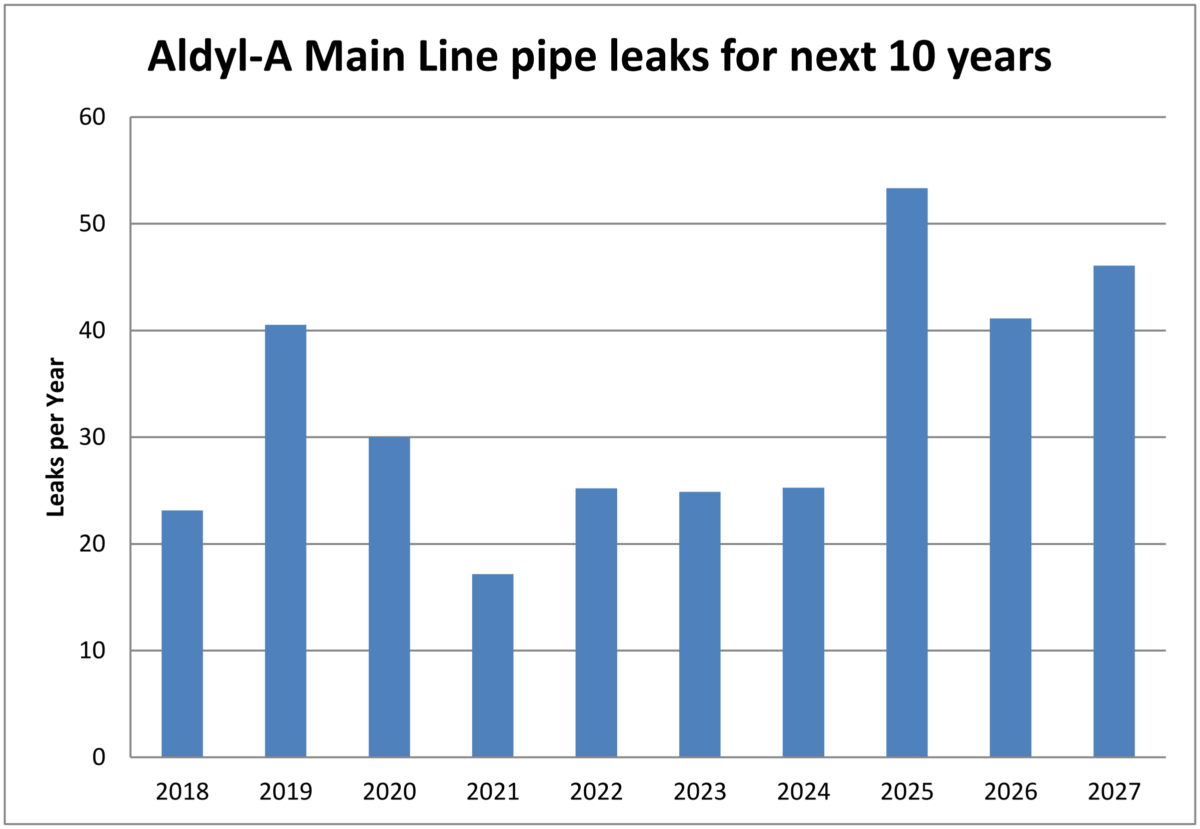


Figure 2: Predicted number of leaks per year in Aldyl-A mainline pipe for next 10 years.

Note: The prediction shown above in Figure 2 and in Figure 3 and Figure 4 assume that repairs are only carried out when a leak occurs. The effect of capital replacement on this profile is not considered as part of the baseline.

If the replacement program were to stop the frequency of leaks for the next 10 years ranges from 17 to 53 and the average number of leaks per year is 32. The uneven increase in leak frequency is most likely due to both pipe of different ages failing, and the actual pipe lengths considered.

It should be noted that the 2013 study predicted an average of 52 leaks per year during the same period. This reduction is caused by the proactive replacement of pipe that has been occurring.

As the pipe continues to age the number of leaks is predicted to continue to increase in the baseline scenario. This can be seen in the 70-year leak prediction for Aldyl-A mainline pipe in Figure 3. The model predicts that the leaks will increase from an average of 36 leaks per year over the next 10 years to an average of 174 leaks per year over a 70-year period.

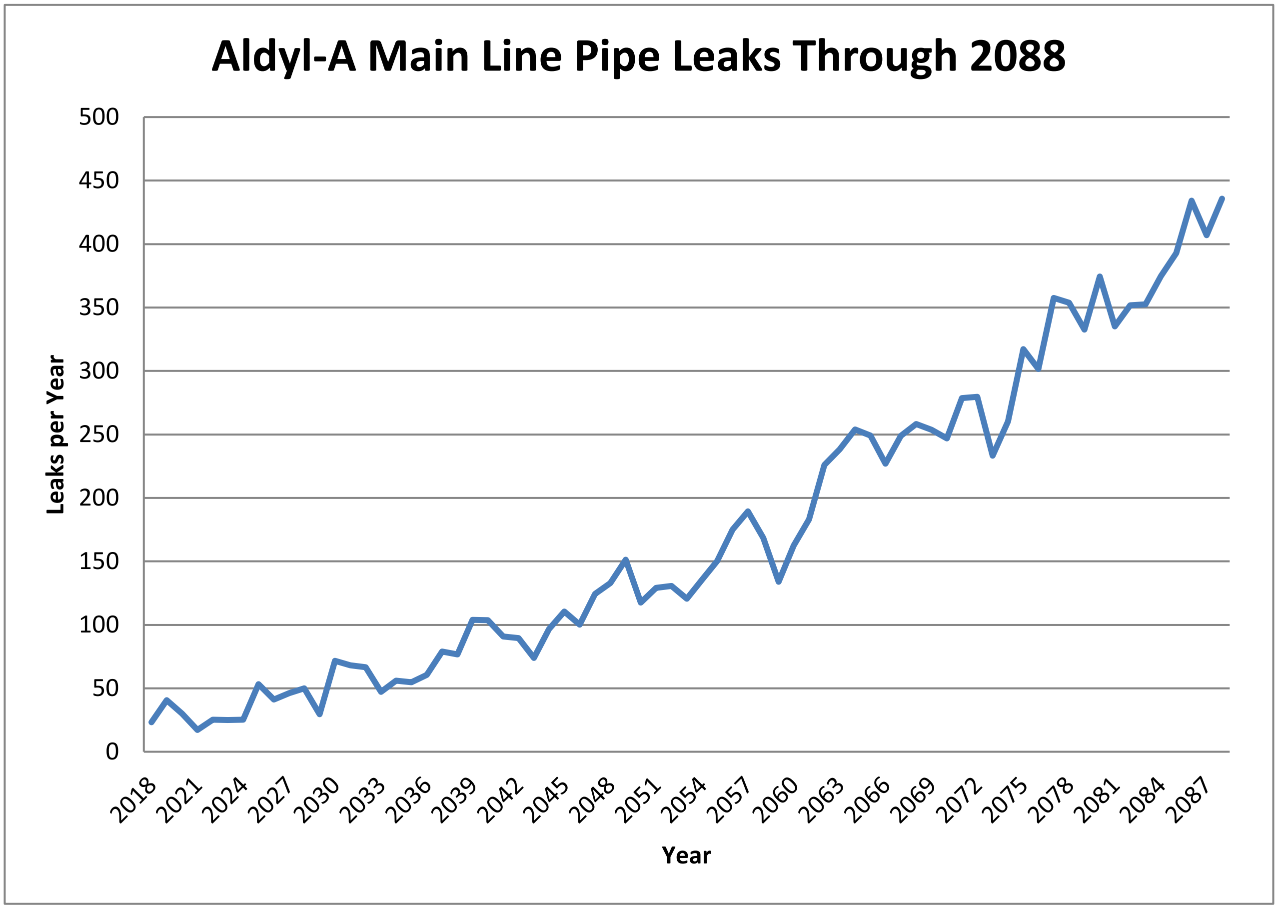


Figure 3: Predicted number of leaks per year in Aldyl-A mainline pipe from 2018 through 2088.

4.2 Maintenance Cost Forecast

By considering all the Aldyl-A mainline pipe installed which has not yet been replaced, a financial forecast can be made based on the number of leaks expected. If an unplanned replacement costs $5,071 is applied to repair each leak, the maintenance budget dedicated to leak repairs can also be determined. The updated baseline maintenance cost forecast is provided in more detail in the following sections of this report.

The total costs, which includes the maintenance costs and effects, is shown in Figure 4 and Appendix A

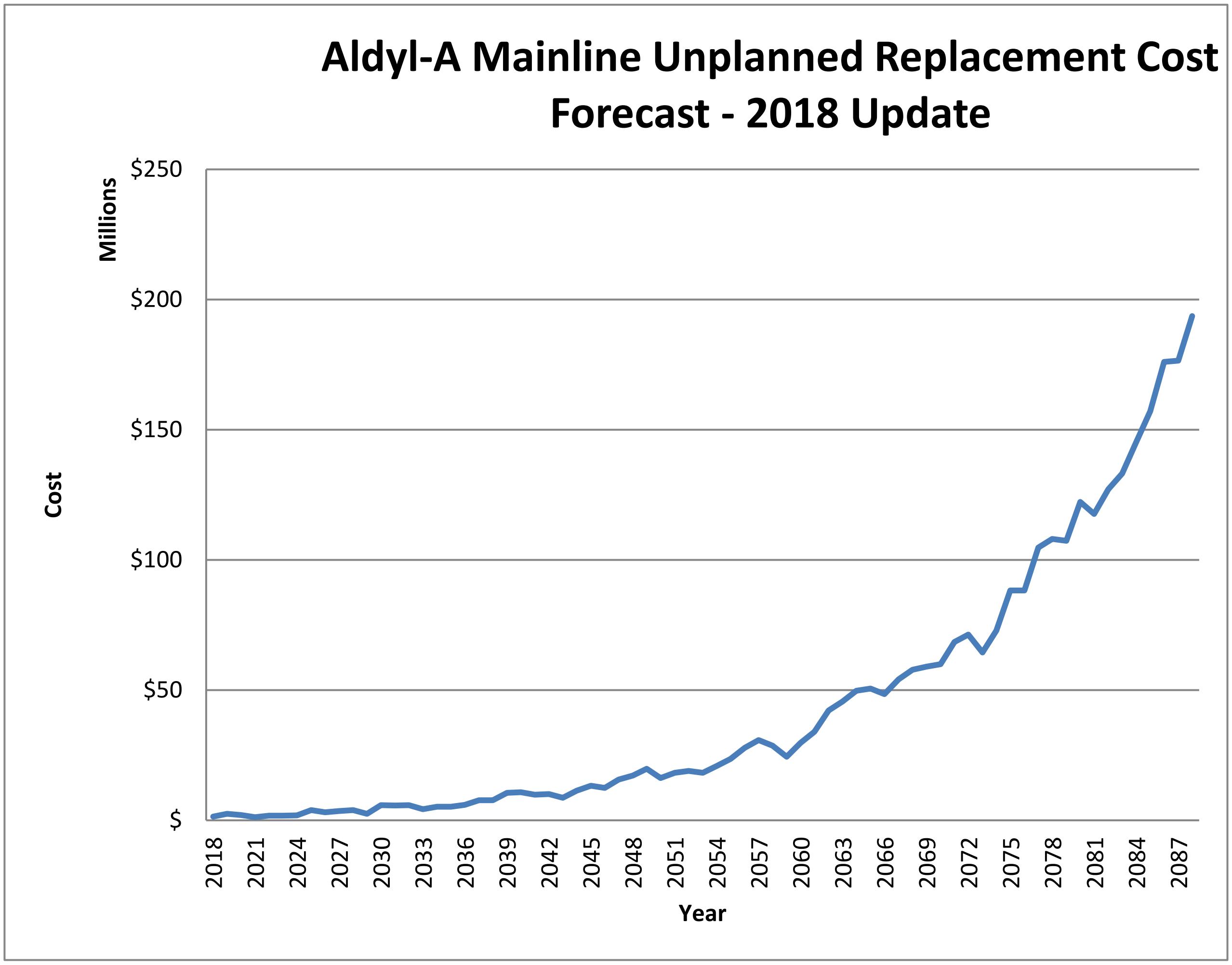


Figure 4: Forecasted unplanned total costs of leaks on Aldyl-A mainline pipe through 2088 per 2018 analysis.

4.3 20 Year Replacement Scenario Update

Avista has previously chosen to replace the Aldy-A mainline pipe over 20 years. To ensure that potential changes in pipe failure rates and costs are taken into account, the results from the 20-year replacement scenario has been updated with pipe replaced from 2013 through then end of 2017 either as part of the replacement program or in response to leaks.

In addition to updated pipe segments, the cost associated with replacement were also updated with current numbers. Capital replacements are assumed to cost $357 per three feet in Washington and Idaho and $360 per three feet in Oregon. These numbers are up from $243.42 in Washington and Idaho and $183.15 in Oregon. Unplanned replacements of leaks are assumed to cost $5,071 per three feet, up from $3,346. The costs were adjusted for inflation and for the additional restoration costs not normally associated with the work (i.e. paving, traffic control, and etc. that get generically billed monthly). Further assumptions are made for the consequence costs, the LCC model and the Revenue Requirement calculator which are standard Avista assumptions and processes and will not be covered in this discussion.

Leaks and capital replacements are not returned to service after repair/replacement to reflect replacing the failed Aldyl-A pipe with a different type of pipe.

Leaks or failures identified through inspection are handled as unplanned replacements with associated costs and consequences. This is reflective of the inspection method which provides no indication of a deteriorating condition, only an indication of a failure or a leak.

The 2018 update of the 20-year replacement program shows a reduction in leaks of 12,079 over from 2018 through 2088 when compared to the updated baseline and an increase of one leak when compared to the original 2013 results. The change in the predictions of the 20-year replacement program is within standard modeling error and could be a result of incorporating the planned replacements that have taken place into the failure rate analysis.

The leak profile comparison can be seen in Figure 5.

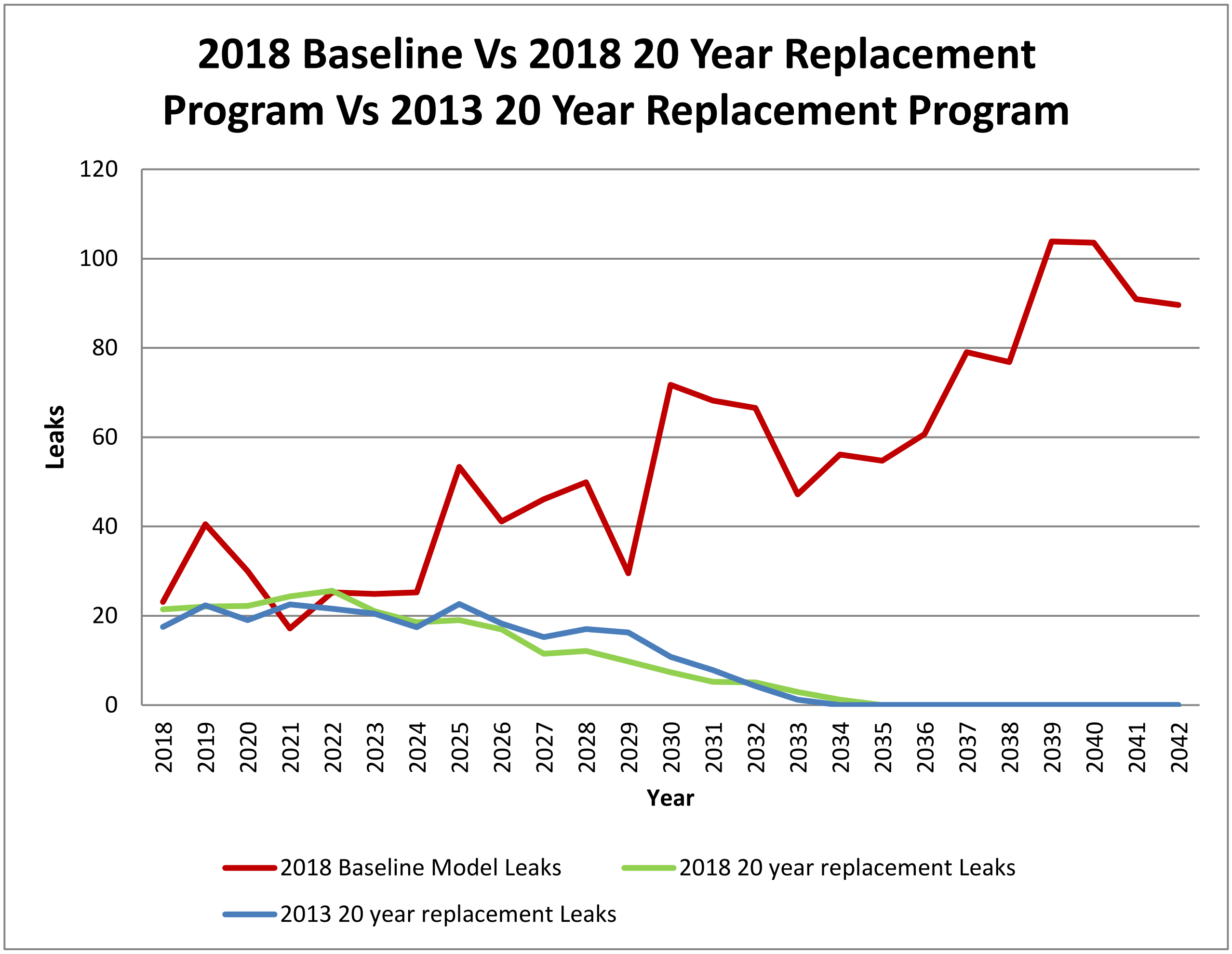


Figure 5: Comparison between Aldyl-A 2018 Baseline, 2018 20 Year Replacement Program and the 2013 20 Year Replacement Program model results.

To show the impact that the replacement program has already had and what can be expected for the remainder of the planned replacements, the total number of leaks over a from 2018 through 2088 are shown below in Table 2. As can be seen, the number of expected leaks if there is no planned replacement program has dropped significantly, while the expected number of leaks with the replacement program has remain basically unchanged.

Study Year	Scenario	Total
2013	Baseline	26,792
	20 Year Replacement Program	255
2018	Baseline	12,335
	20 Year Replacement Program	246

Table 2: Leaks results for Aldyl-A mainline pipe from 2018 through 2088 for 2013 and 2018 studies

To be able to effectively compare the scenarios the results from the RCM and LCC studies were compiled and analyzed in Avista's Replacement Revenue Requirement model. The annual expenditures from this analysis are recorded in Appendix A.

Figure 6 shows the updated cumulative cost comparison of replacing Aldyl-A mainline pipe proactively vs performing replacements as leaks occur. As can be seen, the replacement scenario has significant early life costs when compared to the baseline. After the replacement projects are completed the cost associated with the Aldyl-A pipe is negligible while the baseline maintenance expenditures continue to increase with the increasing number of leaks. Total lifetime expenditures for the baseline surpass the replacement program in 43 years (2061), this is significantly longer than the original study predicted (2049) but that is due to the large amount of pipe that has already been replaced.

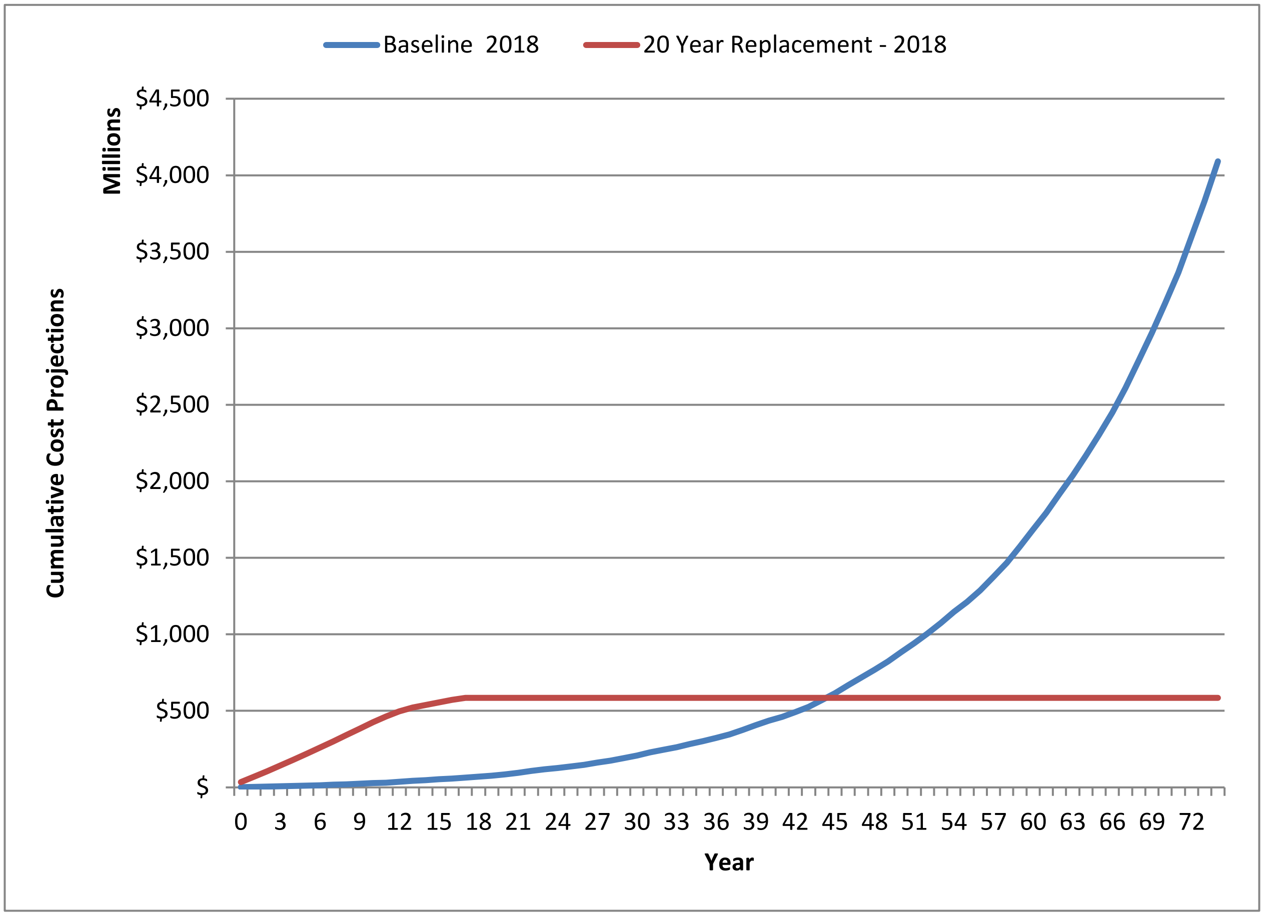


Figure 6: Cumulative Cost Comparison of Aldyl-A mainline Replacement Scenario

Scenario	Leaks from 2018 through 2088	IRR	Levelized Gr. Mar. Requirement*	Lev ROE*	NPV equity*
Baseline with effects - 2013	26,792	9.21%	$16,417	$0	$0
20 Year Replacement with effects - 2013	255	6.04%	$23,229	$6,513	$93,490
Baseline with effects - 2018	12,335	18.04%	$10,785	$0	$0
20 Year Replacement with effects - 2018	246	3.87%	$36,147	$12,214	$177,848

* In thousands

Table 3: Mainline Aldyl-A Replacement Revenue Requirement Analysis Summary

The Aldyl-A Mainline Replacement Revenue Requirement Analysis summary in Table 3 shows that the replacement program is slightly less cost effective than it was in 2013. This is due to the replacement of the worst pipe taking place early in the replacement programs scope. This trend can be expected to continue and should be taken as an indication that the program is meeting its goal of reducing the overall risk of leaks from the Aldyl-A pipe. The option of not replacing the pipe is still more cost effective over though 2088, given the assumptions of the Revenue Requirement model, but it should be noted that as the pipe continues to age the cost and associated risk of leaks increases significantly.

Safety risks and criticality were also considered as part of the study update. It is understood that each failure event (leak) does not always result in an injury and this is incorporated as a percentage of events that result per Avista standard modeling guidelines. The severities used are shown in Table 4 below.

Effect	Severity	% of Failures Where Effect Occurs
Catastrophic event	50 Years	1.82%
Craft injury, WITH Lost Time/Light Duty	1 Year	0.11%
Craft injury, NO Lost Time	3 Months	0.29%

Table 4: Effect Safety Severity and Redundancy Factor

With these assumptions the Safety Criticality was calculated for each segment of pipe in both the baseline and 20-year replacement scenarios. With the pipe that is currently installed, no individual segment exceeded the risk thresholds, but the cumulative risk did exceed the threshold for catastrophic events. The proactive replacement strategy has a significant effect on the overall risk, reducing the expected number of Catastrophic events from 246 to 4 over the next 70 years. It should be noted that slight changes in the percentage of failure events where the effect would occur can have large impacts on the final criticality.

5 CONCLUSION

This study builds upon the 2013 study which showed that soil type was a major contributor to failure rates for Aldy-A pipe. While the basic findings which indicate Rocky soil has the highest likelihood of failure have remained unchanged (see Table 1), the new analysis has shown that the proactive replacements have had a positive effect on failure rates by increasing the characteristic life (eta) of the pipe by an average of 169.7 years. This increase does come with reduced certainty of exactly when failure will happen with the beta value reducing by an average of 0.25 for all soil types.

The 2013 study predicted a total of 26,792 leaks on Aldyl-A mainline pipe from 2018 through 2088 years without any form of a proactive replacement program. Based upon the proactive replacements that have occurred, the number of leaks predicted over the same period has reduced to 12,335 with 246 catastrophic events if the proactive replacement were to not continue.

With the current replacement of all Aldyl-A pipe by 2035, the number of predicted leaks from 2018 to program completion reduces slightly, moving from 255 to 246 leaks of which 4 have the potential to be catastrophic events.

The Avista Revenue Requirement Calculator shows that it is less costly to maintain the current system rather than proactively replacing all Aldyl-A mainline pipe, but it should be considered that current cost forecasts are based on cost of replacement and effects per leak.

While Avista's 20-year structured replacement program has proven to reduce the highest risk in the early years of the program, the continuation of this structured replacement program is both necessary and prudent to mitigating the remaining risks within the system, and to achieving Avista's goal of operating and maintaining a safe and reliable natural gas distribution system.

6 FUTURE DATA COLLECTION

Future data collection focused on better documentation of failures to easily attribute these to Aldyl-A pipe would make it possible to refine the Weibull sets and improve accuracy of model predictions. A better understanding of how soil type affect failures will allow for targeted replacement based upon likelihood of failure. Also, further refinement of per occurrence cost for both planned and unplanned replacements and the associated effects will produce improvement in cost forecasting.

The below Availability Workbench models and excel files have been included in the attachment:

Aldyl-A_Mainline_20YrReplace_2018.awb

Aldyl-A_Mainline_Baseline_2018.awb

2018 Aldyl-A Model Update_Revenue_Requirement.xlsm

For any further information regarding this report please contact:

Scott Gloyna
ARMS Reliability Engineers
Phone: 512-795-5292
Email: sgloyna@armsreliability.com

APPENDIX A – MAINLINE ALDYL-A PIPE ANNUAL EXPENSES PER YEAR BASED ON AVISTA REVENUE REPLACEMENT CALCULATOR

Year	*Baseline Model - 2013*	*20-Year Replacement – 2013*	*Baseline Model - 2018*	*20-Year Replacement - 2018*
2018	$2,768,005	$17,358,435	$1,496,379	$61,501,245
2019	$1,660,312	$18,218,004	$2,623,336	$62,981,210
2020	$1,730,966	$17,973,699	$2,019,458	$64,442,060
2021	$3,499,201	$18,985,577	$1,234,137	$66,193,994
2022	$4,925,618	$19,501,977	$1,809,645	$67,881,054
2023	$4,880,447	$19,365,478	$1,838,287	$68,810,857
2024	$4,747,529	$19,606,495	$1,916,764	$70,036,504
2025	$5,123,168	$21,534,237	$3,981,535	$71,706,793
2026	$4,519,919	$21,076,111	$3,193,069	$73,034,193
2027	$6,249,062	$20,547,201	$3,650,847	$73,867,356
2028	$5,886,914	$21,629,593	$4,044,537	$75,643,774
2029	$8,341,754	$24,204,686	$2,556,338	$64,905,140
2030	$8,130,556	$21,657,261	$6,015,527	$60,997,106
2031	$7,091,184	$21,951,619	$5,887,637	$44,702,636
2032	$8,308,972	$22,528,242	$5,905,559	$28,442,059
2033	$11,558,254	$23,920,821	$4,407,520	$28,700,776
2034	$8,624,054	$54	$5,313,572	$29,052,089
2035	$14,231,303	$148	$5,343,060	$24,851,075
2036	$9,286,458	$92	$6,046,922	$
2037	$10,436,924	$66	$7,949,943	$
2038	$14,639,935	$127	$7,956,556	$
2039	$14,902,569	$112	$10,841,251	$
2040	$18,513,248	$99	$11,109,812	$
2041	$16,612,017	$109	$10,118,637	$
2042	$24,180,445	$197	$10,270,586	$

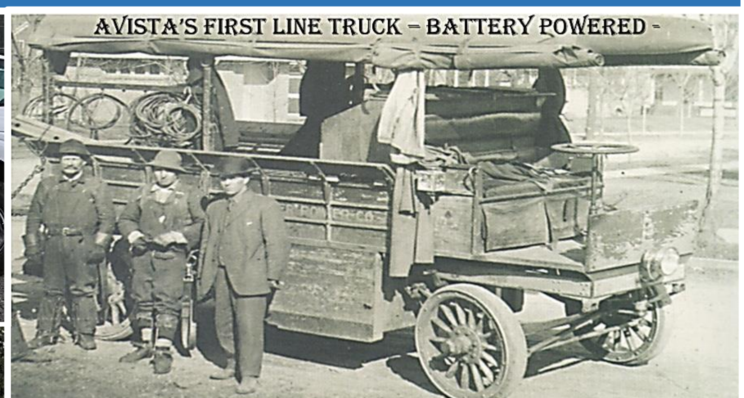
2043	$21,360,174	$194	$8,890,772	$
2044	$21,464,664	$186	$11,664,990	$
2045	$28,159,708	$175	$13,566,634	$
2046	$28,103,552	$192	$12,774,871	$
2047	$34,714,096	$253	$16,018,269	$
2048	$32,353,197	$246	$17,532,703	$
2049	$32,105,620	$201	$20,300,245	$
2050	$39,925,133	$289	$16,626,309	$
2051	$40,815,099	$331	$18,643,501	$
2052	$45,896,431	$408	$19,450,184	$
2053	$45,768,912	$326	$18,670,971	$
2054	$50,456,902	$349	$21,387,078	$
2055	$51,042,099	$369	$24,146,643	$
2056	$57,321,609	$340	$28,499,248	$
2057	$62,998,111	$399	$31,547,188	$
2058	$66,025,281	$397	$29,368,841	$
2059	$69,912,764	$369	$24,958,750	$
2060	$72,925,486	$445	$30,384,694	$
2061	$82,840,530	$558	$34,807,376	$
2062	$79,252,603	$425	$43,078,035	$
2063	$97,983,309	$619	$46,629,474	$
2064	$97,760,020	$613	$50,857,240	$
2065	$106,183,812	$613	$51,715,346	$
2066	$109,769,824	$666	$49,439,082	$
2067	$126,136,597	$762	$55,282,848	$
2068	$133,596,627	$802	$59,044,319	$
2069	$133,736,191	$853	$60,283,820	$
2070	$141,958,882	$762	$61,148,120	$

2071	$155,150,583	$976	$69,908,026	$
2072	$133,517,706	$772	$72,768,143	$
2073	$170,774,975	$1,063	$65,650,856	$
2074	$189,628,157	$1,051	$74,271,741	$
2075	$210,917,084	$1,322	$90,000,418	$
2076	$208,313,915	$1,054	$90,030,087	$
2077	$223,209,649	$1,244	$106,772,575	$
2078	$246,975,709	$1,449	$110,098,227	$
2079	$240,213,479	$1,516	$109,421,453	$
2080	$245,517,144	$1,516	$124,549,809	$
2081	$277,541,496	$1,748	$119,758,689	$
2082	$303,475,254	$1,780	$129,447,210	$
2083	$309,803,301	$1,978	$135,555,922	$
2084	$349,869,383	$2,326	$147,872,500	$
2085	$389,165,746	$2,388	$159,836,970	$
2086	$386,439,169	$2,187	$179,133,673	$
2087	$381,916,092	$2,237	$179,508,246	$
2088	$439,216,355	$2,535	$196,880,391	$

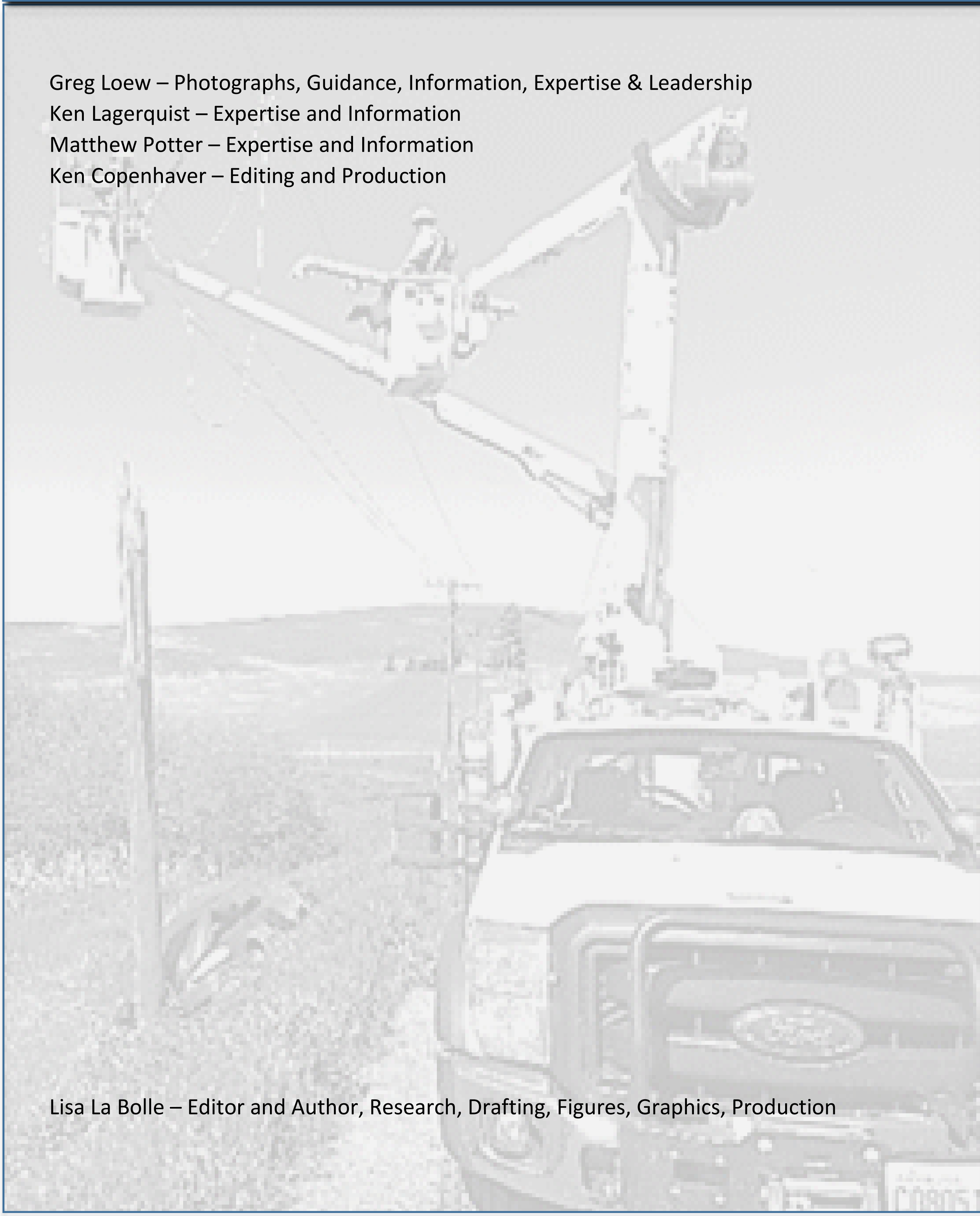
Avista Utilities

Fleet Infrastructure Plan

2020



Thanks & Acknowledgements



Greg Loew – Photographs, Guidance, Information, Expertise & Leadership
Ken Lagerquist – Expertise and Information
Matthew Potter – Expertise and Information
Ken Copenhaver – Editing and Production

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

Table of Contents

Table of Figures

Introduction

Often the most visible representation of Avista to customers are the trucks they see on the road and in their neighborhoods, bringing people and equipment needed to fix a problem or maintain equipment. In fact, a 2018 Avista brand study found that customers are most likely to see and identify with Avista via their bill (69%) and/or the Company's vehicles (65%).[1] These vehicles and associated gear are an essential part addressing customer needs and performing the work required to be an effective and efficient electric and gas utility. This report is focused on Avista's Fleet Management group, those who provide and manage the vehicles and related equipment that play a central role in serving customers.

Avista's Fleet Management team is responsible for mission critical assets that have a direct and significant impact on achieving corporate objectives to provide good service to customers. Utility fleet management requires significant expertise in managing diverse and often geographically dispersed, complex, specialized and sophisticated assets. These fleet assets are wide ranging in type and nature, and can include pickup trucks, service trucks, excavation equipment, backhoes, boom trucks, and a variety of portable and specialty equipment. At Avista, Fleet's area of responsibility also includes motor pools of shared vehicles for corporate staff as well as specialized wheeled equipment such as air compressors, welders, and generators for field crews.

Avista's Fleet Group performs maintenance, repairs, fueling, purchasing and retiring of all these assets, as well as a variety of other tasks intended to uphold the safety and dependability of the Company's vehicles and equipment. They also perform complex and sophisticated work designed to manage the entirety of the fleet and maximize its value, availability, and service levels.

[1] 2018 Avista Brand Study, https://avistacorp.sharepoint.com/:p:/s/SP/surveyresults/EeEzUOReBexJuJV_gFZ_AFUB8P14pMSE20MVoajcUJkbSg?rtime=2-Y98T0910g, Slide 16. It should be noted that bills are an unpleasant association whereas vehicles are typically a pleasant association.

Avista's Fleet is very metrics focused. Using sophisticated asset management techniques, these employees determine the appropriate lifecycle and amount of work needed to deliver readiness of equipment for the least cost. They model costs and benefits in order to maximize asset value. They also use a complex industry model that compares Avista's assets and their performance with those of other utilities across the U.S. This allows Fleet to pinpoint problem areas before they can cause a loss in service, determine if Avista is on track with industry performance standards, and provides information to make rapid and effective changes in their management techniques as needed. This technology helps the Fleet group deliver the most effective fleet management possible. The team has a philosophy of continuous improvement in both managing their resources and in providing everything Avista crews need to quickly and efficiently address any kind of condition in the electric and gas systems. They are keenly aware that the faster the Company can address problems, the better it is for customers, and that the vehicles and equipment they manage are key to a rapid and effective response to issues and providing top level customer service.

Fleet is also faced with the realities affecting fleet operators nationwide: increasing replacement costs for vehicles and equipment, volatile fuel costs, budgetary pressures to reduce costs, increasing regulatory burdens related to issues like emissions, alternative fuels, use of electric vehicles, more sophisticated technology systems both in the vehicles themselves and for use in managing the fleet, and much more. This report attempts to explain the work done by Avista's dedicated Fleet team, their methods and priorities, tools and techniques, and the wide range of equipment under their area of responsibility. It defines the ways in which this group is meeting the challenges faced by the Company and by their peers. It further describes their spending and budgets and the ways they manage expenditures to get the most value for the dollars they are allocated.

Fleet Management

The basic goal of Fleet Management at Avista is to manage all the assets under their control in a manner that is sustainable and cost-effective while ensuring that the vehicles and equipment needed to perform the work of the utility are available when needed.

Fleet Shop Locations

- *Mission Campus*
- *Dollar Road*
- *Clarkston*
- *Coeur d'Alene*
- *Colville*
- *Pullman*
- *Sandpoint*

In order to maximize safety, reliability and responsiveness to meet customer needs including emergency outage restoration, vehicles and equipment should be in optimal working condition. At Avista, 80% of the maintenance is performed in-house. The Company believes that having expertise available at primary work sites rather than depending upon outside expertise helps control the cost and timeline of the work.[2] The work can get done when it *needs* to be done, rather than waiting on someone else's schedule. It also helps to ensure that safety remains a top priority when working on these assets and as part of their functionality. Most importantly, Fleet believes that one of their primary missions is to provide high availability levels, which specifically benefits Avista customers. Avista maintenance shops currently provide an availability of around 95%.[3] Their focus provides the vehicles and equipment needed to quickly respond to customer requirements as well as efficiently manage routine work and maintenance and system events such as outages and equipment failure or damage. When customers need Avista to resolve an issue, the Company wants to be there, as quickly as possible and fully prepared for whatever may be encountered.

Avista crews work to free a customer vehicle that snagged distribution lines. They use a digger derrick (left) to hold the lines up and a bucket truck (right) to place the lineman into position.

This management strategy also benefits Avista employees. Work crews can spend hours at a time in their vehicles. Crews are most effective and efficient if the tools and equipment they need are right at hand. They value having

[2] Outsourcing maintenance for utility vehicles is quite expensive. In Avista's experience this typically costs between $75 and $125 per hour, as compared to the total loaded labor cost for an Avista Journeyman Garage position at around $67 per hour (per Avista Human Resources data).
[3] In the industry, typically new equipment is available 92–98% of the time, older equipment is usually available 80-85% of the time. Source: Lori Sullivan, "3 Ways to Ensure Availability of Equipment," May 3, 2016, https://www.fleetio.com/blog/3-ways-to-ensure-availability-of-equipment. Note that Avista's average unit age is almost exactly the same as the utility industry average unit age.

work vehicles that perform exactly as they want and expect. In effect, the trucks and the crews operate as a unit. These vehicles are mobile work platforms that allow Avista crews to operate and maintain

the electric and gas systems. Having a reliable, properly outfitted vehicle allows them the flexibility of handling almost any type of task that may arise during their working day or in emergency situations.

Properly maintained equipment also contributes to a safe work environment. A poorly maintained vehicle can fail at critical moments, potentially causing accidents and putting lives in jeopardy.[4] Avista addresses potential fleet safety risks in three primary ways: appropriate preventative maintenance on all Company vehicles and equipment, repairing identified issues as quickly as possible, and requiring employees to walk all the way around a vehicle to inspect it (and any specialized equipment associated with it) before it is driven or used. Many of Avista's Fleet vehicles also include specialized accessories like aerial platforms, diggers, cable spools, etc. which are also regularly inspected by specially trained personnel to ensure safe working order.

Fleet also strives to provide clean, high quality vehicles. As mentioned earlier, Avista's vehicles are often the most powerful and visible positive symbols of Avista seen by customers. These vehicles are ambassadors. Just as a dilapidated customer service center can turn customers away and make them doubt the integrity of Company spending, clean professional-looking vehicles instill confidence in Avista's ability to handle any kind of situation. When a big Avista line truck rolls down the street while customers are experiencing an outage, it is reassuring to see a fully loaded professional rig with a crew fully capable of restoring the power quickly.

Specialized equipment needed to set a pole – a backhoe, a service truck, and a digger derrick.

The Nuts and Bolts of Managing a Diverse Fleet

So how does a small group of employees manage such a large and diverse group of assets? At Avista, Fleet mechanics and servicemen provide nearly all the mechanical and automotive related services equipment, and keep that equipment

[4] In fact, motor vehicle crashes are the leading cause of work-related deaths in the U.S. Source: "Motor Vehicle Safety at Work," National Institute for Occupational Safety and Health, https://www.cdc.gov/niosh/motorvehicle/default.html. According to the National Highway Transportation Safety Administration, 20% of those accidents are due to poor maintenance of the vehicle. Carlos Berdejo, "Importance of Car Maintenance To Help Avoid Car Accidents," SAGAS Insurance Pros, https://sagazpro.com/blog/2017/9/18/importance-of-car-maintenance-to-help-avoid-car-accidents

functioning as expected. These experts are available every weekday from 6:30 a.m. until midnight to provide crews with adequate equipment, and to keep that equipment functioning as expected. This extended availability ensures that the vehicles needed for each day's work are ready to go when the crews require them. After hours, crews have access to an emergency phone number to get whatever help is needed. There are also a limited number of loaner trucks, trailers, and a backhoe available if a crew's regular vehicle is out of service. These vehicles are stocked with a basic inventory of tools and supplies, which allows work to continue even if a regular vehicle is undergoing repairs or routine maintenance. Any requests for new or replacement vehicles or accessories go through a rigorous review process, as Fleet manages their portfolio using data and analytics, so these requests must be vetted with specific requirements for adding to inventory. This process creates awareness of the impact to existing vehicles, manpower requirements, and budgets. It will be described in more detail in this report.

Avista Fleet Crew

19 Journeymen Mechanics
5 Garage Foremen
4 Garage Servicemen
1 Coordinator
2 Drivers
1 Parts Specialist
2 Fleet Specialists
1 Fleet Analyst
2 Assistants
1 Manager

Avista's service territory extends over more than 30,000 square miles of very diverse climates and conditions, from steep mountain canyons to desert terrain, cities to farmland. Vehicles providing customer service in Sandpoint face different challenges than those faced by Spokane-based crews or those out in the Palouse. Different types of equipment are also required for different locations and conditions. Avista's Fleet group is responsible for ensuring that the right assets are in the right places, always at the ready to provide any service required of them wherever they may reside. This is especially true in emergency situations such as windstorms, but it is also a necessity for everyday activities like dealing with minor outages, replacing a failed pole, installing new service, or performing routine maintenance.

Left: Crane setting a pole on a steep hillside.
Below: Line truck faces conditions in Sandpoint

A Focus on Safety

Avista has a very strong commitment to safety and safe work practices. In keeping with this philosophy, employees are always required to wear seatbelts on Company time (and strongly encouraged to do so on their own time as well). Using mobile devices in a moving vehicle is prohibited and use of alcohol or any controlled substances is strictly forbidden.[5] All Avista drivers must follow safe driving practices and obey all traffic regulations. A valid driver's license or commercial driver's license (if applicable) are also required. In addition, as mentioned earlier, employees are required to perform a walk around each time they move their Fleet vehicle to ensure that the area is safe and that there are

[5] This includes prescribed medications that can affect driving capability.

no impediments in the vicinity. Employees also have a rigorous safety protocol to follow, such as testing the integrity of the bucket extension and safety gear before starting their shift and ensuring that they have all of the safety equipment they need (like traffic safety cones, reflective vests and flares) before they begin their work day.

Safety cones are set up around Avista vehicles to protect the public

Fleet also follows stringent safety protocols. All aerial equipment is inspected on a strictly enforced schedule. If a new aerial device (such as a boom, bucket, or crane) is placed into service, they are inspected after purchase by Fleet experts at intervals of 30 days, 90 days, 180 days, and 365 days. Thereafter inspections take place every three months. Fleet has two dedicated mechanics with specialized training to perform these critical safety and mechanical inspections. These inspectors are mobile, so can provide onsite inspections across the service territory, which reduces crew down time and fuel costs by eliminating transport of the Company's large trucks. Dates and records related to these inspections are maintained by Fleet, and decals and forms are placed in each truck after inspection to keep truck operators informed of their vehicle's status.

Crash statistics indicate that a vehicle is 130 times more dangerous in backing up than in driving forward.[6] To help guard against these dangers, Avista installs backup alarms and cameras on every new vehicle as part of their standard equipment.

About one in seven vehicle incidents occur in parking areas,[7] so they are a natural place to focus on reducing on-site incidents. Parking lots are filled with obstacles and hazards like moving vehicles and pedestrians, often not paying attention the way they should. The Company encourages the use of pedestrian crosswalks and promotes awareness of this issue for drivers of Avista vehicles and even employee personal vehicles.

In addition, employees at all levels of the Company are encouraged to back into parking spaces, as this provides better views of the surroundings when pulling out of a parking space, helping to avoid oncoming traffic or potentially bumping into pedestrians. Backing into a parking space has two main advantages: line of sight and maneuverability. Pulling out of a parking area frequently means encountering blind zones created by the vehicles parked alongside which obstruct the driver's vision. In fact, about 20% of all accidents occur during parking,[8] so the Company believes that this is a beneficial focus area. Interestingly, studies have also found that the way employees' park when they arrive at

[6] Smith System "Advanced Backing," https://www.drivedifferent.com/industry/utilities/
[7] "Prevent Parking Lot Crashes," State Farm Simple Insights, https://www.statefarm.com/simple-insights/auto-and-vehicles/prevent-parking-lot-crashes
[8] "Parking Lot Accidents: Statistics, Causes, and Liability," My Parking Sign, 2019, https://www.myparkingsign.com/blog/parking-lot-accidents/

work can affect their safety behavior throughout the workday,[9] which adds additional benefit. Avista wishes to encourage safety as a habit and thus addresses this issue with all employees, especially those responsible for operating Company fleet vehicles and equipment.

- Motor vehicle crashes cost $871 billion in societal and economic harm in the US each year, more than $900 per person.[10]
- Motor vehicle crashes cost employers $60 billion annually in medical care, legal expenses, property damage, and lost productivity. They drive up the cost of benefits such as workers' compensation, Social Security, and private health and disability insurance. In addition, they increase company overhead to administer safety programs.[11]
- The average crash costs an employer $16,500, increasing to $74,000 if there is an injury, over $500,000 if there is a fatality.[12]
- Liberty Mutual Insurance Company surveyed business executives and found that 61% believe their companies receive an ROI of $3.00 or more for every $1.00 they spent on improving workplace safety.[13]

To help specifically address driving related safety concerns, the Company and the Fleet group provide the Smith System Driver Improvement Course for employees. The Smith System is used around the world to teach drivers to drive differently. Avista is in good company utilizing this approach. More than half of the Fortune 500 fleets use the Smith System for driver safety training.[14] The Smith method provides a more thoughtful approach to driving, including the knowledge and tools to make better decisions behind the wheel, which leads to a significant return on investment in terms of crash and injury reduction, maintenance savings, fuel savings, higher employee satisfaction and, most importantly, saved lives.

As an example of the effectiveness of driver improvement programs, Nationwide Insurance found that when they implemented such a program, though miles driven increased by 19% that year, the organization's preventable crashes decreased by 53% and total motor vehicle loss costs went down 40%. Pike Industries, an asphalt paving company in Vermont, has approximately 250 employees. These employees travel over 2 million miles each year hauling construction equipment and materials as well as performing construction activities (many in highly dangerous work zones) similar to what utility crews experience in their daily work. After implementing a focused safety and driver training program like Smith, the number of significant roadway incidents dropped to near zero, workers' compensation claims for vehicle incidents dropped from a high of 73% in total losses in one year to 2% the next. Vehicle property damage losses also followed this trend.[15]

This focused methodology is proven to increase safety. Although it is concentrated on Fleet vehicles and equipment, it applies equally to driving while on company business or driving the family to the movies. It is yet another piece of evidence that Avista cares about the safety and well-being of both their own employees and that of the general public.

[9] "4 Reasons Backing Into Parking Spaces Is Safer," SafeStart, March 23, 2016, https://safestart.com/news/4-reasons-backing-parking-spaces-safer/
[10] National Safety Council, "NHTSA: Motor Vehicle Crashes Have $871 Billion Impact," June 11, 2014, https://www.safetyandhealthmagazine.com/articles/10545-nhtsa-motor-vehicle-crashes-have-871-billion-impact
[11] OSHA, "Guideline for Employers to Reduce Motor Vehicle Accidents," https://www.osha.gov/Publications/motor_vehicle_guide.pdf
[12] Ibid.
[13] Ergoweb, "More Liberty Mutual Data on Workplace Safety," September 26, 2001, https://ergoweb.com/more-liberty-mutual-data-on-workplace-safety/ also: OSHA, "Guideline for Employers to Reduce Motor Vehicle Accidents," https://www.osha.gov/Publications/motor_vehicle_guide.pdf
[14] Smith System, https://www.drivedifferent.com/. The Smith System reaches more than 250,000 drivers annually around the world.
[15] Nationwide & Pike stories from the United States Department of Labor, OSHA, https://www.osha.gov/Publications/motor_vehicle_guide.html

Data and Analytics

So how does Fleet balance risk and investment dollars based upon a limited budget while providing vehicles, equipment, and tools that are always at the ready to work as needed? One of the primary ways they achieve this balance is by using statistical analysis and modeling to determine how to optimize the value of their assets. This data-focused approach helps ensure that maintenance and associated costs remain as flat and predictable as possible, keeping capital outlays low and helping guarantee that the customer gets the best possible value for the funding they provide the Company to operate its fleet. Fleet capital spending averages about 3% of Avista's entire capital budget.

Utilimarc Software Insights:

- Vehicle Safety
- Fuel Expenditures
- Maintenance Costs
- Ownership Costs
- Expenses Compared to Peers
- Technician Productivity
- Fleet Mix Makeup
- Vehicle Utilization
- Staffing Ratios
- Vehicle Lifespan
- Asset Expected Life Cycle Cost
- Staff Wage Comparisons
- Tracking Equipment Throughout Asset Life

Fleet uses a modeling system offered by Utilimarc, an industry recognized software and analytics company, to help develop the most practical and cost-efficient decisions related to managing Avista's assets. The Utilimarc tools incorporate a wide spectrum of data to help develop lifecycle expectations, costs, replacement schedules, etc. The broad base of this dataset includes utility industry benchmarks, purchase and auction data, and nationwide vehicle information, providing visibility into how Avista manages its fleet compared to industry peers. It also contains a robust dataset based on Avista's own fleet data, and uses this information to recommend vehicle replacement dates, develop actual and projected costs, and even suggest staffing and expertise needed to manage the Company's fleet most effectively. It also considers annual expected ownership and maintenance costs for each vehicle and equipment class.

Lifecycle Costs

As would be expected, fleet equipment experiences increasing costs related to its operation as it ages. Those costs are driven by the requirement of more parts and more labor to keep a unit up and running as it gets older. As the average age of a fleet increases, more frequent breakdowns occur, along with a need

Vehicle Type	Utilimarc Estimated Replacement Cost 2019
Light Duty Bucket	$169,000.00
Super HD Digger/Derrick/De	$392,909.00
Light Duty Service Truck	$85,000.00
Heavy Duty Bucket	$320,000.00
Light Duty Pickup	$37,000.00
Stake Truck	$95,000.00
Medium Duty Pickup	$41,037.00
Super HD Bucket	$292,000.00

Figure 1. Utilimarc's Estimated Replacement Costs

for additional parts to keep equipment in service, creating a steady but accelerating trajectory of costs and necessitating more complex repairs and more associated maintenance work hours. Those increasing costs are not just the burden of Fleet; the people who depend upon these vehicles and equipment will see the impact in lost productivity and downtime if a vehicle or key piece of equipment is unavailable when needed. The Utilimarc software helps the Company determine how to optimize the value of each asset and when costs will begin to exceed benefits, indicating that replacement is needed. These analytics assist the Fleet professionals in determining how to globally manage the fleet based on solid asset management practices.

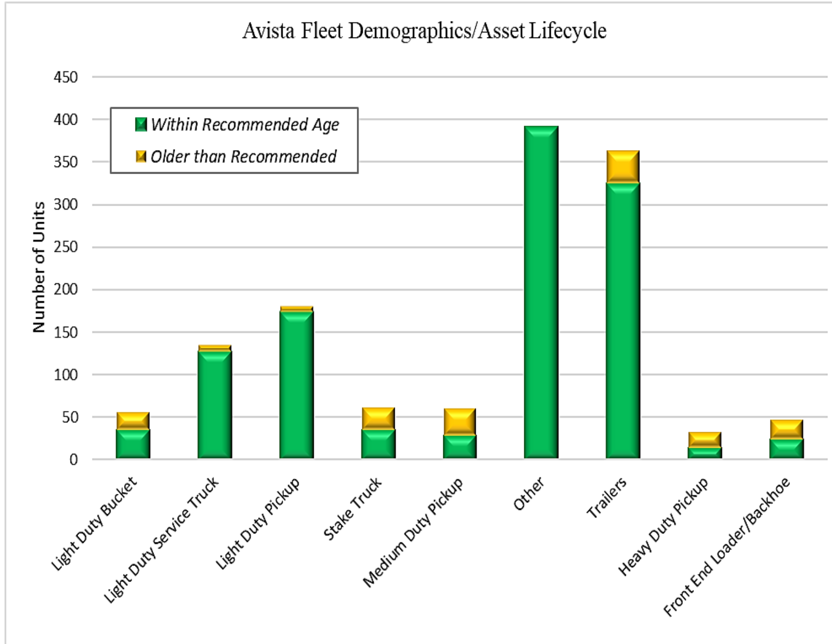


Figure 2. Avista's Fleet Demographics For Recommended Replacement

Avista's average vehicle age is 6.76 years compared to the industry average of 6.4 years.

For each class of vehicle in the Company's fleet, Utilimarc determines what lifecycle achieves the lowest cost of ownership and maintenance for an average asset in that class over its lifetime.[16] The model provides an approximately three year vehicle replacement window, allowing flexibility when planning replacement expenditures to reduce the effect on Fleet's overall budget. The Fleet Manager and Fleet Specialist closely monitor each vehicle, and once a vehicle or piece of equipment reaches its maximum predicted lifecycle based on mileage, hours, and/or overall usage, using the Utilimarc recommendations and their own expertise, they determine if that item should be retired from the fleet and if (and how) it should be replaced. As shown in Figure 2, Fleet's careful management of their inventory is keeping nearly all Avista's vehicles within their recommended lifecycle, helping keep maintenance costs and capital budget requests low and steady.

Vehicle Type	Replacement Age (in Years)
Dump Truck	9-16
Bucket Truck	8-18
Digger Derrick	20
Pickup Truck	9-17
Service Truck	7-13
Stake Truck	18
Cranes	15-20
Passenger Vehicles	5-14
Excavators	11-21
Trailers	20

[16] It does this by calculating annualized total cost for each potential lifecycle. Annualized cost total is the sum of all ownership and maintenance costs a unit incurs over the course of its life, divided by the number of years the unit is in service.

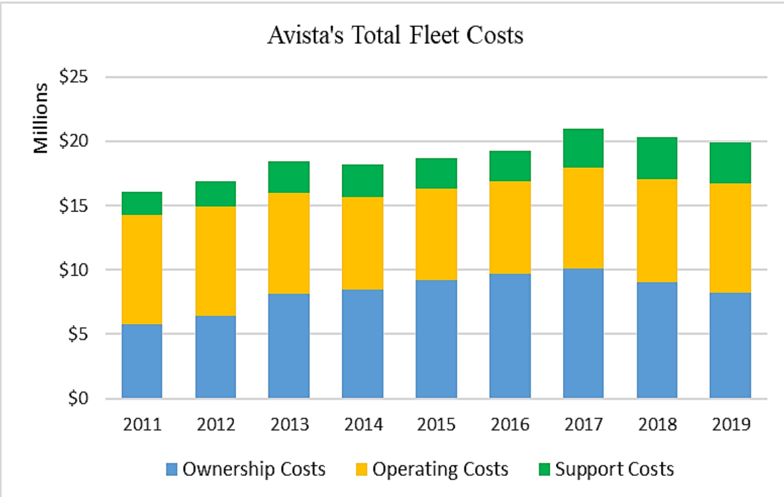


Figure 3. Avista Total Fleet Costs

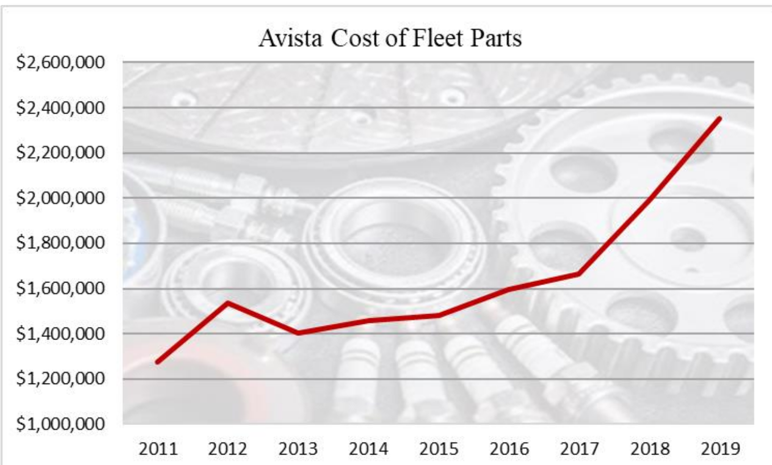


Figure 4. Costs for Parts Over Time

Another consideration is required fleet size.[17] The Fleet group must allow for vehicles to be out of service for maintenance or other unforeseen circumstances. Some assets are more critical than others, especially those that are specialized to particular tasks or one-of-a-kind items, and this criticality is also factored into Avista's maintenance strategies. Fleet must manage their entire inventory to ensure that assets are available when needed under almost any circumstance.

As shown in Figure 3, even with the variability of costs they deal with, Fleet has kept their costs fairly steady. The blue bars, "ownership costs," reflect depreciation, interest costs, and licensing. The yellow bars, "operating costs," include technician costs, parts, outside vendors, and fuel expenses. The green bars, "support costs," contain expenditures for support labor. Just as an example of what this team deals with, Figure 4 shows the cost of parts over the same time period as shown in Figure 3 to provide an idea of the way just one factor impacts the management of Fleet expenses.[18]

Labor Costs

On the employee side of the equation, the Utilimarc tool offers a wage comparison for fleet employee classes, a recommended ratio of staff (and types of staff) to equipment, as well as statistics about technician productivity. Avista's technicians are routinely more efficient than industry averages. For example, Avista's average annual mechanic hours per vehicle in 2018 was 29.2 hours compared to the industry average of 33.4 hours, indicating that Avista's mechanics and fleet maintenance personnel are

[17] For more information about this industry-wide, please see Dan Fellows, "How to Develop a Fleet Replacement Strategy," EMSWorld, April 2016, https://www.emsworld.com/article/12187528/how-to-develop-a-fleet-replacement-strategy
[18] These costs for both Figure 3 and Figure 4 are based on Avista's actual expenditures as tracked by the Utilimarc data system.

highly efficient. In fact, according to Utilimarc, Avista is among the most efficient utilities in the nation in maintaining their vehicles.

As mentioned earlier, Avista believes it is in the best interests of Company operations to perform most maintenance in-house versus outsourcing this critical activity. Avista outsources approximately 11% of its maintenance compared to the industry average of 21%.[19] In-house maintenance allows having more control over vehicle availability, but cost is also a very important factor. Avista Fleet personnel have found that outsourcing maintenance for utility vehicles typically costs between $95 and $125 per hour, as compared to the total loaded labor cost for an Avista Journeyman Garage position at around $67 per hour.[20]

Fuel Costs

Many fleet managers believe one of their greatest challenges is planning, budgeting, and mitigating the variable cost of fuel. Fleet continually assesses expected fuel expenditures and fuel efficiency. Obviously, the size of many of these vehicles makes this a challenge.

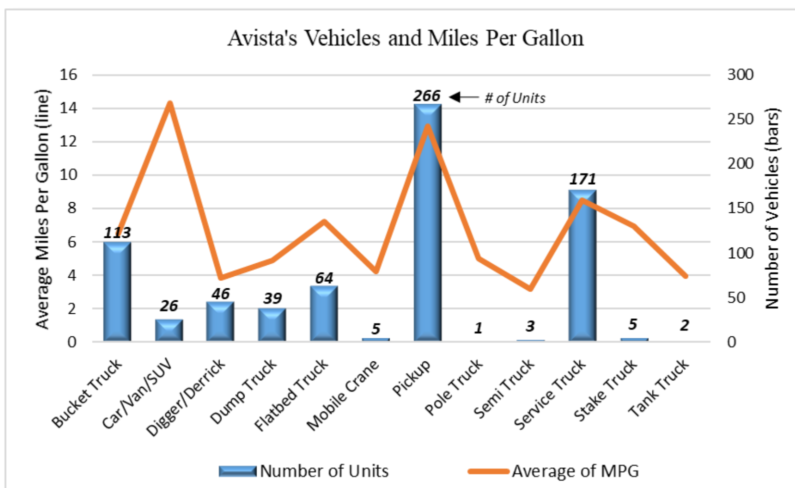


Figure 5. Avista Vehicles and Miles Per Gallon

A combination of addressing driver behavior (over speed, idling, deceleration, acceleration, etc.), selecting more fuel-efficient vehicles when possible, adhering to preventive maintenance schedules, and monitoring fuel usage reports can help, but these cost increases are mostly beyond the control of drivers and fleet managers. The cost is exacerbated by the fact that many Fleet vehicles are very large and do not get high mileage. As an example, some of the largest vehicles such as heavy-duty digger derricks only get about four miles per gallon; the largest bucket trucks may only get around five miles per gallon. The majority of the Company's vehicles are bucket trucks, pickups, and service trucks. These large vehicles drag down the Company average miles per gallon to about 9.3. Thus, fuel costs are always a big factor.

[19] Utilimarc "2018 Fleet Executive Summary: Avista," available upon request.

[20] According to AAA most auto repair shops charge between $47 and $215 per hour for auto repair only, not specifically for the large vehicles Avista utilizes. https://www.aaa.com/autorepair/articles/auto-repair-labor-rates-explained. Avista Journeyman Garage rate is from Avista Human Resources.

In the United States gasoline and diesel prices have varied widely over time, as shown in Figure 6. These commodities mirror the price of crude oil, which is determined by worldwide supply and demand. In addition, taxes add to the price of gasoline. In Washington State, the gasoline and diesel taxes are currently 49.4¢ per gallon with an added federal tax of 18.4¢ per gallon. Only Pennsylvania has a higher state gas tax.[21] The amount of this tax is subject to the decisions of the Washington Legislature.

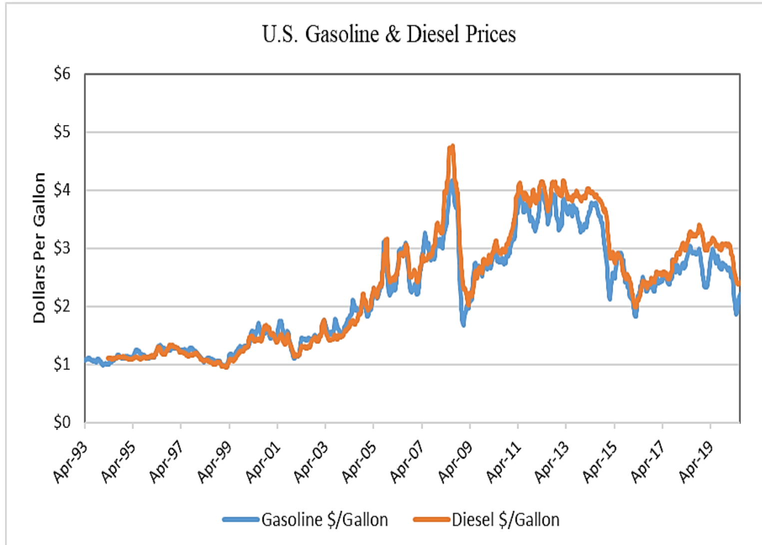


Figure 6. U.S. Gasoline & Diesel Prices Over Time

On a side note, regular drivers of Avista vehicles are given a fuel card so they can purchase fuel as they need it without using their own credit cards and having to submit an expense report. This is another way Fleet has streamlined operations.

Data Tracking

In the Fleet perspective, data is as much a key requirement in caring for assets as the mechanic and his tool set. Vehicle maintenance records provide evidence of failures and the frequency of those events, providing clues about certain vehicle brands or engine types that may be more costly or less reliable than expected. Data provides identifiable patterns that can be incorporated into decision-making. It also provides valuable information that helps continually improve Fleet's asset management practices. This is important, as poor maintenance practices potentially equate to poor customer service. If a key vehicle is not available when needed, breaks down on the way to an outage, or causes other delays due to availability, the customer is poorly served. As mentioned earlier, Fleet is highly focused on availability. Data tracking and maintaining good records helps them stay on top of this. In addition, having a comprehensive set of vehicle records is required by Federal law.[22]

A variety of vehicles may be needed to handle an outage or perform a large installation or repair

[21] "Washington State is Helping You See Exactly How Much You Pay in Gas Taxes," November 17, 2017, https://q13fox.com/2017/11/23/washington-state-is-helping-you-see-exactly-how-much-you-pay-in-gas-taxes/
[22] Federal Motor Carrier Safety Administration, Department of Transportation, § 379.1. https://www.law.cornell.edu/cfr/text/49/379.1

The diversity of conditions across Avista's service territory offers its own challenges. As shown above, crews use a digger derrick to hold up a pole in the river after the riverbank washed out.

Another tool Avista's Fleet group uses to track data is AssetWorks, an asset information management system. Utilimarc provides analysis, statistics, and recommendations on aspects such as asset replacement schedules and costs. AssetWorks is used to track an asset throughout its entire life cycle. It has fully integrated fleet, fuel, motor pool and GPS management systems that Avista's Fleet group uses to keep track of their vehicle maintenance records, track warranties, recalls, ensure that aerial equipment is tested before it is used each day, monitor usage, and handle work orders.

Avista's Fleet also uses the Zonar software system to track and document inspection records and results. The Fleet team utilizes the reports generated by this system to help schedule preventative maintenance and plan repairs efficiently. It is also an important part of the systems and documentation required to remain in compliance with U.S. Department of Transportation regulations.[23] The software also has remote engine diagnostics to provide alerts before issues become serious.

Regulation

Regulatory considerations must also be considered. Any truck or a truck/trailer combination that weighs 10,001 pounds or more must comply with Federal Motor Carrier Safety Regulations regarding maintenance and repair, required inspections, minimum standard equipment, and safety gear specifications. In addition, there are regulations for trucks that include limits on truck sizes, weights and cargo securement rules.[24]

The Washington State Department of Transportation (WSDOT) also administers vehicle size and weight state laws as well as administrative code and issuing the special permits needed to operate vehicles of a size or weight greater than the legal maximum on state highways. They have regulations for

[23] Federal Motor Carrier Safety Administration, https://www.fmcsa.dot.gov/regulations/title49/section/396.17 and https://www.fmcsa.dot.gov/safety/passenger-safety/inspection-repair-and-maintenance-motor-carriers-passengers-part-396

[24] "What Are the DOT Regulations for Trucks?" https://www.reference.com/government-politics/dot-regulations-trucks-1088fb70bee692c

State Regulations:

- *Commercial Driver's License*
- *Vehicle Inspection*
- *Size, Weight, Load*
- *Transportation of Hazardous Materials*
- *Motor Vehicle Transporters*
- *Out-of-State and Interstate Permits*

everything from mirrors to load securement, tires and axels, accident reporting and even recording practices.[25] The Washington State Department of Licensing (DOL) administers state laws and administrative code relating to the licensing and regulation of commercial vehicles and their owner/operators.[26] The Environmental Protection Agency mandates engine and fuel emission controls for non-road diesel engines such as backhoes, forklifts, generators, pumps, and compressors.[27] They also have requirements for all vehicle emissions.[28] There are also national commercial regulations related to everything from driver background checks to vehicle maintenance records.[29]

Federal Regulations:

- *Training Requirements*
- *Drug & Alcohol Testing*
- *Commercial Driver's License*
- *Insurance Requirements*
- *General Requirements*
- *Driver Files (Background Checks, Qualifications, Records)*
- *Rules for Driving Commercial Motor Vehicles*
- *Equipment Requirements*
- *Hours of Service*
- *Vehicle Maintenance Files*
- *Hazardous Materials Transport*

Avista is required by the U.S. Department of Energy (DOE) to acquire alternative fuel vehicles as a percentage of their annual light-duty vehicle acquisitions or, instead, to use specific petroleum-reduction methods. The Company must file an annual report with the DOE to show compliance.[30] To maintain compliance with this directive, Fleet has actively added Compressed Natural Gas (CNG) vehicles as appropriate as well as a CNG filling station on the Mission Campus. They also purchase vehicles capable of running on E85 fuel, which is a blend of gasoline and ethanol.

Compressed Natural Gas Fueling Station on Mission Campus

There are also state regulations related to fuel consumption, utilization practices, driver monitoring, licensing, and reporting requirements.[31] Fleet must track all state, federal, and local regulations associated with every asset type; regulations which continually change over time.

[25] For a full description of WSDOT and National Commercial Vehicle Rules and Regulations, please see: https://www.wsdot.wa.gov/publications/manuals/fulltext/M30-39/CVG.pdf and http://www.wsp.wa.gov/driver/commercial-vehicle-driver/commercial-vehicle-laws/.

[26] https://www.wsdot.wa.gov/publications/manuals/fulltext/M30-39/CVG.pdf

[27] https://www.epa.gov/regulations-emissions-vehicles-and-engines/regulations-emissions-heavy-equipment-compression

[28] https://www.epa.gov/emission-standards-reference-guide/epa-emission-standards-heavy-duty-highway-engines-and-vehicles

[29] http://www.wsp.wa.gov/driver/commercial-vehicle-driver/commercial-vehicle-laws/

[30] The Energy Policy Act of 1992 encourages the use of alternative fuels through both regulatory and voluntary activities. It requires fleets to acquire alternative fuel vehicles including methanol, ethanol, and other alcohols; blends of 85% or more of alcohol with gasoline (E85); natural gas and liquid fuels domestically produced from natural gas, electricity; biodiesel, etc. See: B100U.S. Department of Energy, "State & Alternative Fuel Provider Fleets," https://epact.energy.gov/ and https://afdc.energy.gov/laws/key_legislation#epact92

[31] State of Washington Enterprise Services, https://des.wa.gov/services/travel-cars-parking/fleet-maintenance-service/fleet-management-best-practices

Benefits of a Data-Focused Approach

At Avista, the Fleet group utilizes analysis that is firmly focused upon the key goals of lowest cost of ownership while providing highly reliable (and available) service. This analytical approach has proven highly effective. In fact, the Fleet current monthly availability levels average 95%. At the same time, Fleet capital expenditures have remained very low and stable, as shown in Figure 7.

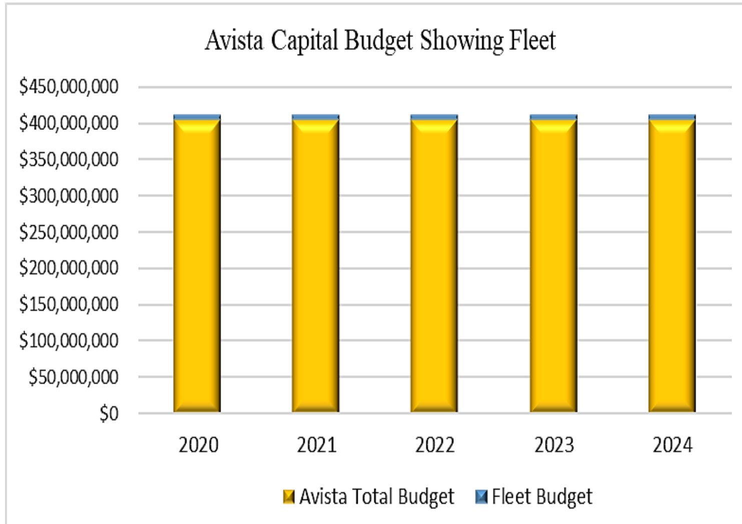


Figure 7. Fleet as Part of Avista Capital Budget

The Utilimarc, Assetworks, and Zonar systems play a valuable role in helping achieve the predictable, consistent capital budget Fleet provides the Company. In part, this is achieved by accurately estimating forward needs and smoothing out potential expenditure "bubbles." For example, if many vehicles are concentrated within relatively few vintages, the Company could experience a sudden increase in parts and labor costs, vehicle downtime, and technician requirements simply due to a large group of vehicles aging at the same rate. Replacing a constant number of units each year avoids this problem. Consequently, the Utilimarc model will occasionally recommend replacing a unit before it reaches the end of its projected lifecycle, or it may let a unit run beyond its lifecycle to maintain this balance.

All of the statistics, data, modeling, and specific information Fleet gathers, analyzes, and utilizes provides a highly reliable budget estimate. It allows Fleet to replace equipment in a predictive manner, with adequate staffing levels to meet expected workloads for maintenance and repair throughout the budgeting period. It also gives the team plenty of heads-up time to prepare for when vehicles should be repaired or retired and what new equipment should be purchased. Thus, Fleet budgets remain highly consistent across the budgeting time frame, as their requests are based upon metrics, analytics, and specific expertise.

Managing Costs

Vehicles and equipment have fixed and variable costs associated with them. These costs fluctuate depending upon the vehicle type, how it is used and driven, external factors such as weather and the type of roads encountered, and market factors such as fuel costs. For example, there are higher fuel and maintenance costs associated with driving in congested urban areas, in rugged terrain, or on rough roads, as these types of conditions reduce fuel efficiency as well as add wear and tear and associated costs. Interestingly, even things as simple as driving on a roadway with a lot of curves requires more energy from the vehicle to counter the centrifugal force, resulting in more wear on the engine and the tires.[32] For the Fleet group, a variety of cost considerations and mission-critical activities are taken into account when managing their assets and associated expenditures.

Maintenance and Operating Costs

Utility vehicles tend to be heavily used and often face adverse conditions such as steep topography, extreme weather and off-road situations. Normally they have more moving parts and complex systems associated with them and endure a much higher level of use and workload than typical vehicles. The cost of ownership for Avista's fleet vehicles varies depending upon the vehicle type, it's usage, and the complexity of its associated systems and equipment, as shown in Figure 8.

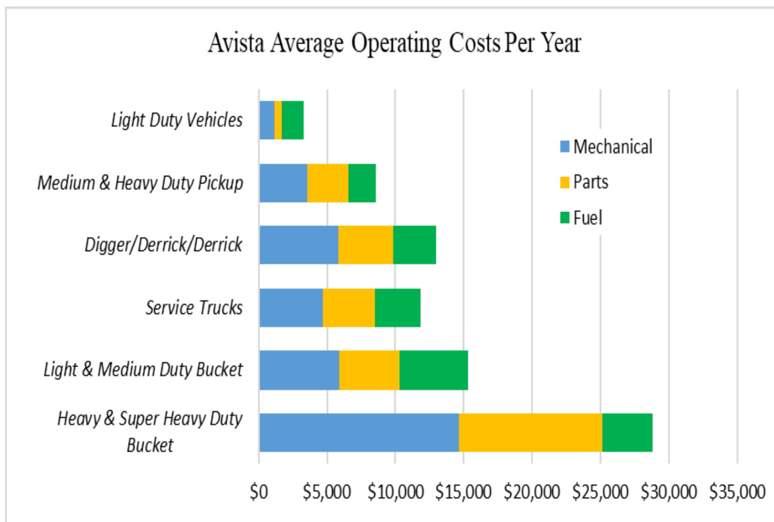


Figure 8. Fleet Average Operating Costs Per Year[33]

Age is also an important factor. Fleet experts estimate that maintenance costs for vehicles over six years of age are about 2.75 times higher than the operating costs for vehicles less than three years old.[34] Cost of maintenance also increases if a vehicle pulls a trailer, experiences excessive idling, is operated by multiple drivers, or experiences off-road, dusty, or extreme weather conditions. To add further complexity, advanced vehicle technology, increased tire prices, and widespread use of engines that require high-capacity and synthetic oils all add significant cost.[35] Increasing shop overhead costs are

[32] "Transportation Benefit-Cost Analysis," http://bca.transportationeconomics.org/benefits/vehicle-operating-cost

[33] These operating costs are based upon Utilimarc data specific to Avista.

[34] Cristina Commendatore, "Vehicle Lifecycles vs. Maintenance Costs," February 12, 2016, FleetOwner, https://www.fleetowner.com/maintenance/vehicle-lifecycles-vs-maintenance-costs

[35] Mike Antich, "Maintenance Costs Increase as Labor Rates Rise," November 1, 2018, Automotive Fleet, https://www.automotive-fleet.com/318193/fleet-maintenance-costs-increase-as-labor-rates-rise

also adding to maintenance costs as a greater number of sophisticated tools and software are needed to service advanced vehicle systems. All of these factors must be tracked and factored into maintenance strategies and practices, and the additional costs required must be managed.

There are basically two types of maintenance: preventative and unscheduled. Preventative maintenance is normally determined by manufacturer recommendations based on periodic mileage and/or calendar intervals. Vehicles routinely undergo inspections, oil and lubrication changes, cleaning, and replacement of elements such as wiper blades and tires, as well as repair of worn or broken parts. This keeps vehicles and equipment operating as expected and safe for drivers and the public. This type of maintenance is preemptive in nature. It helps avoid potential problems while maximizing vehicle availability and, if not performed regularly, will reduce vehicle lifespan and ultimately increase costs.

At Avista, most scheduled maintenance for pickups, dump trucks, and service trucks is based on mileage. Larger equipment such as digger derricks and bucket trucks, construction equipment, cranes and the like are maintained based on the number of hours they have been in operation. Most other equipment such as ATVs and UTVs, trailers, and equipment mounted on trailers like Genie lifts, compressors, tensioners, etc. are maintained on a fixed schedule. For more details on maintenance intervals, please see the Appendix C "Charge-Out Base."

Unscheduled maintenance is also a factor. This may include things like wheel alignments or replacement of parts that have been worn out, damaged or broken. These repairs must be made in a timely manner in order to keep the fleet in a safe, operable condition. Avista minimizes these types of unplanned outages with a robust and thorough maintenance strategy. In addition, the Company encourages equipment operators to report when they notice something not working as it should. Operators have knowledge of the equipment and the expertise to identify issues before they become serious simply by their experience with the asset and their awareness. As shown in Figure 9, Avista's Fleet group has been successful at keeping operating costs consistent over time, and Avista's costs are typically lower than the industry average.

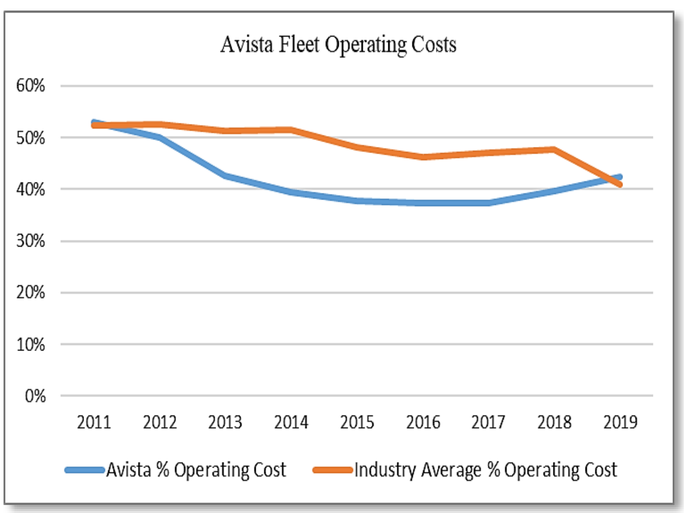


Figure 9. Fleet Primary Vehicles Operating Costs

Replacement

One of the largest expenses facing fleets is the cost of replacing vehicles and equipment. This is especially true of utilities, because their vehicles tend to be very specific, and the types of equipment

they use such as aerial lifts, cranes, drillers, etc. are specialized and expensive to replace. Replacement costs for all types of vehicles have risen significantly in recent years. For example, the average purchase price of light-duty bucket trucks has been steadily increasing nearly every year. The average cost was $92,571 in 2008, and by 2016 the average purchase price had risen to $148,974, a 61% increase.[36] Heavy duty bucket truck average prices are also up significantly, nearly 45% from 2006 to 2014.[37] A single large bucket truck can now cost up to nearly $400,000 depending upon how it is outfitted.[38] The costs for this type of equipment are expected to continue to increase over time. It is also important to note that all capital, ownership, and maintenance costs increase annually due to inflation, which is currently 2% per year.[39] All of these increases have had a significant impact on Avista's Fleet budgets, though in the past years they have been mostly held at bay due to creative and thoughtful choices in managing the assets.

Vehicle Type	Recommended Replacement Age (in Years)
Dump Truck	9-12
Heavy Duty Bucket	13-17
Heavy Duty Pickup	6-9
Heavy Duty Service Truck	11-15
Light Duty Bucket	6-9
Light Duty Pickup	10-14
Light Duty Service Truck	10-14
Medium Duty Pickup	7-10
Stake Truck	11-14
Super Heavy Duty Bucket	6-9
Super Heavy Duty Bucket	11-15
Super Heavy Duty Digger/Derrick	11-15

Utilimarc Current Replacement Age Recommendations

Types of Costs

Fleet managers must know all the costs associated with each vehicle and piece of equipment in order to control and manage budgets and to determine when it is in the Company's best interests to retire or replace assets. There are two main cost classifications for Fleet operations: direct costs and indirect costs. Direct costs are further differentiated by fixed and variable costs.

Direct Costs can be readily connected to a specific asset, for example, all the costs associated with a particular pickup, or it can mean the portion of costs assigned to that asset. Avista utilizes the second approach, assigning maintenance costs utilizing a "clearing account" in which these types of costs are put into a single bucket and then apportioned as appropriate across the fleet. As an asset is

[36] "Utilimarc: Bucket Truck Purchasing Costs Rose 61%," Government Fleet, May 2, 2018, https://www.government-fleet.com/297221/utilimarc-bucket-truck-purchasing-costs-rose-61
[37] Fleet Benchmarking Study: "Heavy Duty Bucket Truck," August 21, 2015, Utilimarc, https://utilimarc.com/fleet-benchmarking-study-heavy-duty-bucket-truck/
[38] KompareIt, "How Much Does a Bucket Truck Cost?" 2019, https://kompareit.com/business/constuction-equipment-cost-bucket-truck.html
[39] Based on latest data available: April 2019, https://inflationdata.com/Inflation/Inflation_Rate/CurrentInflation.asp?reloaded=true

maintained, the related expenses are put into this clearing account, then split between capital and O&M based upon the type of vehicle and how it is used. Some assets are heavier on the capital side, others require more O&M, thus Fleet allocates the expenditures in the clearing account in a meticulous fashion, accounting for these factors and creating a monthly cost that is monitored and tracked.

Note that direct costs are fairly easily measured and are usually the focus of any cost reducing measures. Things like maintenance costs, fuel, tires, insurance, repairs, and labor costs can be at least somewhat influenced by management practices. Direct costs are broken into two primary categories: fixed and variable.

Fixed Costs of Owning a Vehicle

- ✓ Purchase Price
- ✓ Registration Fees
- ✓ Licensing Fees
- ✓ Scheduled Maintenance

Fixed Direct Costs are incurred by a vehicle whether it is being used or not. These costs are typically computed based on time (such as cost per month or year). Fixed costs may include expenditures to purchase the vehicle, license it, and pay for elements like taxes, registration, and other fees. Vehicles and equipment also need regular maintenance even if they are not used frequently.

Variable Costs of Owning a Vehicle

- ✓ Fuel & Oil
- ✓ Tires
- ✓ Unscheduled Maintenance/Repairs
- ✓ Labor Costs
- ✓ Depreciation

Variable Direct Costs are those related to the vehicle's activity, usually computed using the distance traveled or the hours of operation. These kinds of costs include items such tires, fuel, fluids, and wiper blades but also might include maintenance and repairs as they arise from the asset's use. Most direct costs are in the variable category.

Indirect costs are expenses associated with maintaining the entire fleet and are not directly associated with a particular piece of equipment but are still critical to its operation. Mechanics, their labor costs and associated tools and equipment, work areas and buildings, as well as hardware and software applications fall into this category. However, mechanic costs become direct costs during the time they are actually working on a particular vehicle.

"Total cost of ownership" is another commonly used description that includes both the purchase price of the item plus the cost of operating it. Operations costs usually include things like maintenance costs, downtime costs, and driver costs. One of the proven ways to reduce these costs and, at the same time, improve productivity, is using Avista's approach: centralized administration and analytically determined practices.[40]

[40] "Fleet Cost Management: Reducing Costs & Driving Productivity," https://www.elementfleet.com/fleet-solutions/fleet-cost-management

Avista's Fleet

Avista's Primary Fleet Composition

• Pickup Trucks	39.0%
• Service Trucks	21.7%
• Bucket Trucks	14.9%
• Stake Trucks	8.7%
• Digger/Derricks	6.3%

These five vehicle classes make up 48.3% of Avista's total vehicle inventory.

Utilities depend upon a wide variety of equipment in order to serve customers. Beyond a diverse fleet of trucks and other types of vehicles, they require the functionality and usability of everything from boats to jack hammers, snowplows to traffic control equipment. The Avista Fleet team also maintains compressors, generators, welders, and associated equipment needed to keep the utility functioning every moment of every day.

Primary Fleet Resources

Avista's fleet contains over 1300 different vehicles and types of equipment across a wide spectrum, all of which require varying degrees of maintenance and upkeep. Figure 10 shows some of the primary types of vehicles and equipment utilized at Avista. To clarify the categories shown, please note that service trucks are more specialized than pickup trucks, often having additional associated equipment such as water tanks, welders, cranes, plows, buckets, lifters, tool storage, etc. Excavation vehicles include ditch witches, trenchers, vacuum units, front loaders, bulldozers, and other earth-moving equipment. The miscellaneous category includes equipment such as generators. Components include buckets, sanders, jackhammers, reels, booms, and other equipment fitted on vehicles. Figure 11 indicates Fleet's non-vehicle outlays, providing a glimpse into the other types of equipment that must be purchased and maintained to keep Avista operational and serving customers effectively.

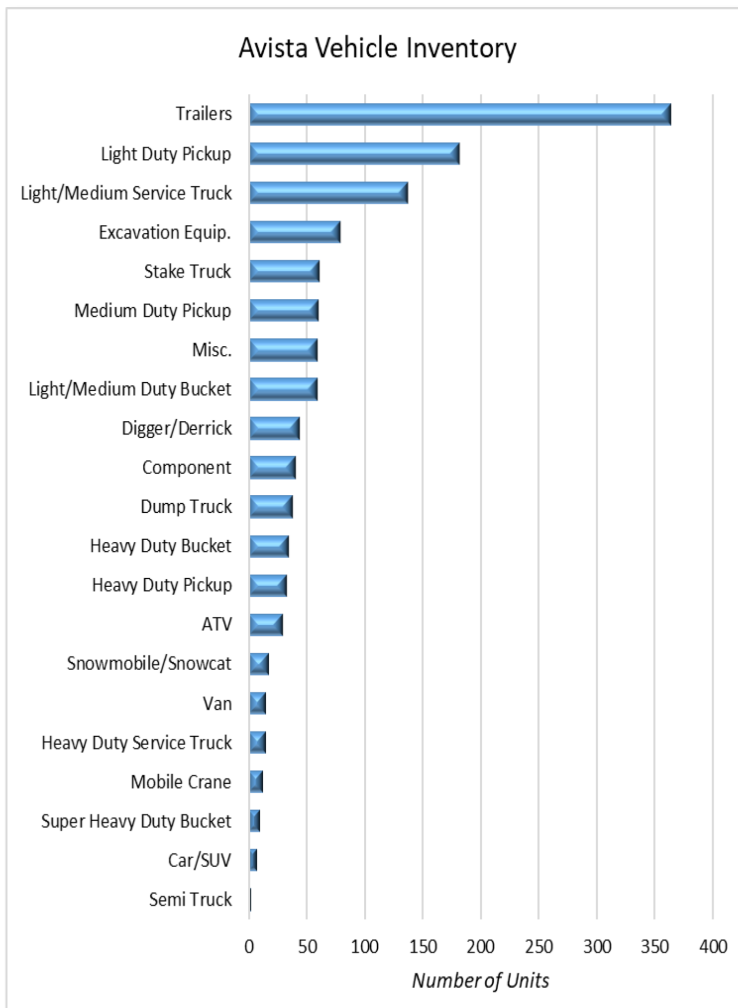


Figure 10. Avista's Complete Fleet Inventory (2020)

Avista's Fleet Trucks

As mentioned earlier, trucks make up a large percentage of Avista's fleet, about half in fact. These vehicles tend to be highly specialized and custom outfitted to perform the work required of them. They may be specially insulated for high voltage work, have heavy-duty frames and drive trains, and components such as drills, buckets, flatbeds, cranes and more. Utility trucks are considered commercial vehicles, which means more government regulations. They are also more expensive and more complicated to operate and maintain than typical trucks.

At Avista these trucks are broken into seven primary categories that will be explained in more detail below.

Truck Type	Count
Digger/Derrick	45
Dump Truck	39
Heavy Duty Bucket	35
Heavy Duty Pickup	34
Heavy Duty Service Truck	16
Light Duty Pickup	182
Light/Medium Duty Bucket	60
Light/Medium Service Truck	138
Medium Duty Pickup	61
Semi Truck	3
Stake Truck	62
Super Heavy Duty Bucket	11
Grand Total	**686**

Avista Truck Inventory 2020

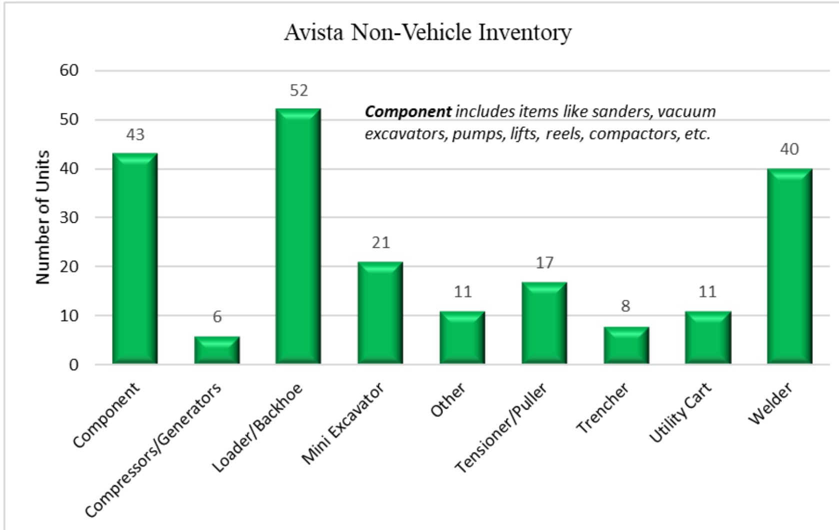


Figure 11. Avista's Fleet Non-Vehicle Inventory

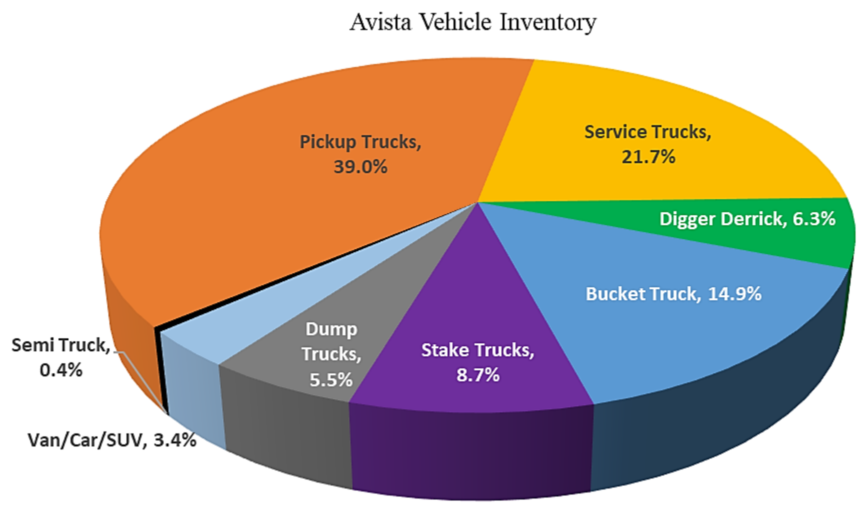


Figure 12. Avista's Vehicle Inventory

Aerial Devices

All bucket trucks play a crucial role in the operation of a utility. Someone once said, "Ask a lineman what they can't live without in the field and you'll find it's a bucket truck."[41] A bucket truck has an aerial work platform known as boom lift which is mounted on its back. The boom lift is outfitted with a bucket that is designed for a person (or two people) to stand in so they can perform work at heights, such as power line maintenance or replacing streetlights. The buckets are designed to be at about waist height for safety, reducing the risk of someone falling out. These trucks are also grounded so they protect against stray current. Some bucket trucks can reach as high as 125 feet in the air, though most have a range of 40 to 60 feet in height. These trucks also have a significant amount of storage onboard for tools and equipment. They are the safest and most efficient way to convey linemen to the heights where they work to manage, maintain, and improve the electric power grid.

Avista bucket trucks on the job

As the primary power line service equipment, these vehicles are on the road almost constantly. Avista currently has over 100 bucket trucks of varying sizes depending upon the area supported and the tasks that need to be accomplished. These vehicles allow safe and efficient access to power lines and critical equipment and are a mainstay in the electric utility world.

Using a variety of different sizes of bucket trucks and support vehicles to repair storm damage in Kamiah

[41] Amy Fischback, "Take A Look Inside A Lineman's Bucket Truck," T&D World, September 5, 2013, https://www.tdworld.com/electric-utility-operations/take-look-inside-lineman-s-bucket-truck

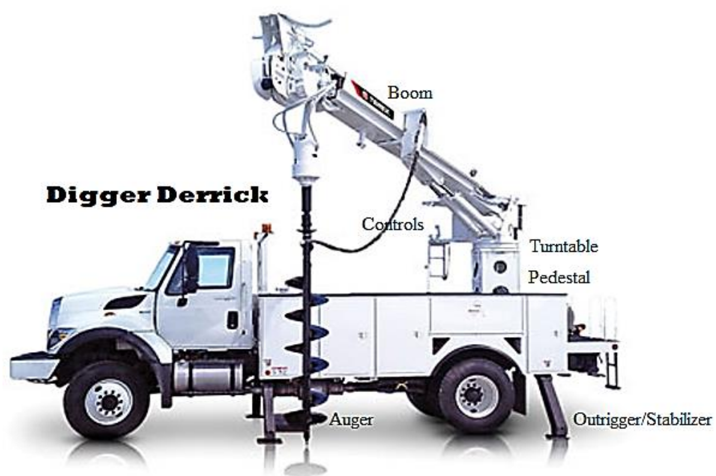
Service Trucks

Avista electric service truck being charged

Service trucks have specialized compartments to carry a variety of tools and equipment, enabling crews to perform routine jobs. These vehicles are also equipped to deal with more complex situations. In a power restoration effort, this level of readiness can mean getting the lights on a lot faster. Service trucks have been compared to having a doctor and a surgical suite in every ambulance, as they enable the technicians to perform more multifaceted tasks onsite because their tools and equipment are close at hand. Many of these trucks are equipped with four-wheel drive to allow them more flexibility in accessing situations in rough terrain. In fact, most of Avista's service trucks are equipped with four-wheel drive due to the topography and required access across the service territory for both the gas and electric sides of the business.[42] Service trucks are highly versatile. Even when they do not have bucket attachments, they allow crews to have all the tools they need with them at all times, with the versatility in storage to allow these vehicles to be customized to the needs of the day or the crew using them.

Digger Derricks

This is a type of truck that is designed to dig holes, hoist, hold, and set poles, and lift very heavy equipment. It is a crane-like truck with a huge boom on its back that has a heavy and powerful hydraulic auger attached. These trucks are designed for very heavy work including digging holes, lifting and setting poles, turning in screw anchors, lifting and setting transformers or maneuvering other sizeable equipment into place. The main components of a digger derrick



[42] Utilimarc studies indicate that the difference in operating and maintenance expenses between 4x2 and 4x4 trucks has significantly narrowed, making it easier to justify the extra upfront expense of a 4x4 based on the broader range of uses it offers. Sean Lyden, "The Rise of the 4x4 Service Truck," Utility Fleet Professional, September 2018, https://utilityfleetprofessional.com/departments/fleet-profiles/the-rise-of-the-4x4-service-truck

Using a digger derrick to set a pole

are the pedestal, the turntable, the boom, the outriggers or stabilizers, the digger motor, the auger and auger teeth, and the controls. From digging to lifting, these trucks are designed to be completely versatile. They are extremely large due to the physical dimensions and heavy weight of the attached pedestal and boom, as well as the hydraulic motor, auger and accessories. The digger derrick (or digger truck) has a powerful engine to multiply the torque and manage the hydraulic system that drives the auger. The auger looks like a giant corkscrew and is used for drilling into the ground. Most can dig holes about 18" in diameter and can dig a 10-foot deep hole in one "dip." Their hydraulic augers dig very quickly and efficiently. Many have cranes as part of their attached equipment and can perform heavy lifting as needed. Often these trucks are used to both dig the hole, put the pole in place, then hold it up as it is being set. Sometimes they are used to hold a pole up to keep lines in service when a pole has been hit by a car and knocked down. They basically serve as the pole until crews can make necessary repairs. These machines are one of the most used, most adaptable tools in line work.

Stake Trucks

Stake truck (foreground) supporting a line crew

These are flat body trucks that have an open platform rather than having a bed like a traditional pickup. These platforms often have sockets along the sides into which removable posts or stakes can be placed to form a fence around a load. These are an ideal solution for hauling loads of various sizes, including loose loads (for which the "fence" can be used). These vehicles tend to have rugged and durable construction so they can be used for a variety of tasks, including hauling supplies and equipment, spools of conductor or gas pipeline, or large bulky items that will not fit easily into a pickup bed. Many of Avista's stake trucks have some tool storage bins on board as well. These vehicles are used extensively by Avista's electric and gas distribution crews and are often important support vehicles on work sites.

Pickup Trucks

Pickups are used company-wide for a great variety of purposes. These vehicles are used by both electric and gas crews for surveys, inspections, maintenance activities, customer services such as meter reading or trouble calls, transporting crews and their equipment, and so much more. These trucks allow engineers to inspect transmission lines in rugged terrain and gas inspectors to access pipelines in all areas. Pickups can carry tools and equipment needed to perform repair or maintenance across the system, including pull trailers with generators, spools of conductor or gas pipe. Most have four-wheel drive to allow access to any terrain.

Avista pickup takes a crew to work on Clearwater Paper's gas system

Semi-Trucks

Semis are used by the Company to haul freight and large payloads. Avista's small fleet of these trucks provide support across the service territory.

Avista has a small number of semi-trucks for really big jobs like hauling generator parts to a power plant

Dump Trucks

Dump trucks are used across the service territory as well. Dump trucks are equipped with an open box bed that is hinged at the rear and equipped with hydraulic lifts so the dump portion of the truck can be lifted to allow whatever is inside to slide out. Some of these have large capacity box beds, others have more of a fence surrounding the cargo area. The Company has about 40 dump trucks of various sizes and capacities, used for jobs such as hauling dirt into and out of construction sites or hauling cargo.

Avista natural gas-powered dump truck

Avista dump truck filled with bags of blankets, hats, and mittens to distribute to low income and homeless in Spokane County

Avista's Other Fleet Vehicles & Equipment

Compressed Natural Gas

Compressed Natural Gas (CNG) capable vehicles are designed to be switchable to compressed natural gas as their primary fuel if the situation allows it, while maintaining the flexibility of using gasoline or diesel as a primary fuel if that is a better option.[43] The Company is adding CNG vehicles, primarily trucks, to the fleet as it is feasible. At present, about 90 of Avista's fleet vehicles are related to CNG by being either CNG bi-fuel vehicles or as the trailers that haul CNG to support these vehicles.

Above: Compressed Natural Gas station at Mission Campus
Left: Avista natural gas-powered work truck

[43] Bi-Fuel or "switchable" vehicles give owners the best of both worlds. These vehicles can run on CNG as long as there is fuel in the CNG tank, then switch to gasoline or diesel until the CNG tank is refilled.

Snow Cats

These vehicles are invaluable assets in the rough country faced by some of Avista's line crews. During the winter, there are times when a line truck simply cannot access a downed powerline. Line crews have had to use snow machines or, at times, had to snowshoe to a situation to initiate repairs. Snow cats are especially helpful, as they typically haul more people and equipment than a snowmobile can.[44] These handy vehicles can also access the Company's mountaintop meter repeater stations during winter months for maintenance or repair, or can be used to plow roads in remote areas for crew accessibility.

Snowcat plows a path for line crews

Above: Some of the terrain Avista line crews face (Pine Creek – Burke Thompson line)

Excavation Equipment

This type of equipment is used across the business as well. Backhoes, excavators, bulldozers, loaders, skid-steers, trenchers, drills, and components such as vacuum systems all help perform routine utility work, flattening areas for substation equipment, digging trenches to install pipeline, laying underground electric cables or gas lines, excavating areas to set poles, building roads to reach transmission lines, snow removal, construction or demolition activities, to name a few. These tools provide what Company crews need for the construction aspect of their jobs, whatever that may entail.

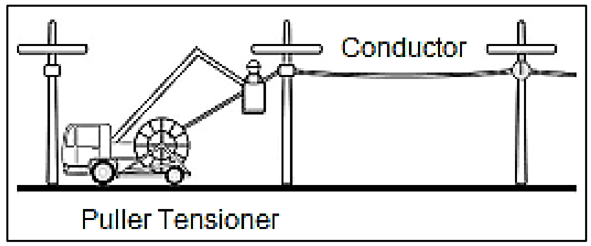
Avista gas crew uses a backhoe to dig up and repair a gas leak in Odessa

[44] Snowmobiles can only accommodate one or two riders, who are exposed to the elements as they travel and have very little or no storage for supplies. Snowcats are enclosed all-terrain vehicles that usually carry 2-6 people plus their gear.

Puller-Tensioners

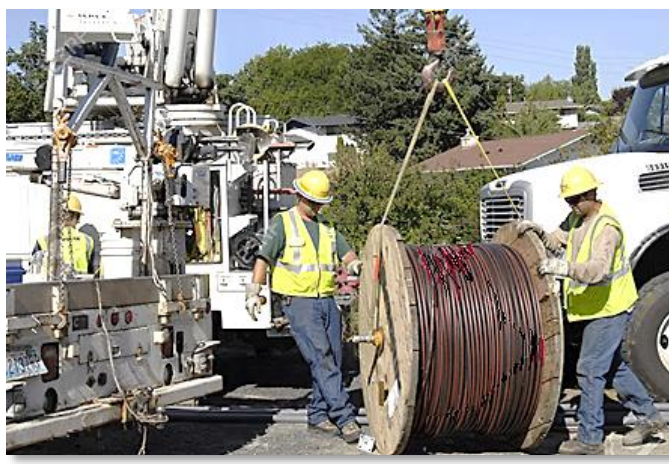
This is specialized equipment used to maintain a constant tension on power line/conductor as it is being strung or taken down. A puller (winch) is set up at one end of the powerline section, and a tensioner is set up at the other end. The reel of conductor is placed behind the tensioner. The end of the pulling line is attached to the conductor end after it has been threaded through the tensioner. Then while the line is being strung, it is held by this device under tension to keep it clear of the ground and other obstructions that could cause damage. These devices can pull out old conductor, wind it on a reel, then release the new conductor under tension to keep it under control as it is being placed on the poles. These devices are also invaluable in holding conductor so it can be spliced if it is broken or damaged.

Puller-Tensioner stringing a high voltage transmission line



Mobile Crane

This is a cable-controlled moveable crane with a telescoping boom that has a hook on the end. These cranes are used to lift and move very heavy objects, aiding in construction projects or helping crews extract, place, or maintain large items like transformers or conductor spools. Most of Avista's mobile cranes are attached to a truck, enabling them to quickly and easily respond as needed as well as access even relatively small areas.



Avista service truck with a crane lifts a spool of cable

ATV/UTV

All terrain or utility vehicles are a staple for a utility with a service territory as challenging as some of Avista's areas. All-terrain vehicles (ATVs) are small, typically meant for one or two people, and are very nimble. These are more like motorcycles with four wheels – riders straddle them to ride. ATVs also have a handlebar system for steering. Utility task (or terrain) vehicles (UTVs) are larger, often seating between two and five people, typically have covers on top and bench or bucket seats (i.e. are more carlike) and sometimes small beds for hauling equipment. These units have steering wheels rather than

Left: ATV
Right: UTV

handlebars and are designed for rougher terrain than a traditional four-wheel drive pickup. ATVs are usually cheaper than UTVs but do not have the horsepower and hauling capacity of a UTV. Avista utilizes both types of vehicles for various applications. For example, a transmission inspection engineer may use an ATV to access lines in remote, heavily forested areas where roads cannot reach. Line crews might use UTVs to access these same types of locations when they need the extra room to haul people and equipment.

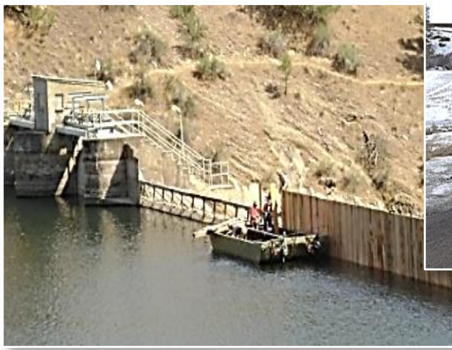
Trailers

These make up a high percentage of Fleet's inventory, as they are so versatile. Avista uses trailers of all different shapes and sizes, covered and flatbed, open and ready to haul whatever is needed, or heavily customized to specific utility uses. Trailers haul everything from backhoes to conductor reel, poles, CNG or water tanks, ATVs and UTVs, snow cats, boats, generators, various excavation equipment, power plant parts, welders, compressors, and some even perform as mobile substations. They are a versatile and invaluable part of Avista's fleet inventory.

Miscellaneous Equipment

Vehicles and equipment such as fleet cars and SUVs, boats, and backyard mobile equipment, as well as equipment like utility carts, generators and welders are also managed by Avista Fleet.

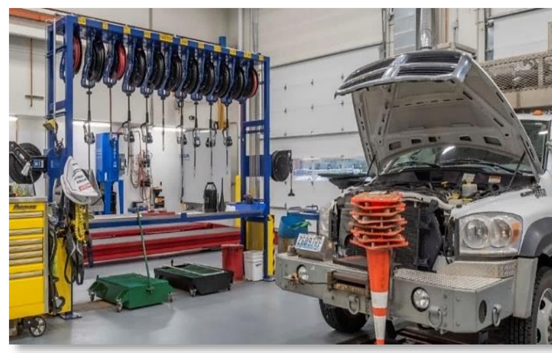
Using a small caterpillar to set a pole on Palouse farmland to minimize field damage



Using a boat to set flashboards at Little Falls

Crews must use a boat to access a pole that crosses a river.

Additional Equipment Needs



The Fleet Department has the capability of renting specialized vehicles, specifically utility trucks or heavy equipment, if they are needed for a particular project and are not available within the Company's inventory. If the rental includes any aerial equipment such as lifts or buckets, it must first be inspected by Fleet specialists to ensure that it is in full compliance with Avista's safety requirements before being released into use.

Fleet is also responsible for renting passenger vehicles or providing Company loaner cars for regular employees. If an employee needs transportation for two days or less while on Company business, Avista has three loaner cars available. Two of their loaner passenger vehicles are electric vehicles.[45] If the vehicles routinely provided are not adequate or if an employee is traveling outside the area, the Company has very specific requirements around employees renting vehicles from an outside source. The Company utilizes Enterprise Rent-a-Car for these situations. Reservations for Enterprise vehicles must be made at least 12 hours in advance. A few of their rental cars are parked at the Mission Campus for convenience.

Fleet provides electric vehicles for employee use in conducting Company business

[45] Of these two electric vehicles, one has a total trip limit of 50 miles so can only be used within Spokane, and the other can travel as far as 250 miles on electric power if the batteries are fully charged.

If employees are traveling on Company business, they are required to select the most economic and efficient ground transportation method available (rental car or public transportation, for example.) If they are renting a vehicle, standard class is the default option unless there are special considerations. This concept helps the Company manage and control costs.

Dollar Road Fleet Building (above) includes multi-purpose lifts (below)

Employees are only eligible to drive a dedicated Company vehicle if their manager determines that their job duties and responsibilities justify such use.[46] Once approved, drivers are required to submit their mileage records monthly for every vehicle they utilize without exception. Company vehicles may be driven to an employee's home only if that person is on call or is a first responder for the Company.

Fleet Definitions

Fleet Vehicle – A Company owned, rented, or leased vehicle available for employee use.

Assigned Vehicle – A fleet vehicle assigned to a specific employee or work group on the basis of job duties.

Fleet Pool Vehicle – A fleet vehicle that is available to loan when an employee or department's regular vehicle is undergoing inspection, maintenance, or repair.

Personal Vehicle Used for Business Purposes – Use of an employee's own vehicle to engage in Company business. Eligible for mileage reimbursement.

Finally, employees are expected to be responsible for their vehicles. They must report anything they notice that might indicate a mechanical problem, and they must try to keep their vehicles clean and well organized, not only for efficiency in their work, but because these vehicles represent a physical symbol of Avista to customers.

[46] This is done through the use of an "Assigned Vehicle Decision Matrix" based on specific requirements and criteria such as driving over 18,000 miles per year on Company business, having to carry tools or supplies that are not practical for a personal vehicle, daily trips to multiple locations, customer safety and concern considerations (sometimes an identified Company vehicle provides necessary credibility), or if the employee faces extreme driving conditions such as off road driving. See Appendix A for the Assigned Vehicle Decision Matrix.

Avista's Fleet Investments

Operations & Maintenance (O&M) Expenditures

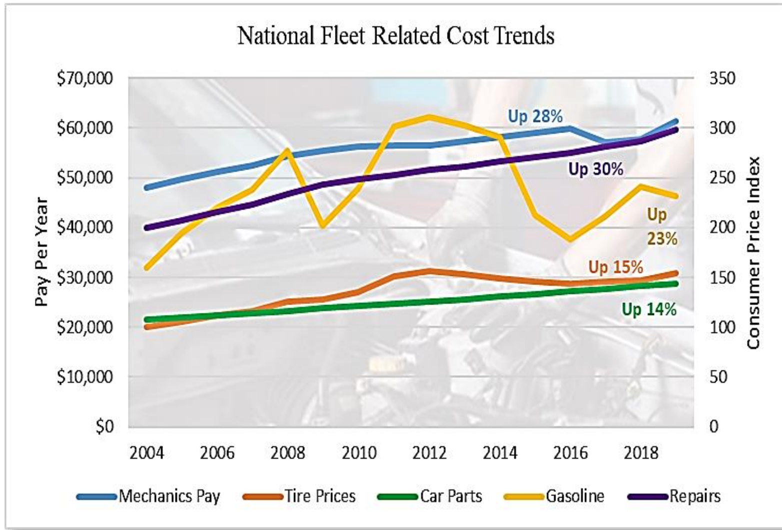


Figure 13. Fleet Related Expense Cost Trends (U.S.) [47]

Avista's Fleet group manages primary Operations and Maintenance/non-capital expenditures using a clearing account, as mentioned earlier. All these types of costs are put into one bucket then dispersed monthly across the fleet based on the type of vehicle or equipment and how it is used.

These types of expenditures can vary based on market conditions, such as fuel, parts, tires, and even employee pay. As shown in Figure 13, these types of costs have gone up over time, mostly at somewhat standard inflation levels, though fuel costs have been widely variable. Even with often changeable costs in the market, Avista's Fleet O&M costs have stayed relatively stable and typically below budget, as shown in Figure 14, indicative of the careful, analytical, measured approach this team takes to managing their people and equipment.

The Fleet group manages a great variety of vehicles and devices and therefore must maintain a fairly complex inventory. Beyond the expected vehicles and equipment, their non-capital expenses also include elements such as hardware and software, taxes, permits and the like. This category also includes employee training and travel, union contractual obligations, parts and supplies for both vehicles and supporting equipment, tools, uniforms, leases and rentals, costs of regulations and compliance,

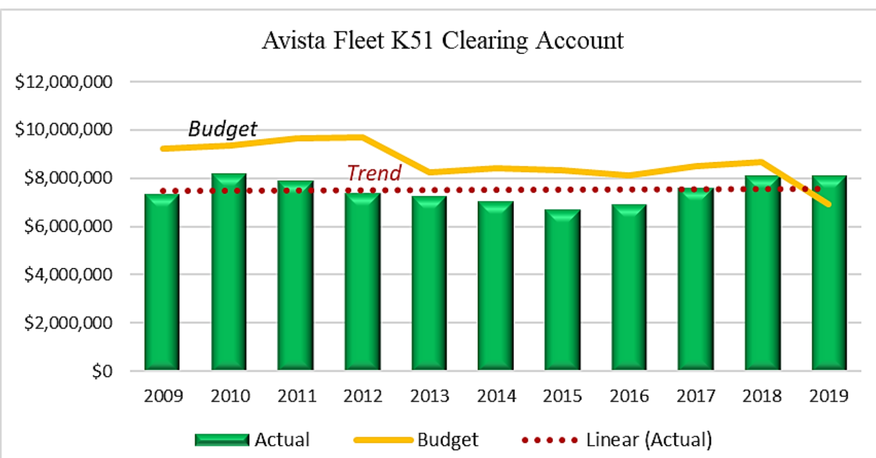


Figure 14. Fleet Budget and Actual Clearing Account Related Expenditures

[47] Data sources: Mechanics Pay: https://www.federalpay.org/employees/occupations/automotive-mechanic, Tire Prices: https://www.statista.com/statistics/262841/us-producer-price-index-of-car-tires/, Car Parts: http://www.in2013dollars.com/Motor-vehicle-parts-and-equipment/price-inflation, Gasoline: https://www.ceicdata.com/en/united-states/consumer-price/consumer-price-average-gasoline-unleaded-regular

and labor expenses related to maintenance and repair.

The largest expenditure categories are fuel, employee pay, repairs, parts, and tires, as shown in the pie chart of Figure 15. This is all a balancing act. Fuel, tires, parts, and repair services are priced by the market, though the team attempts to shop around for the best prices whenever possible. Employee pay is another primary category. Avista must stay competitive with the industry to attract and retain the high-quality employees needed to achieve the levels of availability the Company's work crews need and expect. Avista is also bound by union requirements.

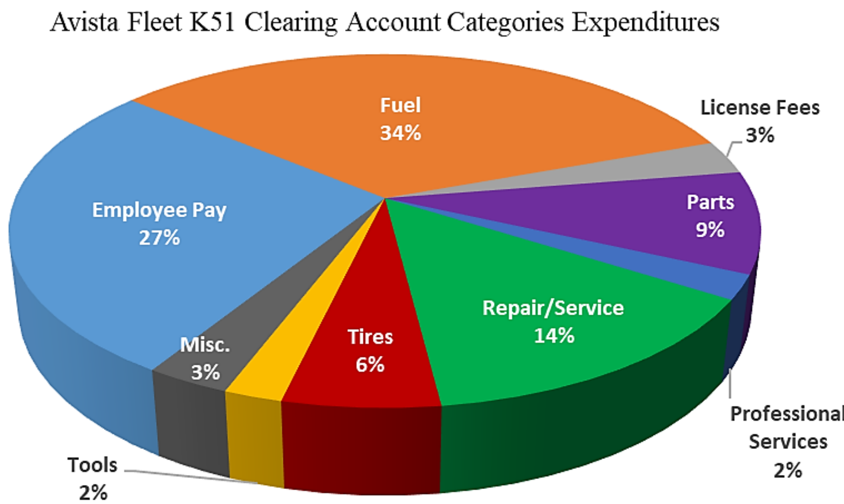


Figure 15. Fleet O&M Clearing Account Historic Expenditures

Capital Expenditures

Fleet's capital budget requests also tend to be stable, as shown by the "Average Budget" line in Figure 16, especially with the guidance of the Utilimarc software regarding replacements. Note that the blue bars are actually approved, not requested, budgets, which can vary substantially. Over the last several years, approximately $7 million per year is spent on vehicles and equipment, depending upon the need. Some budget years are dramatically affected by the type of equipment required. As an example, in 2009 and 2010 the Company purchased twelve digger derricks (some at nearly $400,000 each) and twelve heavy duty bucket trucks, pushing their requested funding temporarily above typical levels, as shown in Figure 16. However, they plan for a stable budget of about $7 million per year, in part based on the historical year average. Though this team controls some of the Company's key assets, Fleet capital expenditures typically comprise only about 2%-3% of the entire Avista budget, as shown in Figure 17. This year

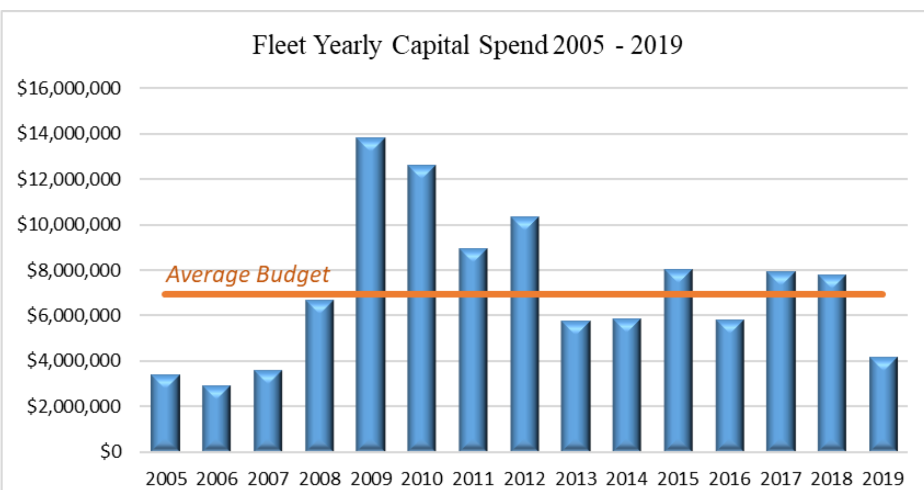


Figure 16. Fleet Capital Spending 2005-2019

they were allocated about $6.2 million for each of the next five years.

Many of Fleet's capital purchases are for trucks as mentioned previously. However, many other components are also required to perform routine utility work. The historic capital expenditures for these are shown in Figure 18.

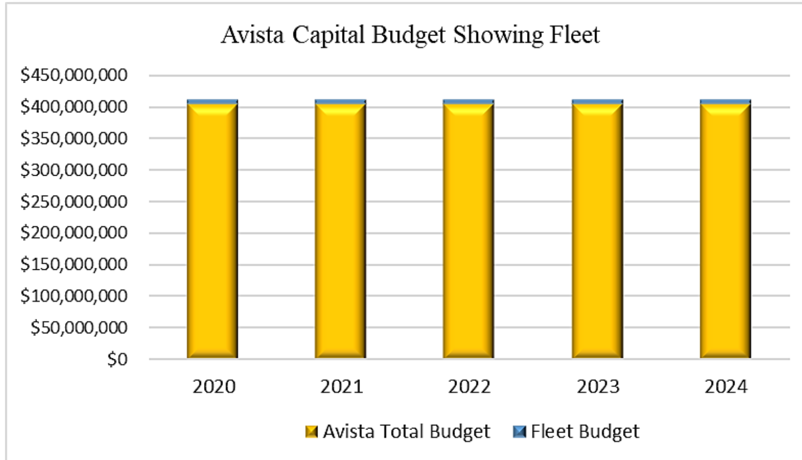


Figure 17. Fleet Capital Budget as Part of Avista Total Capital Budget

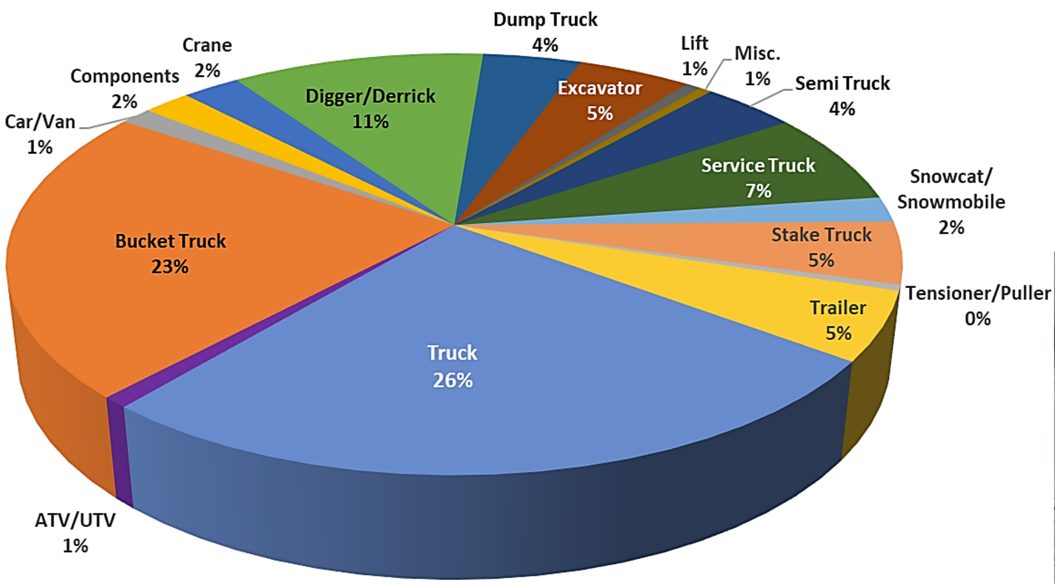


Figure 18. Fleet Historic Capital Spending Since 2005

As shown in Figure 19 on the right, Fleet is responsible for purchasing, maintaining, and retiring assets across the service territory and in every major area of the Company. Large operations such as those in Spokane, Pullman, Lewiston-Clarkston and Coeur d'Alene by their natures require more equipment, but Fleet also provides vehicles and equipment for business units like Generation, Substations, and the Meter Shop.

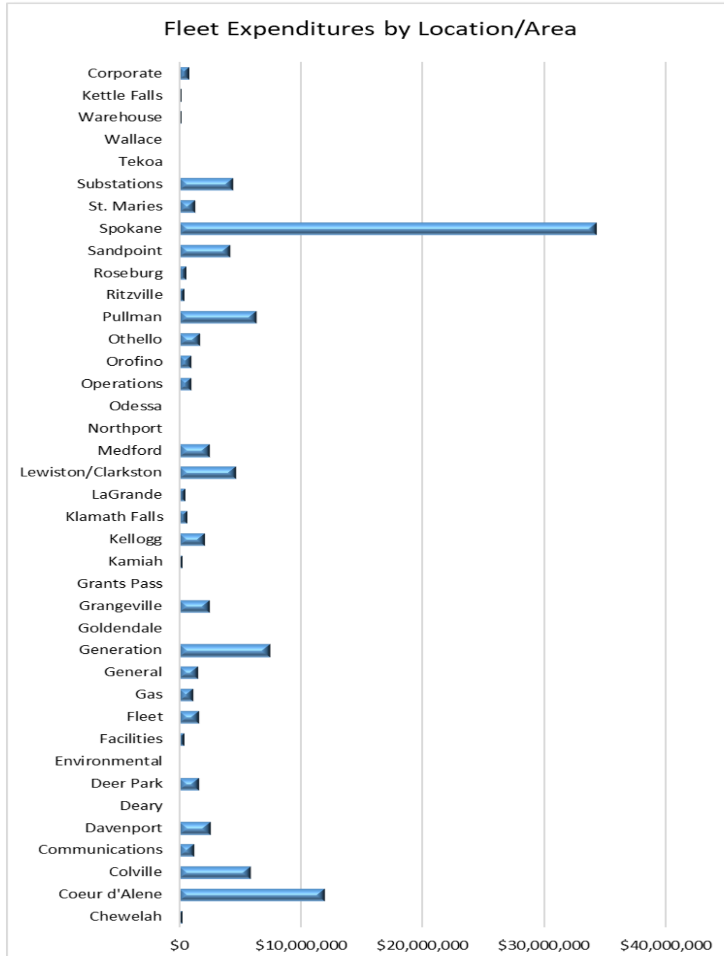


Figure 19. Fleet Historic Capital Purchase Dollars By Location

Managing such a diverse fleet has wide ranging yet and often subtle challenges as well. Keeping a lid on costs, maximizing value from contracts, forging strategic partnerships, seizing opportunities presented by new technology, preparing for a zero-emission future, managing occupational road risk, and dealing with ever changing legal requirements and regulations pose their own problems. In addition, managing utility vehicles is more complex than a handling a typical fleet of cars and trucks. Utility vehicles are normally highly customized for various tasks, carry a lot of very expensive equipment and people, and are required to perform perfectly under every kind of weather and road condition. They must be safe for both employees and the public. They must be protected against theft and vandalism and be licensed and permitted. Importantly, they must be supported by adequate maintenance staff and practices, a sufficient parts and service inventory, and suitable storage areas.

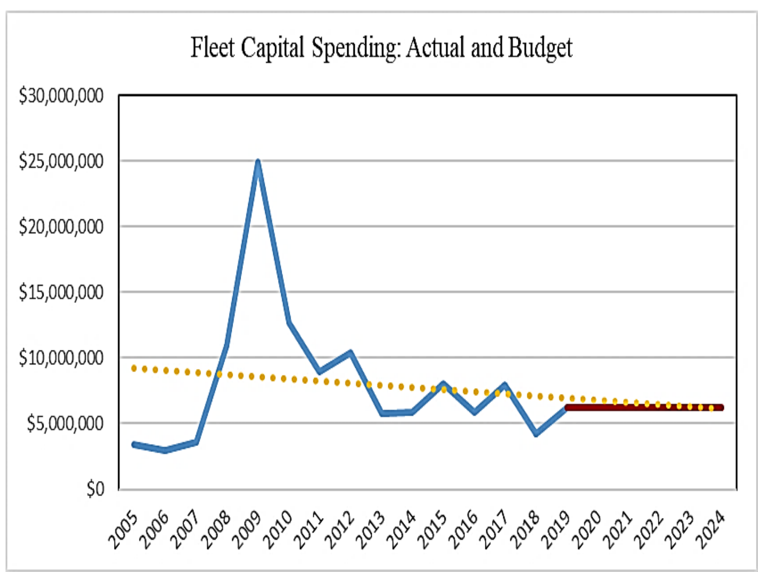


Figure 20. Fleet Capital Actuals and Budget

As shown in Figure 20, Avista's Fleet group has been highly successful at keeping their costs low over the long term, as indicated by the trend line, staying at an average of about $7 million per year. This consistent spending pattern is expected to continue into the future.

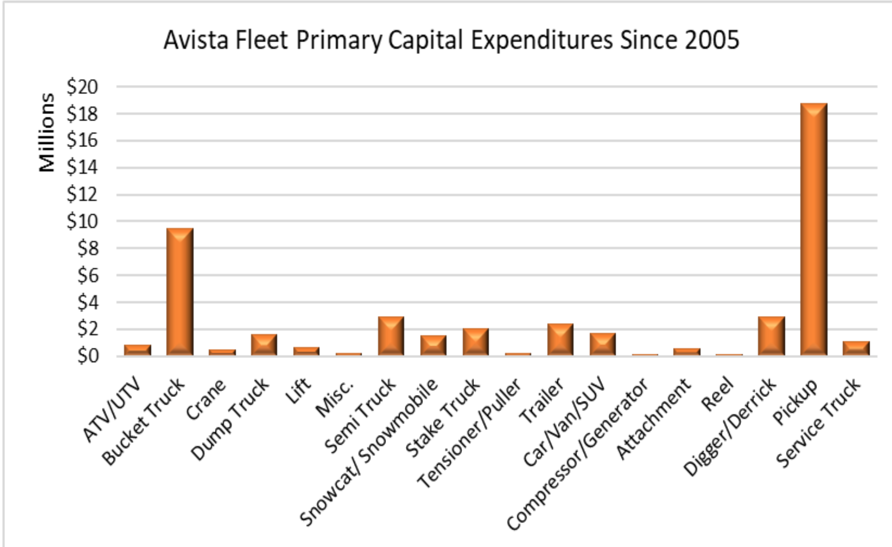


Figure 21. Fleet Historic Primary Capital Expenditure Categories

Utilimarc recommends that Avista spend about $8 million per year in capital replacements. This is based upon replacing 91 of Avista's 1,334 Fleet assets annually over the next five years, which is about 7% of the existing fleet. Replacement, as mentioned earlier, is based on asset management strategies related to maximizing lifecycle costs. This data includes mileage, hours of operation, and general performance and costs. About 58% of these planned replacements are for various trucks or digger derricks, the other 42% are components and equipment such as welders, compressors, generators, lifts, excavation equipment, and the like.

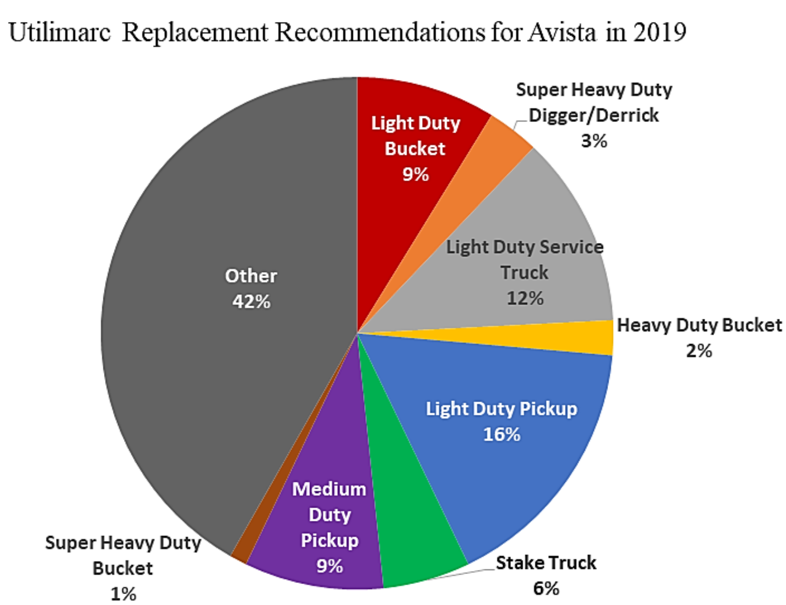


Figure 22. Utilimarc Recommended Replacements

Bucket truck and Genie lift allow crews access to transmission tower at Noxon

Fleet has managed their budgets so effectively that the Company has been able to maintain the recommended industry average age for their fleet vehicles, leading to controlled maintenance costs over time, as shown by the green line in Figure 23 (note that this budget amount includes inflation). Utilimarc recommends a replacement budget based primarily on lifecycle costs. If more assets are being used beyond their recommended life, it will inevitably lead to more breakdowns or failures as the asset ages. As shown in Figure 24, the Company is driving toward a goal of having all Avista's Fleet assets at or near their expected life to keep costs low and service availability as high as possible. As mentioned earlier, the typical budget for Fleet is about $7 million. This year the Capital Planning Group allocated $6.2 million per year for the next five years.

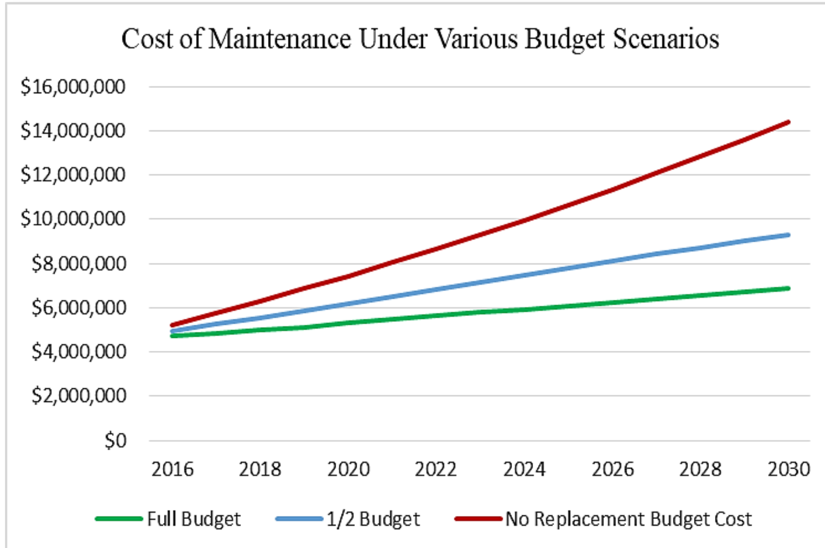


Figure 23. Maintenance Costs Under Various Budget Scenarios

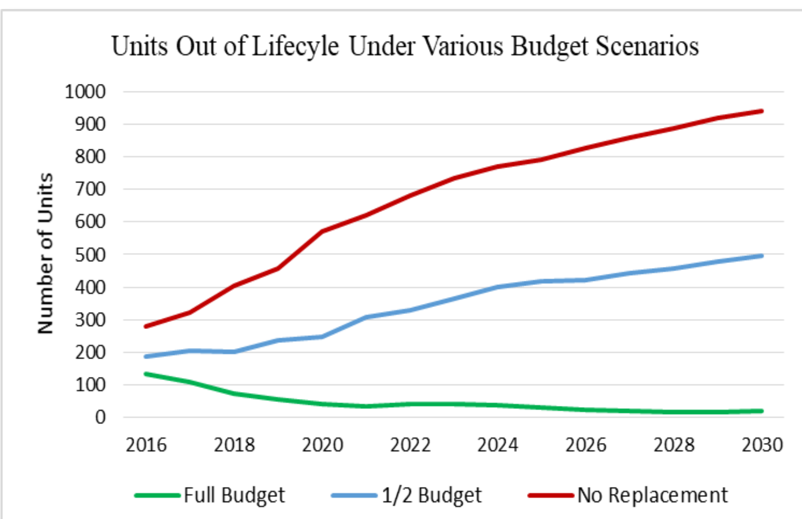


Figure 24. Number of Units Past Recommended Lifecycle Under Various Budget Scenarios

Summary

Avista's Fleet ensures that every vehicle and piece of equipment meets operators' needs and expectations. The information shared in this report is evidence of the Fleet team's commitment to providing the efficiency, cost effectiveness, safety, reliability, and availability around equipment that is critical to keeping Avista's energy delivery system operating. Fleet performance is enabled and proven by data that that has been collected consistently for over a decade. This information allows the Fleet team to make value driven, data focused decisions for each business unit and for the Company. Data and analytics play a key role, but there are many more factors.

When it comes to safety, the Fleet team is constantly working to ensure that they are rolling out the latest safety information and technology to all vehicle and equipment users. Safety systems are in place for all Fleet equipment. The Fleet team works closely with OSHA as well as state regulators to make sure that all safety equipment, technologies and practices meet regulatory requirements. They collaborate with vehicle ergonomic experts to reduce any chance of injury. As an example, due to advanced safety systems, Avista crews now have a new and safer way to handle energized conductors on the job site, reducing outage duration and making maintenance or repair faster and more efficient, while at the same time protecting employees from harm. As another example, at the end of 2019 Fleet is deploying the first Avista heavy duty vehicle with advanced safety features, including collision avoidance systems. Efforts such as these have a positive impact on reducing long term injury rates for field workers and making work areas safer for the general public as well.

Storms and the related outages have severely tested Avista's fleet in recent years. 95% availability sounds impressive, but what does it mean when it really counts? Time and experience prove that Fleet's performance does not disappoint. The Company's largest outage event, the November 2015 windstorm, pushed Fleet equipment to the edge. In a ten-day period, almost a quarter of a years' worth of fuel was consumed. Equipment was utilized 24 hours a day, non-stop, but there was not a single catastrophic failure of equipment. Small repairs and maintenance were completed during rest periods to maximize crew and equipment availability. Avista's Emergency Operations Plan incidence results consistently show that Fleet performs at a very high level during major impact events. It is clearly evident that Fleet programs, data driven analytics, and investment strategies are working to provide Avista with exactly what is needed to perform work as a utility under any condition.

Value is another important element provided by Fleet. As reported earlier in this report, Fleet performance and results are typically in the first and second quartile compared to industry data, proving that Avista's Fleet team manages the Company's key work resources wisely. Expenditures have stayed level even though some costs change constantly. This is due to careful and thoughtful Fleet management and choices. Fleet delivers what is needed to perform work for customers and provide new and innovative safety solutions, never losing sight of reliability and availability. Fleet's performance is proven to be outstanding. This dedicated group of people work hard every day to ensure success in all the key areas necessary for operating Avista's electric and gas systems.

APPENDIX A: ASSIGNED VEHICLE DECISION MATRIX

Assigned Vehicle Decision Matrix

Manager Evaluation: Should Avista provide the employee an Assigned Vehicle for business purposes? (Please answer the following questions for clarification.)

Is this add request as follows:	All other requests please answer the following questions in section one.
A field position that requires a vehicle as a part of the positions tool (i.e. bucket truck, stake trucks, tester van, service truck, etc.)?	
If YES skip to section 2, if NO see next column	

Section 1

- Will the annual mileage in exceed 18,000 miles

OR

- Do the job duties regularly require necessary tools, materials or equipment or supplies that are not practical to carry or load daily into a personal vehicle?
(Regular usage is defined as 3-5 times per week)

OR

- Do the conditions under which a vehicle is frequently used pose an unreasonable risk of damage or excessive wear to an employee's personal vehicle, such as driving off road or parking in state right of ways where minimum traffic awareness measures must be taken?
(Frequently is defined as at least 1 or more times per month)

OR

- Does the job function require daily trips to multiple locations and a vehicle with required Company identification?

Section 2

YES	NO
1. Manager to complete business case with financial analysis - submit to Fleet. 2. Manager to complete a VLC request form in conjunction with vehicle capital specialist. 3. Submit VLC for Officer approval. 4. Coordinate order and delivery with Fleet Services. 5. Provide an Assigned Vehicle to the employee.	• Employee will submit an Expense Report with business mileage for reimbursement at the IRS-approved rate per business mile. OR • Use of a pool vehicle OR • Rent a vehicle (Contact Fleet Coordinator)

Appendix B: Vehicle Use Policy

AVISTA

Revised January 2018

Purpose

The purpose of this Vehicle Use Policy ("Policy") is to ensure the safety of employees and the public while driving during the course of doing business; provide employees with expectations for the use of company-owned and rented vehicles; provide expectations on the use of personal vehicles for company business; and ensure compliance with all federal, state, city and local motor vehicle regulations.

Policy Statement

Avista provides company-owned or rented vehicles for employees whose job duties and responsibilities necessitate driving. Driving any vehicle carries significant risk of injury. Avista is dedicated to ensuring the safety of its employees, and therefore has developed guidelines for the assignment, use, operation and maintenance of fleet vehicles and the use of personal vehicles while being used for business. This Policy supplements Part 4 of Avista's Incident Prevention Manual, which is incorporated and referenced herein.

Policy Definitions

Fleet Vehicle – A Company-owned, rented, or leased vehicle available for employee use. A Fleet Vehicle is designated as either an Assigned Vehicle or a Fleet Pool Vehicle.

Assigned Vehicle – A Fleet Vehicle that is assigned to an employee or to a department on the basis of a specific department's or employee's job duties and reserved for day-to-day use.

Fleet Pool Vehicle – A Fleet Vehicle assigned to and issued by Fleet Services as a loaner when a department's Assigned Vehicle has been scheduled for inspection, maintenance or repair.

Personal Vehicle Used for Business Purposes – The use of a personal vehicle during the course of business that would qualify for mileage reimbursement under Avista's Travel & Expense Reimbursement Guidelines.

Scope and Applicability

The vehicle use policy applies to all employees when using fleet, assigned or fleet pool vehicles as defined above, as well as personal vehicles while being used for business. The employee's record of acknowledgement will be kept in Avista Learning Network and will be acknowledged annually.

The policy is broken into two sections: Personal Vehicles Used for Company Business and Company Owned Vehicles. Since any employee may find it necessary to travel outside the office for business reasons, this policy shall be reviewed by all employees. The Company Owned Vehicles Section is for employees who may as a course of their duties operate a company-owned vehicle as defined above.

Personal Vehicles Used For Company Business

Vehicle Safety Rules:

- Employee must wear a safety belt at all times the vehicle is in motion and must ensure that all occupants do the same.
- Employee shall follow Avista's Mobile Device Policy, which limits the use of mobile devices (including hands free) in personal vehicles on company business. The use of a mobile device shall happen only when the vehicle is pulled to side of the road and legally parked.
- The use of alcohol and controlled substances prior to and during operation of any vehicle is strictly prohibited.
- Vehicles shall be operated within the legal speed limit at all times and at lower speed where conditions warrant.
- Employee shall take steps to ensure the security of Avista-owned property that is being transported.
- Employee must follow generally accepted safe driving practices and obey traffic regulations for the state, city and county in which they are operating the vehicle.
- Employee shall ensure that their vehicle is in safe operating order.

Reporting Requirements:

- Before driving a personal vehicle for company business, employee must notify his or her manager if there is a change in status to their driver's license for any reason, including but not limited to, revocation, restriction or permission.
- Employee will be solely responsible for payment and any defense of citations received while operating their personal vehicle during the course of business.
- If an accident occurs during the use of an employee's personal vehicle for business purposes, they shall notify their manager to complete an Avista Report of Accident Form.

Company Owned Vehicles

Eligibility:

Employees are eligible for an Assigned Vehicle if their manager determines their job duties and responsibilities satisfy the criteria set forth in the "Assigned Vehicle Decision Matrix" (See Appendix A.) Managers will evaluate and determine an employee's eligibility and submit the necessary information to Fleet Services.

Once issued an Assigned Vehicle, employees are required to maintain a valid and current driver's license for the type of Fleet Vehicle they are operating and comply with all rules and requirements in this policy. An employee's failure to comply with this policy will result in loss of vehicle privileges and/or discipline up to and including termination.

General Requirements:

- Employee shall not use Fleet Vehicles for non-business reasons, except for "de minimis" use (such as a short stop for an errand on the way between a business purpose and the employee's work location or home).
- Pets are not allowed to ride in Fleet Vehicles including the truck bed.
- Smoking and vaping are strictly prohibited in Fleet Vehicles.
- Absolutely no hitchhikers are allowed in Fleet Vehicles.
- Towing of any type of employee owned recreational equipment is prohibited.

Passengers:

During the course of business employees may need to transport passengers who are not employees of Avista. Passengers must always use a seatbelt. If the vehicle is outfitted with a laptop mount, the driver and passenger must take precaution that the device and mount is not in the airbag deployment zone. The device and mount should be placed in the center of the cab.

In limited and non-recurring instances employees may need to provide transportation for a family member in a company owned or rented vehicle while on call, commuting or traveling for business purposes. If this is needed the employee should notify their manager. If there is a need outside of the previous definition the manager must contact the Fleet Manager for guidance.

Company Owned Vehicles (cont.)

Vehicle Safety Rules:

- Employee must wear a safety belt at all times the vehicle is in motion and must ensure that all occupants do the same.
- Employee shall follow Avista's Mobile Device Policy, which limits the use of mobile devices (including hands free) in both company owned and leased vehicles and personal vehicles on company business. The use of a mobile device shall happen only when the vehicle is pulled to side of the road and legally parked. The full policy can be found in the Avista Incident and Prevention Manual section 4.
- The use of alcohol and controlled substances prior to and during operation of any vehicle is strictly prohibited.
- Vehicles shall be operated within the legal speed limit at all times and at lower speed where conditions warrant.
- Employee is responsible for the security of vehicles. Employee should avoid leaving any items of value in vehicles wherever possible.
- Employee must follow generally accepted safe driving practices and obey traffic regulations for the state, city and county in which they are operating the vehicle.

Employee Reporting Requirements:

- Employee must turn in vehicle mileage, no Avista vehicle is exempt. An Operations employee using Maximo for time keeping will submit mileage as a part of their daily time reporting. All other employees must turn in their mileage sheets on a monthly basis to Utility Plant Accounting.
- Employee must notify his or her manager immediately if there is a change in status to their driver's license for any reason, including but not limited to, revocation, restriction or permission. Managers and Fleet Services reserve the right to review any Employee's motor vehicle records for any reason at any time.
- Employee must notify his or her manager of any inspections and citation(s) received while operating a Fleet Vehicle.
- Employee will be solely responsible for payment and any defense of such citations.

Fueling Fleet Vehicles:

- Employees who are provided with a Fuel-Only card must use it to fuel Fleet Vehicles at off-site retail stations. The assignment and distribution of off-site fueling cards is managed by Fleet Services. When fueling, employees are expected to enter accurate data, including fuel pump number, vehicle number, current odometer reading, and engine hours (if applicable).
- Employee must use the appropriate gasoline for each Fleet Vehicle. Fleet Vehicles that utilize regular unleaded gasoline do not require "Unleaded Plus" or "Unleaded Supreme" gasoline. Use of premium fuel is only for small tools that require fuel with no ethanol. If the vehicle is an alternative/dual fuel vehicle then the alternative fuel should be used when available.
- Employee must not keep fuel card instructions and codes with their assigned fuel card to prevent unauthorized persons from fueling.

Fleet Vehicle Maintenance & Inspection:

- Employees shall perform a "walk around vehicle" inspection each day prior to moving the Fleet Vehicle to ensure it is safe. This inspection shall be completed after required paperwork or data entry and must always be the last task completed prior to moving the Fleet Vehicle.
- Employees must inform Fleet Services of any Fleet Vehicle maintenance needs or safety problem.
- Any Fleet Vehicle that does not meet safe operating conditions shall be immediately removed from service; its use will be prohibited until unsafe conditions have been corrected and re-inspected before being placed in service again. Employees should use "lock out- tag out" procedure for unsafe vehicles.
- Fleet Vehicles must be cleaned (interior and exterior) regularly to help maintain a good appearance.
- Employees must maintain the visible logo and equipment number on the Fleet Vehicle. Employees must report to Fleet Services if the Fleet Vehicle's logo or equipment number becomes less visible or otherwise less noticeable to others. Fleet Vehicles greater than 10,000 pounds Gross Vehicle Weight Rating (GVWR) are also required to display USDOT number.
- Employees must not modify or add accessories to any Fleet Vehicles unless the modifications or accessories are authorized and/or coordinated through his/her manager and Fleet Services. Window tinting will not be authorized.
- Employee must not decorate any Fleet Vehicle unless authorized by his/her manager and Fleet Services. Decorations include but are not limited to bumper stickers, window clings, antennae balls and advertisements.

Company Owned Vehicles (cont.)

Vehicle Accidents:

All employees must follow the requirements in the most recent Vehicle Accident Handbook, which is kept with each Fleet Vehicle and includes a Vehicle Accident Report form. The current Vehicle Accident Handbook can be accessed through the Safety Department Sharepoint site or at this link: Vehicle Accident Handbook.

There will be an incident assessment conducted on each accident to determine cause and how the accident could have been prevented. Employee will fully cooperate with such assessment. Upon conclusion of the review, Employee will be notified of the results of the assessment.

Policy Responsibilities

Fleet Services Responsibilities

- Maintaining a database of all Fleet Vehicles, assigned departments, and assigned employees Acquiring and disposing of Fleet Vehicles.
- Ensure proper care of Fleet Vehicles through maintenance and inspections.
- Maintaining the Assigned Vehicle Decision Matrix.
- Facilitating and coordinating efforts with department management to train employees regarding this Policy and any changes.
- Annual review of the policy, updating as needed.

- Maintaining a database of all Fleet Vehicles, assigned departments, and assigned employees Acquiring and disposing of Fleet Vehicles.
- Ensure proper care of Fleet Vehicles through maintenance and inspections.
- Maintaining the Assigned Vehicle Decision Matrix.
- Facilitating and coordinating efforts with department management to train employees regarding this Policy and any changes.
- Annual review of the policy, updating as needed.

Each Department Manager Responsibilities

- Understanding, communicating the Policy.
- Requesting Fleet Vehicles for eligible employees using the Assigned Vehicle Decision Matrix Notifying Fleet Services when a vehicle needs to be acquired, reassigned or the status of an employee with an Assigned Vehicle has changed. Reasons for reassignment include job change or transfer, long term disability, termination, relocation, change to driver's license status, leave of absence or retirement.
- Ensuring that employee possesses a valid driver's license appropriate for the type of vehicle being operated in accordance with Part 4 (Vehicle and Equipment Operation) of the Avista Incident Prevention Manual.
- Approving exceptions to allow employees to drive vehicles home in certain cases.

Appendix C: Vehicle Classes

Vehicle Class	Description	Gross Vehicle Weight Rating	Charge Out Base
32	Passenger Cars		Mileage
46	4 x 4 pickups/SUV's, 1w/single rear wheels	6,000 GVWR or less	Mileage
47	4 x 2 Service trucks, Cargo Vans, w/single rear wheels	16,000 GVWR or less	Mileage
48	4 x 4 Service trucks/Cargo Vans, w/single rear wheels	16,000 GVWR or less	Mileage
56	Service trucks, high cube vans, flat beds, dumps, w/dual rear wheels	under 26,000 GVWR	Mileage
57	Dump & Flat Beds (Over 26,000 GVWR)		Mileage
58	Digger derricks, Service body trucks, boom or crane trucks, etc., w/single rear axles	Over 26,000 GVWR	Hours
65	Road Tractors		Mileage
66	Digger Derricks, cranes & knuckle booms, w/Tandem Rear Axles	Over 33,000 GVWR	Hours
67	Bucket trucks (45 ft and under)		Hours
68	Bucket trucks (Over 45 ft)		Hours
76	Off road construction equipment		Hours
77	ATV's, UTVs, snowmobiles		fixed monthly rate
78	Snow Cats		Hours
79	All terrain aerial equipment, cranes, manlifts, and back yard booms		Hours
85	All other equipment and trailers with mounted equipment, including: Genie lifts,		fixed monthly rate
	welders, vacuum units, compressors, line tensioners, stringing equipment,		
	boats, air compressors, pipe trailers, generators, drilling equipment		
86	Equipment Trailers, flatbed, and box/van only * No Mounted Equipment *	10,000 GVWR and under	fixed monthly rate
87	Equipment Trailers, flatbed, and box/van only * No Mounted Equipment *	10,001 GVWR and over	fixed monthly rate

Avista Class 46 Vehicle

Avista Class 48 Vehicle

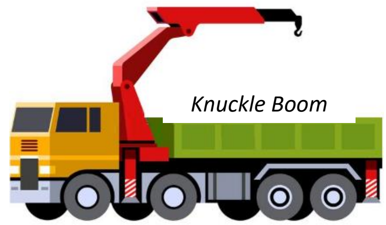
Avista Class 67 Vehicle

Left & Above: Avista Class 56 Vehicles

Above: Avista Class 68 Vehicle

Above & Right: Avista Class 66 Vehicles

Appendix D: Fleet Glossary of Terms

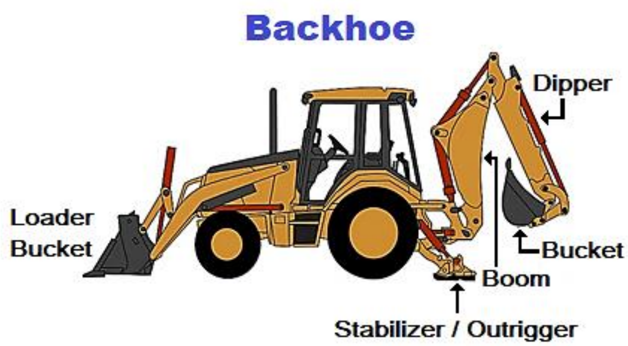



Trolley Boom

Aerial Device: Sometimes called a boom truck or cherry picker, this is a vehicle with a long foldable arm (also called a boom) that can be used to lift workers to a height. The boom is typically mounted to a truck bed. If the arm is short and compact and is primarily used to lift items off the truck bed, it is called a "knuckle boom." If when folded it is the length of the truck bed, it is called a "trolley boom."

Alternative Fuel Vehicles: This category includes electric hybrid vehicles and those that use compressed natural gas (CNG), biodiesel, or electrically charged batteries.

Backhoe: This is a piece of excavating equipment that consists of a digging bucket on one end of a two-part articulating arm, usually mounted on the back of a tractor or front loader. The section of the arm closest to the vehicle is called the boom, while the section the bucket is attached to is called the dipper.



Backup Alarm: These are activated when a vehicle goes into reverse, notifying anyone behind that vehicle that it will be backing up, providing more safety for anyone who may be behind the vehicle.

Benchmarking: This means comparing performance from one organization with that of other organizations, measured according to specified definitions and standards so that the data is directly comparable. In the Fleet world, this usually focuses on fuel usage, service delivery, maintenance practices, life cycles, costs, etc.

Compressed Natural Gas (CNG): This is natural gas, primarily methane, which is compressed to less than 1% of the volume it takes up in its natural state, allowing it to be stored in higher volumes than standard natural gas and be more easily transported. CNG burns cleaner than gasoline, reducing emissions up to 80%. It is also abundant and inexpensive compared to gasoline. However, it requires significant modifications in order to be utilized in vehicles and must have adequate storage space and filling stations, which are currently not widely available.[48]

[48] "Advantages and Disadvantages of Natural Gas," Conserve Energy Future, https://www.conserve-energy-future.com/advantages-and-disadvantages-of-natural-gas.php

Cost Benefit Analysis: This means looking at the costs and benefits associated with a particular course of action or choice of actions. For example, the cost of purchasing a larger bucket truck versus the potential risk of not being able to reach some of the equipment that may need to be repaired.

Digger Derrick: A utility truck also called a digger truck or a pole truck, this vehicle is equipped with an auger to drill holes for setting poles. These very heavy-duty trucks can also pull, hold poles or lines in place, haul thousands of pounds in a single load, and lift extremely heavy items.


Avista Digger Derrick

Direct Costs can be readily connected to a specific asset, for example, all the costs associated with a particular pickup, or it can mean the portion of costs assigned to that asset such as Fleet's tools.

Fit for Purpose: A vehicle or piece of equipment that is designed specifically for the purpose it serves.

Fleet Register: A database containing all the details about the vehicles and equipment in the Company's fleet.

Fleet Maintenance Records: These are details kept about each vehicle, including vehicle description, year of purchase and cost, mileage, fuel type, safety inspection results, routine maintenance reports, vehicle defect information, and repair records.

Fixed Costs are incurred by a vehicle whether it is being used or not and are typically computed based on time (such as cost per month or year).

Gross Vehicle Weight (GVW): This is the maximum operating weight of a vehicle as specified by the manufacturer. It includes the vehicles chassis, body, engine, fluids, fuel, accessories, passengers, and cargo. It is a term used for both motor vehicles and trains. (It does not include any trailers being towed.)

Plug-In Hybrid Electric Vehicle (PHEV): These vehicles tend to use gasoline or diesel as a main source of fuel but also have an electric motor to either assist in powering the vehicle or to provide primary power for a period of time.

Indirect Costs are expenses associated with maintaining the entire fleet. These costs are not directly associated with a particular piece of equipment but are still critical to its operation such as mechanics and their labor costs, tools and equipment, fleet buildings, as well as hardware and software applications.

Meantime Between Service: This is a metric that defines the average operating time between regularly scheduled services/maintenance. It provides an indication of the quality of the services an asset receives. A high mean time between service dates may indicate a lack of investment in caring for an asset, which can lead to accidents or other safety issues along with the potential for premature failure.

Mechanic Per Vehicle is the ratio between the number of mechanics on staff and the number of vehicles in the fleet.

Operating Cost: This cost is associated with the maintenance and upkeep of an asset. It includes the sum of all Company mechanic labor, contract mechanic labor, parts, tires, and fuel expenses. It can also include depreciation, insurance, registration and the like.

Ownership Cost: This includes all costs associated with owning an asset, including the purchase price, maintenance costs, insurance, and any costs related to operating the asset.

Power Operated Equipment (POE) is a unit that operates off-road, including backhoes, skid steers, generators, etc.

Skid Steer: This is a small, rigid-framed machine with either four wheels or a track movement system that has lift arms attached to a bucket, small backhoe, plow, trencher, auger or other attachments.[49] These are used to lift and carry material or aid in excavation. They are capable of zero-turn radius, which makes them highly maneuverable, especially in situations requiring a small and agile loader.

Skid Steer

Stake Truck: Also called a platform truck, this has a plain flatbed or side panels (which are often removable) for hauling equipment.

Support Cost: The sum of all expenses related to management and support staff, the facilities, and associated shop supplies.

[49] For an idea of all the attachments available to these versatile machines, see: https://www.casece.com/northamerica/en-us/products/skid-steer-loaders/overview/attachments

Support Staff Per Vehicle is the ratio between the number of support staff and the number of vehicles in the fleet.

Total Cost or Total Cost of Ownership: This is the sum of ownership, operating and support costs. It includes both the purchase price of the item plus the cost of operating it. Operations costs usually include things like maintenance charges, downtime costs, and driver costs.

Utilization is the usage of vehicles based on annual average miles driven within a minimum mileage threshold.

Units: This is a general term for a vehicle, trailer or piece of power equipment like a generator, Genie lift, or compressor.

Variable Costs are those related to the vehicle's activity, usually computed using the distance traveled or the hours of operation. These kinds of costs include items such tires, fuel, fluids, and wiper blades.

Vehicle is a unit that operates on the road.

Vehicle Equivalency (VE) or Vehicle Equivalency Units (VEU): This weighs the number of units and vehicles in the fleet according to the annual average maintenance and repair hours needed for that particular unit or vehicle. For example, adding up how vehicles a company has in order to determine how many mechanics need to be hired. It also allows comparing the requirements of one vehicle (such as an employee fleet car) to another (such as a digger derrick) to ascertain maintenance and repair budgets. A car might have a ratio of 10 VEU to maintain compared to a digger derrick of 100 VEU to maintain.

Avista Utilities

Facilities Infrastructure Plan

2020

Thanks & Acknowledgements

Anna Scarlett – Guidance, Leadership
David Schlicht – Data, Insights, and Expertise
Eric Bowles – Expertise, Data, Guidance
Jennifer Deline – Writing, Editing
Julie Lee – Budget and Actual Expenditures
Ken Copenhaver – Editing, Publication
Lindsay Miller – Co-Author, Expertise & Guidance
Robert Johnson – Data, Insights, and Editing

Lisa La Bolle – Primary Editor and Author, Research, Drafting, Figures, Graphics, Production

Table of Contents

Table of Figures

Table of Tables

Introduction

A utility is an asset-heavy entity, requiring a great deal of infrastructure to support its operations. Trucks, crews, office and operations buildings, large storage areas, equipment and supplies, support staff and more are required in order to provide 24-hour a day customer service for Avista's electric and gas customers. As would be expected, many of the facilities built over time to support Avista operations are quite dated. Some were built in early Company days during the late 1800s, many others were built in the 1950s and 1960s (almost 70 years ago!) Others are modern and provide sufficient service for today's purposes.

In order to continue to adequately serve customer needs and customer investments in infrastructure going forward, buildings must be maintained, upgraded and updated to meet the uses for which they are intended. Common sense and good stewardship indicate that facilities will need more maintenance over time if they are to remain useful. Complete replacement may be required to remain functional, not only to keep up with current requirements, but also to save money over the long term. For Avista, these requirements include a steady increase in customer base and increasing focus on customer service, which naturally requires more employees and equipment over time.

Avista Facilities Team Responsibilities Include:

- *All maintenance requirements for office buildings, shops, call and service centers, equipment & vehicle areas, warehouses, docks, storage facilities, parking zones, and all other Company physical spaces*
- *Heating, cooling, ventilation, electrical, plumbing, and lighting system functionality & efficiency*
- *Space management*
- *Property and grounds*
- *Janitorial services*
- *Lease management*
- *Handling employee moves & accommodations*
- *Energy efficiency measures*
- *Facilities construction*
- *Shared space scheduling*
- *Parking areas*
- *Employee moves*
- *Planning, budgets, project management, record keeping*

Above: Mission Campus Pole Yard
Below: Lewiston Office

Trucks and vehicles have also increased in size and complexity, requiring more space as well as specialized maintenance and support. Materials and supplies must be located in close proximity to crews in an organized, efficient space for quick access in order to provide effective daily work flow and to remedy outages in a timely manner. Employees must have adequate and safe work areas to perform their jobs and serve customers. All of these facets come into play in order for Avista to provide an appropriate level of customer service, and they are centered in the facilities that support Company operations.

"Maintenance" is defined as the act of keeping assets in acceptable condition. It includes preventative care, normal repair, replacement of parts and structural components, and other activities needed to preserve the asset so it can continue to provide acceptable service and achieve its expected life.

Facilities underpin the success of most organizations, and this is especially true in the utility industry. The heart of the ability to serve customers lies in the crews and equipment that go out and perform the work, from the daily practices such as replacing failed equipment or installing service for new customers, to crisis situations of putting the system back together after a major storm. This necessitates reliable, dependable vehicles, ready access to tools, equipment and supplies, effective and efficient employees, and a strong focus on safety. These requirements are at the heart of Avista Facilities Management work, plans, and strategies.

Avista Facilities Staff

- 1 Corporate Facilities Manager
- 1 Building Ops. Supervisor
- 1 Quality Assurance Inspector
- 3 Building Servicemen
- 1 Electrician
- 3 HVAC Technicians
- 1 Painter
- 1 Groundskeeper
- 2 Project Managers
- 1 Corporate Space Planner
- 1 Interior Planners
- 1 Administrative Assistant

Utility infrastructure also includes the support functions that are required for Avista to function as a business, such as accountants, engineers, mechanics, customer service representatives, line patrol vehicles, phone systems, work cubicles, chairs, computers, service bays, and so much more. All of this requires a framework for which the Avista Facilities team provides systems, structures, maintenance, and associated support.

This small group of seventeen employees is responsible for all of Avista's lands and buildings, which includes a wide spectrum of responsibilities such as managing janitorial services, ensuring a roof is repaired before it fails, replacing a structure when it no longer serves the necessary purpose or becomes cost ineffective, handling major construction projects, fixing clogged plumbing, and even spraying weeds. It should be noted that only about 57% of the Facilities staff performs actual maintenance and repair work across the Avista service territory; others execute capital projects, and others provide general support across the organization. This group manages and maintains 51 facilities totaling 1,265,514 square feet on over 59 acres, in addition to 38 sites across a service territory containing nearly 1.6 million customers scattered across 30,000 square miles in four states.[1] In addition, the Company service territory is split into sections of 12 operating districts, each containing

The little Avista service center in Kamiah

[1] Avista Quick Facts 2019, https://myavista.com/about-us/our-company/quick-factsqs

regional crews, support employees, buildings, storage yards, and associated equipment and facilities. Supporting such a vast area and such a diverse group of assets requires leadership, vision, good planning, expertise, experience, and decision-making tools. The Facilities team utilizes all of these aspects, including performing regular studies of facility condition, receiving feedback from employees when they identify issues, and using common sense, industry standards, surveys and evaluations, as well as asset management techniques such as life cycle costs and asset health indices. They consider issues such as safety, criticality, efficiency, cost, potential savings, and long term costs and value while holding to a clearly defined budget. It is a balancing act, as the age of Avista's buildings means that the needs and demands for repair, remodel, or replacement have continued to grow and become more pressing over time, while the budgets for maintenance have remained relatively flat. To add to this situation, the amount of facilities space being added to the Company portfolio continues to increase. This issue is clearly shown in Figure 1.

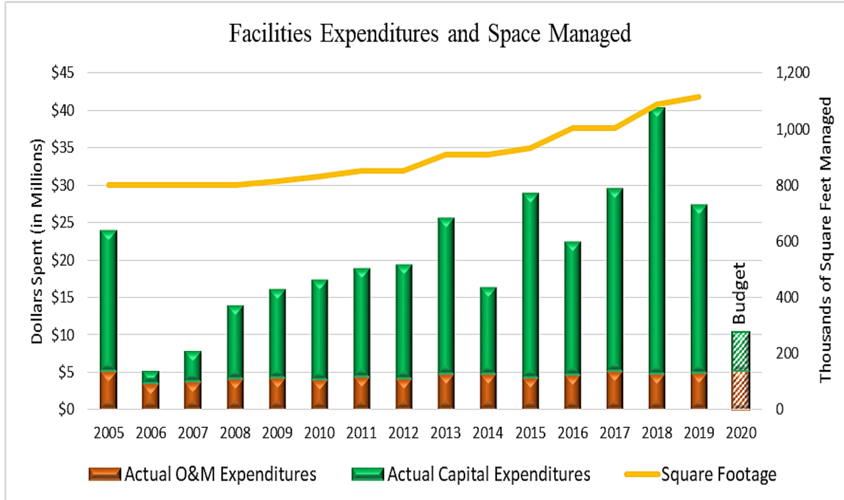


Figure 1. Avista Facilities Managed and Related Expenditures [2]

Manpower levels in Facilities have remained nearly the same for over a decade, as shown in Figure 2. Though industry standards recommend one full time employee per 49,000 square feet of space managed,[3] Avista currently has one employee per 55,903 square feet of space managed, putting ever increasing burdens on very few employees who are maintaining facilities which continue to grow older.

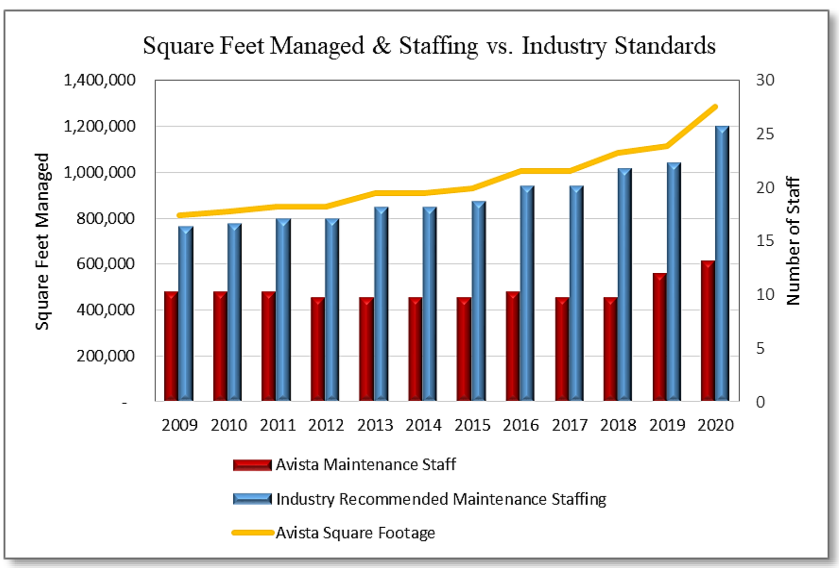


Figure 2. Avista Staffing Levels per Square Foot vs. Industry Standard

As shown in Figure 2, Avista has increased the number and size of its properties over 62% in the past ten years. Though capital expenditures to

[2] Larger expenditures in 2018 are due to the new Fleet Building ($6.3 million) as well as constructing the Dollar Road Facility ($14.3 million) and the Deer Park Service Center ($5.1 million).

[3] International Facilities Management Association, "Operations and Maintenance Benchmarks: Research Report #32," page 51. This report is not available online. It must be purchased. However, Avista has one available if requested.

purchase and build new facilities have increased, over the same time period O&M budgets have remained relatively flat, which means they are maintaining a far greater amount of space with the same amount of dollars.

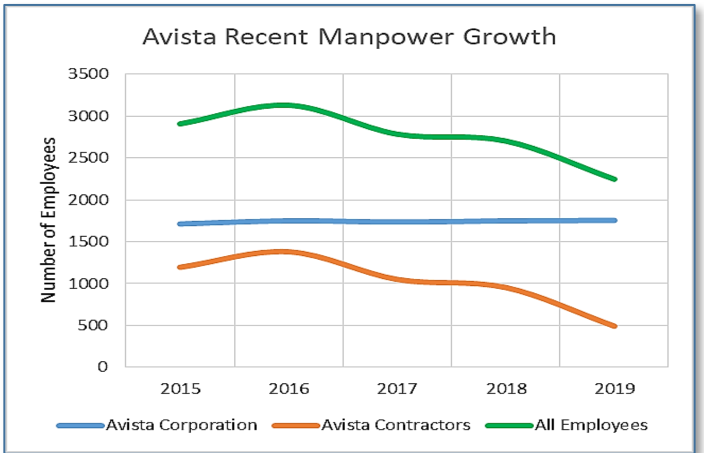


Figure 3. Avista Employee Counts

Avista's full time employee levels have remained relatively stable over the past few years as can be seen in Figure 3 (blue line). Figure 4 highlights the fact that most of Avista's space needs are related to professional level employees (both Avista employees and temporary employees or contractors.)

Often temporary employees are associated with technology, such as hiring specialists to install the new Windows 10 operating system company-wide. When temporary projects wind down, temporary employee levels decline accordingly, as shown in Figure 3. Contracting is a cost-saving measure, typically used when the Company either does not have the expertise in-house or lacks the manpower to perform labor and time-intensive tasks like wood pole and gas line inspections, or for short term tasks such as technology installations as mentioned above. Contractors are an important work source, and though they are not full-time long-term employees, they still need a place to work, even if just temporarily. Thus, finding adequate office space, maximizing the use of existing space, and minimizing splitting up teams is an ongoing struggle.

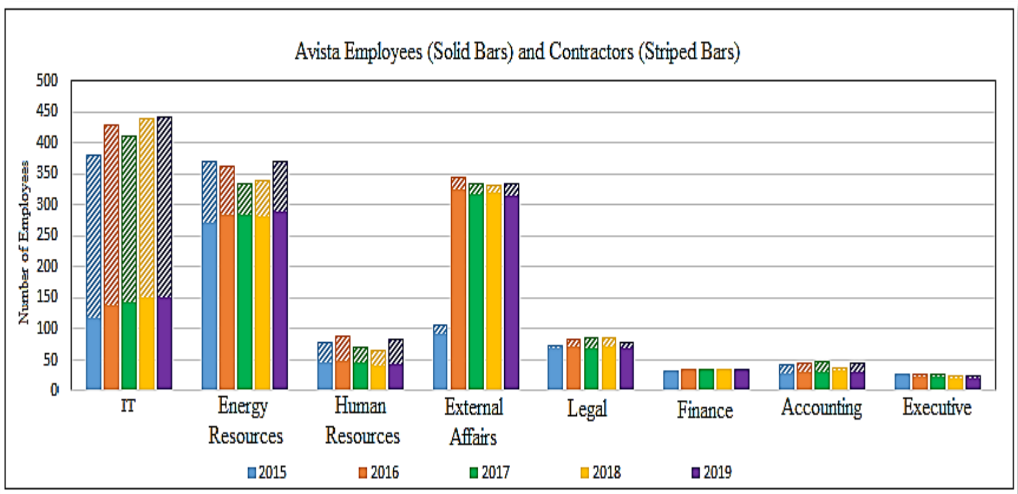
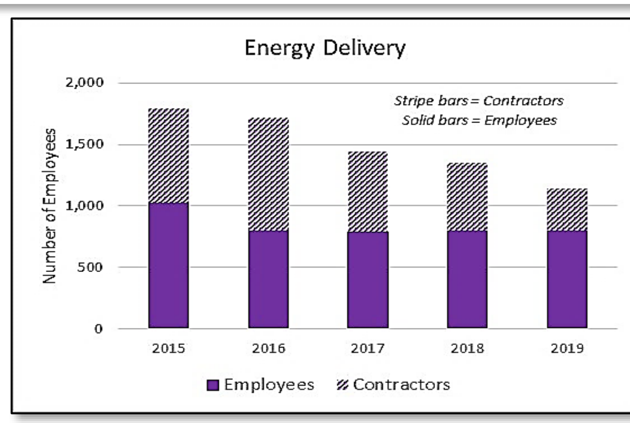


Figure 4. Avista Employee Area Growth

Note that Energy Delivery is broken out because it contains the largest number of employees and would skew the main chart.



Another issue repeatedly faced by the Facilities team is declining customer satisfaction. They face constant complaints from customers, employees and contractors about the condition of the buildings they manage, including dirty windows, stained carpets, pot holes in the parking lots, odors, cracks, loss of paint, too few (or no) conference rooms, lack of adequate work space, etc. To make matters worse, work response time to internal customer issues at Avista facilities has increased significantly in the past ten years. Currently what used to be same-day response has increased to an average of three days to react to non-emergency concerns simply due to lack of manpower.

IFMA Recommended Maintenance Staff	
Square Feet Managed	**# of FTEs**
Less than 50,000	2
50,000 - 100,000	4
100,001 - 250,000	5
250,001 - 500,000	9
500,001 - 750,000	13
750,001 - 1,000,000	16
1,000,001 - 1,500,000	27
1,500,001 - 2,000,000	35
2,000,001 - 3,000,000	44
More than 3,000,000	140

Unfortunately, existing funding has required an O&M shift to maintaining only the most critical systems, thus more aesthetic problems such as dirty carpets and windows are "selectively neglected." These types of issues tend to be very noticeable to employees and customers, affecting the perceptions of both with respect to the Company. It also reduces the expected life of assets and increases long term maintenance costs. As can be imagined, all of these issues along with the constant pressure of not being able to address basic problems, unhappy customers both internal and external, and being understaffed and overworked is taking a toll on Facility employee morale as well as the lifecycle expectations and costs associated with these assets.

Even facing all of these challenges, the Facilities team has achieved numerous successes and awards. Facilities has worked to achieved LEED GOLD status for each floor of its corporate office building. A LEED certified building has incorporated sustainability into its design and construction, and thus can potentially perform more sustainably than typical comparable buildings in the marketplace. Addressing this phase of a building's life is important because many irreversible decisions with impacts on sustainability are made during the design and construction processes. At Avista, this sustainability focus was included as part of an overall renovation of the corporate office building, including the HVAC, electrical and plumbing systems for each floor.


Avista Officers and Facilities staff receive the LEED GOLD Award

Upon the completion of this work, the Facilities team chose to apply for the designation of LEED-Existing Building (EB). LEED-EB aims to maximize operational efficiency while minimizing environmental impacts. Its main users are building owners and facilities managers. Since LEED-EB is based on actual building O&M practices, a LEED-EB certified building is actually performing more sustainably than its peers. Addressing the operations phase of a building's life is critical, because on a life-cycle basis, that is typically when most of the environmental impacts occur. Moreover, improvements in this phase lead to actual, concrete, measurable benefits. Facilities was able to demonstrate all these benefits and received LEED GOLD for this work.

Another designation that Facilities has worked toward is an Energy Star rating. Buildings that earn the U.S. Environmental Protection Agency's Energy Star use 35% less energy and generate 35% fewer greenhouse gas emissions than similar buildings across the nation. The financial value of energy savings isn't just limited to utility bills. It accrues across the board — from asset value to shareholder value to operating income. Beyond the positive financial impacts, saving energy also makes a real-world impact in meeting environmental goals of reducing greenhouse gas emissions. To date Facilities has achieved this designation at two of its facilities, the Spokane Valley Call Center and the Corporate Office Building.

Benefits of Well Maintained Facilities

Buildings and facilities are exposed to all kinds of weather – rain, sun, snow, wind and other natural elements. Over time, this exposure has an adverse effect on roofs, windows, doors, paint, asphalt, wood and other building materials. Paint begins to peel, doors warp, and covers leak. If left unattended, interior walls, floor coverings and ceilings can also be damaged through routine use, resulting in costly repairs if not addressed in a timely manner. Avista's buildings house employees and expensive equipment that must be protected. These are Avista assets, paid for by customers, and must be adequately maintained in order to continue to perform their intended purposes, be it storing poles and transformers, providing maintenance and storage areas for vehicles, or creating working spaces for employees.

Performing adequate maintenance allows the Company to preserve and fully utilize their properties while reducing expensive repairs in the long term. It also ensures a safe environment for people and equipment. Damaged or poorly maintained facilities can create very real safety risks and associated liability for employees, customers, and contractors. The Facilities group focuses on reducing risk by monitoring the condition of Avista facilities across the service territory using a variety of tools and techniques described in further detail later in this report.

Damaged Roof

Broken Gutter

One of the subtle but important aspects of maintaining facilities is to provide comfortable, safe, and efficient work spaces. This is one of the keys in attracting and maintaining quality employees. It is estimated that over 30% of current utility employees are within five years of retirement.[4] The utility industry is seeing a huge shift in

[4] Gil C. Quiniones, "30% of Utility Workers Retiring in 5 Years, New Recruiting Strategies Essential," Breaking Energy, June 12, 2014, https://breakingenergy.com/2014/06/12/utilities-preparing-for-massive-workforce-turnover/

attracting, motivating and training new employees. Today's employees, especially those with specialized skills, know that they are in high demand in every industry and are no longer interested in being employed by one organization or industry for their entire careers. Utilities such as Dominion Energy, with an employee base of over 16,000 employees, have found that employee workspaces play a large role in helping them retain talent. They state: "A company that hopes to have a successful future must attract strong candidates and retain talented employees. We strive to create work spaces that meet the needs of our current employees and help attract new ones."[5] One of the ways they achieve this is to focus on providing a comfortable, clean, efficient and welcoming workplace. A recent study found that 2 out of 3 employees in today's workforce say that the physical environment of their workplace affects their decision to stay or leave an organization and, in fact it ranked 8 out of 10 in impacting their satisfaction and job performance.[6]

Many of Avista's work areas are less than ideal

Employees view their work setting and the workplace services offered as an extension of their level of care by a company. A recent study revealed that high workplace satisfaction is also positively correlated with high employee production, meaning the physical workplace can be used as a strategic asset to improve engagement, employee motivation, and performance. In fact, studies prove that a "shabby" work environment creates negative attitudes in employees, reducing their output and actually affecting the bottom line.[7] Satisfied employees provide higher quality customer service, which is a primary goal at Avista.

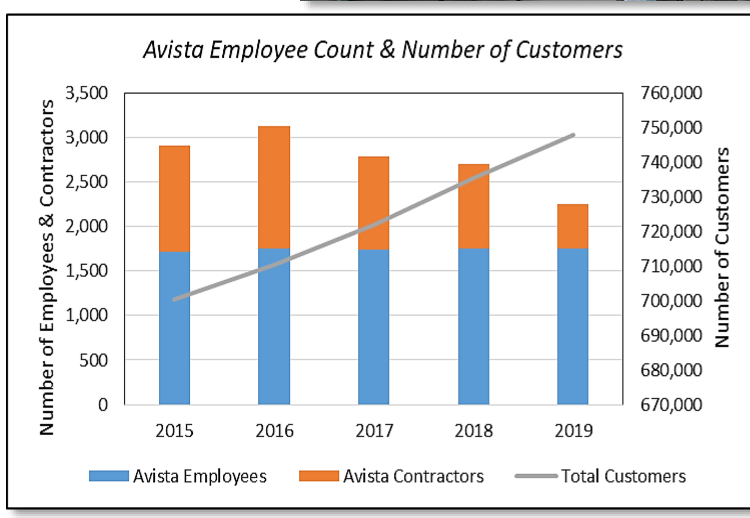


Figure 5. Avista Employee Headcount and Customer Growth

[5] "Attracting, Developing, and Retaining Talent," Dominion Energy, https://sustainability.dominionenergy.com/talent-strategy/ and https://sustainability.dominionenergy.com/employee-experience-overview/
[6] Michael Guta, "23% of Employees Decide Where to Work Based on the Office Environment, Survey Finds," Small Business Trends Magazine, July 8, 2018, https://smallbiztrends.com/2018/07/office-design-can-attract-employees.html and Lindsey Pollak, "What Do Multigenerational Employees Want in a Work Environment?" https://www.lindseypollak.com/multigenerational-work-environment/
[7] "Facilities Management Plays Key Role in Employee Satisfaction," Buildings Magazine, March 20, 2012, https://www.buildings.com/article-details/articleid/13762/title/facilities-management-plays-key-role-in-employee-satisfaction also "Employee Engagement Linked To Workplace Satisfaction," Executive Magazine, May 27, 2016, https://facilityexecutive.com/2016/05/employee-engagement-linked-to-workplace-satisfaction/

The Facilities staff participates in helping Avista retain its talent base by attempting to provide work areas that help promote job satisfaction and work production, have ergonometric designs to safeguard employee health, and that are safe, effective and efficient. Adequate meeting areas, maintenance and work stations, cafeteria and break areas, exercise facilities, and the like all add to employee quality of work life. However, providing these basic amenities is a constant challenge at Avista, given the age of many of the facilities and lack of funding to provide space, furniture and equipment.

Customer perception is also a subtle but important Facilities consideration. Run down, dilapidated facilities give the impression of poor service and performance. Customers may hesitate to enter a customer service center in this condition, isolating them from interactions with the Company. Poorly maintained facilities may also encourage customers to feel that the money they send in every month as they pay their bills may not be spent wisely or to preserve the assets they have provided for the Company through their rates. Avista strives to be engaging and welcoming with customers, encouraging interaction. That makes this is an important facet in maintaining the appearance and condition of the physical presence of the Company in its service buildings, operations areas, storage yards, and customer service centers.

Management Practices: The "How"

We know why this work is important, so how does the Facilities team effectively tackle such a large, complex, and diverse asset base and the associated tasks? One methodology employed is the utilization of systematic procedures and protocols to determine how to best manage Avista's facilities. Part of this evaluation includes industry best practices as determined by national organizations that specialize in this area, including Building Owners and Managers Association (BOMA) and the International Facility Management Association (IFMA).

BOMA uses their expertise in the industry to provide training as well as research results and recommendations to building owners across the nation. They also give out highly prestigious industry awards. Avista has received the BOMA 360 Performance Program

INTERNATIONAL FACILITY MANAGEMENT ASSOCIATION (IFMA)

Founded in 1980, IFMA is the world's largest and most widely recognized international association for facility management professionals, supporting 24,000 members in more than 100 countries. Together they manage more than 78 billion square feet of property and annually purchase more than $526 billion in products and services. They focus on best practices, training, research, and education.

BUILDING OWNERS AND MANAGERS ASSOCIATION (BOMA)

The Building Owners and Managers Association (BOMA) International is a federation of 88 BOMA U.S. associations and 18 international affiliates. Founded in 1907, BOMA represents the owners and managers of all commercial property types including nearly 10.5 billion square feet of U.S. office space that supports 1.7 million jobs and contributes $234.9 billion to the U.S. GDP. Its mission includes advocacy, education, shared knowledge, and best practices.

Certification for the Corporate Headquarters Building.[8] This certification was granted to Avista as a result of the Facilities team's efforts to add energy efficiency measures when they remodeled this 1959-era building, and acknowledges the fact that they operate and manage it better than most comparable buildings around the world.[9]

IFMA is also recognized as an international expert on managing facilities, offering certification, education, and industry-specific information and research.[10] The expertise offered by these organizations helps guide Avista's facilities management practices. In addition, Facility's employees utilize technology to monitor equipment, systems, energy usage, etc. Specialized analysis is also used to help predict failures and to help identify issues prior to failure. Data is gathered to track issues and concerns over time in the service of developing a more proactive approach to sustaining assets. The Company also calls in outside expertise to objectively evaluate the condition of facilities and provide professional guidance on facilities and conditions as described below.

Terracon Facilities Evaluation

In 2017 the Company hired Terracon Consultants to perform a condition assessment on 76 Avista-owned facilities and 35 real estate sites at 34 different locations, comprising approximately 981,000 square feet. These facilities were constructed between 1903 and 2016. Terracon estimated the value of this infrastructure at approximately $242 million.

The Terracon study was highly detailed and in depth. They examined every characteristic of each facility from a variety of perspectives. External structures from asphalt in the parking lot to roof condition, fences, curbs, and storage areas were examined to ascertain and score condition and to identify issues and note concerns. Internal aspects such as walls, carpets, and furniture condition were evaluated. They surveyed building systems including plumbing, heating and cooling, electrical, lighting, air quality, drainage, and security. They looked at safety aspects from both the customer and employee perspective. Then each item in the facility was rated based upon its condition and assigned a budget category of O&M Preventative Maintenance, O&M Deficiency Repairs, Capital Replacement, and Capital Renewal/In-Kind Replacement.[11]

[8] https://www.boma.org/BOMA/Recognition-Awards/BOMA_360_Performance_Program/BOMA_360_Buildings/BOMA/Recognition-Awards/BOMA_360_Buildings.aspx?hkey=651693fa-b5df-4923-b091-0b3a9987e937

[9] "BOMA 360 Performance Program," BOMA International, https://www.boma.org/BOMA/Recognition-Awards/BOMA_360_Performance.aspx

[10] International Facility Management Association (IFMA), https://www.ifma.org/

[11] O&M Preventative Maintenance is planned maintenance conducted regularly on equipment still in working condition. O&M Deficiency Repairs involve unplanned maintenance conducted on equipment to get it into working condition. Capital Replacement is unplanned, replacement or refurbishment of assets that have failed. Capital Renewal/In-Kind Replacement involves planned, cyclical replacement or refurbishment of assets at the end of their useful lives to maintain a state of good repair.

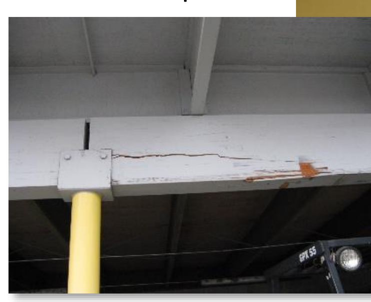
Facilities Evaluated by Terracon			
Site	Square Feet	Acres	Value
Beacon Substation	31,670	19	$4,729,932
Chewelah Facility	5,200	1.6	$1,094,625
Clarkston Service Center	24,678	4.3	$5,080,245
Coeur d'Alene Service Center	51,084	9.4	$10,794,280
Colfax Facility	2,169	0.3	$263,453
Colville Service Center	20,105	6	$5,364,761
Courtyard	56,000	1	$16,082,583
Davenport Service Center	13,608	0.7	$2,443,993
Dollar Road Service Center	15,000	1	$4,566,811
Downtown Project Center	25,000	1	$4,676,144
East Davenport	2,000	0.9	$377,072
Elk City Facility	1,800	1	$276,358
Grangeville Facility	9,904	0.5	$1,036,402
Grants Pass Service Center	1,126	0.3	$1,129,175
Jack Stewart Training Center	26,108	34.5	$4,260,418
Kamiah Facility	800	0.5	$378,818
Kellogg Service Center	13,622	1.9	$3,074,896
Klamath Falls Service Center	5,132	1	$3,680,695
LaGrande Service Center	3,730	0.6	$2,646,677
Lewiston Call Center	5,468	0.6	$1,614,292
Main Campus	463,692	37.9	$118,237,135
Medford Service Center	29,800	1	$5,555,944
Orofino Facility	7,190	0.5	$2,127,522
Othello Service Center	6,400	0.5	$1,644,203
Pierce Facility	1,200	1	$239,668
Pullman Service Center	25,436	6	$5,128,085
Ritzville Facility	2,500	1	$404,586
Roseburg Service Center	4,000	1	$1,417,649
Sandpoint Service Center	17,931	6.5	$3,857,002
Spokane Valley Call Center	14,022	2.8	$3,136,360
St. Maries Service Center	12,209	4.3	$2,625,370
Steam Plant Square	81,500	1	$23,384,227
Tekoa Facility	1,383	0.1	$186,134
Total	**981,467**	**149.7**	**$241,515,515**

Figure 6. Avista Square Feet of Property Managed & Value

Terracon Inspection Items Included:

- Building Exterior (lighting, paint, glass, doors, siding, trim, general condition)
- Outbuildings & Storage Areas
- Perimeter (fences, sidewalks, parking, storm drains, landscaping, storage yards, signage, lighting)
- Roof (general condition, drains, gutters, downspouts, seams, flashings)
- HVAC (type, age, filters, belts, fans, air intakes, general condition)
- Electrical Systems (panels, lighting, service mast, etc.)
- Emergency generator (age and condition)
- Plumbing (restroom condition, toilets, sinks, septic systems, general infrastructure)
- Building Interior Systems (paint, carpets, tile, casework, general furniture condition & usability)
- Line Docks
- Elevators
- Fire Protection Systems
- Security (general and security systems)
- Roll Up Doors
- Waste Collection
- Compressed Air Systems

The Terracon study identified and prioritized issues they found with the goal of extending the overall service life of these facilities and reducing the possibility of unplanned repairs, safety issues, failures or service interruptions. It also provided a thorough inventory and condition assessment of all Avista-owned facilities, including current deficiencies, forecasted costs for repairs and anticipated future maintenance needs. Terracon prioritized the maintenance and replacements they identified using a specialized software product designed for this purpose.



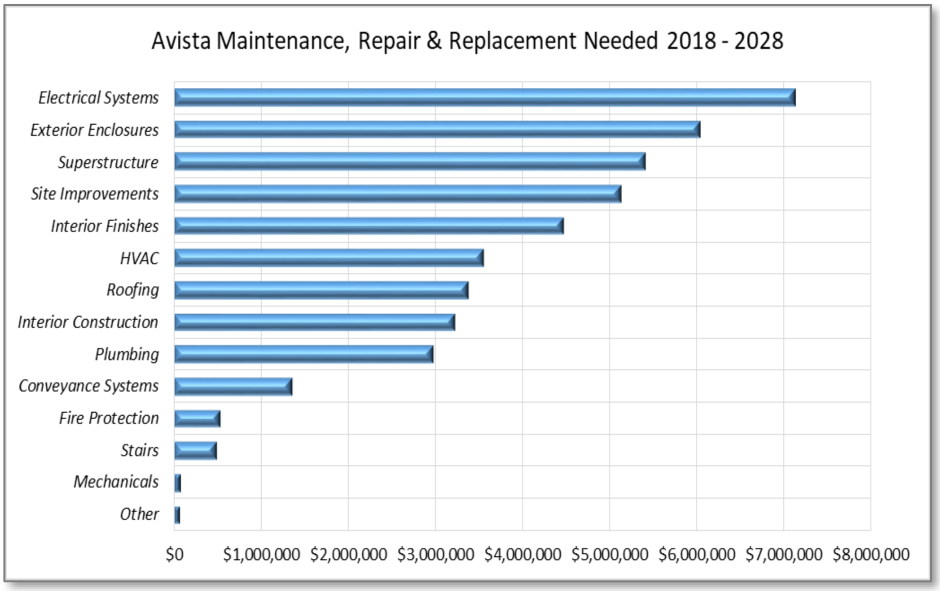


Figure 7. Terracon Identified Avista Facilities Total Issues by Cost

Terracon's research into Avista's infrastructure and practices found that Avista is underfunding preventative maintenance activities, leading to a reduced service life of Company assets and their components and increasing the possibility of unplanned service interruptions. In Terracon's expert opinion (which is backed by the industry), funding levels for preventative maintenance should typically run from 2-4% of the plant replacement value of the assets being maintained.[12] This level of funding provides the necessary expenditures to maintain only the <u>basic functionality</u> of facilities. In fact, they assert that this funding level should be used as an absolute minimum value, encouraging that "Where neglect of maintenance has caused a backlog of needed repairs to accumulate, spending must exceed this minimum level until the backlog has been eliminated."[13]

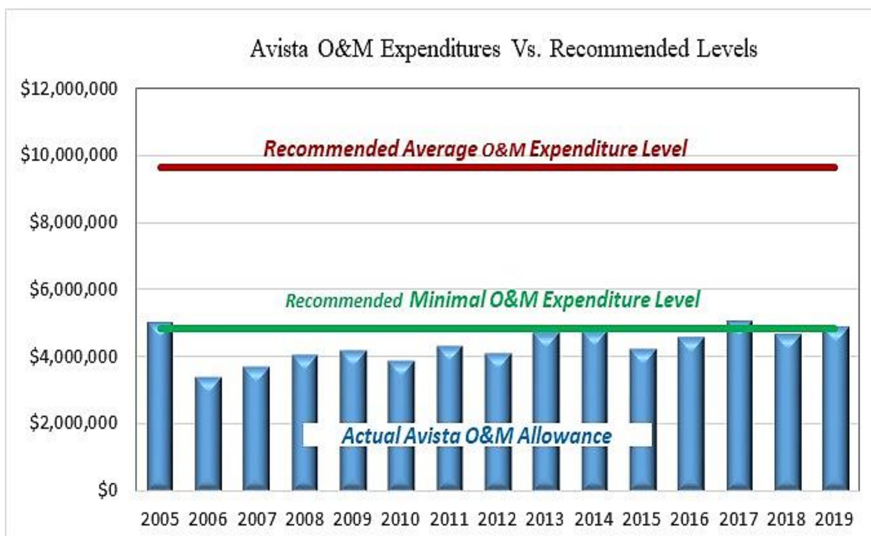


Figure 8. Avista Maintenance Expenditures vs. Industry Recommendation

The estimated replacement value of Avista's assets when the survey was taken in 2018 was approximately $242 million, with estimated maintenance and replacement requirements based on the Terracon report of $8,800,640 *per year*, which equals 3.64% of the current replacement value of Avista's facility-related assets. Figure 8 clearly demonstrates that the

[12] The 2-4% is mandated by the Building Research Advisory Board, a branch of the National Academy of Sciences, in their report "Committing to the Cost of Ownership - Maintenance and Repair of Public Buildings," https://www.nap.edu/catalog/9807/committing-to-the-cost-of-ownership-maintenance-and-repair-of. This percentage level is also recommended by the Federal Facilities Council, "Determining Current Replacement Values," https://www.nap.edu/read/9226/chapter/4. It is also recommended by the Building Research Board Committee on Advanced Maintenance Concepts for Buildings report "Committing to the Cost of Ownership – Maintenance and Repair of Public Buildings," https://eric.ed.gov/?id=ED322581

[13] The National Academies of Sciences, Engineering, and Medicine, "Budgeting for Facilities Maintenance and Repair Activities: Report Number 131," https://www.nap.edu/read/9226/chapter/3

amount spent by Avista at about $4 million per year (the blue bars), does not reach the minimum level of O&M expenditures standard in the building industry for basic sustenance of facilities (the green line). At Avista, O&M expenditures have actually decreased with the addition of more square footage. In fact, over the past ten years Facilities has increased its portfolio of square footage by almost 63% with no significant increases in staff or funding levels for maintenance and repair.

Out of the approximately $4 million budgeted for facilities O&M annually, only about $850,000 is applied to actual maintenance, which primarily consists of changing filters. The rest goes to pay for utility bills including electricity, gas, water, sewer, garbage service, internet service, and the like.

Unfortunately, facility maintenance activities compete for limited funding with many other programs: transmission line rebuilds, turbine replacements or upgrades, substation transformers, technology programs, gas line extensions, wood pole inspections, etc. and it is relatively easy to push building maintenance activities to the bottom of the priority list. Often deferred maintenance is not immediately reported, if at all, and the associated issues can go unrecognized until assets fail, start to incur significant costs, create safety hazards, or present noticeably poor service to the public.

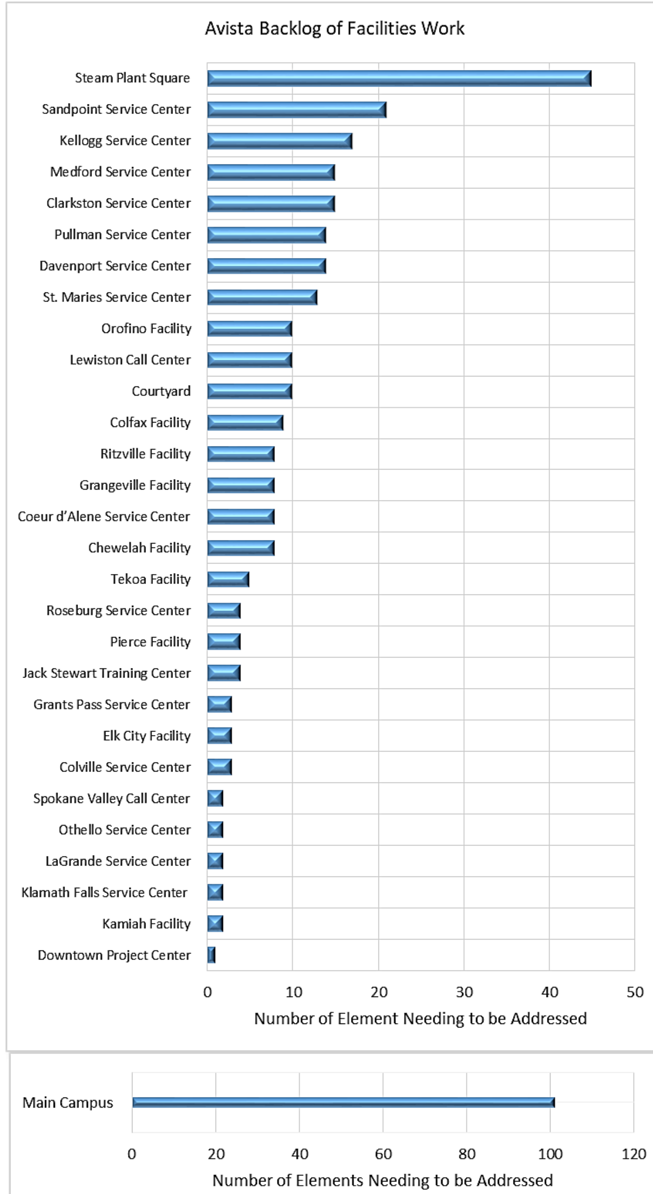


Figure 9. Avista Work Backlog Identified by Terracon Study

Mission Campus

Headquarters	**381,110**
Warehouse	**35,000**
Investment & Recovery	**13,200**
Waste & Asset Recovery	**15,000**
Ross Park	**17,000**
Line Dock	**28,750**
Covered Areas/Canopies	**8,000**
Fleet Building	**30,000**
Parking Garage	**171,000**
TOTAL SQUARE FEET	**699,060**

The backlog of work required to adequately maintain Avista facilities continues to grow as shown in Figure 9. Nearly every facility requires some kind of corrective work, and this has been especially true at the Mission campus, which houses nearly 60% of the Company's buildings.

To get a handle on this situation, Terracon recommends that Avista change to a budgeting concept that is based upon projected maintenance requirements rather than the straight-line (plus inflation) approach currently used by the

Company. They believe that this will help the Company get a handle on this backlog and move to a more proactive strategy. They also encourage an increase in preventative maintenance activities to extend the remaining service life of the Company's assets, thus delaying the need to capitalize expenditures required when replacing these assets before their expected end-of-life timeframe.

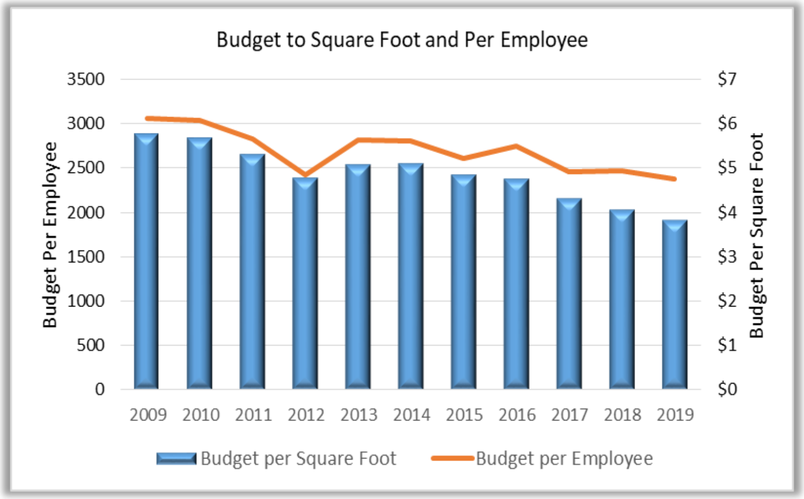


Figure 10. Avista Budget by Square Foot & Per Employee

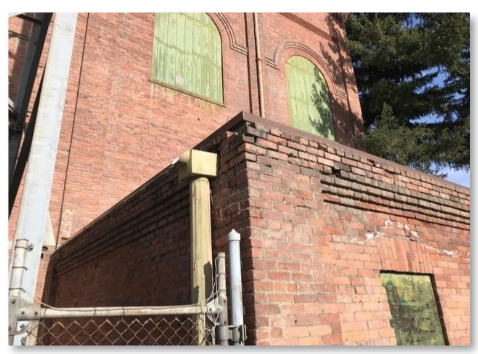
This Terracon study is the center of the Company's Facilities asset management plan. It provides both a benchmark of the current building performance and a defensible estimate of reinvestment costs needed to keep Avista's facilities functioning at an acceptable level. Terracon's extensive study of Avista's facilities resulted in a list with specific, detailed descriptions of condition and issues identified. This list includes everything critical to the operation of Avista's facilities. Items such as 60-year old electrical panels no longer in compliance with safety standards, old motors that have far exceeded their expected life and for which parts are no longer available, wood surfaces desperately in need of paint to protect them from the elements, missing lights, leaking roofs, and more can be found on this list.

Terracon's list is sorted by relative risk and the impact the item has on the Company's ability to perform its work, making the highest priority projects readily apparent. Of the 363 "at risk" items Terracon identified, nearly 60% had a risk rating higher than 5 (on a 1 to 10 scale) and 20% were identified as having an actual impact on operations. All of the items on list were identified as needing an immediate fix at a cost of almost $6.4 million, a mixture of capital and O&M required dollars. Though each year as many elements on this list as possible are being addressed in a priority fashion, the list will continue to grow as the infrastructure continues to age, especially if it is not receiving adequate maintenance in the meantime. The Terracon priority list is on the next page.

Sorted by Number of Issues Identified							
Facility	# of Items	Total Cost to Repair or Replace	Ave. Risk Factor	Ave. Impact Rating	Highest Risk Rating	Highest Critical Rating
Main Campus	101	$2,505,742	5.7	3.3	7.68	10
Steam Plant Square	45	$1,583,121	5.6	2.8	6.56	8
Sandpoint Service Center	21	$189,662	5.7	3.5	7.07	8.5
Kellogg Service Center	17	$87,440	5.2	2.5	6.4	2.5
Clarkston Service Center	15	$365,264	5.7	2.6	6.71	4
Medford Service Center	15	$73,166	4.8	2.7	7.35	6
Davenport Service Center	14	$82,945	4.6	3.6	6.16	8.5
Pullman Service Center	14	$141,803	4.9	2.7	6.16	4
St. Maries Service Center	13	$214,844	4.9	3.2	6.56	6
Courtyard	10	$573,117	6.0	4.7	7.07	10
Lewiston Call Center	10	$68,191	4.9	3.1	6.16	8
Orofino Facility	10	$96,053	3.9	5.1	5.83	10
Colfax Facility	9	$41,622	5.1	3.4	6.48	8
Chewelah Facility	8	$37,956	4.9	4.1	6	8.5
Coeur d'Alene Service Cente	8	$25,174	3.9	6.1	4.36	10
Grangeville Facility	8	$113,191	5.2	4.1	6.16	10
Ritzville Facility	8	$32,273	4.2	6.2	5.1	10
Tekoa Facility	5	$16,469	4.9	3.9	6.71	10
Jack Stewart Training Center	4	$44,414	4.2	3.5	5.1	6.5
Pierce Facility	4	$19,850	6.0	2.0	6	2.5
Roseburg Service Center	4	$14,230	4.2	2.5	5.39	2.5
Colville Service Center	3	$2,465	3.5	6.5	3.74	6.5
Elk City Facility	3	$2,765	5.0	4.0	5.39	5
Grants Pass Service Center	3	$8,158	3.7	2.5	4.36	2.5
Kamiah Facility	2	$1,115	4.8	2.5	5.39	2.5
Klamath Falls Service Center	2	$20,691	3.9	2.5	4.12	2.5
LaGrande Service Center	2	$952	4.5	4.5	5.2	6.5
Othello Service Center	2	$35,295	4.3	3.5	4.9	4.5
Spokane Valley Call Center	2	$906	4.4	8.3	4.36	10
Downtown Project Center	1	$10,469	3.7	2.5	3.74	2.5

Figure 11. Terracon Number of Issues Identified by Location and Risk

Equipment Monitoring



Another tool in the Facilities toolkit is the use of equipment monitoring technology. This technology allows Facilities to actively monitor and track equipment and building performance, and to create more thorough and cost-effective preventative maintenance (PM) schedules. For the buildings that have this specialized equipment installed, the information provided allows observing and controlling the building environments in real time as well as scheduling and modifying mechanical equipment operation remotely. These systems also collect and store data about system performance for trending and analysis. Results can be used to predict failures and correct issues before critical failure. The type of data collected includes temperatures, run hours, BTUs, gas or electric consumption rates, pressure, and more.

Building Automation Management Systems

The Company's Building Automation Management System is similar to the equipment monitoring systems, collecting a variety of information similar to that collected by the other equipment monitoring systems. However, the Automation System also includes a graphical front-end user interface, making it easier to use and understand. HVAC operational information such as temperature, run hours, pressure levels, energy usage, etc. is collected to provide early identification of problems within the building's systems, automatically optimize their operation and performance, monitor and make changes in real time, and generate customized reports of performance. The Automated System is incredibly helpful in troubleshooting issues as well as identifying when a system has failed (or is getting close to doing so) before it significantly impacts general building operations.

Both of these systems also help maximize building energy efficiency. For example, they may help Facilities experts see that window blinds are needed for a work area that is requiring higher-than-expected cooling, or that the run schedule of an HVAC can be modified to reduce operating time. These systems collect searchable data with complete maintenance records of all equipment and systems to help identify recurring problems, to identify trends, and to perform analysis.

About 75% of Avista's facilities (based on square footage) have added automation to increase the efficiency of building management, primarily in larger facilities and service centers. The Company's objective is to have 100% of existing buildings automated. This is a key component of Facility's goal of continual improvement in managing their facilities. For new buildings, this technology is a Company standard, along with required energy efficiency measures to keep Avista in compliance with Washington State Energy Code.[14] It is difficult to measure the full savings impact of these systems on new buildings other than what common sense would dictate, but as an example, the Company's existing HVAC system upgrades to this technology saved 60% of HVAC electrical cost alone, so it is apparent that the savings from this careful monitoring are significant.

Project or Site	Year of Impact	Added Square Feet	Total Square Foot Increase	Avista Facilities Work Staff	Industry Recommended Staffing
2008 Baseline square Footage	2008		**800,937**	10	16
Spokane Valley Call Center	2009	14,022	814,959	10	17
Colville Service Center	2010	8,000	822,959	10	17
Dollar Road Truck Storage	2010	8,000	830,959	10	17
Mini Line Dock Addition	2011	13,000	843,959	10	17
Jack Stewart Training Center Modular	2011	2,000	845,959	10	17
St. Maries Offsite Parking	2011	5,000	850,959	10	17
New Mission Warehouse Building	2013	35,000	885,959	10	18
New Dollar Road Fleet Building	2013	23,000	908,959	10	19
New Waste and Asset Recovery	2015	15,000	923,959	10	19
Kettle Falls Office	2015	7,800	931,759	10	19
Investment Recovery Building	2016	7,000	938,759	10	19
Beacon Vehicle Storage	2016	21,000	959,759	10	20
Noxon/Cabinet Gorge Bunkhouses	2016	20,000	979,759	10	20
Downtown Project Center	2016	25,000	1,004,759	10	21
Mission Fleet Building	2018	15,000	1,019,759	10	21
Deer Park Service Center	2018	12,000	1,031,759	10	21
Dollar Road Phase 2	2018	35,000	1,066,759	10	22
Airport Hanger	2018	4,000	1,070,759	10	22
Dollar Road Wash Bay	2018	16,000	1,086,759	10	22
Dollar Road Phase 3	2019	28,000	1,114,759	12	23
Mission Parking Garage	2020	171,000	1,285,759	13	26
Total Square Feet		**484,822**	**20,219,739**		

Figure 12. Avista Facilities Growth 2008 – Present and Associated Staff

[14] https://www.energycodes.gov/adoption/states/washington under "Washington State Certification of Commercial and Residential Building Energy Code"

Contracted Services

Limited staff means that some of the work required must be performed by contractors. Currently approximately 60% of Facilities work is contracted. Contractors are selected based upon a variety of criteria, including performance benchmarks, cost, and evaluations. In Facilities, these individuals are primarily utilized for repetitive tasks such as grounds keeping, janitorial work, snow removal, and cafeteria duties. Contracting can be less expensive than using Company employees, but that is not always the case, so Facilities makes this choice based on the type of work needed, length of contract required, and the criticality of the work being performed. A recent complication in bringing in contract help is that the main campus is now a "locked down" security site. This means that all contractors must be escorted by an employee at all times while on site, so when help is brought in for the Mission Campus, both the cost of the contractor and the associated escorting employee must be factored in.

Although contractors provide a beneficial resource for Facilities, an important factor to note is that Avista Facility employees manage all of the Company's buildings and primary systems. Being well acquainted with these facilities provides a quick and efficient response to issues. It may take days or even weeks to schedule a contractor to do a repair, and the issue may be of such a nature that waiting is not an option. Having skilled employees available to do specialized work, and relatively quickly, with a robust understanding of the equipment or buildings involved and loyalty that encourages performing the work well is a great benefit to the Company.

Given limited manpower and budgets, a careful blend of resources helps allow Facilities to keep operating at current levels.

Managing Regulatory Issues

The Facilities group is heavily impacted by regulations. Building codes, rules, and standards all have an impact on work processes and expenditures. There are a wide variety of regulations related to facilities and how they are managed, such as state and federal requirements for energy efficiency when building new facilities or renovating existing ones, fire codes, safety regulations, city statutes and building codes, federal requirements to provide adequate accessible parking spaces and building accommodations, and much more.

DEPARTMENT OF ENERGY HAS CODE REQUIREMENTS FOR:

- *Total building performance*
- *Air leakage*
- *Mechanical systems*
- *Interior & exterior lighting*
- *Elevators*
- *Transformers & meters*
- *Motors*

These apply to any new buildings, additions or any building alteration.

State of Washington Has Code Requirements for:

- *Energy efficiency standards*
- *Insulation*
- *Mechanical systems*
- *Water heating systems*
- *Climate zones*
- *Arrangement of windows & doors*
- *Plumbing*
- *Electrical & lighting systems*
- *Footings, foundations & walls*
- *Equipment & system controls*
- *Fans*
- *Duct sealing*
- *Lighting*
- *Location of daylight zones*
- *Air barriers/thermal envelopes*
- *Construction elements*
- *Accessibility*

These apply to any new buildings, additions or any building alteration.

Federal regulations impact most elements of buildings.[15] According to the U.S. Department of Energy: "The legal obligation to comply with the energy code (meeting all the applicable requirements) rests squarely on the professionals who design and construct buildings."[16] Many of these codes also apply to maintenance. For Avista, this means Facilities. It touches the way they design and remodel buildings, which heating, cooling, and lighting systems they install, and how they sustain key elements of each building.

Federal law mandates that each state have an energy code and establish minimum requirements for that code. It is up to each state to implement and enforce its own code that meets or exceeds the federal government requirements. Thus the State of Washington also has a lengthy list of requirements.[17] In addition, different counties have their own requirements, and so do cities and towns. An example of some of the regulations that impact Facilities are the impacts of today's Energy Code on new construction projects. These requirements include the allowable watts per square foot of lighting systems, the minimum energy efficiencies required of mechanical systems, occupancy requirements for offices and conference rooms, and use of energy efficiency techniques to meet the requirements of the code.[18] All of these items cause an increase in scope, schedule and budget for most new construction projects and remodels as well, but are required in today's regulatory environment.

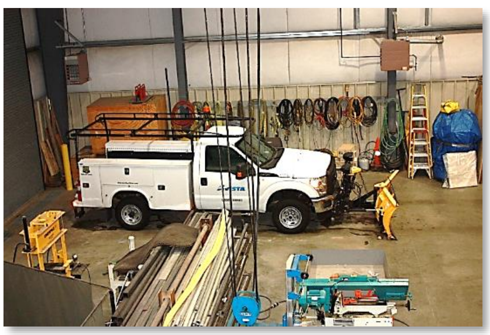
Managing Environmental Issues

Another, often unrecognized, issue facing Facilities is the impact of environmental regulations. There are federal, state, and local permits and requirements for elements such as managing runoff associated with parking lots, state and county storm water compliance, wells and water quality permits, zoning and setbacks, right-of-ways, protection mitigation for sensitive areas, and the like. Many of Avista's facilities were designed and built in the 1960's. The codes and requirements between now and then have increased greatly, causing many of the Company's locations to fall below not only Avista's environmental standards, but below state and federal requirements as well. The chart on the next page indicates the Company's current environmental compliance ratings.

[15] U.S. Department of Energy, "Building Energy Codes Program," 2018, https://www.energycodes.gov/sites/default/files/becu/2018_IECC_commercial_requirements_lighting.pdf
[16] U.S. Department of Energy, "Building Energy Code Compliance," November 14, 2016, https://www.energy.gov/eere/buildings/articles/building-energy-code-compliance
[17] "Washington State Energy Code, Commercial Provisions," https://fortress.wa.gov/ga/apps/SBCC/File.ashx?cid=6195
[18] For more information, please see: "Whole Building Design Guide," https://www.wbdg.org/resources/energy-codes-and-standards

Colville District Office

Medford Weld Shop



Rathdrum Service Center

ENVIRONMENTAL COMPLIANCE FACILITY RANKING 10.16.2019	Stormwater Management	Critical Areas/ Physical Location	Waste Management	Oil Containment	Score Average
Washington					
Central Operating Facility	3	3	0	1	2
Chewelah Facility	4	3	0	3	3
Clarkston Service Center	3	0	0	2	1
Colville Service Center	0	2	0	0	1
Colfax Facility	1	2	3	1	2
Davenport Service Center	5	3	0	3	3
Dollar Road Service Center	2	1	0	1	1
Deer Park Service Center	0	0	0	0	0
Downtown Project Center	2	0	0	1	1
Downtown Network Ops Bldg	2	0	0	1	1
Goldendale	1	3	0	0	1
Othello Service Center	3	2	0	2	2
Post Street Substation / Annex	2	3	0	4	2
Pullman Service Center	5	2	0	2	2
Ritzville Facility	1	0	0	1	1
Tekoa Facility	2	0	3	2	2
Idaho					
Coeur d'Alene Service Center	2	3	0	1	2
Elk City	0	2	3	0	1
Grangeville Facility	4	3	0	3	3
Kamiah Construction Office	1	1	0	1	1
Kellogg Service Center	3	3	0	2	2
Orofino Facility	3	0	0	2	1
St. Maries Service Center	2	1	0	3	2
St. Maries Storage Yard	2	4	0	2	2
Sandpoint Service Center	4	3	0	3	3
Oregon					
Grants Pass	1	1	0	0	1
Klamath Falls	0	0	0	0	0
LaGrande	0	0	0	0	0
Medford	0	0	0	0	0
Roseburg	1	0	0	0	0

Ranking Scale/Risk Level

0 = Lowest Risk
5 = Highest Risk

Figure 13. Environmental Compliance Issues and Ranking

Avista's Facilities Investments

Managing Expenditures

The Facilities group is responsible for a continually growing – and growing older – portfolio of infrastructure while staying within an established budget. Though capital budgets have grown along with Company expansion, Operations & Maintenance expenditures have not kept pace, as shown in Figure 14. Since 2008 Avista has added 464,577 square feet of facility space, as reflected in the increased capital expenditures, but during the same period, O&M expenditures have remained nearly flat.

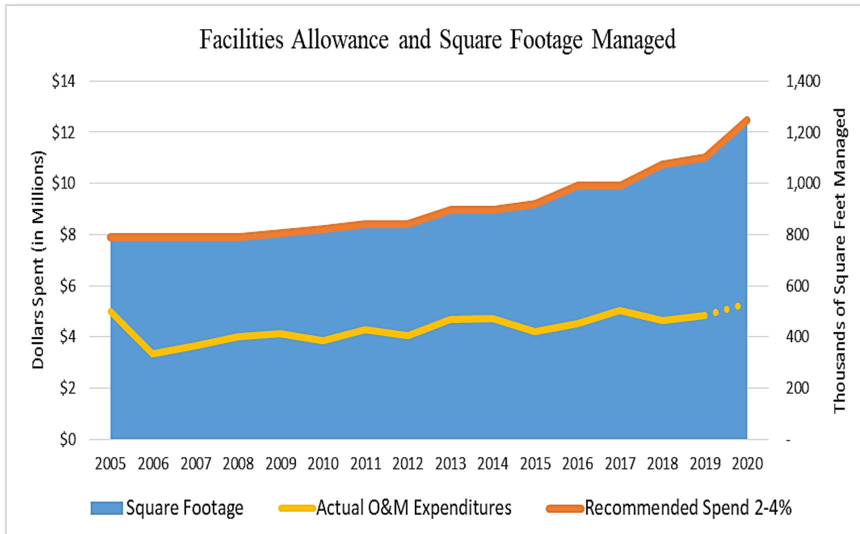


Figure 14. Facilities Spending Compared to Space Managed

Some of the largest capital expenditures in recent years include extensive renovations of the headquarters and other old buildings on the main campus. This work took place from 2013 through 2018. The new Dollar Road Service Center and the Downtown Network warehouse were completed in 2017 and 2018, and the new Deer Park Service Center entered into service in 2018. These projects are discussed below in further detail.

Dollar Road facility under construction

The new Deer Park Service Center

Over the past several years, Facilities has also dealt with a great deal of change in their O&M funding allowances, making managing expenditures more and more difficult. As an example, in the past, Facilities would submit O&M projects for planned maintenance activities each year, but as O&M Facility's budgets have become flat, they no longer have the funding for planned maintenance. Discretionary income has been reduced to nearly zero, meaning most maintenance is reactive in nature. Often assets are not repaired or replaced until they fail.

Emergency repairs are almost always more expensive than planned work, and when these types of situations arise, the impact on their already limited budget is significant.

Another major factor in the Facilities O&M budget is the impact of weather. As mentioned earlier, Facilities does not have available funding for discretionary work. Safety regulations require an entire plow of sidewalks and parking areas for every inch of snow, which can cost approximately $15,000 per event just for the Corporate Headquarters, not counting all of the service and customer centers. Snow removal is allocated an annual budget of $50,000 per year, which is enough to manage about 1.5 snow events within that year. However, experience has shown that an average winter can result in up to $220,000 in snow removal costs, which include snow and ice removal from company parking areas for the safety of customers and employees. Freezing rain requires de-icing and its associated costs as well. These unpredictable costs often result in Facilities exceeding their budget. There have been times when the parking lots have required several plowing events within just a few days. In a heavy snow year, the cost of snow removal and de-icing can add up quickly. As an example, in 2019, almost $330,000 was spent for snow removal and de-icing for the Mission Campus parking areas, using up not only the snow removal budget, but the entire yearly unplanned budget for Facilities.

Expense requests and costs also change over time. For an example, outlying service centers used to take care of routine maintenance of their land and buildings themselves, including plowing their parking lots, but in recent years these activities have gradually returned to central Facilities. These expenses were not anticipated or budgeted for, thus they drain funding from other competing needs. Trying to find the money needed to match every Terracon-identified issue, employee identified issue, and unexpected expense that arises is a balancing act. We will try to describe the processes for trying to maintain this balance in the next section.

AVISTA'S FACILITIES CAPITAL INVESTMENTS

CAPITAL PROJECT INVESTMENT SELECTION PROCESS

In the Facilities world, the allowed capital budget is quite small, typically between 2% and 5% of the entire Avista budget, thought this varies significantly based on large projects they are given, such as building a new service center. The Facilities capital budget includes the Structures and Improvements program for Asset Condition work. This typically comprises things like replacing a compressor, roof, shop door or pump as well as remodeling space for improved efficiency or to meet new needs. It also includes repairing damage from storms or general use. This bucket is wide ranging and varies based on the conditions Facilities faces every day. Facilities apportions approximately 50% to Asset Condition work that is identified using Paragon Asset Condition software (Terracon), 30% is set aside for manager requested projects, and 20% is kept aside for unexpected capital needs and furniture replacements.

Business Case	Primary Driver	2020	2021	2022	2023	2024
New Pullman Service Center	Asset Condition	$0	$0	$5,000,000	$7,000,000	$0
Service Building Basement Renovation	Asset Condition	$3,000,000	$0	$0	$0	$0
Structures and Improvements/Furniture	Asset Condition	$2,000,000	$2,200,000	$2,500,000	$2,750,000	$2,750,000
Central 24 HR Operations Facility	Performance & Capacity	$0	$0	$0	$10,000,000	$9,000,000
Sandpoint Service Center	Performance & Capacity	$0	$0	$0	$1,500,000	$8,500,000
	Total Facilities Capital Budget	$5,000,000	$2,200,000	$7,500,000	$21,250,000	$20,250,000
	Total Avista Capital Budget	**$405,000,000**	**$405,000,000**	**$405,000,000**	**$405,000,000**	**$405,000,000**
	% of Total Capital Budget	1%	1%	2%	5%	5%

Table 1. Facilities Capital Budget Compared to Avista Capital Budget

Facilities Capital Request Board

Since the Terracon list has been described at length in previous sections, we will now describe the approval process for capital projects that are proposed by Avista personnel (the 30% allotment).

Proposed Capital Projects Approval Process

Manager

Department Director

Facilities Capital Request Board

Facilities Project Steering Committee

Capital Planning Group

These types of requested facilities projects undergo a multi-level internal review process. It begins with the related manager who either identifies the capital need themselves or is notified of an issue that needs to be resolved by an employee. If the manager believes the project is in the best interests of the group and the Company, the proposal is submitted to that manager's director. If the director also sees the value of the request, it is submitted to a group known as the Facilities Capital Request Board.

This Board meets every fall to review the requested projects for the upcoming year. Managers from each major business area send a representative. The employee chosen usually changes every year. In addition, there is a requirement of at least one person from Environmental Affairs, Operations, Materials Management, and Facilities. This broad mixture of perspectives is designed to provide a neutral and "outside" perspective while having access to the expertise and experience of the directly related and impacted business entities.

Business Units Represented in the Facilities Capital Request Board

- *Shared Services*
- *Information Technology*
- *Security*
- *Natural Gas*
- *Financial Planning & Analysis*
- *Generation & Substations*
- *Corporate Communications*
- *Environmental Affairs **
- *Operations **
- *Materials Management **
- *Facilities **

** Key Advisors*

By the time the Board receives the list of requests, it has already been vetted twice within its related department. The requests are prioritized based on the Capital Request form[19] that was filled out and approved.

At this level, each request is reviewed for required criteria such as risk, safety, environmental impact, and compliance. It is important to note that peer pressure is a very effective tool in these negotiations. People tend to work in natural silos. A leaking roof in Colville seems just as important to those employees as a broken service bay door does to the employees in Colfax. When the Board members see all of these requests together, the impacts, cost/benefit, and priority can be examined comparatively, making it much easier to prioritize them and see which would have the most positive impact or create the most value for the Company as a whole. Thus this process is designed to ensure that multiple stakeholder participation provides a thorough and robust analysis of all facility needs and alternatives across the Company.

Facilities Steering Committee

For standalone Business Cases, such as the new service building in Deer park, approval comes from the Facilities Project Steering Committee. This Committee is comprised of directors who are responsible for approving the submission of all Business Cases to the Capital Planning Group. Before approval, it is the responsibility of Facilities to make sure each business case includes a description of the business problem and background on the situation, alternatives, projected costs, savings, requirements, timelines and deadlines, benefits, proposals/options and a recommended solution. Once Facilities has demonstrated the need for a capital investment, the Steering Committee will allow the Business Case to move forward into the Capital Planning Process.


Chewelah Service Center

[19] A copy of the Capital Request/Business Case Request Form can be found in Appendix B.

Capital Planning Group

Once they pass through the processes described above and are approved for consideration, business cases are submitted to the Capital Planning Group (CPG), a group of Avista Directors that represent capital intensive areas of the Company. This group is comprised of directors from a variety of business units to add a depth of perspective, though their role is to consider capital decisions from the perspective of *overall* Company operations and strategic goals. Facilities business cases are evaluated equally with those from Transmission, Distribution, Enterprise Technology, Generation, etc.

The Capital Planning Group (CPG) reviews the submitted business cases from business units across the organization, including Facilities, and prioritizes funding to meet the upcoming five year capital spending guidance as set by senior management and approved by the Finance Committee of the Board of Directors. The CPG meets monthly to review the status of the capital projects and programs, evaluate changes requested, and approve or decline new business cases. They also monitor the overall current year capital budget. This group develops and recommends a 5-year capital expenditure plan by investment driver to the Company's officers based upon the amount of funding available as approved by the Company's Board of Directors. The CPG is responsible for reviewing, approving, deferring, or denying capital requests, and for appraising productivity and strategic proposals.

Initial expenditure requests may need to be modified based on the timing of equipment, permits, available crews, priorities of projects, etc. The CPG approves or declines these changes based on managing a total budget amount. Therefore, as changes occur throughout the project, project funding may change, or one project may be funded while another is removed or delayed to allow higher priority projects to be funded. This is done while remaining within the total approved capital spending amount. This group reprioritizes as needed to ensure that the highest priority projects are identified and funded.

Avista's Capital Planning Group evaluates aspects such as the project description, alternatives, cost and other financial assessments, risk, justification, resource requirements, and how each project fits into the Company's overall strategies. They provide a comprehensive and strategic perspective that helps ensure that the right projects are funded adequately at the right time.

Ultimately the individual investments selected to be included in Avista's final budget represent a portfolio of projects and funding levels intended to optimize:

1) *The overall demand for 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.*

In setting its overall infrastructure spending limits, the Company considers a range of factors referred as "key planning principles" as shown in the bubble diagram on the right. The result demonstrates a reasonable balance among competing needs required to maintain the performance of Avista's systems, as well as prudent management of the overall enterprise in the best interest of customers.

External factors such as new regulatory or legislative requirements may drive changes in the plan. The projects in the Company's portfolio are continuously reviewed for changes in assumptions, constraints, project delays, accelerations, weather impacts, outage coordination, system operations, performance, permitting/licensing/agency approvals, safety, and customer-driven needs that arise.

Classification of Infrastructure Need by Investment Drivers

Each year Avista makes investment decisions with the goals of maximizing the value of limited funding and other resources while managing competing requirements and alignment with the Company mission and values. A variety of projects are proposed for each budget cycle with varying characteristics.

Avista utilizes a method of organizing infrastructure investments to create more clarity around the particular needs being addressed with each investment and to simplify the organization and understanding of overall project plans for the entire Company. This process organizes capital investments using six classifications of need or "Investment Drivers." Utilizing the standards and principles described previously, Facilities develops projects that are within their allocated budget and that are intended to make best use of the funds they are given. Like the other business units, they group their requested projects into the appropriate investment driver to help promote understanding of the basic need related to their requests. The Company's investment drivers are defined below.

Note that all of Avista's capital expenditures across the Company can be characterized by one of these drivers, though not all of the investment driver categories are represented for each asset class. For example, electric distribution investments encompass all six categories; however, investments planned for Facilities only utilize two of the six categories: Asset Condition and Performance & Capacity. Definitions of the others are included here for the reader's information to help promote understanding of the Company's strategic budgeting categorization. It is also important to note that even though not all of the investment drivers will be used in all of Avista's primary asset categories in every budgeting cycle, they remain an efficient and effective way of categorizing expenditures in a clear and transparent fashion that promotes better understanding of how the Company makes business decisions.

Facilities Capital Budget 2020-2024

By Investment Driver

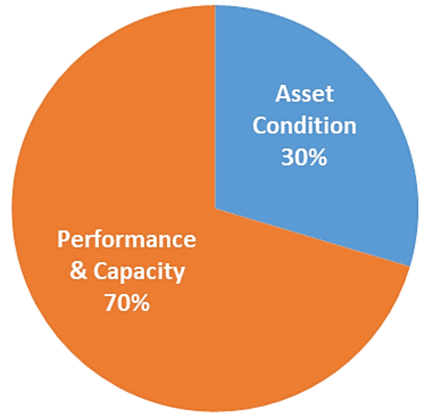


Figure 15. Facilities Capital Budget

- ***Asset Condition*** – All assets have a functional service life. The Asset Condition category provides funding to replace assets or portions of assets as needed. This may include replacing parts as they wear out or when items can no longer meet their required purpose, as systems become obsolete and replacement parts are no longer available, if safety or environmental issues are identified, or if the condition of an asset is such that it is no longer optimizing its own performance or customer value and actions need to be taken to restore the condition of the equipment or replace it. Some things are so critical that they cannot be allowed to fail. When these types of items reach an age when they are close to or at the end of their useful life, the Company preventively replaces them to maintain reliability and acceptable levels of service. Examples in this category include everything from building new service centers in Pullman and on Dollar Road as the old centers have deteriorated and been outgrown, to replacing failing roofs and installing energy efficient lighting. This broad category for Facilities is called "Structures and Improvements" and it is comprised of everything from replacing a broken door to purchasing property.

- ***Performance & Capacity*** – Programs in this category help ensure that assets satisfy business needs and meet performance standards. This may include upgrading systems and controls, remodeling work areas, providing equipment such as cranes for lifting large transformers, spools of conductor and the like, replacing old and inefficient HVAC and electrical systems, consolidating supplies into a common area for efficiency and inventory control, security and safety measures, providing warehouse space, etc. It the other primary driver for the Facilities group.

- ***Mandatory & Compliance*** – The Company makes a large number of business decisions as a direct result of compliance with laws, regulations and agreements, including projects related to air and water quality permits, equipment essential to legally operating within the interconnected grid, public safety, contractual obligations, etc. These expenditures are compelled by regulation or contract and are largely beyond the control of the Company. The Facilities group does not have money set aside under this category, as their expenditures related to environmental compliance, for example, are typically part of a larger project belonging to another group and are therefore not specifically singled out in this category.

- ***Failed Plant & Operations*** – This category funds replacement of failed equipment. At times assets will fail unexpectedly due to damage or an accident or will wear out earlier than expected, but this category also accounts for equipment that requires periodic replacement. Facilities accomplishes these types of programs using their Structures and Improvements capital spending category under the Asset Condition driver.

- ***Customer Requested*** – This category is primarily related to connecting new distribution customers or large transmission-direct customers. This category is not applicable to Facilities.
- ***Customer Service Quality & Reliability*** – This category is set aside for expenses relating to meeting customer expectations for quality of service and reliability. Typical expenses the Company would see in this category might include distribution feeder automation which allows isolating the sections of a line so customers not directly impacted by a faulted section can maintain their service. No funds were set aside in this budget cycle for Facilities in this investment driver category.

Business Case	Primary Driver	2020	2021	2022	2023	2024
New Pullman Service Center	Asset Condition	$0	$0	$5,000,000	$7,000,000	$0
Service Building Basement Renovation	Asset Condition	$3,000,000	$0	$0	$0	$0
Structures and Improvements/Furniture	Asset Condition	$2,000,000	$2,200,000	$2,500,000	$2,750,000	$2,750,000
Central 24 HR Operations Facility	Performance & Capacity	$0	$0	$0	$10,000,000	$9,000,000
Sandpoint Service Center	Performance & Capacity	$0	$0	$0	$1,500,000	$8,500,000
	TOTAL	$5,000,000	$2,200,000	$7,500,000	$21,250,000	$20,250,000

Table 2. Facilities Capital Projects 2020 - 2024

As mentioned earlier, it is easy to push Facilities projects to the bottom of the priority list. Many of the issues this group deals with are not as obvious as a failed transformer or a broken cross arm. Aging buildings and structures typically affect only those who work there, and there is a lack of direct correlation between these failures and/or constraints and providing exceptional service. However, these issues do impact employees and their efficiency and effectiveness in performing their jobs, as well as impacting job satisfaction, loyalty and pride. Customers also take note of deteriorated buildings, sidewalks, and landscaping, which impacts their perceptions about the Company. These factors, though they may not be directly connected with dollars, are important and have a value. Thus they are an underlying component of Facilities planning and cost requests.

Recent History Capital Expenditures

Facilities uses their capital funding to tackle a wide variety of required work. The general categories are shown in Figure 16.

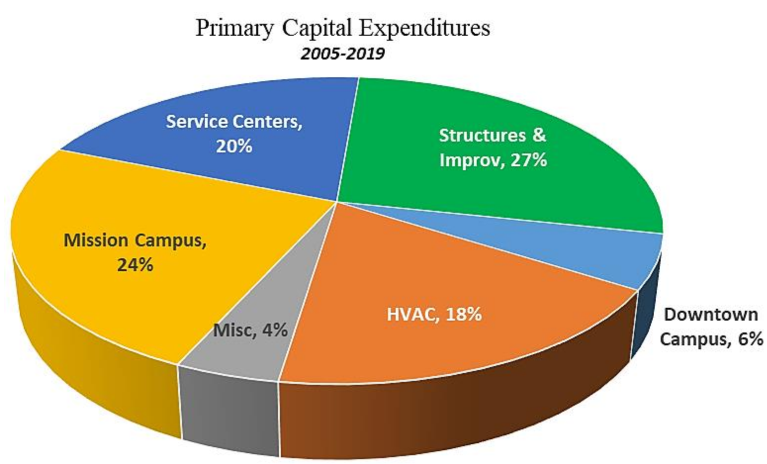


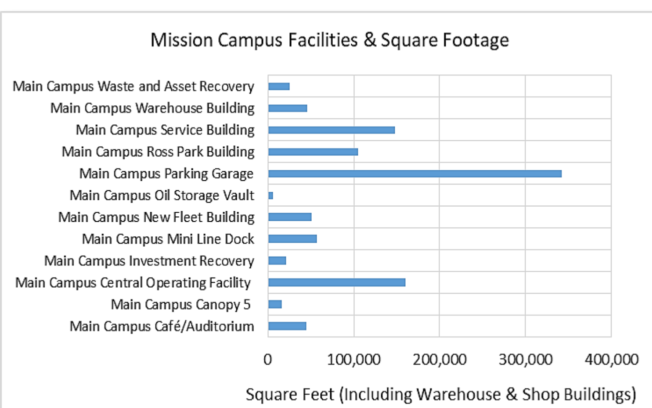
Figure 16. Primary Capital Expenditures for Facilities 2005-2019

The Company's area service centers are on a continual track for repairs and upgrades. All of them made the Terracon list with at least one item that is considered "immediate repair required," with an average of eight items each and an average cost of $64,000 to make each of the required repairs. Repairs are initiated using a priority process (as described earlier) so the strategy is not necessarily to tackle an entire service center at a time, but to start with the most pressing needs at each service center as determined by safety, customer service, and impact on the business based upon Terracon's risk rating system or as determined by the Steering Committee.

The "miscellaneous" category shown on the pie chart includes a broad spectrum of capital projects, including security expenditures like fencing, cameras, and fire suppression systems, parking lot repair or improvements, and storage solutions to name a few. In the recent past, this category included the cost to reroute North Crescent around the Mission Campus as an example.

Structures and Improvements is an ongoing category that includes capital maintenance, site improvement, and furniture and equipment budgets at over 40 Avista offices, storage buildings, and service centers. It includes major repairs such as leaking roofs, control systems, and floors; replacing equipment such as air conditioners, windows, generators, pumps, and lighting; installing sprinkler systems, handrails, exterior siding, and condensers. It also includes larger-scale projects such as remodels and renovations such as adding covered storage areas and warehouse space. Items can range from purchasing a cash register that cost about $100 for the cafeteria to a completely new HVAC system for the Corporate Headquarters building that cost over $22 million.

Avista's buildings range in age from the late 1800s to today, and many are facing the associated age challenges. The HVAC category focuses on replacing end-of-life heating and cooling systems in older facilities with new energy efficient systems. Most of this work over the past ten years was performed on the Company's buildings in Spokane, but several outlying service areas have also been updated. This effort will continue into the future as aging and end-of-life systems are replaced and upgraded to help save energy costs. In the current budgeting cycle, it is expected that expenditures will follow a very similar pattern



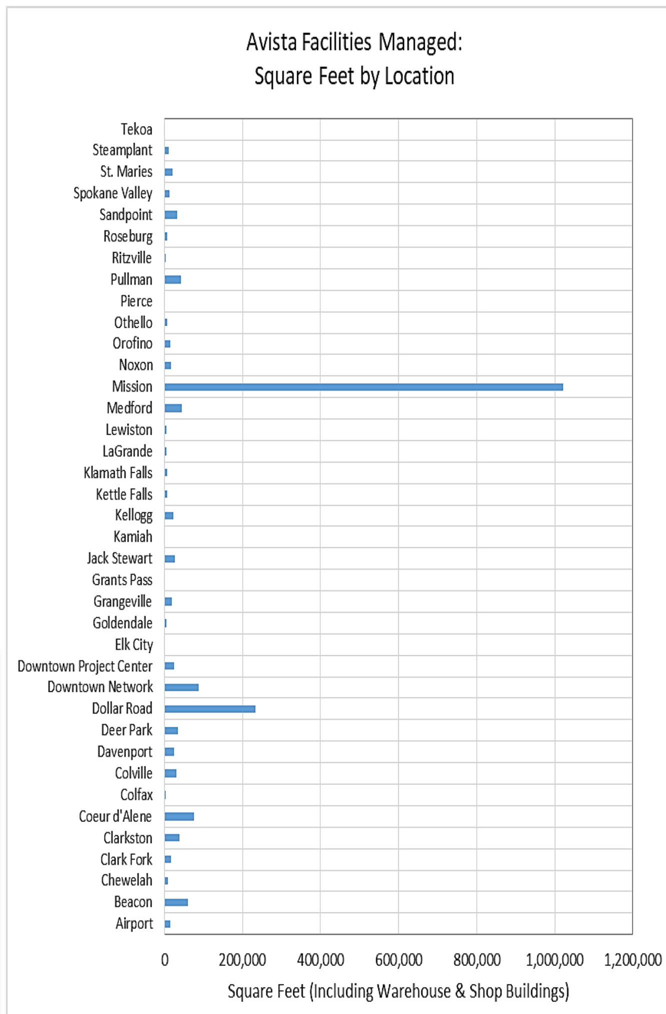


Figure 17. Square Footage of Avista Facilities Managed

for Facilities capital spending with the exception of the Mission Campus, for which the long-term upgrade is nearly complete.


Mission Campus Buildings

Over the past ten years, the main campus has undergone updates, renovations, additions, and repairs which are being finalized this year. The Corporate Headquarters building, completed in 1959 and designed by famed architect Kenneth Brooks, has undergone extensive upgrades. The Mission campus and associated buildings comprise nearly 60% of the Company's buildings and infrastructure, so this was a very large project. The Corporate Headquarters building was renovated one floor at a time, upgrading outdated heating, cooling, electrical and plumbing systems, remodeling the existing space to increase usage efficiency, and removing asbestos. Avista applied its own energy management practices to this restoration, which earned them a BOMA 360 designation, LEED Gold Certification, and achieved significant energy savings of more than $350,000 per year in electricity costs (depending upon the weather) plus nearly an 82% reduction in water usage, all due to energy and water efficiency measures included in the remodel.

Mission Campus

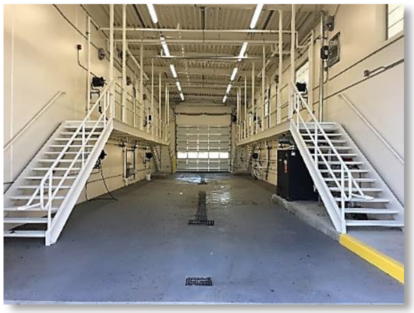
Headquarters	**381,110**
Warehouse	**35,000**
Investment & Recovery	**13,200**
Waste & Asset Recovery	**15,000**
Ross Park	**17,000**
Line Dock	**28,750**
Covered Areas/Canopies	**8,000**
Fleet Building	**30,000**
Parking Garage	**171,000**
TOTAL SQUARE FEET	**699,060**

This large long-term project included replacing several old outbuildings with new buildings able to provide service for today's larger trucks and equipment, as well as renovating storage areas to more effectively manage the supplies and equipment the Company requires to serve customers (such as transformer and pole inventories). When the campus parking structure is finished in 2020, the ten-year Mission Campus Plan should be complete and this project will no longer require a large percentage of Facilities capital budget.

Main Campus Parking Structure When Completed

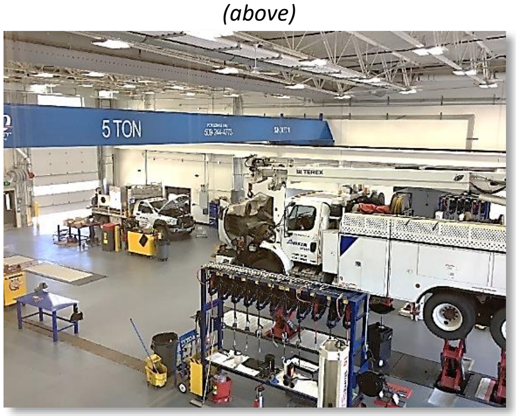
One of the highlights of the Mission renovation is the new Service Building on the campus, which now allows Avista to efficiently service and maintain their own fleet of trucks and vehicles rather than having to use outside maintenance sources, which are far more expensive.[20] It also provides space for storing valuable vehicles and equipment inside an enclosed and secure area.

The Fleet Building is a great example of the creative and efficient ways the Facilities Group manages projects. To design the new Fleet building in a way that maximizes its effectiveness, the Facilities team put together a Business Process Improvement (BPI) team. This team observed existing workflow and processes. They watched Fleet employees performing their jobs, specifically how they maintained vehicles in the existing building. They interviewed personnel on what would make their work more efficient and safer. They drew a "spaghetti" diagram of existing work flows showing, for example, how many times an employee had to go to the back of the building to get supplies and how long that took. They toured other fleet operations facilities to glean best practices. At the end of this process, and with extensive input from Fleet personnel, a building was designed which stayed in budget while providing a state-of-the-art facility that has become an example for other fleet buildings around the country.



New Fleet Building wash bay and service areas (above)

In this new building, personnel have the capability of adding or removing booms, buckets, and accessories as needed, there are pull-through lanes to increase safety,[21] parts and fluids are located directly adjacent to each of the maintenance bays (rather than in the back of the building), safe wash bays were added,[22] doorways are wide enough to fit today's larger vehicles,[23] and lifts are included that can be quickly adapted to fit a variety of vehicle sizes. The Company is adding



Our largest vehicles can fit into the Fleet Building for maintenance & repair

[20] According to AAA most auto repair shops charge between $47 and $215 per hour for auto repair only, not specifically for the large and specialized vehicles Avista utilizes, which can cost much more.
[21] Prior to pull through lanes, trucks had to back out into a tight turnaround area with a number of flaggers on hand to direct them so they didn't back into anything or anyone.
[22] This may seem like a trivial thing, but one of the ways Avista strives to keep their vehicles well cared for includes cleaning them. In the past, this was done by an employee with a spray hose on a ladder, an obvious safety concern. The new wash bays have decks all around them on the second story of the building, allowing employees to clean the largest rigs safely.
[23] The previous fleet building literally had one inch of clearance on either side for many of the Company's largest work trucks; many would not fit inside.

Compressed Natural Gas vehicles to its fleet, and the new building provides the capability of servicing these specialized vehicles as well. Energy efficiency was also a major consideration. Rather than heat this large open space with traditional HVAC systems, in-floor heating was chosen. This system keeps the work areas warm at far less cost. The new Fleet building can service Avista's largest vehicles inside an enclosed area rather than out in the parking lot. Employees state that having their tools readily at hand saves them hours of work every month and has greatly enhanced employee satisfaction.

Facilities Budgeted Capital Projects By Business Driver

Asset Condition Projects/Programs

Asset Condition	2020	2021	2022	2023	2024	Five Year Total	Five Year Average
New Pullman Service Center	$0	$0	$5,000,000	$7,000,000	$0	$12,000,000	$2,400,000
Service Building Basement Renovation	$3,000,000	$0	$0	$0	$0	$3,000,000	$600,000
Structures and Improvements/Furniture	$2,000,000	$2,200,000	$2,500,000	$2,750,000	$2,750,000	$12,200,000	$2,440,000
Total	$5,000,000	$2,200,000	$7,500,000	$9,750,000	$2,750,000	$12,200,000	$5,440,000

Table 3. Facilities Planned Asset Condition Budget

During this budget cycle, Facilities has three projects in the Asset Condition category, including general structures and facilities improvements, renovation of the existing Mission Campus Service Building, and building the new Pullman Service Center. These projects are described in detail below.

Pullman Service Center

The Pullman Service Center was constructed in the 1950s, and although it has experienced upgrades, remodels, and additions since that time, it has been outgrown for today's needs and size of equipment. The current center provides support to nearly 41,000 natural gas and electric customers scattered over some 5,000 square miles. Forty one employees work out of this facility. The Pullman area is one of the fastest growing in Avista's service territory, significantly increasing the workload requirements of the crews there as well as the amount of equipment needed onsite.

Above: Pullman break room/meeting room/work area
Below: One of the many Pullman storage areas

The current facility is simply too small to efficiently and effectively support employees in serving customers. Supplies are scattered across a variety of storage areas around the Pullman area, not onsite. Expensive company vehicles have no protected parking areas and today's large work vehicles cannot fit into the existing shop for maintenance. There is also insufficient space for employee work areas.

Current Pullman Service Center Highway Location

A third-party assessment found that the building suffers from a serious need for repairs to the electric, water, plumbing and septic systems, roof, floors, and ceilings. The shop roll-up doors (original to the building) have become a safety concern for both employees and the vehicles that use them. There is no fire system in place at all. This independent survey identified over $5 million in repairs needed to continue to utilize the original building.

Analysis determined that it made more fiscal sense to let go of the concept of trying to invest in the old building and start again with a new, larger, more efficient facility that will provide the services needed to best serve customers. It will include space for all of the Pullman crews and their functions to be located in one central location. It also provides a materials yard large enough to hold and organize all of the equipment crews need to perform their jobs in one location, which is especially important in an outage situation where quick access to supplies can directly shorten customer outages. Employees will be located in a clean, safe work space with room for both offices and maintenance areas.

Safety is also a major consideration. The new location will not be located on a major highway, unlike the existing facility, which has an entrance that requires entering and exiting onto a 55 mph highway. Trucks pulling large equipment onto that roadway can be terrifying for both Avista crews and passing motorists as well. The new location will also provide environmental benefits, with storm water protection and oil containment measures.

Service Building Renovation

The Gas Meter Shop was located on the Mission Campus in the Service Building, which is attached to the corporate office building. It was recently relocated to Dollar Road, leaving 13,000 square feet of total vacated space in the basement of the Service Building. The design and use of the vacated space will need to be determined. There are a number of space requests that Facilities has received and these needs will be evaluated to determine the best solution for developing that space. Regardless of the option chosen, capital expenditures would likely include HVAC, electrical, plumbing, lighting, sprinkler systems as well as asbestos abatement and wall construction.

Possible solutions being explored for this space include:

- Work Space - Facilities has found itself in continual need of space. Included in this request would be workstations, offices, conference rooms and a breakroom. There are currently no enclosed offices open within Mission Campus, with a mix of open area workstations scattered throughout the General Office Building. It is possible that there will be more need for offices and office space in the future.
- Meeting Space - Facilities has received many requests for large meeting rooms for 50 or more employees. Currently the only room that can accommodate a crowd of this size is the Auditorium, which is not an effective meeting space.
- Training Space - There is an increasing need for additional training areas, especially given increasing mandatory training requirements, many in the craft area. The Jack Stuart Center has limited training room available and is only available when not being utilized by the Line School. The Service Building location could be designed to accommodate both training and multi-purpose events.
- "MakerSpace" – This is a collaborative work space for making, learning, exploring and sharing ideas which would allow employees to work on projects together.
- Increase Wellness Center - There have been many requests to expand the current Wellness Center, perhaps including a multi-purpose room to offer larger classes and provide additional workout equipment.

Structures and Improvements

As described earlier, this program is responsible for the capital maintenance, site improvement, and furniture budgets at all of Avista offices, storage buildings, and service centers. There is money budgeted in this category each year; it is an ongoing program. Its purpose is to systematically evaluate the condition of all the Company's facilities and develop plans and strategies for functionality while being cost-effective. Part of these expenditures are driven by the Terracon condition study, and part are determined via an internal Facilities Condition Assessment Survey, which takes into account the condition, lifecycle costs, age, functionality, and criticality of each facility and ranks their needs accordingly.

Above: Roof repairs needed

Left: A line truck impedes a stairway in order to fit inside a service bay

The work in this category may include repairing or replacing a roof, replacing asphalt, concrete or old furniture, repairing broken structural elements, adding security features such as fencing and gates, augmenting materials storage areas, installing irrigation systems, replacing a boiler that fails, purchasing emergency generators, or replacing old and inefficient electric or plumbing systems. It can also include work improvement elements such as adding a crane to safely lift heavy equipment, shelves to store maintenance materials closer to work areas, or adding ergonomics to improve productivity. One focus area is for canopies, the covered areas used to shelter trucks and equipment. Many of these have become unstable over time and require replacement.

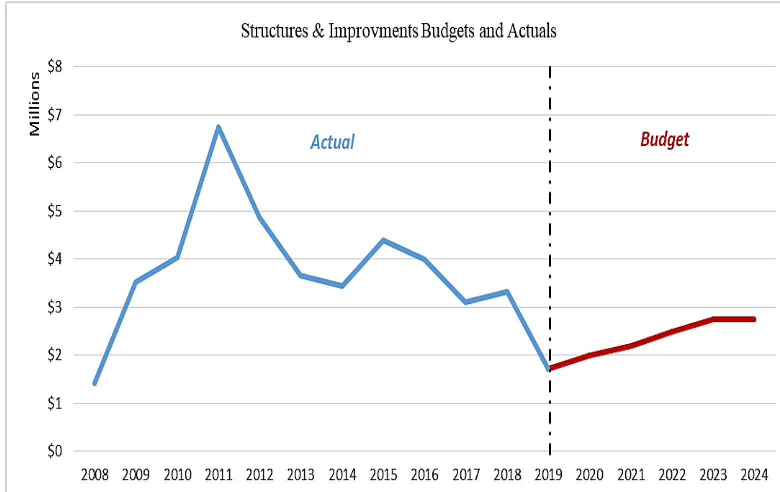
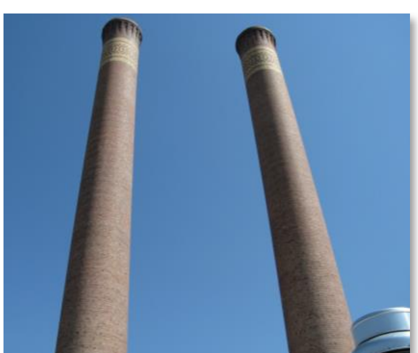


Figure 18. Facilities Structures & Improvements Capital Budget & Actuals

Employee efficiency is also a tangible benefit of adequately maintaining facilities. The turnaround time for performing routine maintenance on a line truck for example, can be reduced significantly if tools, supplies, and equipment are readily available. Even simple things like having a truck lift that allows the crew to move freely underneath the vehicle to perform maintenance and repairs quickly reduces downtime and increases vehicle availability.

In order to continue to function, buildings must be maintained. The Company recognizes that letting assets fall into disrepair ultimately impacts the ability to provide the best possible customer service, creates safety risks, and ends up costing much more in the long term. The goal of the Structures & Improvements program is to adequately maintain Company properties while trying to keep costs low as well as remain within the Facility allotted budget.

Above: Mission Campus canopy buildings



Facilities work involves complex systems like those above and on the left as well as historically significant assets such as the Steam Plant in Downtown Spokane (far left)

Performance & Capacity Projects

Performance & Capacity	2020	2021	2022	2023	2024	Five Year Total	Five Year Average
Central 24 HR Operations Facility	$0	$0	$0	$10,000,000	$9,000,000	$19,000,000	$3,800,000
Sandpoint Service Center	$0	$0	$0	$1,500,000	$8,500,000	$10,000,000	$2,000,000
Total	$0	$0	$0	$11,500,000	$17,500,000	$29,000,000	$5,800,000

Table 4. Facilities Planned Performance & Capacity Budget

The current budget cycle has two Performance and Capacity projects: construction of a 24-hour Operations Facility and a new service center in Sandpoint. These projects are described in detail below.

Central 24-Hour Operations Facility

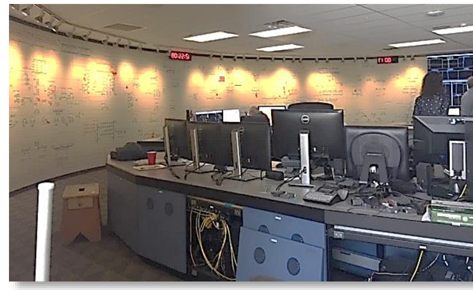
Avista is a 24-hour a day operation. Employees from Transmission, Delivery, Information Technology, Security, Customer Service, Electric and Gas Dispatch, SCADA and Operations are on the job constantly to ensure the integrity of Avista's systems, continual customer service and that customer load requirements are being met every minute of the day. At Avista, the current location for both System and Distribution Operations is the fourth floor of the Corporate Headquarters building.

Above: Distribution Operations tight workspace

Below: Work space conditions when extra personnel are brought in for emergencies

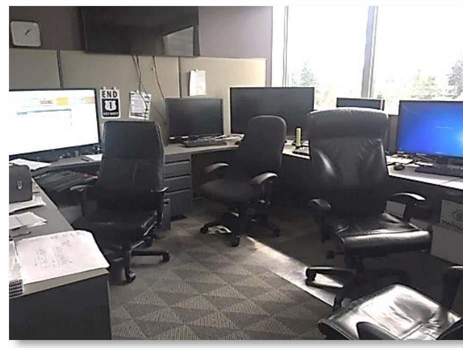
The existing Distribution Operations area is congested, in great part due to the large number of computer screens required to monitor distribution system conditions and handle daily distribution operations, as well as deal with outages and emergency situations. This group is also responsible for dispatching crews for maintenance activities or to address issues. Distribution Operators work 12-hour shifts, 24 hours a day, every day. As they hand off their work to the next Operator on shift, there is no room at the desk for the incoming Operator to sit beside the on-shift Operator to be brought up to speed on current conditions. In addition, there is no space in their area for training or to utilize when they bring in additional personnel and expertise during events such as storms.

System Operations faces a similar situation, primarily due to regional and federal issues. They are regulated by the North American Electric Reliability Corporation (NERC). NERC oversees developing and supporting standards related to the entire American interconnected grid as the regulatory body for all U.S. utilities. NERC requires all System Operators to be certified and regularly pass a national test, which requires continuous training. Currently the training area is the Training Coordinator's office, which allows room for only 3-4 additional employees at a time, making it difficult to adequately provide required employee training in a timely fashion.



Above: One desk in System Dispatch: note the number of required screens and space needed

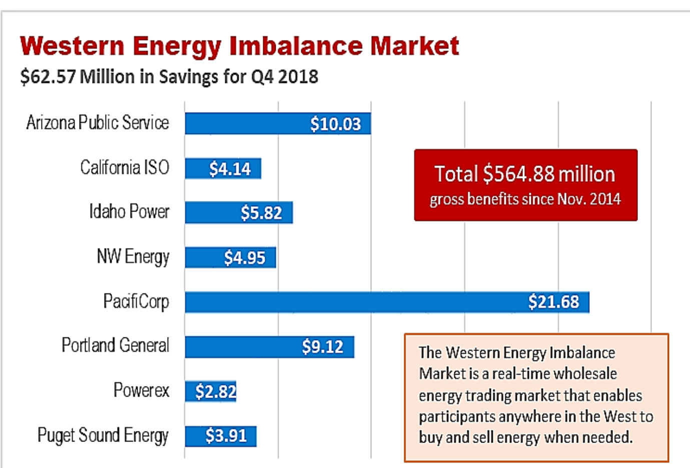
Below: The current training area



In addition, in April 2022 Avista will be joining the Western Energy Imbalance Market (EIM),[24] which will heavily impact System Operations in both workload, training, and space requirements. This Market encompasses about 75% of the loads and resources in the Western Interconnection, providing Avista (and its customers) additional buying and selling power in the Western energy market. The EIM provides a number of advantages for its participants which will directly benefit Avista and its customers. The Western EIM's state-of-the-art technology automatically finds and delivers the lowest cost energy to serve more than 42 million consumers in eight western states and parts of Canada. In addition to optimizing diverse resources from a larger pool (which lower costs for all participants) the EIM provides environmental benefit by spreading intermittent renewable energy integration across the Western U.S., helping more renewable energy assimilate into the system. The broad base of participating utilities allows Avista, for example, to purchase excess low-cost California solar energy when that state's customer demand levels are low but Northwest loads are high. The decision by Avista to become part of this system has obvious and tangible benefits to customers, including access to a broad, diverse resource pool, more opportunities to access low cost power, ability to leverage the diversity of loads and demands across the region (i.e. selling

Western Energy Imbalance Market Benefits

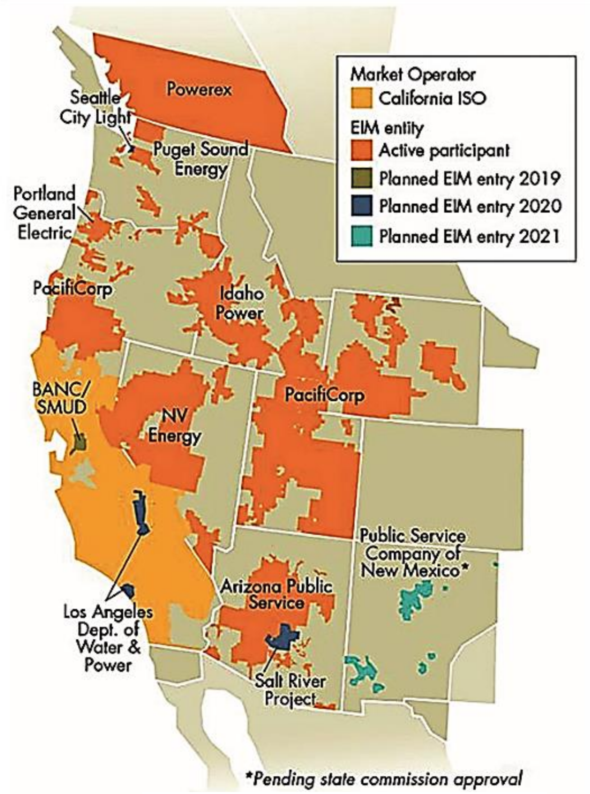
Year	Curtailment Avoided (MWh)	CO2 Emissions Avoided (metric tons)
2015	31,082	13,220
2016	328,238	140,486
2017	161,097	68,951
2018	194,988	83,455
Total	**715,405**	**306,112**



[24] The Western Energy Imbalance Market (EIM) is administered by the California Independent System Operator (CAISO). For more information, see https://www.westerneim.com/pages/default.aspx

energy to a southern utility when it's loads are peaking, then buying back from them when Avista's loads are high in the same day or even across seasons.) In addition, this forum provides increased access to renewable energy that is expected to be required in the near future by the Washington Legislature.[25]

In order to integrate the complex requirements of this new market into existing Company operations, changes will be required in the way the Company manages the real time system. This will require an estimated 13 additional personnel in System Operations.[26] The space for the current critical Operations functions has been maximized for the existing staff. These additional positions will require more space than is available without a significant remodel, moving other employees, or moving this entire group to a new location. These specialized employees also require additional equipment beyond the typical employee, for example, extra space for computer monitors (some of these positions utilize 8 to 12 large screens or more for monitoring the system and operating conditions), and therefore require significantly larger workspaces than a typical employee.[27]



Current Energy Imbalance Market Participants surrounding Avista

System and Distribution Operations are the nerve center of the utility, controlling the distribution, transmission and generation system in real time. These employees perform a critical function, operating Avista resources in balance with the energy market to ensure that resources exactly meet load requirements for customers every minute of the day. Utilities often separate these critical 24-hour operations from their headquarters for security reasons, typically locating these key people and associated systems in unmarked locations, as the disruption of this group could be devastating to system operations, reliability, and stability. The change in manpower requirements associated with the EIM creates an opportunity to move System Operations to a more secure and anonymous location. At the same time, this project would enable providing an upgrade to

[25] Western Energy Imbalance Market chart from their home page: https://www.westerneim.com/pages/default.aspx
[26] System Operators are mandated by NERC Standards to ensure that frequency, voltage, interchange and system stability are within acceptable ranges and to respond to emergencies accurately and within a specified time frame. System Operators must respond to ever-changing conditions of normal operations and emergency conditions due to weather, equipment malfunctions, public accidents and even vandalism and sabotage. They ensure that adequate resources are available to meet customer load demands within Avista's system, and to guarantee that Avista is adequately managing its part of the Western Interconnection. The new positions will manage the Company's participation in the EIM.
[27] This is true for both Distribution Operations and System Operations. It is estimated that an additional eight workstations will be required for the new System Operators as these are 24-hour positions served in 12 hour shifts.

the technology used by these employees to monitor and control grid operations and to incorporate the new systems required for Avista to integrate into the Western Energy Imbalance Market.

Another important consideration in the physical location of the operations-related employees is that the Federal Energy Regulatory Commission (FERC) Standards of Conduct Requirements demand separation between electric and natural gas transmission system employees and wholesale operations employees.[28] Due to the changing nature of FERC's Standards of Conduct regulations over time, most utilities have taken a conservative approach in ensuring they are in compliance with this mandate. They have found that it can become extremely complex to adequately separate these employees if they are in the same building. Structural and physical separation and information technology network controls have not always been sufficient. Moving Avista's System Operations offsite would mitigate any risk of non-compliance with FERC Standards of Conduct now and in the future, as well as address the current space limitations.

Sandpoint Service Center

The Sandpoint Service Center dates to the 1950s. It was acquired by Avista when the Company took over PacifiCorp's electric operations there in 1996. This area is experiencing a high level of growth, with a rate of 2.9% from 2017 to 2018[29] compared to about 1.8% growth in Spokane over the same time period,[30] spurred in part by some great publicity for Sandpoint such as being named "Best Small Town" by both Sunset Magazine and USA Today.[31] Over time the Company has outgrown the Sandpoint facility. The existing storage area does not have room for all of the inventory required to keep up with current work demands, and there is no adjacent property available for expansion. The Sandpoint storekeeper has become incredibly inventive, utilizing every spare nook and cranny in the facility, but that makes it difficult to track and manage inventory effectively. To add to the storage issue, the Sandpoint area has a unique voltage level which differs from the rest of Avista due to its development by another utility. This requires unusual materials and supplies that cannot be acquired from other district offices and so must be stored onsite in Sandpoint.

Sandpoint Office cracked walls, end-of-life bay doors and HVAC equipment

[28] "FERC Standards of Conduct and Business Support Functions," FindLaw, https://corporate.findlaw.com/litigation-disputes/ferc-standards-of-conduct-and-business-support-functions.html.
[29] World Population Review 2019, http://worldpopulationreview.com/us-counties/id/bonner-county-population/ /
[30] World Population Review 2019, http://worldpopulationreview.com/us-counties/wa/spokane-county-population
[31] "Best Small Town: Sandpoint, Idaho," Sunset Magazine, https://www.sunset.com/travel/northwest/best-small-town-sandpoint-idaho-0 and "USA Today, Rand McNally name Sandpoint most beautiful small town in America," Coeur d'Alene/Post Falls Press, https://www.cdapress.com/archive/article-763b3f51-0162-5d6f-a396-093d843e5552.html

Safety concerns at this facility are very real. There are no exit lights or smoke detection systems. The yard is so small that there are both vehicle and employee safety issues as vehicles attempt to maneuver into and out of the yard and up to the loading dock. Some of the roll up loading bay doors are damaged beyond repair, the lighting must be upgraded, the roof requires repair, the windows must be replaced, the concrete sidewalks and asphalt parking areas are cracked and pitted, the fences are broken in places, there are security issues, and the list goes on. Many of the building's systems, including electrical and HVAC, are antiquated and inefficient and some violate current code requirements.

Overcrowded storage area

Sandpoint also has some unique environmental concerns. A creek runs through the Service Center property that floods in the spring, inundating the pole yard with water. This close proximity to water sources that drain into area waterways demands a higher level of accountability, especially with Avista's environmental focus. This highly utilized service yard contains trucks and equipment that by their nature experience leaks and create mud and runoff that cannot be adequately contained with the current set up.

This area also experiences some of the highest amounts of snowfall in Avista's service territory, averaging about 58 inches of snow per year.[32] A great effort goes into removing snow from work vehicles before they can go out into the field because there are not adequate places for Company vehicles to be sheltered. In fact, one of the old shelters collapsed in 2017 due to snow loading and poor construction. Recently another vehicle suffered significant damage due to ice unloading from an Avista storage area due to lack of covered vehicle spaces.

Covered parking would be great! At times, vehicles must be shoveled out before use

The Company proposes acquiring a new site (not located on a major highway) upon which to construct a new service building, line dock, storage yard, warehouse, and covered storage areas for vehicles and equipment. This will include energy efficient heating and cooling systems, security and fire systems, plus adequate room for employees and maintenance operations. One of the focus areas will be on environmental protection, with storm water management, oil handling facilities, and protected transformer storage, ensuring compliance with legal and environmental regulations. Another key benefit will be in bringing all of the Sandpoint area employees together in one location along with the supplies and equipment they need to most capably perform their jobs. The existing facility will be sold to help offset the cost of the new location.

[32] https://www.bestplaces.net/climate/city/idaho/sandpoint

Avista's Facilities O&M Investments

Since 2005 the Company has spent an average of $4.3 million on Facilities operation and maintenance, divided into sections based on expected levels of need. O&M spending pays the utilities at every site, including electricity, water, sewer, garbage pickup, and natural gas service. It also funds repairs for leaking roofs, energy management audits and upgrades, grounds keeping, office supplies, building supplies such as lights and toilet paper, coordinating employee moves, and managing office space, to name a few. To add further complexity, the definition of what can be considered capital has become more restrictive, forcing more requests into the limited O&M category. As shown in Figure 19, not only has Facilities kept their O&M budgets fairly flat, but they have stayed very close to their budget allocation even with the variability they face in this category of spending.

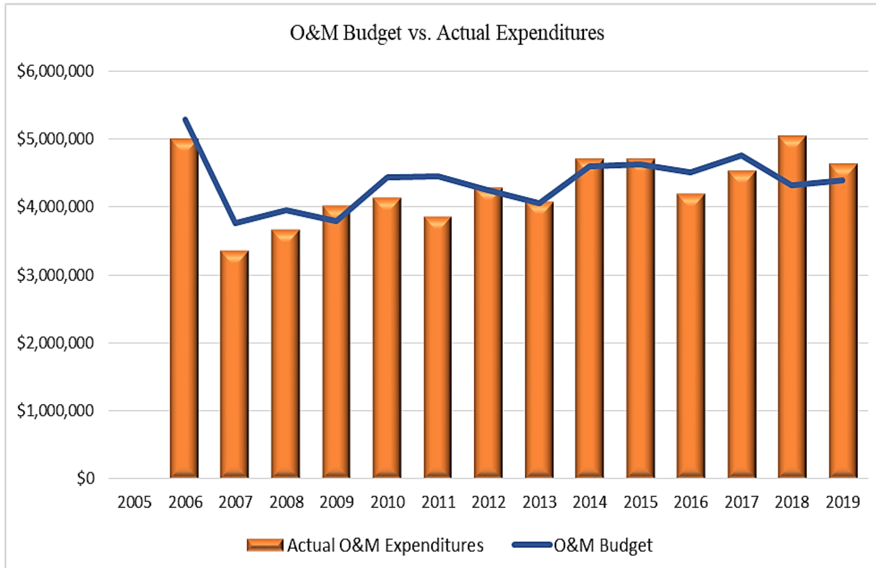


Figure 19. Facilities O&M Budget and Actual Spending

Facilities Operations and Maintenance work is separated into two categories, discretionary and non-discretionary. Discretionary work is maintenance not related to asset lifecycle or safety, such as carpet cleaning, general equipment maintenance, exterior upkeep, asphalt repairs and painting. Non-discretionary spending is primarily related to safety. This includes maintenance of elevators, fire systems, and lighting as well as snow and ice removal. It also includes building automation, janitorial/cleaning services, and utilities such as electricity and sewer. Due to budget limitations, facilities is often forced to choose not to do sustaining maintenance and instead "run to fail" those particular assets that do not fall under the category of public or employee safety. General operating costs such as utility bills have continually increased, requiring Facilities to postpone or eliminate more and more maintenance projects in order to stay within their allocated budget.

The Terracon (and industry standards) recommended spending levels for simply sustaining a company's facilities and meeting the basic needs (such as providing utilities) should be between 2-4% of the value of those facilities.[33] In Avista's case, their infrastructure value has been placed at $241,515,515, meaning the minimum sustainability O&M facilities spending level should be between

[33] "Budgeting for Facilities Maintenance and Repair Activities," National Academy of Sciences, Engineering, and Medicine, https://www.nap.edu/read/9226/chapter/3

$4.8 million and $9.6 million per year. As mentioned earlier, the total funding for Avista Facilities O&M budget is about $4.3 million on average, somewhat lower than the lowest recommended percentage, but that is somewhat misleading. The industry standard number assumes that this funding will sustain buildings, that is, provide preventative maintenance. Almost none of Avista's O&M money is spent for preventative work unless replacement of filters is included. Most of this money instead goes to paying for basic utilities.

Ritzville Service Center exterior (above) and interior (right)

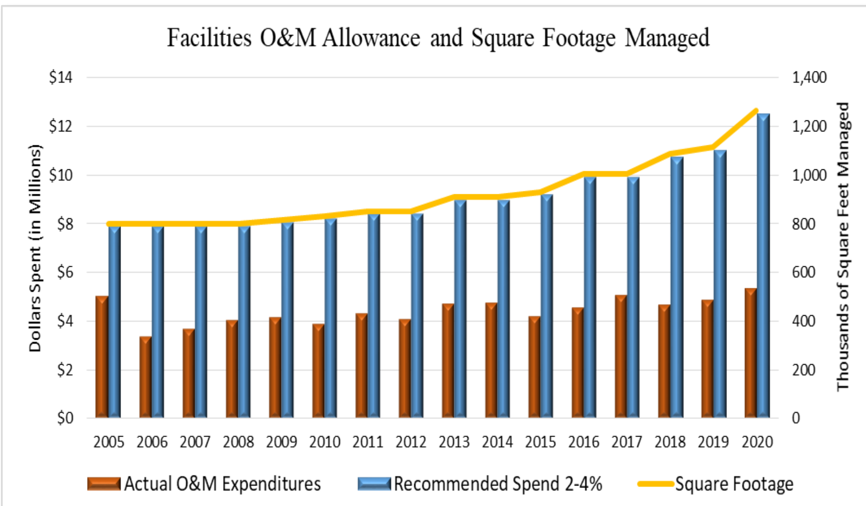


Figure 20. Avista O&M Spending vs. Industry Recommended Levels

Avista parking area & sidewalk

To add complexity, analysis of Facilities investments is not necessarily as straight-forward as other assets can be, as they are dealing with so many variables. The buildings this team manages are a variety of ages and are comprised of a variety of materials. For example, the Clarkston Service Center has an exterior made of wood rather than composite siding or brick. It has been in serious need of repainting for quite some time and, as a result, has suffered weather damage. Because Facilities was unable to do proper maintenance over time, the cost to make this repair is now significantly higher than it should be, costing an estimated $60,000, which is not manageable in the current funding model. Thus this work, though it needs to get done, continues to fall back on to the "to do" list or "fun to fail".

For another example, many of the Company's parking areas have broken curbing, pot holes, and cracks. Though these problems can cause safety issues, there is not enough funding to address them all. Facilities does its best to care for all of its assets, but this team is constantly fighting an uphill battle in trying to stay ahead of the need.

SUMMARY AND WRAP-UP

It is quite possible that Facilities is the most underrated and least appreciated team at Avista, which is somewhat understandable. Every employee utilizes dozens of Facility assets in their daily work lives, from parking lots to cubicles, bathrooms, water fountains, break areas, truck maintenance facilities, conference room technology, heating, cooling, and the like. We benefit from cleaning services, mowed and green lawns, exercise facilities, security, and so much more, but most are not really cognizant of the effort it takes to provide these routine services. Employees just naturally expect to have them, much like customers, who don't really pay much attention to the convenience of their electric power until there is an outage.

Facilities uses the best technology and information available to them to try to manage their buildings with the lowest cost and highest efficiency. When given money, this group focuses on using it to provide both long term value and customer benefits. As shown here, they have very little funding; thus, it is in the very best interests of all parties that this money is used wisely.

The Terracon study provides invaluable insights into areas of highest need for replacement or repair, which provides great assistance in delegating funds to get the most possible value. Facilities also utilizes automated building management systems to track building operations and help identify recurring problems and trends which should be addressed. The Facilities team is always on the go. There is never an end to the need to repair or replace something in their 1.2 million square feet of real estate. It is important to note that they do this extremely successfully given their limited funding. They are operating at about half the recommended national staffing level for facilities per square foot, with approximately half the amount required to effectively maintain facilities according to national standards, and with almost no O&M budgets or discretionary funding for handling unexpected expenses such as a heavy snowfall or a failed HVAC system. Their O&M expenditures often go over budget, much to their chagrin, because they simply cannot predict when something might fail and must be repaired or replaced.

Even with all of the efficiencies the team has developed and creative solutions they employ, there is a consequence to running at such lean manpower and funding levels. Many basic objectives cannot be achieved. Buildings simply cannot be sustained at the level they should be, which leads to early deterioration and, eventually, higher costs to repair or replace. Systems cannot be maintained adequately without preventative maintenance needed for the assets to achieve their optimum lifecycle and provide the most economic value. Employees cannot reasonably be expected to continue to do their best work under constant criticism and frustration. This situation is simply not sustainable and is ultimately not in the best interests of the Company or customers.

Appendix A: Awards

ENERGY STAR® Application for Certification

LEARN MORE AT energystar.gov

99

ENERGY STAR ® Score[1]

Avista Spokane GOB

Registry Name: Avista Spokane GOB
Property Type: Office
Gross Floor Area (ft²): 151,400
Built: 1950

For Year Ending: 08/31/2017[2]
Date Application Becomes Ineligible: 12/29/2017

1. The ENERGY STAR Score is based on total source energy. A score of 75 is the minimum to be eligible for the ENERGY STAR.
2. Applications must be submitted to EPA within 120 days of the Year Ending Date. The award is not final until approval is received from EPA.

The Facilities Group raised over $10,663 for the Second Harvest Foodbank in 2019, enough for 53,000 meals

Appendix B: Capital Request Form

<Business Case Name>

1 NATURE OF THE CHANGE

Type of Change	Choose an item.
Primary Reason for Change	Choose an item.
Response needed by	Click here to enter a date.

Year	Current Approval	Requested Change	Proposed Total
2019	$0	$0	$0
2020	$0	$0	$0
2021	$0	$0	$0
2022	$0	$0	$0
2023	$0	$0	$0
2024	$0	$0	$0

This section must describe the reason for the funds change request. Including but not limited to:

- *Identify what has changed such that the current approval is not sufficient.*
- *Identify why this work is needed now and what risks there are if not approved or deferred.*
- *Please reference studies that support the problem and attach to this document.*
- *Outline, at a high-level, what business functions/processes may be impacted and how, by the business case for it to be successfully implemented including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.*
- *Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).*
- *Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.*
- *Please delete this blue text, and format your response in non-italicised black font.*

2 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
	BC Owner		
	BC Sponsor		

3 CAPITAL PLANNING GROUP RESPONSE

Response			
Name	**Role**	**Signature**	**Date**
	FP&A		

Exhibit No. 11, Schedule 9
Capital Investment Business Case Justification Narratives Index

Business Case Name	**Page Number**

EXECUTIVE SUMMARY

The Electric Replacement and Relocations (Road Moves) program is driven by compliance mandated by the "Franchise Agreement" contracts with local city and state entities and "permits" issued by Railroad owners. Within each agreement are provisions for relocation of utilities at the request of the right-of-way (ROW) owner. Under a Franchise Agreement or Permit, Avista is allowed to occupy space within a ROW owned by the respective jurisdiction in order to serve its customers. Electric relocations occur every year during the construction season, but are unplanned, so historical trends are used to estimate the annual cost to fully fund all the relocation projects. The annual costs of electric relocations have very little variance year to year, therefore fully funding the business will likely ensure all electric relocations under Franchise Agreements or Permits will be completed. This is mandatory work to maintain compliance with existing franchise and operating permits with state highway districts and railroads. This impacts WA and ID Customers.

The Electric Relocations business case is unplanned and demand driven work, contractually obligated, and adds high risk to the company if not completed. Funding allocation is based on historical spending trends. The average historical spend for Electric Relocation over five years is $2.7 million (three-year average = $3.1 million). Because electric relocations are directly correlated with the number of highway and street projects, the reason for the upward trend in spend is likely an increase in transportation project spending.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Initial draft of 2020 Business Case Refresh*	*6/30/2020*	
1.0				
1.1				
2.0				

GENERAL INFORMATION

Requested Spend Amount	$3,000,000 annually
Requested Spend Time Period	Ongoing Program
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Amy Jones | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The Electric Distribution and Transmission Replacement and Relocations (Road Moves) program is driven by compliance mandated by the "Franchise Agreement" contracts with local city and state entities and "permits" issued by Railroad owners. A "Franchise Agreement" generally refers to a non-exclusive right and authority to construct, maintain, and operate a utility's facility using the public streets, dedications, public utility easements, or other public ways in the Franchise Area pursuant to a contractual agreement executed by the City and the Franchisee. Although each Franchise Agreement or permit is a little different, they all serve a similar purpose in providing utility access along city, county, state and railroad right-of-way (ROW). The agreement(s) make provisions for Avista to install electric equipment along these ROW's in order to provide service to Avista customers.

Within each agreement are provisions for relocation of utilities at the request of the ROW owner. These requests are usually driven by road and or sidewalk re-design projects.

> For reference, **franchise 95-0990** recorded with Spokane County paragraph VI states ***"If at any time, the County shall cause or require the improvement of any County road, highway or right-of-way wherein Grantee maintains facilities subject to this franchise by grading or regarding, planking or paving the same, changing the grade, altering, changing, repairing or relocating the same or by constructing drainage or sanitary sewer facilities, the grantee upon written notice from the county engineer shall, with all convenient speed, change the location or readjust the elevation of its system or other facilities so that the same shall not interfere with such County work and so that such lines and facilities shall conform to such new grades or routes as may be established."***
>
> For example, a State Department of Transportation (DOT) is widening an intersection or highway, which requires Avista to relocate their overhead or underground electric facility to accommodate the new DOT design. A smaller example for instance is a local municipality is installing new ADA ramps on the corners of local street intersections, which sometimes requires Avista to relocate a utility pole to accommodate the new ramp design.

The asset conditions replaced through Electric Relocations can vary since the relocations are unplanned and therefore not coordinated with Avista's Asset Maintenance programs. Most assets in an Electric Relocation project are replaced because they are unsalvageable and close to their useful life. In the case of relocating newer assets, efforts are made to re-use as much material as possible.

Under a Franchise Agreement or Permit, Avista is allowed to occupy space within a ROW owned by the respective jurisdiction in order to serve its customers. Electric relocations occur every year during the construction season, but are unplanned, so historical trends are used to estimate the annual cost to fully fund all the relocation projects. The annual costs of electric relocations have very little variance year to year, therefore fully funding the business will likely ensure all electric relocations under Franchise Agreements or Permits will be completed.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

This major driver of this business case is Mandatory & Compliance. Franchise agreements, typical state highway and railroad permits, and DOT prescribe that the utility will relocate at their expense when in conflict with entity activities. Mandatory work to maintain compliance with existing franchise and operating permits with state highway districts and railroads.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This program has been funded for several years and ensures compliance with our Franchise agreements and/or railroad permits. If not funded, we would be out of compliance with our Franchise agreements and/or railroad permits. The work would need to occur and would be funded under another business case.

Work under Franchise Agreements or Permits are contractual, agreed upon, and if the terms of the agreement or permit are not executed a breach of contract will likely ensue. Also, state and local government departments which oversee highways, roads, and city streets incorporate the guidelines set forth in the American Association of State Highway Transportation Officials (AASHTO) Roadside Design Guide into the design of the highways and roads. The guidelines are based on the type of roadway and posted speed, but generally do not allow for any fixed objects inside the traveled way or sides of the roadway (“clear zones”) for public safety. As a result, nearly all new road projects require utilities to relocate or remove all poles inside and outside the traveled way. The new roadside design guidelines allow for placement of new facility in a location that improves the safety of the driving public, thus reduces risk to Avista. Avista designers coordinate with each state or local road project to ensure the new relocations meet the clear zone standards yet minimize cost. Most Franchise Agreements have provisions to prohibit the ROW owner from requiring the utility to move the same facility more than once over a span of years, usually five.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Measures to determine successful delivery on business case objectives include:

- YTD Spend
- Compliance with Franchise agreements and/or railroad permits

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

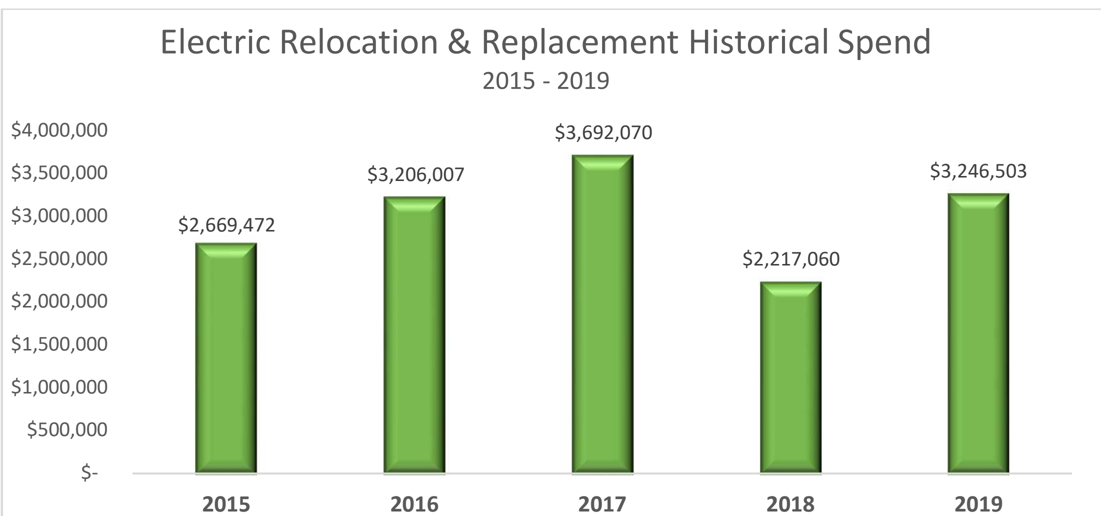
NA

Option	Capital Cost	Start	Complete
Relocate/replace facilities in conflict with street and highway projects where established franchise agreements and/or permits exist.	*$3,000,000 annually*	*Continuous Program*	
UNFUNDED: Avista would be out of compliance with established franchise agreements and/or permits if work is not completed.	*$0*		

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The Road Moves business is unplanned work, contractually obligated, and adds high risk to the company if not completed, no alternative analysis is considered. This program is demand driven and unplanned work. Funding allocation is based on historical spending trends.

The graph below shows the historical spend for Road Moves (2015 – 2020 YTD - May). The average spend over the five years is $2.7 million. Because electric relocations are directly correlated with the number of highway and street projects, the reason for the upward trend in spend is likely an increase in transportation project spending.



2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

This funding will enable us to relocate/replace facilities in conflict with street and highway projects where established franchise agreements and/or permits exist. The funding will ensure we are in compliance with our existing franchise agreements and/or railroad permits.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

If funded, the outcome of this business case will have minimal impact on existing operations. This funding has been in place for several years to maintain compliance with our franchise agreements and railroad permits. If not funded, the work is required to maintain compliance with our franchise agreements and/or railroad permits and will need to occur.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The work covered by this funding is mandatory to maintain compliance with our franchise agreements and/or railroad permitting. Because the Road Moves business is unplanned work, contractually obligated, and adds high risk to the company if not completed, no alternative analysis is considered. This program is demand driven and unplanned work.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

This is an ongoing project. All investments/assets are used and useful at time of install.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This work is required to maintain compliance with our franchise agreements and/or railroad permits. This work focuses on our Customers and performance (safety and compliance).

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project.

The work covered by this funding is mandatory to maintain compliance with our Franchise Agreements and/or railroad permitting.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Internal customers and stakeholders are the local area operation engineers and area construction managers

The primary external stakeholders in the business include all state and local transportation governments as well as customers since they live in the territory governed by these agencies and use the transportation system.

2.8.2 Identify any related Business Cases

NA

3.1 Steering Committee or Advisory Group Information

The Road Move work is overseen by the local area operations engineers and area construction managers.

3.2 Provide and discuss the governance processes and people that will provide oversight

The work is mostly unplanned and non-specific in nature but occurs regularly and historical averages are used to estimate a quantity. Electric Relocations (Road Moves) are agreed to and executed per the jurisdictional Franchise Agreement or Permit.

The governance in place over the business case is set by the Operations Roundtable (ORT) group, which sets forecasted budgets, monitors the incurred costs and submits any additional funds requests as needed. Oversight of the program is provided by the local area operation engineers and area construction managers manage the work as it is identified throughout the given construction season.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

For the funding: Decision making, prioritization and change requests will be documented and monitored through the Operations Roundtable (ORT).

For the work: Each office will work with their Area Engineer and impacted jurisdiction/Railroad in determining priority.

The undersigned acknowledge they have reviewed the **Electric Replacement and Relocation (Road Moves)** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Amy Jones	Date:	08/01/2020
Print Name:	Amy Jones		
Title:	Asset Maintenance Business Analyst		
Role:	Business Case Owner		

Signature:	David Howell	Date:	8/2/20
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

Joint Use is the regulated use of utility poles and other structures by 3rd party telcommunications companies in order for them to provide their services to the customers we have in common. Avista licenses 76 unique entities that are attached to over 150,000 poles across Avista's service territory and is required by federal, state and local laws to allow non discriminatory access to those assets. Even though this relationship is mandated by law, and is compliance driven, Avista agrees that this practice provides a direct benefit to our customers who desire those services.

Part of this requirement includes the obligation of Avista to replace infrastructure to taller stronger structures in order to accommodate or "make ready" those facilities for new attachments. This make ready work falls under capital expense and Avista is allowed to recover the actual costs from the requesting attacher. Avista is also allowed to recover a portion of the cost of replacing & maintaining shared infrastructure via a regulated yearly pole rental fee. Avista would face potential regulatory and or civil legal action if timelines and obligations are not met due to a lack of funding.The outcome of these actions could result in significant financial loss and penalties.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Stephen Schulte*	*Initial draft of original business case*	*6/302020*	

GENERAL INFORMATION

Requested Spend Amount	$2.75m
Requested Spend Time Period	*Year to year*
Requesting Organization/Department	Operations/Joint Use
Business Case Owner | Sponsor	Stephen Schulte | David Howell
Sponsor Organization/Department	Operations/Joint Use
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

1.1 What is the current or potential problem that is being addressed? Access to safe and reliable utility infrastructure by third parties is not only a crucial element of the connected world in which we live but it is also mandated by regulators at the federal and state levels. Avista therefore has a duty to repair, replace or add infrastructure to accommodate those requests.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* **and the benefits to the customer.** The major drivers of this business case are the joint use and licensee's who request new pole attachments or who must upgrade their existing systems to meet the burgeoning and ever increasing demand for reliable and cost efficient communication needs. This has a direct benefit to not only Avista customers but Avista itself as we are also consumers of those same telecommunicaitons products. As mentioned previously fair and non discriminatory access to investor owned utility infrastructure is codified in Federal and State laws dating back to the Federal Telecommunicaitons Act of 1934 which laid the groundwork for the current system of asset sharing.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred. This work is needed currently and will be needed on an ongoing basis not only for existing wired telecommunication providers but for wireless providers who are more often than not reliant upon existing vertical utility assets to locate their equipment. These technologies are commonly referred to as 4G, 5G and LTE. The risk of not executing to meet these demands could result in regulatory action, resultant fines, and possible civil litigation that could far outweigh any short term savings. Damage to Avista's reputation and loss of customer trust could also result whose monetary costs are incalculable.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above. Avista's joint use team utilizes several systems to track compliance and adherence to Federal, State and local regulations.On physical and practical level, success is more often realized when 2nd and 3rd parties construct their facilities, and follow up quality control is performed. Anectodally the joint use team has been approached by Avista customers who are very happy with their new telecommunication service that was made possible solely by the ability of the provider to attach their cables to Avista utility poles.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem. Tracking, invoicing and budget information is located on the joint use drive located on Avista network drive c01m289.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

Option	Capital Cost	Start	Complete
Replace capital assets when requested	*2.75*	*Ongoing*	*Ongoing*
[Alternative #1]	*$M*	*MM YYYY*	*MM YYYY*
[Alternative #2]	*$M*	*MM YYYY*	*MM YYYY*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request. Current joint use capital business case amounts were derived from historic spend data coupled with projected activity that is based on trends seen in the joint use request tracking sheet. Avista receives a direct benefit of joint use related capital work by way of receiving a new asset at a decreased cost to rate payers. Due in large part to the dedication of fair and non discriminatory access to utility infrastructure, and the timeliness of completing requested capital make ready work.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.** Given the current workload, and requests for capital asset replacement in support of joint use, current funding levels will be fully spent by the end of the budget year. Similar funding levels will be required on an ongoing basis with additional funding request sought as conditions warrant. The majority of assets being replaced should not add any additional operating costs beyond current levels such as wood pole test and treat, vegetation management etc.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented. Additional workload resulting from increased joint use make ready could be experienced by several workgroups including but not limited to; Distribution Operations, Maximo, Real Estate, GIS, Asset Management, Transmission Operations.

[For example, how will the outcome of this business case impact other parts of the business?]

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative. No realistic alternatives exist nor were discussed. The only alternative would be to cease performing this work which would result in regulatory/legal action and customer dissatisfaction.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year. This capital work related to this business case are ongoing and immediate. Transfers to plant occur on a monthly basis and the assets become used and useful immediately following physical construction.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization. The investment that is made in Avista's physical plant to accommodate joint use telecommunications benefits the shared customer base of Avsita and the joint use providers. It places our customer at the center of our focus and helps Avista to provide a safe, reliable and cost effective services. It also helps to provide a safe working environment for all workers who require access to the electric distribution system.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project. Joint Use requested capital make ready work is and will always be a prudent investment as the majority of assets that are being replaced are typically near the end of their life and Avista benefits from a newer, stronger structure. Pole replacements and new assets are typically the solution of last result and are only offered after careful consideration and review. High dollar cost replacements such as transmission pole receive addtitional scrutiny and review for appropriateness and cost effectiveness.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case. Avista Electric rate payers, Distribution operations, Distribution Engineering, Electric Design.

2.8.2 Identify any related Business Cases. The Joint Use business case was carved out of the Miscellaneous Capital Overhead Expense business case so that it could be more closely monitored and tracked.

[Including any business cases that may have been replaced by this business case]

3.1 Steering Committee or Advisory Group Information. The advisory group for this business case is the Operations Resource Team. It consists of the Manager of Operations Analytics (Julie Lee), Operations Analyst (Sherry Bentley), Facilitor of the Operations Round Table (Amy Jones), Manager of Distribution Engineering (Caesar Godinez), Operations Engineers (Brian Chain and Tim Figart), Operations Director (David Howell), and the Joint Use Program Adminstorator (Steve Schulte). Meetings are held at least once per quarter and as needed depending on necessary required changes or requests.

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

3.2 Provide and discuss the governance processes and people that will provide oversight. The business case spending levels are tracked and monitored by the Manager of Operations Analytics (Julie Lee) and Operations Analyst (Sherry Bentley) in Utility Accounting with monthly spend reporting to the Operations Director (David Howell).

3.3 How will decision-making, prioritization, and change requests be documented and monitored . Desicision for funding increases will be discussed during the Operations Resource Team meeting. If additional funding is deemed necessary then the business case owner Steve Schulte will complete the necessary documentation which will then be forwarded along to the Capital Planning Group for consideration. All documentation will be kept on file in the joint use server share in a 'budget' folder.

The undersigned acknowledge they have reviewed the Joint Use Projects business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Stephen Schulte	Date:	7/2/20
Print Name:	Stephen Schulte		
Title:	Joint Use Administrator		
Role:	Business Case Owner		

Signature:	David Howell	Date:	7/20/20
Print Name:	David Howell		
Title:	Director of Electric Operations		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Saddle Mountain 230-115kV Station (New) Integration Project Phase 2

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

Large commercial customers in the Othello area have continued to expand their businesses. The business expansion has created demands on the electric system that are not able to be adequately backed up with the reliability that they deserve. Meeting the increased load demands are possible, but equipment failures could cause outages that would be time consuming and difficult to restore quickly.

This business case would replace the Othello City substation with a new station having 2-30MVA transformers. The business case also includes substancial upgrades to the transmission system in the area to integrate the new Othello City substation with the new Saddle Mountain substation. This business case is important to customers so that they can continue to have the reliability of the electric system that they have become accustomed to receiving.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2017-64

Cost of Solution: $25,650,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Unknown	Initial Version	2017	
2.0	Karen Kusel / Glenn Madden	Update to 202 Template	6/2020	

GENERAL INFORMATION

Requested Spend Amount	$11,000,000
Requested Spend Time Period	4 Years
Requesting Organization/Department	Transmission / System Planning
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Planning
Category	Project
Driver	Mandatory & Compliance

1 BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

This business case would replace the Othello City substation with a new station having 2-30MVA transformers. The business case also includes substancial upgrades to the transmission system in the area to integrate the new Othello City substation with the new Saddle Mountain substation.

1.1 What is the current or potential problem that is being addressed?

There are performance issues in the Othello area, it is also difficult to maintain the equipment at the Othello 115kV Substation due to load deam on all feeders.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Mandatory & Compliance are the main priority of this project due to TPL-001-4 non-compliance at this time. There are also Performance & Capacity issues that will be remedied with this project. Overall, this rebuild will relieve load and outage concerns for large commercial customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Due to increased load in the area, we are risking large customer outages due to equipment failure.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

System Planning Assessments.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

Project Report: Saddle Mountain Study.pdf

2016 Avista System Planning Assessment Report (Page 56)

Othello City Substation Area Load Analysis

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

System Planning Assessments.

2 PROPOSAL AND RECOMMENDED SOLUTION

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

Alternative 1: Status Quo. This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not adhere to NERC Compliance regulations.

Alternative 2: Build new 115kV Transmission Line. This alternative is not recommended as it does not mitigate the low voltage issues in the Othello area.

Alternative 3: Close "Star" Points. This alternative is not recommended due to its high cost. It is anticipated that $75M of reconductoring would be needed to mitigate any potential violations comparable to the preferred alternative.

Alternative 4: Install Generation. This alternative is not recommended due to its high financial costs, the potential for must run operation and the lead time on this project will be well beyond the time this project is needed per NERC requirements.

Alternative 5: Build Saddle Mountain 230/115kV Substation Phase 2 Project with associated support projects. This alternative is the most cost effective option considered and provides enough voltage support and capacity into the area for the next 50 years. This alternative mitigates all identified deficianencies in the Othello area documentes in the 2016 Planning Annual Assessment. This alternative is the best solution for the long term.

Phase 1: See Associated Phase 1 Business Case Narrative.

Phase 2:

1) Rebuild Othello Substation to 115kV Ring Bus with 5 positions.
2) Build new Transmission line from Saddle Mountain 115kV to Othello Substation 115kV.

This alternative is the most cost effective option considered and provides enough voltage support and capacity into the area for the next 50 years. This alternative mitigates all identified deficiencies in the Othello area documented in the 2016 Planning Annual Assessment. This alternative is the best solution for the long term.

Option	Capital Cost	Start	Complete
Recommended Solution: Build Saddle Mountain 230/115kV Substation Phase 2 Project with associated support projects	$11M	01 2020	12 2021
Alternative 1: Status Quo	$0M		
Alternative 2: Build new 115kV Transmission Line			
Alternative 3: Close "Star" Points	$75M		
Alternative 4: Install Generation			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:
- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

System Planning Assessments, previous outage information.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

2020 - $2,500,000

2021 – $24,650,000

2022 – $1,000,000

2022 – Closeout

O&M will be comparible to before this project.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system in the Othello area.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See Section 2.0 for alternative discussion.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Design work was begun in 2020, construction will be completed by 2022 and closout may continue into 2023. Transfers to plant will occur when the new station is commissioned and energized.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

This project will alleviate concerns regarding large customer outages and will provide the ability to maintain major substation equipment.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The scope for the project, which is to increase transformation in the Othello area as well as to increase reliability by creating the switching station is the least cost option. Adhering to the scope and project objectives will be reviewed regularly by the project team including the project engineer and the project manager.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Saddle Mountain 230/115kV Station (New) Integration Project Phase 1 was completed in 2020.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

The Engineering Roundtable initially is designated as the Steering Committee for this project, with a more project-specific Steering Committee to be potentially identified at a later date.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Saddle Mountain 230-115kV Station (New) Integration Project Phase 2 and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	Josh DiLuciano		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	Damon Fisher		
Title:	Principle Engineer		
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

The Electric Storm Business Case is focused on restoring Avista's transmission, substation, and distribution systems (damaged plant) into serviceable condition during a weather storm event or other natural disaster where assets are damaged. These storm events are random and often occur with short notice. This business case is to fund a rapid response to unexpected damages and outages, so customer outages are minimized. The business case provides funds for replacing poles, cross arms, conductor, transformers, and all other defined retirement units damaged during weather storm events. The damage can be due to high winds, heavy ice and snow loads, lightning strikes, flooding, or wildfires as an example. The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers. This impacts customers in WA and ID.

The annual budget amount is determined based on the historical average rate of capital restoration work and excludes major event days (MEDs). If not funded, the work will still occur as needed for outages caused by weather storm events or other natural disasters and would be absorbed through other business cases.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Initial draft of Business Case refresh 2020*	*7/1/2020*	

GENERAL INFORMATION

Requested Spend Amount	$3,200,000 annually
Requested Spend Time Period	Ongoing program
Requesting Organization/Department	Operations
Business Case Owner | Sponsor	David Howell | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The Electric Storm Business Case (BC) is focused on restoring Avista's transmission, substation, and distribution systems (damaged plant) into serviceable condition during a weather storm event or other natural disasters where assets are damaged. These events are random and often occur with short notice. This business case funds a rapid response to unexpected damages, so customer outages are minimized. The business case provides funds for replacing poles, cross arms, conductor, transformers, and other defined retirement units damaged during storm events. The damage can be due to high winds, heavy ice and snow loads, lightning strikes, flooding, or wildfires. The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The primary driver for the Electric Storm BC is **Failed Plant and Operations**. The work is a key component to minimizing customer outage times and contributes to Avista's reliability indices like SAFI and CAIDI. The secondary driver for this business case is **Customer Service Quality and Reliability**.

<u>Benefits to Customers</u>
This business case allows funding for a rapid response to unexpected damages and service interruptions so customer outage times are minimized. The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers. The Electric Storm BC is to fund a rapid response to unexpected damages and outages, so customer outages are minimized. If this business case is not funded the costs to restoring power to our customers will be absorbed by another business case. The needed work will continue to occur.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The primary measure that will be used to determine success is outage duration including other reliability measures such as Avista's reliability indices like SAFI and CAIDI. These measures will demonstrate the impact of the work charged to this business case.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

N/A

Option	Capital Cost	Start	Complete
Fully Funded	*$3,200,000 annually*	*Continuous Program*	
Unfunded: The work would need to be completed if unfunded and would need to be absorbed by another business case.	*$0*		

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The annual budget amount is determined based on the historical average rate of capital restoration work.

Figure 1 shows the historical costs (2010 – 2019) for the distribution storm business case. From 2010 to 2013, the average annual cost for distribution storms was $2.1 million dollars, with a range of $1.3MM (2011) to $2.7MM (2013). The years of 2014 and 2015 experienced an anomaly with 2014 having two uncharacteristic major wind events during the summer and November 2015 was a historic 100-year windstorm event. Consequently, 2014 and 2015 realized record spending on storm related distribution work. The year 2016 had a distribution storm spend of nearly $4 million, but much of the work was related to clean up of the historic November 2015 storm event. The proposed funding level does not account for the storm anomalies that occurred in 2014 and 2015 (Major Event Days).

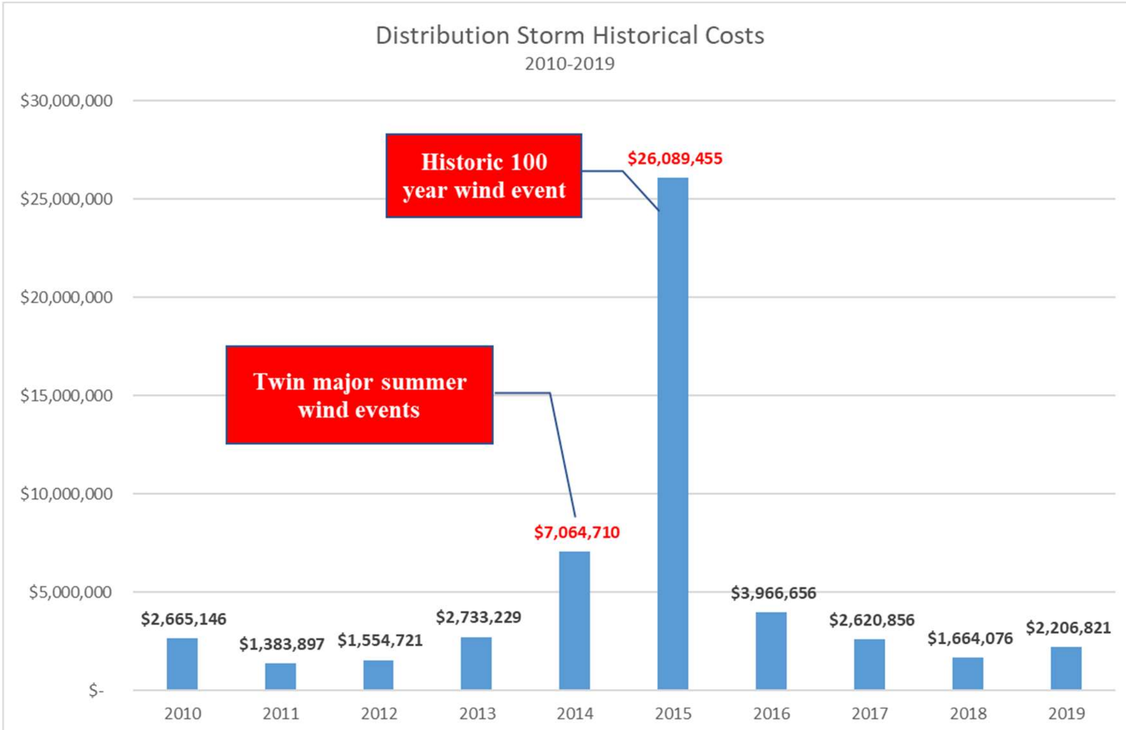


Figure 1: Dx Storm Historical Costs

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

The requested capital cost amount will be spent as needed, driven by customer outages as a result of a weather storm or natural disaster event. Historical spend is an indication of future spend.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Work under this business case occurs when repair is needed to facilities that are damaged during weather storm events or natural disasters. Depending on the severity and the duration of the specific outages, various business functions and processes may be impacted. Impacted areas can affect one office area or multiple Avista service territories.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The alternative to this business case request is not funding. The costs associated with repairing damages as a result of a weather storm event or a natural disaster would be covered through a different business case. Damages from these events will have to be repaired, regardless of funding.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

Weather storm events or natural disasters are a continuous risk. Work will occur as needed as a result of damaged facilities related to these events. Many times, multiple events may occur within one year in different office areas. Past data shows there has not been a year where a storm has not happened. Since this is often emergency work, assets become used and useful and transferred to plant immediately.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The Electric Storm business case aligns with the company's strategic goal of **Safe and Reliable Infrastructure**. The work is a key component to minimizing customer outage times and thus contributes to Avista's reliability indices like SAFI and CAIDI.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers. The Electric Storm BC is to fund a rapid response to unexpected damages caused by weather storm events or natural disasters, so customer outage times are minimized. If this business case is not funded, the costs to restore power to our customers will be absorbed by a different business case, as the work will need to occur.

The YTD spend is tracked and reviewed each month during the Electric Operations Roundtable (ORT) meetings. The ORT reviews monthly spend and manages any additional funds requests.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The Electric Storm work is overseen by the local area operations engineers and area construction managers. In the event of larger scale storms or natural disasters, like the historical storm event in November 2015, a formal Incident Command System (ICS) is created to manage the resources needed to respond. Leaders will declare Emergency Operating Procedures (EOP) and Stakeholders from every area of the company are involved on safely restoring power to our electric customers.

2.8.2 Identify any related Business Cases

N/A

3.1 Steering Committee or Advisory Group Information

The Electric Storm work is overseen by the local area operations engineers and area construction managers. The work is unplanned and non-specific in nature but occurs regularly.

In the event of larger scale storms or natural disasters, like the historical storm event in November 2015, a formal Incident Command System (ICS) is created to manage the resources needed to respond. Other large events are managed through an EOP with the Director of Operations.

3.2 Provide and discuss the governance processes and people that will provide oversight

The governance in place over the business case is set by the Operations Roundtable (ORT) group, which sets forecasted budgets, monitors the incurred costs and submits any additional funds requests as needed. Electric Storm work is overseen by the local area operations engineers and area construction managers.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Decision making, prioritization and change requests will be documented and monitored though the Operations Roundtable (ORT).

The undersigned acknowledge they have reviewed the ***Electric Storms Business Case*** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ______________________________ Date: ______________

	David Howell		8/2/20
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Owner		

Signature:	David Howell	Date:	8/2/20
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

1 GENERAL INFORMATION

Requested Spend Amount	$505,000*
Requesting Organization/Department	Z08/Electric Meter Shop
Business Case Owner	Dan Austin
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Operations
Category	
Driver	

Note: 2017 Request includes additional one time request of $205,000 for the A-base meter replacement project. This work is in support of the AMI project.

1.1 Steering Committee or Advisory Group Information

The determination for how the funds in this business case will be spent is a joint decision made by the Manager and General Foreman. A meter usage forecast will be used to guide the decision making process. The forecast will be based on the past five years of meter installs, current install rates, and manufacturer lead times.

2 BUSINESS PROBLEM

The primary driver for this business case is failed plant and operations. We regularly experience failed plant when meters and/or metering equipment fails. Meters are a critical component to supplying our customers with electricity and to accurately measure their energy consumption. Please refer to Attachment 1 for the most recent meter failure analysis completed by Asset Management in early 2017. This analysis shows the failure curves for both digital and mechanical meters. The analysis suggests that the more digital meters that are installed the higher the meter failure rate becomes. However, mechanical meters are no longer manufactured by our meter vendors because they have moved to the digital market.

When meters fail at existing customer service point's immediate action must be taken to repair or replace the meter. This is because a failed meter will not provide accurate consumption data. Funding is necessary to replace or make needed repairs otherwise the customer billing data will have to be estimated. Billing estimation lowers the quality of service we provide our customers because estimated data can be viewed by the customer as inaccurate. Additionally, estimated billing data can put rate pressure on our customer base if usage is under estimated. If usage is over estimated it unfairly penalizes the customer whose bill is being estimated.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	O&M Cost	Start	Complete
Fully fund new electric meter purchases	*$505,000*	*$0*	*01 2017*	*12 2017*
RMA meters	*313,994*	*$278,448.72*	*01 2017*	*12 2017*
Repair or Refurbish meters	*313,994*	*$281,013.48*	*01 2017*	*12 2017*

This business case will reduce the O&M required to replace failed meters. As you can see tabulated in the above table the lowest cost option is to fully fund this business case. The reduction in O&M is associated with the meter replacement portion of this business case.

Historically there has been three solutions to replace failed meters:

1.) Refurbish and repair in house
2.) Return Merchandise Authorization (RMA)
3.) Replace failed meter with new meters

3.1 REFURBISH AND REPAIR IN HOUSE

As Avista's population of digital meters grows and the mechanical meter population shrinks the less viable this option becomes. This is because digital meters require special equipment and training to repair, which is not available to our technicians. Also of note is that mechanical meters are no longer manufactured by our meter vendors because they have moved to the digital market. It is very rare for our technicians to remove a mechanical meter from the field as a result of failure. The majority, if not all, of the meter failures we experience in a given year are from the digital meter families. Table 1 shows how many digital and mechanical meters we have installed in WA and ID. This table also shows the average failure rate we experience annually. This option was not chosen due to the equipment and technical training required as well as the higher cost associated with the labor to refurbish meters.

Meter Type	Qty.
Single-Phase Mechanical	172,215
Single-Phase Digital	187,100
Poly-Phase Mechanical	5,781
Poly-Phase Digital	17,346
Total	**382,442**
Average failures per year	3882

Table 1: Meter Quantities by Type

Charge Type	Cost
Refurbish Labor	$37.26
Install Labor	$35.76
Total	$73.02

Table 2: Tabulated Cost to Refurbish Meters

3.2 RETURN MERCHANDISE AUTHORIZATION (RMA)

Option 2 is more costly than purchasing new meters due to the manufacturer's costs, shipping costs, and labor associated with the RMA process. Recent repair costs were quoted from our meter vendor to be between $20 and $40 dollars per meter. Table 3 shows the total cost to RMA a single meter. This cost was developed using very conservative values for each charge type and may be higher if more expensive (Poly-phase) meter types were included. This option was not chosen due to the high cost.

Charge Type	Cost
RMA Labor	$9.31
Shipping	$7.17
Repair Charges	$20.00
Install Labor	$35.76
Total	$72.74

Table 3: Tabulated Cost to Install RMA Meters

3.3 REPLACE FAILED METERS WITH NEW METERS

The final option is to purchase meters new for meter failure replacements. This is the lowest cost solution as shown in Table 4. There is a cost savings with new meters because there is no labor associated with refurbishing and testing and there is no RMA charges as compared to Options 1 and 2. This business case supports Options 3 to purchase new meters to replace failed meters.

Charge Type	Cost
Purchase Cost	$20.43
Labor	$35.76
Total	$56.19

Table 4: Tabulated Cost to Install New Meters

Do nothing is not an option because at minimum we need functioning meters to replace failed meters. Doing nothing would keep Avista from accurately billing our existing customer base.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Meter Minor Blanket and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ____________________ Date: ____________

Print Name: Dan Austin

Title: Electric Meter Shop Manager

Role: Business Case Owner

Signature: ____________________ Date: ____________

Print Name: Bryan Cox

Title: Sr Dir of HR Operations

Role: Business Case Sponsor

Signature: ____________________ Date: ____________

Print Name: ____________________

Title: ____________________

Role: Steering/Advisory Committee Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Dan Austin	4/13/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 03/07/2017

Attachment 1: Electric Meter Model Review

Electric Meter
Model Review.pptx

EXECUTIVE SUMMARY

Maintaining system reliability is an important part of providing quality service to Avista's customers. Planned investments in the distribution system are necessary to efficiently maintain reliability while keeping costs low for customers. The Grid Modernization Program (GMP) is the largest program focused on planned maintenance and improvements beyond wood poles driven by a comprehensive engineering analysis across Avista's 19,000 miles of electric distribution lines (Avista 2019 Quick Facts). The GMP's mission is to replace aging and failing infrastructure within the electric distribution system while also improving reliability and performance and capturing energy savings through the efficient use of company resources. Avista's distribution system has numerous facilities at, or near, the end of their useful life. Over decades, many of these were built to different construction standards using a wide variety of materials. These factors contribute to increased outages that take longer to restore and fall short of modern expectations that utilities face. The program benefits all Washington and Idaho electric customers and is intended to operate on a 60 year cycle averaging 190 circuit-miles addressed per year. The current average cost per mile requires a $28.88MM annual investment to achieve a 60 year cycle. The 60 year cycle is based on the average lifespan of distribution infrastructure, and the twenty year cycle of the Wood Pole Management Program (WPM) (Avista Utilities Electric Distribution Infrastructure Plan June 2017).

A systematic approach is recommended to address the rebuild and upgrade of the distribution system. This approach utilizes a prioritization method balancing feeder health, performance, and criticality. Design decisions are made through a consistent process and construction adheres to established overhead and underground standards. Upon the completed construction of GMP projects, customers benefit from improved system reliability, safety, and performance. These can be measured by a reduction in outage frequencies and durations in addition to power quality metrics. As Avista's distribution facilities continue to age, it becomes more important to be proactive in their replacement. Delaying the business case increases the likelihood and severity of various risks including equipment failure, wildfire, and energy losses. A delay would also impact the cycle time of WPM. Not approving the business case places the responsibility of rebuilding the system on the individual offices throughout the company which are responsible for daily maintenance and operations as well as new revenue projects. Additionally, it jeopardizes the ability to holistically address system wide performance. Overall, not funding or delaying this business case would reduce the efficiency that the GMP provides to the company and customers while elevating the risk of an inconsistent application of design and construction standards.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft		*Initial draft of original business case 2020*	*7/31/2020*	
1.0				

GENERAL INFORMATION

Requested Spend Amount	$77,000,000
Requested Spend Time Period	5 years
Requesting Organization/Department	Asset Maintenance
Business Case Owner | Sponsor	Heather Webster | Alicia Gibbs | David Howell
Sponsor Organization/Department	T51/Asset Maintenance
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The Grid Modernization Program (GMP) addresses the aging and failing infrastructure found throughout the electric distribution system. Other issues addressed include sub-optimal system performance and inaccessible facilities that drive increased routine maintenance costs. Outage durations and frequencies and power quality problems are also evaluated for improvement through the installation of automated devices. Safety is also a key benefit of the Program as Grid Modernization projects bring facilities up to current NESC and Avista construction standards, fulfill the efforts of Wildfire Resiliency, address the Transformer Change Out Program, and address structures located within the control zone of roadways subject to Washington State's Department of Transportation Target Zero requirements.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The GMP business case is driven by asset condition and performance and capacity. Customers benefit from in the following ways:

- Replacement of aging and failed infrastructure.
- Fewer outages that can be resolved more quickly.
- Automation devices produce results immediately optimizing system performance, reducing costs, and reducing outages.
- Cost effective work due to program efficiencies and long-term planning.
- Improved safety.
- Providing additional expertise with design and construction resources that are not available at outlying offices.

Reliability improvements have been quantified that are a direct benefit to the customers in feeders that the GMP has addressed. The analysis was performed by comparing reliability metrics in years before and after the GMP for all feeders completed through 2018. Figures 1-4 show these reliability metrics, and the raw data and analysis is located at:
c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Data\grid mod reliability data analysis before and after.xlsx

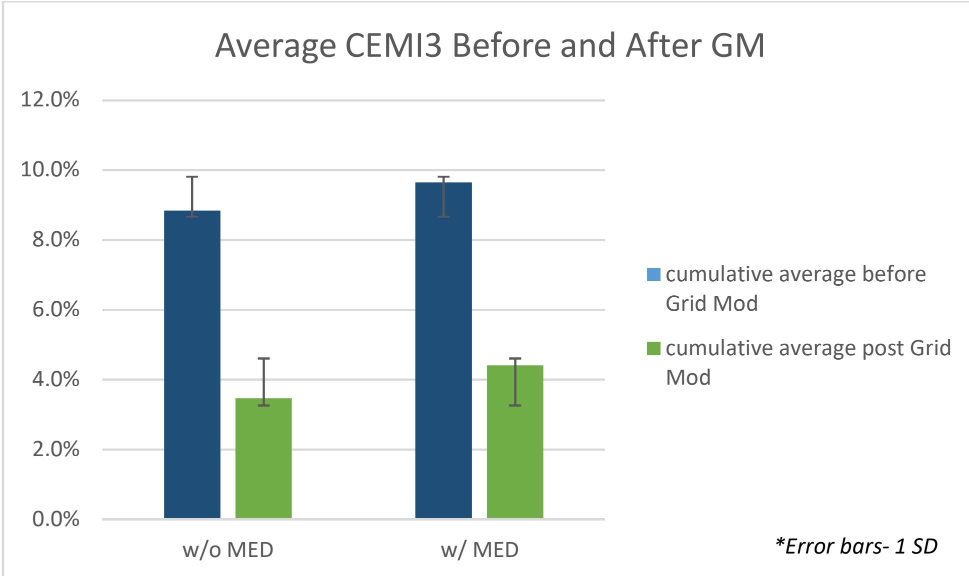


Figure 1: Average CEMI3 on feeders that have been fully addressed by GMP. This includes all the feeders completed through the end of 2018.

Figure 1 shows CEMI3 which is the percentage of customers experiencing 3 or more interruptions per year. The data show that customers on feeders that have been addressed by the Grid Modernization Program experience a 61% reduction when major event day (MED) are not included and a 54% reduction when MED are included.

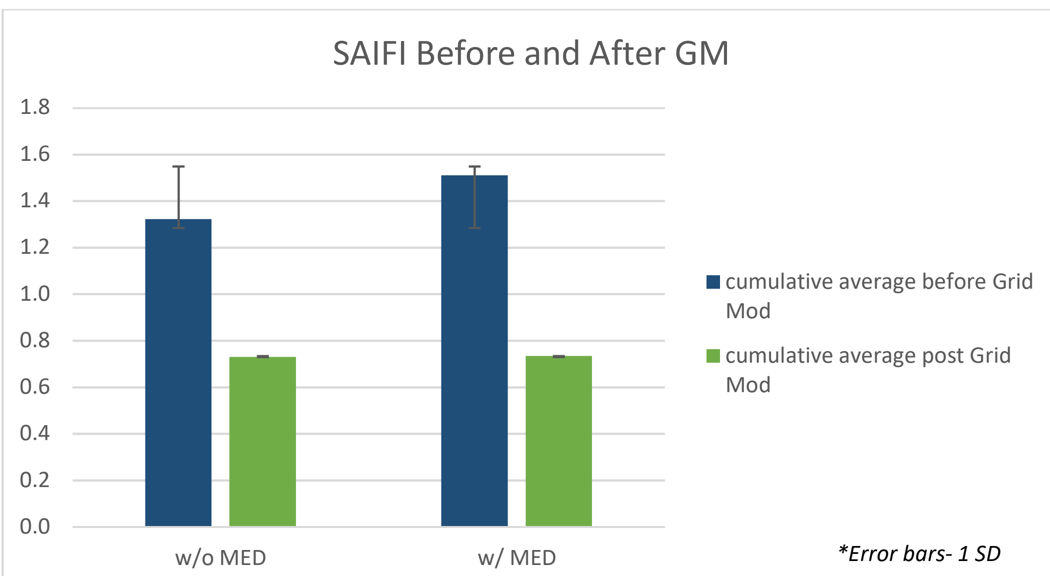


Figure 2: SAIFI before and after Grid Modernization on feeders completed through the end of 2018.

SAIFI is the sustained average interruption frequency index. The data show that customers on feeders addressed by the GMP experience a 51% reduction (with MED) and a 64% reduction in the duration of power interruptions.

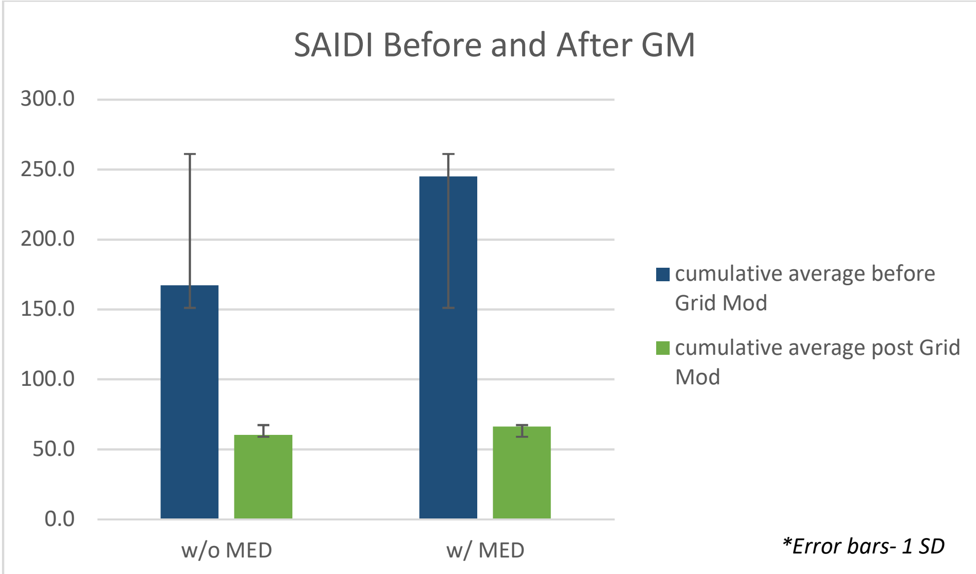


Figure 3: SAIDI before and after GMP for feeders completely addressed by the end of 2018.

SAIDI is the total duration of interruptions experienced by customers (in this case, the customers on one feeder). Customers on feeders addressed by the GMP experience a 64% reduction (without MED) and a 73% reduction with MED included. This means that outages customers experience are shorter in duration.

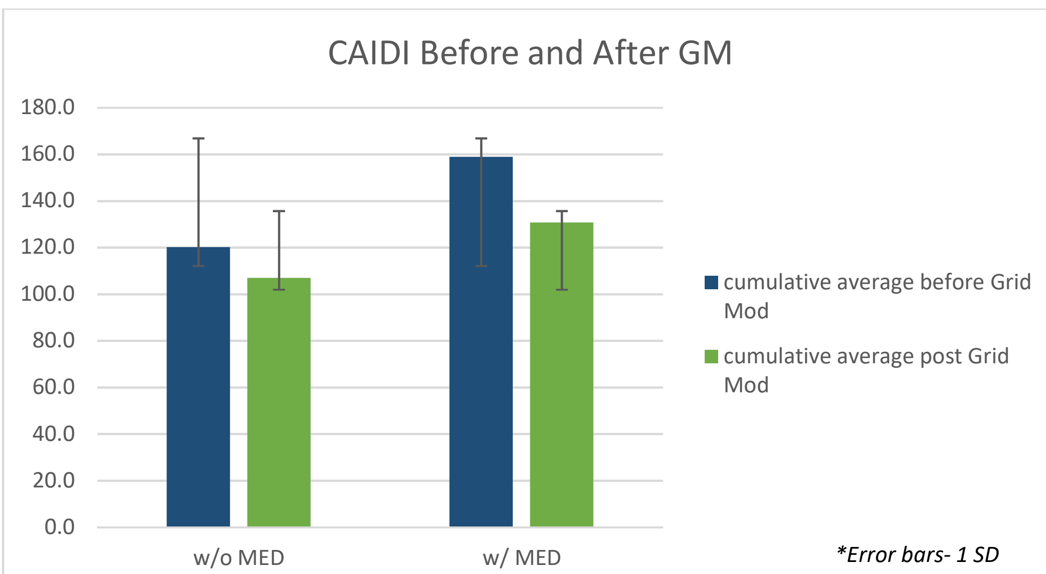


Figure 4: CAIDI before and after being addressed by the Grid Modernization Program.

CAIDI is the customer average duration index, which indicates the amount of time it takes to restore service. Customers experience an 11% reduction (without MED) and an 18% reduction with MED after GMP.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Delaying the work performed by the GMP would result in an increased risk of equipment failure, energy losses over time, expanded system maintenance costs, and unplanned outages. There would also be a lost opportunity to apply holistic and sustainable solutions following an in-depth engineering analysis to locations that experience recurring unplanned outages.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The previously mentioned performance metrics; SAIFI, SAIDI, CAIDI, and CEMI3 can all be used to gauge system performance improvements after construction is completed. Voltage quality at any individual point along the feeder can also serve as an indicator of whether a project was successful. Across the entire program, an annual total of the feeder miles addressed serves as a measure of progress toward addressing the entire system across a 60 year cycle as intended.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Feeder Status Report: The feeder status report details the analysis of attributes of the distribution system in three major categories:

- Performance: Thermal utilization, efficiency, voltage regulation, reliability performance (MAIFI, CAIDI), power factor, FDR imbalance.
- Health: Age, OH/UG ratio, pole rejection rate, reliability health (CEMI3, SAIFI).
- Criticality: Essential services, commercial account density, customer density, load density.

c01m19:\Distribution Feeder Status Report\Feeder Status Report 2019\2019FeederStatusReport.xlsm

Using the information that the Feeder Status Report provides, each feeder is prioritized by a combined score assessing the three categories within a tool in the location below and selected to maintain a balance between work done in Washington and Idaho.

c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Feeder Selection

Feeder analysis reports: Once selected, a distribution engineer performs a thorough analysis on the entire circuit to determine what work is needed to make the feeder most efficient and to bring the feeder up to current standards to improve operation, safety, and support future loads. These reports are located at the following location:

c01m19:\Feeder Upgrades - Dist Grid Mod\~Feeder Analysis\

2017 Distribution Plan: The 2017 Distribution Plan summarizes a variety of topics including the different drivers for investing in system improvements and planned investments such as Grid Mod, which is cited often.

Avista Utilities Electric Distribution Infrastructure Plan June 2017: c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Data\Distribution Plan FINAL 2017.pdf

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The Distribution Feeder Status Report annually quantifies the performance, health, and criticality as outlined in section 1.5.1. More specifically, Wood Pole Management commissions inspections on selected Grid Modernization feeders identifying deteriorating, broken, and/or missing equipment. Individual reports can be found on the c01m19 feeder, the Feeder Upgrades – Dist Grid Mod folder, the specific feeder folder in question, and finally the ~Admin and Wood Pole Mgmt folders.

Option	Capital Cost	Start	Complete
[Recommended Solution] The Distribution Grid Modernization Program provides benefits to customers, employees, and shareholders by replacing problematic poles, cross-arms, cut-outs, transformers, conductor, etc. Additionally, automated line devices are installed which increase energy efficiency and system reliability. The 2021 request is $10MM to begin ramping up to the $28.88MM necessary to maintain a 60 year program cycle.	$28.88MM annually	01 2012	12 2072
[Alternative #1] Address issues through the different specific company initiatives, such as WPM, TCOP, URD, Segment Reconductor, etc. This means that a crew would potentially go out to the same area multiple times. This costs more for set up, travel time, flagging, etc. which means higher rates for customers. It also means the customer could have multiple planned outages and be impacted by multiple street closures for crews to address needed work at separate times. The risk reduction is also cut in half compared to the comprehensive work completed by GMP.	$UNK		

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The GMP capital request was calculated using a 60 year cycle as a goal while addressing almost 12,000 circuit-miles of electric distribution facilities. With the average spend rate of $152,000/mile over the past thirty months, an estimate of $28.88MM is determined.

When considering the prudency of this investment as part of a single program rather than spread across multiple departments, it is worth considering the design and construction support experience that GMP resources provide as a dedicated subject matter expert on projects. Other departments with competing priorities might find it difficult to maintain a focus on projects of this size. Another important benefit of work done is the O&M savings of each automated device that is installed. Using a thirty month long span of data over the past three years, the devices installed by GMP has saved the company an annual amount of $346,825. (c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Data\Automation device activation data and hard O&M costs.xlsx)

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

The capital cost of the Program is spread across numerous projects that typically span at least two years in a process summarized in Figure 5.

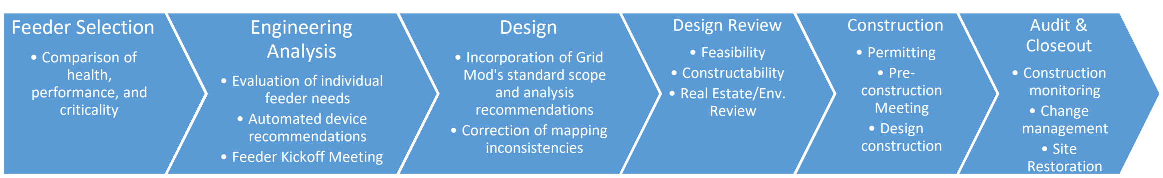


Figure 5: The Grid Modernization Project Life Cycle

Once metrics are gathered, individual feeders are evaluated to determine how they rank in comparison to the rest of the electric distribution system. Once chosen, the Program Engineer analyzes the feeder for opportunities to improve its reliability, power quality, potential for energy savings, and accessibility. That analysis is conveyed in a report to project stakeholders outlining feeder specific opportunities for improvement that have been agreed upon by individuals with experience in the area. Design follows the publishing of the report and in addition to feeder specific improvements, a set of standard criteria are applied to the existing equipment in the field. Designs are reviewed by subject matter experts evaluating the designs constructability and accuracy, real estate needs, and environmental and cultural risks. Construction then takes place along with an audit evaluating workmanship and accuracy relative to the design. Deviations are tracked through a design change order process. The project then moves towards completion as site restoration and accounting activities are completed.

Future O&M costs are reduced by relocating, removing, or converting sections of Avista facilities that present an opportunity to improve the feeder's performance. Vegetation Management costs are reduced by the removal of troublesome species that outpace routine maintenance cycles and the installation of automated devices reduces the need for servicemen to trouble shoot outages and performance issues.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

- **Wood Pole Management** – The GMP incorporates WPM's scope within its projects thereby assisting with its 20-year cycle target. Grid Modernization also relies on WPM for poles inspection reports.
- **Vegetation Management** – The GMP supports and relies on Vegetation Management during the course and completion of its projects. After design and prior to construction, trimming crews address any conflicts that a proposed design might have with existing vegetation. Upon the completion of a project, the GMP reduces the need for future tree trimming by targeting the removal of cycle-breaking species or the relocation and conversion of electric distribution infrastructure.
- **Real Estate** – Locations throughout the GMP designs are reviewed by the staff within the Real Estate department for conflicts that would arise during construction. Permitting is another consideration that is addressed once a design has been completed. The comprehensive GMP approach that partners with Real Estate's analysis results in the mitigation of outstanding issues that have existed in the field, thereby reducing a litigation risk to the company, and the establishment of sustainable alignments and corridors for Avista facilities.
- **Environmental Compliance** – Environmental items of concern are addressed during design and prior to the construction of proposed GMP work. Examples include avian and wildlife protection, the avoidance of any impact on cultural and heritage sites, and the impacts a project may have on public lands managed by tribal, municipal, state, and federal agencies.
- **Segment Reconductor and FDR Tie** – The GMP's holistic approach on feeders selected after a thorough prioritization process addresses issues that might otherwise be included on segment reconductor and FDR tie projects. The investment of Grid Modernization funding on selected feeders improves local office resource availability.
- **Distribution Minor Rebuild** – GMP's holistic approach on feeders selected after a thorough prioritization process addresses issues that might otherwise be included on minor rebuild projects. The investment of Grid Modernization funding on selected feeders improves local office resource availability.
- **Wildfire Resiliency** – The GMP incorporates efforts to reduce the risk of wildfires caused by electric distribution lines by relocating or converting lines in addition to the scope of the Wildfire Resiliency program.
- **Distribution Transformer Change Out Program (TCOP)** – The GMP incorporates the replacement of PCB transformers into each of its projects fulfilling the objective of the TCOP and reducing environmental risks and liabilities to the company and customers.
- **LED Change-Out Program** – The GMP incorporates the replacement of outdated streetlights to fulfill the mission of the LED Change-Out Program across its projects.
- **Primary URD Cable Replacement** – The GMP incorporates the replacement of outdated underground cable to fulfill the objective of Primary URD Cable Replacement across its projects.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Replacing equipment upon failure is an alternative to the GMP business case. It would maximize the value of an individual piece of equipment but result in numerous unplanned outages that could arise from and be the cause of unsafe situations to employees and customers. To mitigate the increase of unplanned outages, additional crews would be needed for trouble responses. Aside from a dedicated resource to respond, a variety of equipment and materials would also need to be available to minimize the impact of system failures.

GMP's scope could be addressed through various company initiatives such as WPM, TCOP, Primary URD Cable Replacement, Segment Reconductor and FDR Tie, etc. Given the poor condition of selected GMP feeders, it would certainly mean that the different initiatives would visit the same location multiple times over a short period resulting in elevated mobilization costs and disturbances to customers and communities as crews complete their work. The additional costs of working on the same feeder through multiple initiatives would be evident in increased rates. A possible solution to these issues would be to attempt a large coordination effort with a single construction resource that would receive all work packages from each initiative and attempt to carry out their construction simultaneously.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

Work across the program is intended to be completed on a 60 year cycle becoming used and useful throughout each year as projects are constructed. Figure 5 above (Section 2.2) illustrates the life cycle of individual projects that can last at least two years.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

GMP aligns with Avista's mission: We improve our customers' lives through innovative energy solutions. Safely, Responsibly, and Affordably. We put those we serve at the center of everything that we do. GMP directly improves the lives of our customers by improving system reliability and performance by planning the work to minimize costs of long-term maintenance or unplanned work to maintain the distribution system. The collaboration that takes place throughout the program improves results upon the completion of each project: an efficient delivery experienced by customers and communities and a reduced risk to Shareholders.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

- By addressing necessary work on the distribution system through the work of one program, there are reduced costs to the customer due to mobilizing crews one time, closing roads, and having planned outages one time instead of many times.
- The GMP plans work ahead of time and invests in the feeders that will receive the highest benefit from the scope of the program. The efficiency of this work is planned through earned value measurements which track the cost and schedule efficiency of the work compared to plan. The planning and tracking of the program use best project management practices.

- The work that will be performed on the program is planned through a thorough engineering analysis and the designs go through a full design review process to ensure that any replacements are prudent and in the best interest of the customer. This prevents work that is out of scope or does not provide adequate benefit from being added to the plan.
- Auditing the completed work ensures that the work performed and charged for was included in the plan or managed and tracked through the approved design change order process.
- Competitive bidding ensures that the work is awarded in a manner that reduces risks and keeps costs lower.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Internal Customers/Stakeholders: Real Estate, Transmission Engineering, Distribution Engineering, Environmental Compliance, Construction Services, Electric Shop, Meter Shop, Area offices, Account Executives, Regional Business Managers, Avista line crews, WPM, Supply Chain, and Vegetation Management.

External Customers/Stakeholders: Electric distribution customers, Municipalities, State DOT's, US Army Corps of Engineers, Public Land Management agencies, Joint Users, Adjacent Utilities, Native Tribes, Community action groups, Contract line crews.

2.8.2 Identify any related Business Cases

Wood Pole Management, Primary URD Cable Replacement, LED Change-Out Program, Wildfire Resiliency, Distribution Transformer Change Out Program, Distribution Minor Rebuild, Segment Reconductor and FDR Tie

3.1 Steering Committee or Advisory Group Information

The steering committee is comprised of the project sponsor, Asset Maintenance Manager, Director of Operations, and the Asset Management Manager. This group meets as needed, usually annually, for an update on the program or when key program decisions or changes in scope need to be discussed. The members of this group are called out in the Grid Modernization Communication Management Plan.

Provide and discuss the governance processes and people that will provide oversight

The Grid Modernization Communication plan details the individuals that receive communication, the type of communication, and the frequency of communication. This document is located at: c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Admin\Project Management Plan

Documents\03 Communication Management Plan.docx

Program Communication Plan

Stakeholder Group *(From Stakeholder Checklist)*	Communication Method *Communication Artifact*	Frequency	Members
Internal			
Project Team	Project Kickoff Meeting for each feeder	Once	Keystake holders
	Bi-weekly internal team meeting	Bi-weekly	Avista CPCs, Distribution Engineer, APM, PM
	Monthly team meeting	Monthly	David Clark, John Hanna, Seth Rounds, David Garnetti, HDR contract designers, Alicia Gibbs
Key Stakeholders	Stakeholder Report *One Pager document*	Monthly	Ops managers, CPCs, team members, stakeholders
	Key Stakeholder Check-in Meeting	As-needed	
Steering Committee	Steer-Co meeting	Bi-monthly/ad-hoc meetings and Monthly one pager	Glenn Madden, Darrell Soyars, Rod Price, David Howell, Brian Vandenburg, Dave James, Cody Krogh, Shane Pacini, Alicia Gibbs
Project Sponsors	Stakeholder Report *One Pager document*	Monthly	David Howell
Officers	Ops Council Presentation *Slide Deck*	Annually	
Director	Stakeholder Report *One Pager document*	Monthly	David Howell
Manager	Stakeholder Report *One Pager document*	Monthly	Alicia Gibbs
	Check-in Meeting	Bi-weekly	
External Communications	Media Talking Points *Project Talking Points document*	Once	At the beginning of construction for each feeder
	Stakeholder Report *One Pager document*	Monthly	
Departmental Managers (Responsible)	Project Kickoff Meeting *Roles & Responsibilities document*	Once	
	Stakeholder Report *One Pager document*	Monthly	
Departmental Managers (Informed)	Stakeholder Report *One Pager document*	Monthly	
Departmental Rep. (Responsible)	Project Kickoff Meeting *Roles & Responsibilities document*	Once	
	Stakeholder Report *One Pager document*	Monthly	
Departmental Rep. (Informed)	Stakeholder Report *One Pager document*	Monthly	
End Users	Project Requirements Meeting *Project Charter, Functional Requirements document*	Once	Area engineer, Area Manager
	Stakeholder Report *One Pager document*	Monthly	
	Pre-construction Meeting *minutes*	Once	

How will decision-making, prioritization, and change requests be documented and monitored

- Decision making is documented in meeting minutes in the Program Onenote folder.
  - c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Meetings & Presentations\~1Shared Grid Mod Program notebook
- The prioritization of feeder work is managed in the Feeder Selection management tool which is stored in the Grid Modernization drive. The prioritization is updated every one to two years with updated data from the Feeder Status Report. The feeders are then ranked based on equally weighted health, performance, and reliability scores. The top feeders may undergo an engineering analysis and gather feedback from area engineers to determine which order these feeders are selected in.
- Change requests are managed through a change order process. Any proposed changes that occur during construction to the approved designs are first evaluated, then approved, and tracked through the change order process.

The undersigned acknowledge they have reviewed the ***Distribution Grid Modernization*** business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Heather Webster	Date:	7/31/2020
Print Name:	Heather Webster		
Title:	Asset Maintenance Project Mgr.		
Role:	Business Case Owner		

Signature:	David Howell David Howell	Date:	7/31/2020
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

The Distribution Minor Rebuild business provides a solution for the utility to address small unplanned asset failures and customer driven modifications to the distribution system but excludes fixes to the system considered to be maintenance. Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in reliable condition for customers, maintaining safe conditions for the workers, providing response to unplanned damages to distribution assets not related to weather events, as well as responding to small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds, or replacements of asset units need to be completed to maintain system reliability and safety. This work impacts customers in WA and ID. By not funding, various types of work will need to be absorbed into some other funding due to the necessity of the work (i.e. the replacement of a car-hit pole in the alley, a broken cross-arm, a failed transformer, and other safety related projects.) Some minor rebuilds left unrepaired may not result in an immediate catastrophic failure. Over time an adverse accumulation of unrepaired assets would greatly put line workers and the general public at risk as minor asset failures begin to deteriorate pockets of the distribution system.

Historically costs for unplanned minor rebuild work have increased for several reasons. Many assets on the distribution system are past their end of life cycle and contributing to this increase. The 3-year average actual spend for minor rebuild work is $11,900,000 per year. This is expected to continue for the next 5 years. On average, Minor Rebuild spends approximately $1,000,000/month.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Draft of 2020 Business Case Refresh update*	*6/30/2020*	

GENERAL INFORMATION

Requested Spend Amount	$10,000,000 annually
Requested Spend Time Period	Ongoing Program
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Amy Jones | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Distribution Minor Rebuild is an ongoing program that focuses on: keeping the distribution system in reliable condition for customers, maintaining safe conditions for the workers, provides providing responsiveness response to unplanned damages to distribution assets not related to weather events, as well as responding to small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds or replacement of asset units need to be completed to maintain system reliability and safety.

The work includes; Asset Condition, NESC/Operating Standard Violation, Facility Upgrades, Facility Route Location Modification, Trouble and customer requests. Occasionally, larger projects with an identified need and short timeframe for implementation are constructed under the Distribution Minor Rebuild business case. Even though the work is unplanned, Minor Rebuild work occurs regularly due to the nature of the utility business and numerous assets in the field spread over a wide geographical area.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The primary driver for the work is Asset Condition. This work focuses on keeping the distribution system in reliable condition for customers, maintaining safe conditions for the workers, providing response to unplanned damages to distribution assets not related to weather events, as well as responding to small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds or replacements of asset units need to be completed to maintain system reliability and safety which are a benefit to customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Distribution Minor Rebuild work is one of the many components that support the overall reliability of the distribution system as well as responsiveness to customer requested service demands and system safety. Safety is of utmost concern for linemen and the general public and the minor rebuild business case provides the funding for work such as; replacement of a car-hit pole in the alley, a broken cross-arm, a burned-up transformer, and other safety related projects. In addition, if the business case is not funded, this will also affect the ability to respond to customers' needs for modifications to their electrical service. It is acknowledged some minor rebuilds left unrepaired will not result in immediate catastrophic failures to the distribution system, but over time an adverse accumulation of unrepaired assets would greatly put line workers and the general public at risk as minor asset failures begin to deteriorate within areas of the distribution system.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Historical information and the continuance of tracking spend by categories will be useful in determining the effectiveness of the program and meeting its original objectives.

In 2020, Distribution Minor Rebuild transitioned to an activity-based structure that divided the business case into six general activities, which embody the major types of work performed. This division will allow for improved reporting on spend. Below is a categorical breakdown for the six general activities.

- **Customer Requested Rebuilds** – Work is initiated by an existing customer or property owner, and the costs associated with the work are typically reimbursed by the requesting party. Examples could be a customer requested reroute, overhead to underground line conversion, or customer load increase.
- **Trouble Related Rebuilds** – Emergency work required to repair damaged facilities related to non-storm and non-fire related outages. Activities include a car hit pole, car-hit padmount enclosure, copper theft, or unforeseen failed equipment that needs immediate response.
- **NESC / Operating Standard Violations** – Activities include, but are not limited to, NESC violations (not related to Joint Use clearances), secondary/service-related voltage mitigation, fusing protection mitigation, aerial trespass, and undersized equipment (transformers, regulators, etc.).
- **Asset Condition**– Activities include, but are not limited to, deteriorated wood poles, leaking transformers, condition related replacement (not outage related) of line devices and equipment.
- **Facility Upgrades/Efficiency Improvements** – Activities include, but are not limited to, small scale reconductors, small scale feeder ties, installation of new switches or sectionalizing devices, feeder balancing, installation of new regulators, reclosers, or capacitor banks, and removal of open wire secondary.
- **Facility Route / Location Modifications** – Activities include, but are not limited to, overhead to underground conversions, facility re-route, or relocation of midline devices to facilitate future maintenance and optimize sectionalization.

Figure 1 shows a chart of the estimated spend by general activity. The new general activities were implemented in January 2020.

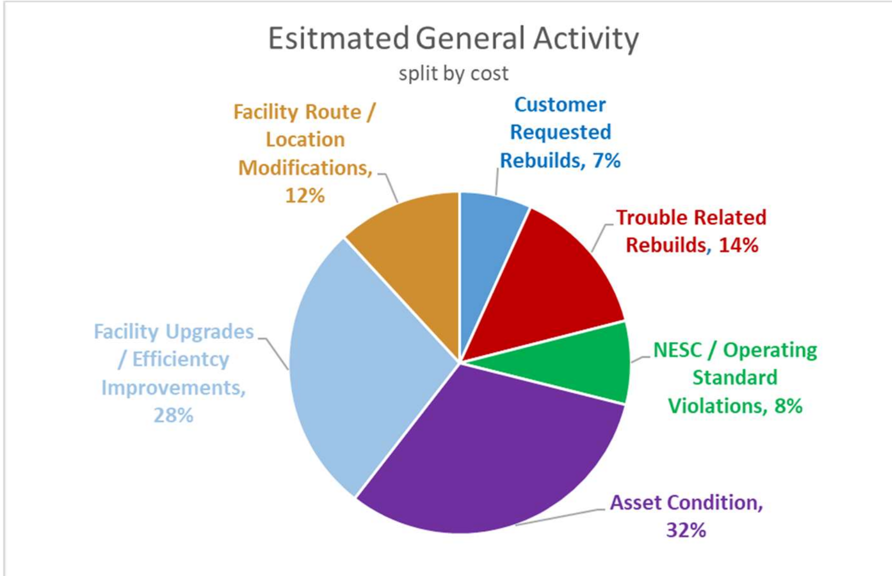


Figure 1: Estimated General Activity split by cost

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

NA

Option	Capital Cost	Start	Complete
Fund Unplanned Work (based on historical quantities)	$10,000,000	Continuous Program	
Some other Program covers the needed work.	$10,000,000	Continuous Program	
Unfunded	$0	NA	

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Historical spend was used to determine the requested amount. A steady increase in costs for unplanned minor rebuild work has occurred for several reasons. Many assets on the distribution system are past their end of life cycle and contributing to this increase. The 3-year average actual spend for minor rebuild work is $11.9MM per year. This is expected to continue for the next 5 years. Minor Rebuild spends approximately $1MM per month. Figure 3 shows the historical spend amount by year. Starting in 2020, the Joint Use spend is no longer included in the Minor Blanket Business Case as it now has its own business case.

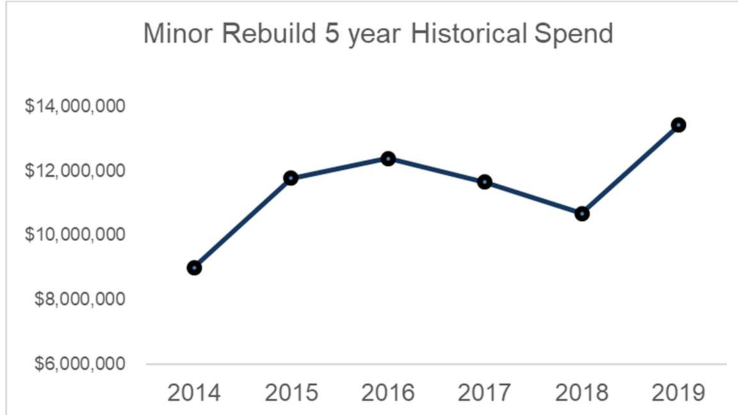


Figure 2: Minor Rebuild Historical Spend

In 2019 2,481 work orders were created with the average cost equaling $4,398, which demonstrates the work is made up of thousands of small dollars, critical non-discretionary jobs. Occasionally, larger rebuild projects such as small reconductor projects, are undertaken as a Distribution Minor Rebuild project if prioritized by the Area Operations Engineer. Only 53 of the 2,481 work orders created in 2019 were over $25,000. Those 53 work orders averaged $52,662.

Figure 2 displays a breakdown of the different types of charges that occur in the Minor Rebuild business case. The majority of charges are from specific work orders. Distribution Minor Rebuild work often consists of isolated replacement of failed asset(s) that do not lend themselves to a specific project (i.e. trouble related work), which are charges falling under craft and non-craft expenditures.

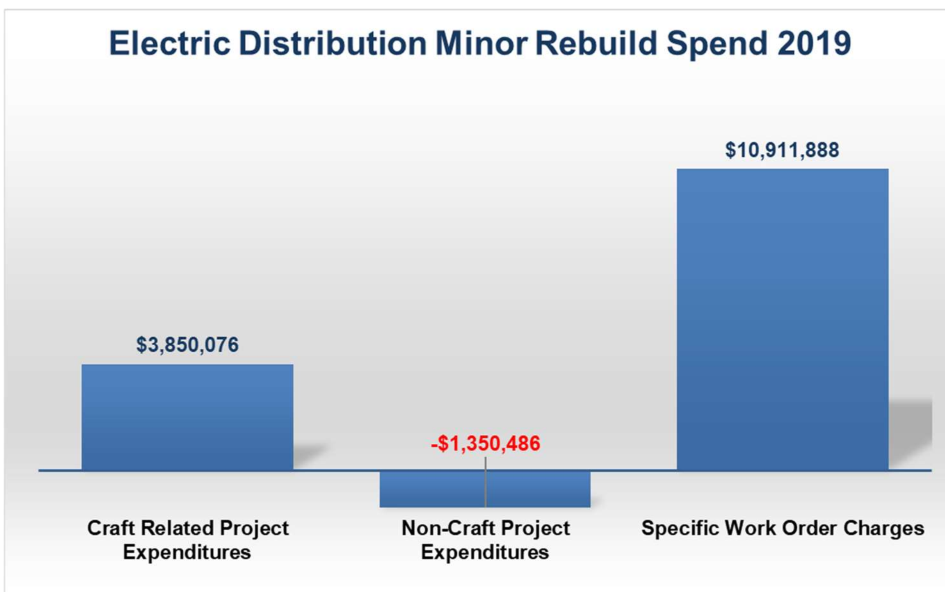


Figure 3: Types of Charges to Minor Rebuild (2019)

The following is a brief description of each type of charge.

- **Craft Related Project Expenditures**: Craft labor (servicemen, general foremen, local rep), associated vehicle usage, trouble related work charges
- **Non-Craft Related Project Expenditures**: Non-craft labor, associated vehicle usage, contribution reimbursables (credits), and material issues/returns
- **Specific Work Order Charges**: The work order number is referenced on timesheets, material requests, invoices, and vehicle charges/loadings

The Non-Craft Project expenditures show a negative value due to customer contributions being greater than charges.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in reliable condition for customers, maintaining safe conditions for the workers, provides providing responsiveness response to unplanned damages to distribution assets not related to weather events, as well as responding to small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds, or replacement of asset units need to be completed to maintain system reliability and safety. Spend will continue as it has in previous years.

The work includes**;** failed asset replacements, small mandatory and compliance work, slight performance and capacity improvements, or unplanned customer requests. Occasionally, larger projects with an identified need and short timeframe for implementation are constructed under the Distribution Minor Rebuild business case. Even though the work is unplanned, Minor Rebuild work occurs regularly due to the nature of the utility business and numerous assets in the field spread over a wide geographical area.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

The Distribution Minor Rebuild business case has been in operation for several years so there will be minimal impact to other business functions and processes with funding this business case. Distribution Minor Rebuild reaches across multiple departments in Engineering and Operations. The business involves operation area engineers, local customer project coordinators, and construction technicians who work directly with customers and perform all the designs for the business. Once the minor projects are designed and ready for construction, field personnel such as a Foremen, Journeyman Linemen, Line Servicemen, Meter men, Equipment Operators execute the work.

Not funding would have a significant impact on business functions and processes as other areas would be responsible for the work and it would also impact the ability to respond to customers' needs for modifications to their electrical service.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The other alternative that was considered is not funding the business case however, the needed work will continue to occur. These costs would be covered under other business cases. The body of work within the Distribution Minor Rebuild business case consists of very small unplanned projects across the entire distribution system in response to a variety factors (customer requested, trouble related work, deteriorated pole replacements, and general rebuilds), therefore the alternatives are generally not available to analyze. Typically, as each project arises, any alternatives available for individual rebuild projects are evaluated during the design phase by the designer.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

The Distribution Minor Rebuild business case is an on-going program, and assets typically go into service at the time the project (service order/ job) is completed and does not have a final cost. The program has an average annual cost around $11.5MM. The minor rebuild projects are so small in nature they almost always go into service the same day as constructed

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The Distribution Minor Rebuild business aligns with the company's focus of Our Customers, Our People, and Perform by investing in our infrastructure to achieve optimum life-cycle performance – safely, reliably and affordably. This business case provides a solution to address those small unplanned asset failures and customer driven modifications to the distribution system.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The Distribution Minor Rebuild business maintains flexibility for the utility to address small, unplanned asset failures and customer driven modifications to the distribution system but, excludes fixes to the system considered to be maintenance. While the work is unplanned, minor rebuilds to the distribution system occur on a regular basis every year to maintain system reliability and safety. The Distribution Minor Rebuild business case provides a solution for the utility to address those small unplanned asset failures and customer driven modifications to the distribution system. Safety is of utmost concern for linemen and the general public and the minor rebuild business case provides the funding for work. Some minor rebuilds left unrepaired may not result in an immediate catastrophic failure. Over time an adverse accumulation of unrepaired assets would greatly put line workers and the general public at risk as minor asset failures begin to deteriorate pockets of the distribution system.

The YTD spend is tracked and reviewed each month during the Electric Operations Roundtable (ORT) meetings. The ORT, reviews monthly spend and manages any additional funds requests.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders that interface with the Distribution Minor Rebuild work are the local area operations engineers, general foremen, and area construction managers.

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

The Operations Roundtable (ORT) acts as the Advisory Group for this business case. The Distribution Minor Rebuild work is managed by the local area operations engineers, general foremen, and area construction managers.

3.2 Provide and discuss the governance processes and people that will provide oversight

The governance in place over the business case is set by the Operations Roundtable (ORT) group, which proposes annual budgets, monitors the incurred costs and submits any additional funds requests as needed**.**

The work done under Minor Rebuild, by way of projects, is overseen by Area Engineers. Area Engineers receive a weekly report on all active work orders under the business and managed which projects get done according to current needs and priorities. The local customer project coordinators (CPCs), who design the projects, are required to seek Area Engineer approval for projects above a $10,000 threshold before performing the work.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Decision making, prioritization and change requests will be documented and monitored though the Operations Roundtable (ORT).

The undersigned acknowledge they have reviewed the ***Minor Rebuild*** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Amy Jones	Date:	08/01/2020
Print Name:	Amy Jones		
Title:	Asset Maintenance Business Analyst		
Role:	Business Case Owner		

Signature:	David Howell	Date:	8/2/20
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

The Transformer Change Out Program (TCOP) was originally implemented in 2011. The Program is focused on removing or replacing transformers containing, or potentially containing, Polychlorinated Biphenyls (PCB) oil. In 2020, there were 284 targeted transformers remaining. This impacts customers in WA and ID.

In 2020, the program was funded at $541,000, for 2021 we are requesting $500,000. The benefit to customers is decreasing environmental risk. This program is anticipated to be completed by the end of 2021. If not funded or if deferred, it does increase the risk of environmental hazards (i.e. oil spill).

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Initial draft for 2020 business case refresh*	*6/30/2020*	
1.0				
1.1				
2.0				

GENERAL INFORMATION

Requested Spend Amount	$500,000
Requested Spend Time Period	*1 Year (2021)*
Requesting Organization/Department	Asset Maintenance
Business Case Owner | Sponsor	Amy Jones | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The Transformer Change Out Program (TCOP) was originally implemented in 2011. The Program has focused on eliminating transformers containing or potentially containing Polychlorinated Biphenyls (PCB) oil. The areas initially targeted were near the Spokane and Pend Oreille River watersheds and has since moved to all transformers containing PCBs. These transformers have specific work plans for removing them from the system. At the start of 2020, there were 284 targeted transformers remaining and scheduled to be replaced by the end of 2020. However, over the past two (2) years, the carryover from the previous year has been approximately 50%. For 2021, an estimated carryover-total of 150 targeted transformers is expected.

BACKGROUND:

PCBs and PCB wastes are regulated by both the Washington Department of Ecology (Ecology), through the Dangerous Waste Regulations, Chapter 173-303 WAC, and by the U.S. Environmental Protection Agency (EPA) under 40 CFR Part 761, the Toxic Substances Control Act (TSCA). The transformers to be removed early in the program are those that are most likely to have PCB-containing oil and their replacement will reduce the risk of PCB-containing oil spills which are a public safety, environmental, and a public relations concern.

On April 10, 2010, the EPA had issued an Advanced Notice of Proposed Rulemaking (ANPR) on new PCB regulations. Washington State Department of Ecology created an “urban waters initiative” to investigate persistent and bio-accumulative toxins; this initiative included the Spokane River watershed. The Spokane River is listed on the Clean Water Act “impaired” list for PCB contamination. The City of Spokane began a storm water study to find and reduce sources of PCBs in its storm water system. In addition, PCB cleanup is very difficult in any environment and nearly impossible in aqueous environments. These and other efforts reflect how important it is to keep PCBs from entering the environment. As a result, Avista is determined to aggressively remove PCBs from its electrical distribution system in a disciplined manner.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The driver for TCOP is Asset Condition. However, by removing these targeted transformers, the environmental and public safety risks associated with these transformers will also be addressed.

Customer Benefit: Avista customers will be impacted by this program positively through safe equipment.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Currently there are 264 targeted transformers remaining (as of May 30, 2020). There are environmental risks associated with these transformers (large volume transformer oil spill, hazardous waste cleanup, moderate to low volume or level of PCBs, impacts to waterways, repeated or moderate air emission exceedance). PCB cleanup is very difficult in any environment and nearly impossible in aqueous environments. These and other efforts reflect how important it is to keep PCBs from entering the environment. In addition, environmental spill cleanup for PCBs can be costly. If not funded or deferred, the risk is low due to the small number of remaining transformers.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

This Program has been successful throughout previously funded years. It is anticipated that all transformers will be replaced by the end of 2021.

Metrics that will be used to determine successful delivery throughout the program year include:

- Planned vs replaced transformers
- Count of remaining transformers
- Budget to actual spend

1.5 Supplemental Information

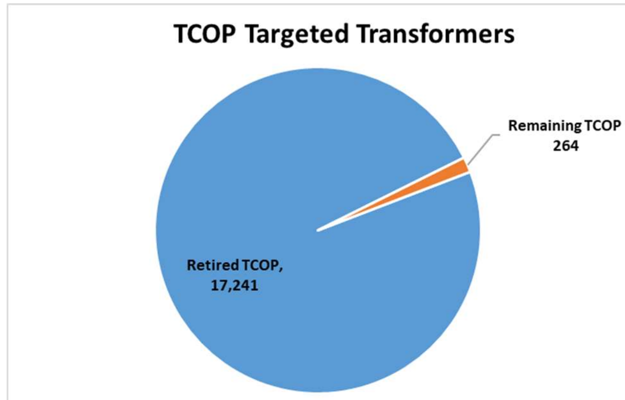
1.5.1 Please reference and summarize any studies that support the problem

References:

- “Distribution Transformer PCBs” report, February 2010
- Electric Distribution System, 2016 Asset Management Plan

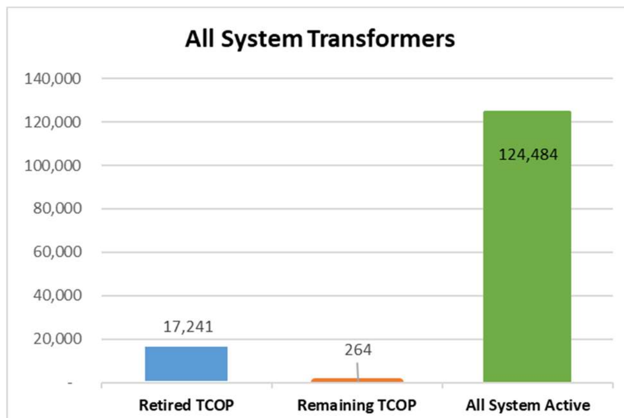
1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

17,241 transformers have been replaced since the start of the program. As of 5/30/2020, there are 264 pending replacement due to PCB containing oils. We anticipate 150 remaining at the end of 2020.



This program has been successful in meeting its objective.

Remaining TCOP transformers are included in the All System Active count. The remaining targeted transformers represent .02% of all active transformers. All targeted transformers (retired and remaining) represent approximately 14% of all system transformers.



Option	Capital Cost	Start	Complete
Continue to replace targeted transformers.	$500,000	01 2021	12 2021

No planned replacement program for distribution transformers and the replacement would occur organically through storm replacement or as projects occur on the pole. Substantially higher risk of a PCB containing oil spill occurring.	$0	NA	
Planned replacement of PCB transformers only through programmatic work over the next 20 years.	$670,000	01 2021	12 2041

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

When the program began in 2011, there were over 17,000 targeted transformers. Currently, .02% of the 17,000 are remaining. This program has been successful in replacing targeted transformers.

Metrics considered during the analysis of this program included;

- Count of remaining transformers
- Historical review of yearly planned vs. actual transformers
- Yearly budget to actual spend

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

The requested capital cost amount will be spent on replacing targeted TCOP transformers for newer models that do not contain PCBs. The costs associated with the change outs will be for designs, labor, and material associated with each replacement.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

The outcomes of this business case impact each construction office and their remaining TCOP transformers. The work to replace the targeted transformers is widely used for fill-in work for crews. There is also an environmental impact if spills were to occur.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

This Program has been funded since 2011. There were several alternatives that considered different implementation schedules. The current approach is considered the best solution for mitigating environmental risk.

Two alternatives exist as mentioned above.

1. No planned replacement program for distribution transformers. Substantially higher risk of a PCB-containing oil spill occurring. Transformers would be replaced through a reactionary method either through a spill that may occur, through storm or other type of damage

replacement or through random projects. Transformers containing PCB oils would remain active in our system for years through this method.

2. Planned replacement of PCB transformers only through programmatic work. This method would be a very slow pro-active progression. Through this method, transformers containing PCB oils would also remain active in our system for years.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

This program has been in operation since 2011 and is set to be completed by the end of 2021. The newly installed transformers and other materials become used and useful immediately at the time of install. Transformers are replaced throughout the year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This program aligns with the company's strategic vision, goals, objectives and mission statement with its focus on customers by reducing environmental impacts through replacement of older transformers containing PCBs.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

This project has been in operation since 2011. Currently there are 264 targeted transformers remaining (as of May 30, 2020). The Transformer Change-Out Program (TCOP) work is needed for the following reason. Asset Management periodically reviews maintenance strategies.

The targeted transformers contain, or have the potential to contain, Polychlorinated Biphenyls (PCB) oil. PCBs and PCB wastes are regulated by both the Washington Department of Ecology, through the Dangerous Waste Regulations, Chapter 173-303 WAC, and by the U.S. Environmental Protection Agency under 40 CFR Part 761, the Toxic Substances Control Act. The transformers to be removed early in the program are those that are most likely to have PCB containing oil and their replacement will reduce the risk of PCB containing oil spills which are a safety, environmental, and a public relations concern.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Avista stakeholders include;

- The Asset Maintenance Department who is responsible for the work.
- The Environmental Department that is responsible for our environmental footprint in our service territory.
- Electric Operations that will perform the construction work.
- Asset Management for tracking system reliability and risk.

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

This program is managed by the Asset Maintenance Department and progress is overseen by the Operations Round Table

3.2 Provide and discuss the governance processes and people that will provide oversight

Early in the program, asset condition and outage information were collected and analyzed by Asset Management. This information was reviewed with Asset Maintenance to establish an effective risk mitigation plan that prioritizes work by frequency and duration of outages.

Currently, the Environmental group provides prioritization guidance as needed. Asset Maintenance manages the program and collaborates with Electric Operations and Contractors to coordinate the work. Asset Maintenance tracks the work budget, scope, and schedule.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Through existing work planning documentation and through recommendations from the ORT.

The undersigned acknowledge they have reviewed the Distribution Transformer Change Out Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	
Print Name:	Amy Jones		
Title:	Asset Maintenance Business Analyst		
Role:	Business Case Owner		

Signature:	David Howell	Date:	8/2/20
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for vehicle driver and pedestrian safety. Avista manages streetlights for many local and state government entities to provide such street, sidewalk, and/or highway illumination for their streets by installing overhead streetlights. Upon light burn-out, lights are converted to LED. This work occurs in WA and ID.

Since this is a service our customer's pay for, they benefit from lighting service being restored upon light burn-out. Based on our historical burn-out rate, a spend of approximately $750,000 is needed. If this business case is not approved, failed lighting may not get replaced, resulting in customer dissatisfaction and increased public safety risks.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Business Case Refresh Draft*	*7/2/2020*	

GENERAL INFORMATION

Requested Spend Amount	$750,000 annually
Requested Spend Time Period	Ongoing program
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Amy Jones | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for driver and pedestrian safety. Because they have an overhead distribution system in most urban areas, Avista provides a convenient streetlight service in almost every local and state government entity they serve, and manages the streetlights to provide street, sidewalk, and/or highway illumination.

Initially, the LED Change-Out Program was on an accelerated five-year schedule (2015 – 2019) to change-out all existing Avista owned streetlights to LED (Light Emitting Diode).

In the spring of 2018, upon Asset Management review, Avista executives, directors, and team leaders decided to adapt the replacement strategy to replace lights as they burned out.

Background:

The desire to begin the LED Change-Out Program in 2015 stems from a delay in energy savings, negative financial impacts, associated personal injury and property theft risks, and resource needs. Benefits are also found in the 2013 Asset Management Street Light Plan.

- Each 100 watt and 200-watt HPS light replaced will save 65 watts and 128 watts, respectively, per fixture. Once all the 100 watt and 200-watt HPS streetlights are replaced, the annual energy savings will be 9,903 MWH each year.
- With respect to the financial impacts of converting to LED streetlight technology, the customer internal rate of return is 8.46%, assuming the current cost of materials and life expectancy of the photocells and LED streetlight fixtures.
- From a public safety perspective, the consequence of converting to LED streetlights in lieu of replacing burned-out HPS bulbs shows a risk reduction of nearly eight times less for potential injury, a serious fatal accident, and property theft.
- Lastly, company resource demands are reduced after the initial conversion to LED technology. The average annual labor man-hours for current practices of changing burned-out HPS bulbs is estimated at 5,200 man-hours and 2,600 equipment hours, while the average man-hours required during the life of the LED fixtures are 3,200 man-hours and 1,800 equipment hours.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The primary driver for converting overhead streetlights from High-Pressure Sodium (HPS) lights to LED lights is Asset Condition. By focusing on Asset Condition, there will be a significant improvement in energy savings, lighting quality for customers, and resource cost savings.

Secondly, converting streetlights to LED technology helps bring Avista in compliance with the Washington State Initiative 937 (or the Clean Energy Initiative), which ensures that at least fifteen percent of the electricity Washington state gets from major utilities comes from clean, renewable sources, and that Washington utilities undertake all cost-effective energy conservation measures. LED streetlight technology is part of the mentioned energy conservation measure.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for driver and pedestrian safety. Due to having an overhead distribution system in most urban areas, Avista provides a convenient streetlight service in almost every local and state government entity they serve, and manages the streetlights to provide street, sidewalk, and/or highway illumination.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Measures to determine success include:

- Count of Replacements per year.
- Energy savings per year.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

- LED Replacement Analysis - One Pager
- 2013 Street Light Asset Management Plan - Final

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

A lifetime material usage analysis on the HPS light fixtures estimated a mean time to failure (MTTF) for the various light fixture components. Table 1 shows the results for each streetlight component.

Component Groups	Material Usage Quantities	Replacement Ratio	MTTF (Years)
fuse	641	1%	84

Lamp	7,930	15%	7
photocell	5,151	10%	10
starter board	1,126	2%	48
streetlight fixture	683	2%	55

Table 1: 2011 Mean Time to Failure (MTTF) for HPS Streetlights

Upon completion of all streetlights changed out to LED fixtures, energy savings can be measured on an individual light fixture basis and then extrapolated to the entire system. Also, once all the streetlights are converted to LED, the number of service requests for streetlight burn-out should drop from the number of service requests prior to 2015.

Option	Capital Cost	Start	Complete
RECOMMENDED: Base Case (current practice of replacing burned-out HPS bulbs or replacing a fixture if broken)	$750,000	Ongoing program	
ALT #1: Optimized Case (planned replacement of HPS bulbs and photocells)	$1.67M	1/1/2015	Ongoing - 15-year cycle replacement
ALT #2: LED Case (change-out all fixtures to LED)	$2.32M	1/1/2021	5- or 10-years cycle bulb vs photocell.

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Three alternative cases were initially considered in the analysis of converting the streetlight to LED technology. **Base Case** replaces failed streetlight components only when they fail. The second case, called the **LED Case**, replaces the current HPS streetlights with new LED fixtures and implements a planned replacement at fifteen years for the fixture and photocell. At the time of the initial analysis, a fifteen-year replacement strategy proved more cost effective over the lifecycle than running LED lights to failure. Thirdly, the **Optimized Case** represents keeping the current HPS light fixtures and performing planned replacements of the bulbs and photocells at five-year cycles for the bulbs and ten-year cycle for the photocells.

In 2018, the replacement strategy moved from a five-year proactive program strategy to a run to failure (or “burn-out”) strategy. A run to failure strategy is the same as the Base Case mentioned above. By the end of 2018, nearly all Avista owned cobrahead streetlights had been converted to LED, with the majority of the remaining HPS streetlights in Idaho; mainly Coeur d Alene, Lewiston, Moscow, and Grangeville. However, thousands of customer area lights and thousands of decorative streetlights remained as HPS throughout the entire service territory and were being converted to LED on a burn-out replacement strategy. Because LED conversions of area lights and decorative streetlights have nearly the same cost savings and energy savings as the cobrahead streetlights, the program sponsors supported Asset Maintenance’s proposal to expand the scope of the program to include both types of lights. Starting in 2019, all area and decorative streetlights changed out will be charged to the LED Change Out Program.

Key assumptions made in the alternative's analysis are outlined below.

- The **Base Case** and the **Optimized Case**, because they propose using HPS fixtures, have the same failure characteristics shown in Table 2.

Table 1, HPS Light Component Failure Characteristics

Component	Initial Population Failure Rate (10%) by Year___	Initial Population Failure Rate (20%) by Year___	Mean Time to Failure (50% of the initial population will have failed by ____ Years)
100-Watt Bulb	3.4	4.4	6.7
Photocells	5.7	7.3	10.6
Starter Board	7.4	10.5	16.3

Table 2 shows the failure characteristics assumed for LED fixtures and components based on manufacturer's information and an assumed failure shape characteristic.

Table 2, Assumed LED Light Component Failure Curves

Component	Initial Population Failure Rate (10%) by Year___	Initial Population Failure Rate (20%) by Year___	Mean Time to Failure (50% of the initial population will have failed by ____ Years)
New Style Photocell	7.9	10.2	14.9
LED Light Fixture	12.1	15.5	22.6

For each of the cases, a model was created to help compare the risks, resource needs, potential energy savings, and financial impacts of each case. In the end, the **LED Case** will save customers money over the **Base Case**. While the **Optimized Case** provides a better financial return to our customers compared to both the Base Case and LED Case. The customers will still see savings over the life of the LED fixtures compared to today's practices in the Base Case and eliminate the need for 2.3 Megawatts of generation at night.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

The LED Change Out Program currently replaces LED lights upon failure (burn-out). Funding calculations are based on historical spend (2019 spend was approx. $678,000).

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

The impacts of the LED Change-Out Program span across many departments at Avista. Operations is responsible for managing the work and executing the light change-outs in the field, primarily by Avista's servicemen and local reps. Avista's Operations Support Group (Mobile Dispatch) and EAM Technology are responsible for creating work orders for all change-outs and dispatching them to the field. The Customer and Shared Services department, particularity the Enterprise Systems – CC&B, is impacted by the project because the customer billing changes upon converting to LED light fixtures.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Three alternative cases were initially considered in the analysis of converting the streetlight to LED technology. **Base Case** replaces failed streetlight components only when they fail. The second case, called the **LED Case**, replaces the current HPS streetlights with new LED fixtures and implements a planned replacement at fifteen years for the fixture and photocell. The analysis noted that inside the new LED Case model, a fifteen-year replacement strategy proved more cost effective over the lifecycle than running LED lights to failure. Thirdly, the **Optimized Case** represents keeping the current HPS light fixtures and performing planned replacements of the bulbs and photocells at five-year cycles for the bulbs and ten-year cycle for the photocells

For each of the cases, a model was created to help compare the risks, resource needs, potential energy savings, and financial impacts of each case. In the end, the **LED Case** will save customers money over the **Base Case**. While the **Optimized Case** provides a better financial return to our customers compared to both the Base Case and LED Case. The customers will still see savings over the life of the LED fixtures compared to today's practices in the Base Case and eliminate the need for 2.3 Megawatts of generation at night.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

This is an ongoing program that started in 2015.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The LED Change-Out Program is in alignment with the company's strategic vision of delivering reliable energy service and the choices that matter most to our customer's. As part of the program, infrastructure is replaced with longer lasting equipment. By providing more efficient equipment and quality lighting, this results in an energy savings and an increase in driver and pedestrian safety for our customers and communities we serve.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for driver and pedestrian safety. Due to having an overhead distribution system in most urban areas, Avista provides a convenient streetlight service in almost every local and state government entity they serve, and manages the streetlights to provide street, sidewalk, and/or highway illumination.

Results of this program include; significant improvement in energy savings, lighting quality for customers, and resource cost savings.

Secondly, converting streetlights to LED technology helps bring Avista in compliance with the Washington State Initiative 937 (or the Clean Energy Initiative), which ensures that at least fifteen percent of the electricity Washington state gets from major utilities comes from clean, renewable sources, and that Washington utilities undertake all cost-effective energy conservation measures. LED streetlight technology is part of the mentioned energy conservation measure.

The YTD spend is tracked and reviewed each month during the Electric Operations Roundtable (ORT) meetings. The ORT reviews monthly spend and manages any additional funds requests.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The LED Change-Out Program extends across multiple departments at Avista impacting them directly or indirectly. Each department identified as a stakeholder will nominate an engaged representative to act as the liaison between the program and their department. The department stakeholder representative will also take part to promote their department's interests in the business. Some internal departments include; Construction Services, Distribution Engineering, Warehouse and Investment Recovery, Supply Chain, External Communications, Mobile Dispatch, Enterprise Asset Management, Customer Enterprise Technology, and Regional Business Managers.

External stakeholders in the program include all state, county, and local agencies that have a streetlight account with Avista, as well as neighborhood councils, and local law enforcement agencies. All external stakeholders have a vested interest in the business because the streetlights illuminate their streets and sidewalks for the purpose of public safety.

2.8.2 Identify any related Business Cases

- **Grid Modernization:** With HPS lights changed out as they fail, Grid Modernization is likely to find and convert more HPS lights on selected feeders. (The System Wide DFMP says on page 34 that designers should change HPS lights when performing work in the supply space of a pole.)

3.1 Steering Committee or Advisory Group Information

The ORT acts as the advisory group for the LED Change Out Program.

3.2 Provide and discuss the governance processes and people that will provide oversight

The governance in place over the business case is set by the Operations Roundtable (ORT) group, which sets forecasted budgets, monitors the incurred costs and submits any additional funds requests as needed. LED Change Out Program work is overseen by the local area operations engineers and area construction managers.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Decision making, prioritization and change requests will be documented and monitored though the Operations Roundtable (ORT).

The undersigned acknowledge they have reviewed the **LED Street Lights** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ______________________ Date: ____________

Print Name: Amy Jones

Title:	Asset Maintenance Business Analyst
Role:	Business Case Owner

Signature:	David Howell	Date:	8/2/20
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

1 GENERAL INFORMATION

Requested Spend Amount	$1,000,000
Requesting Organization/Department	Asset Maintenance
Business Case Owner	Cody Krogh
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Asset Maintenance
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Cable condition and outage information is collected and analyzed by Asset Management. This information is reviewed with Asset Maintenance to establish an effective construction plan that prioritizes work based on faults and number of customer impacted. Asset Maintenance then collaborates with Electric Operations to coordinate the work. Asset Maintenance tracks the work budget, scope, and schedule.

2 BUSINESS PROBLEM

The primary driver for the Underground Residential Development (URD) Cable Replacement Program is to improve system reliability by removing URD cable with a high failure rate. The other driver is to reduce O&M costs related to responding to customer outages caused by the failed cable.

This work is needed to complete the replacement of the un-jacketed first generation underground primary distribution cable referred to as URD cable. This first generation URD cable was installed from 1971 to 1982. There was over 6,000,000 feet of URD cable installed during this time period. Subsequent to installation the URD cable began to experience an increasing failure rate. From 1992 to 2005 the cable failure rates quadrupled from 2 faults to 8 faults per 10 miles of cable. The faults reached a peak of 238 annual failures in 2007. Increased capital funding to replace this URD cable from 2005 through 2009 helped stabilize the failure rates. Continued funding and replacement of the cable has enabled a downward trend in failures as shown below in table 1. Cable installed after 1982 has not shown the high failure rate.

This work is required to continue to reduce primary URD cable failures and increase reliability. Historically there have been over 200 cable faults per year. The average cost to respond to a fault in 2015 was about $3000 per event due to the challenging nature of the work to locate and repair the cable underground. The estimated remaining pre-1982 cable is around 1,000,000 circuit feet.

The tables below demonstrate the effectiveness of this program to reduce faults and outage expenses through the replacement of the defective cable. The trend of cable faults and expenses decrease over time as the older cable is removed from the system.

Table1: URD Cable Replacement Results

KPI Description	Projected URD Cable - Primary OMT Events	Actual URD Cable - Primary OMT Events	Projected Number of Feet Replaced	Actual Number of Feet Replaced
2009	143	136	178,000	213,000
2010	119	93	178,000	217,883
2011	94	95	178,000	225,823
2012	70	72	178,000	117,247
2013	45	93	0	35,874
2014	45	88	0	35,515
2015	45	64	0	24,155

Table 2: URD Cable Replacement Cost Impact

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

Reference:

Electric Distribution System, 2016 Asset Management Plan

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
[Recommended Solution] Continue to Replace	$1M	04 2017	12 2037

The Primary URD Cable Replacement Program requires design resources and construction labor to complete the field work. There is also some analytics/engineering to identify remaining cable segment locations. Given the projected low capital spend level, the majority of the construction labor will be performed by Avista Crews. Contract crews are typically used to plow in the cable, bore conduit or trench and install conduit in the trench. Avista crews then pull the cable into the conduit and complete the installation.

The Do Nothing approach presents significant reliability risk and added O&M cost. The historic positive results from the URD cable replacement program shown above in section two provide strong justification for continuing the current funding plan.

Over 6,000,000 feet of URD was installed before 1982. Programmed replacement of the problem cable has been on-going at varying funding levels. The estimated remaining pre-1982 cable is around 1,000,000 circuit feet. At the current proposed funding rate of $1M per year this program is planned for the next 20 years. Reduced funding would extend this time and result in additional outages and O&M expenses.

The URD Cable Replacement Program aligns with Avista's strategic vision by increasing reliability to the electric distribution system. Safe and Reliable infrastructure is the focus area for this program.

The projected annual capital spend of $1M per year is reasonable based on the realized reduction in faults from previous work and this spend level enables continued replacement of the high failure rate cable. Repair of the cable has not shown to be cost effective because the cable typically faults in another location.

Avista customers will be positively impacted by this program by realizing fewer outages from the URD cable failure. This results in improved system reliability. Avista electric operations is positively impacted through converting this work to planned work that enables more efficient use of labor. It also reduces O&M expenses. Asset Management is responsible for tracking URD cable outages from Outage Management Tool (OMT) and tracking replacement locations and cost. The Asset Maintenance group is responsible for identifying cable segments and managing the coordination of work.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Primary URD Cable Replacement and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	4-14-2017
Print Name:	Cody Krogh		
Title:	Mgr Asset Maintenance		
Role:	Business Case Owner		

Signature:		Date:	4-17-17
Print Name:	Bryan Cox		
Title:	Sr Dir of HR Operations		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Cody Krogh	4/14/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 03/07/2017

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

Replacing and upgrading major substation apparatus and equipment as it approaches end of life or becomes obsolete is necessary to maintain safe and reliable operation of Avista's transmission and distribution systems. Rebuilding significant portions of stations may be necessary to accommodate the replacement of failing or obsolete equipment since new standard-use apparatus and equipment is often of higher capacity and newer technology and may need to meet updated equipment spacing and operating standards.

Failure to replace old and obsolete equipment will increase the risk of more frequent and/or extended duration of outages due to major equipment failure and inability to maintain major apparatus. Substation outages may have significant consequences as they tend to impact a large number of customers. This Business Case is important for customers because it is critical toward Avista’s ability to continue to provide the reliable electrical service that customers have grown accustom to receiving.

Service: ED – Electric Direct

Jurisdiction: Various. Each rebuild project has its own Jurisdiction.

Engineering Roundtable Request Number: Various. Each rebuild project has its own ERT Request.

2020 Expected Spend: $18,900,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart	Initial Version	4/14/2017	
2.0	Jeff Schlect	Consolodation of capital maintenance and major rebuild business cases	5/19/2017	
3.0	Karen Kusel / Glenn Madden	Update to 2020 Template	6/30/2020	

GENERAL INFORMATION

Requested Spend Amount	$20,000,000 per year
Requested Spend Time Period	On Going
Requesting Organization/Department	T&D – Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Execution
Category	Program
Driver	Asset Condition

1 BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

Replacing and upgrading major substation apparatus and equipment as it approaches end of life or becomes obsolete is necessary to maintain safe and reliable operation of Avista's transmission and distribution systems. Rebuilding significant portions of stations may be necessary to accommodate the replacement of failing or obsolete equipment since new standard-use apparatus and equipment is often of higher capacity and newer technology and may need to meet updated equipment spacing and operating standards. While asset condition is the primary driver triggering the need to replace major apparatus and equipment, additional factors that may contribute to the need to broaden the scope of a station rebuild project include operational and maintenance requirements, updated design and construction standards, SCADA communications, future customer load-service needs, and other programs (e.g. Grid Modernization).

Major apparatus include high-voltage circuit breakers, lower voltage circuit breakers and reclosers, circuit switchers, capacitor banks, power transformers and step voltage regulators. Associated equipment includes relays, meters, surge arrestors, station rock and fencing, panel houses, instrument transformers, high voltage fuses, air switches, autotransformer diagnostic equipment, batteries and chargers, and panel houses.

Failure to replace old and obsolete equipment will increase the risk of more frequent and/or extended duration of outages due to major equipment failure and inability to maintain major apparatus. Substation outages may have significant consequences as they tend to impact a large number of customers.

1.1 What is the current or potential problem that is being addressed?

Aging apparatus and equipment plus changes in customer needs and compliance requirements.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The major driver of the business case is Asset Condition. Good asset condition leads to fewer customer outages.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This is an on-going program to stay ahead of the curve of asset age and condition.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

General age of all major substation equipment.

System Planning Assessments.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

System Planning Assessments, Maximo Work Orders.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

As of July 2020, here are samples of data we use to view asset information used to determine viable options for substation rebuilds.

Equipment Type	Average Manuf Year
Air Switch	2005
Breaker Recloser	2000
Circuit Switcher	1991
HV Circuit Breaker	1996
Power Transformer	1986
Switchgear Breaker	1985
Voltage Regulator	2002

Equipment Type	Oldest Mfg Yr and Substation
Air Switch	1930 - Leon Jct
Breaker Recloser	1924 - South Lewiston
Circuit Switcher	1968 - Osburn
HV Circuit Breaker	1952 - Sunset
Power Transformer	1946 - Garfield
Switchgear Breaker	1963 - Chester
Voltage Regulator	1960 - Bunker Hill

Location	Avg Age of Major Equipment
Coeur Shaft Mine 13kV	1961
Chester 115kV	1974
Rockford 115kV	1975
Post Falls 115kV	1977
Dry Gulch 115kV	1978
Wallace 115kV	1979
Metro 115kV	1979
South Lewiston 115kV	1980
Roxboro 115kV	1981
Leon Jct. 115kV	1981

2 PROPOSAL AND RECOMMENDED SOLUTION

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

The recommended approach is to replace station apparatus and equipment as needed due to asset condition and consider broader station rebuilds when the majority of assets in the impacted area of a station have been determined to have reached their end of life.

This business case aligns with the Company's mission to deliver safe and reliable electric service to customers by preventing the degradation of reliability and mitigating the frequency and duration of outages due to equipment failure.

Option 1: Do nothing - Not recommended

Option 2: Maintain current funding level - Current spending on the Asset Condition risk category is $12.85 million annually. Project prioritization will be supported by Asset Management and substation subject matter experts for prioritization of work within this risk category. Project and funding levels will be reviewed on an annual basis.

Option 3: Reduce current Asset Condition capital improvements. Not recommended. May lead to a reduction in the level of reliability and or operating flexibility that can be achieved by the transmission and distribution systems.

Option	Capital Cost	Start	Complete
Maintain present level of Station Rebuilds	$20M	On Going	On Going
Alternate 1: Do nothing	$0M		
Alternate 2: Maintain minimum level of Station Rebuilds	$0-12M	-	

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:
- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*
-

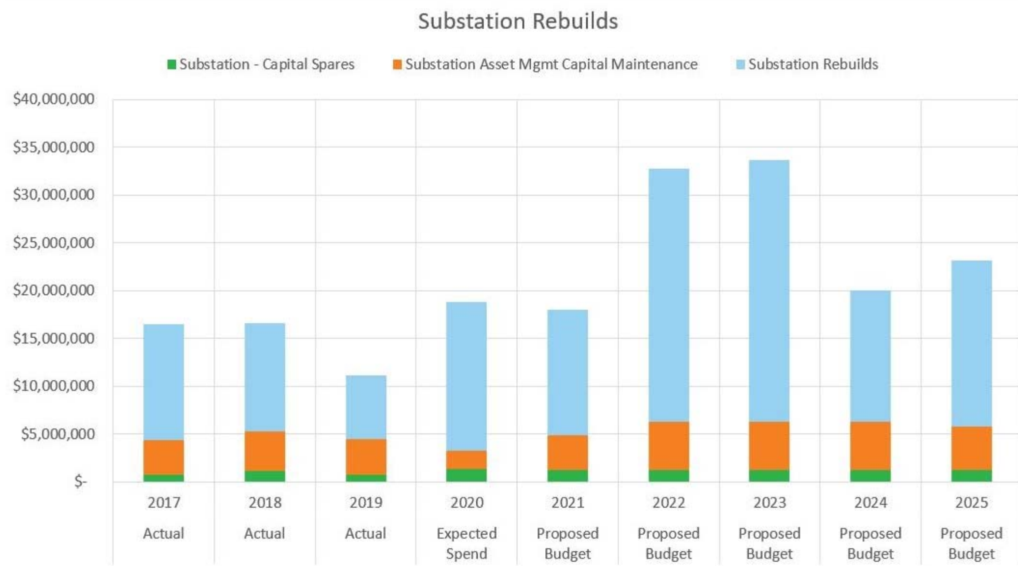
Reference key points from external documentation, list any addendums, attachments etc. System Planning Assessments and Asset Management information.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

Ongoing improvements to the BES via substation rebuilds will result in system reliability, fewer customer outages and smaller O&M costs.



2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Reduce the numbers of capital improvements or Doing Nothing causes equipment to age and become obsolete and difficult to maintain.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Ongoing average of two rebuilds per year with multiple projects being in various stages of design, construction and closeout.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

These projects will help Avista stay ahead of the curve of load growth and equipment age to prevent customer outages.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Customer outages are longer and larger when older equipment fails.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Not Applicable.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

The Engineering Roundtable manages the prioritization of projects within this business case as supported by Asset Management studies and input from company subject matter experts. The Engineering Roundtable is comprised of representatives from the following departments: Asset Management, Compliance, System Planning, System Operations, Telecommunications, Transmission Contracts, Protection Engineering, Substation Engineering, Transmission Engineering, and Substation Support.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Substation - Station Rebuild Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Glenn Madden Date: 12-23-2020
Print Name: Glenn Madden
Title: Manager, Substation Engineering
Role: Business Case Owner

Signature: Josh DiLuciano Date: ~~1/5/2020~~ JDD 1/5/2021
Print Name: Josh DiLuciano
Title: Director, Electrical Engineering
Role: Business Case Sponsor

Signature: Damon Fisher Damon Fisher Date: 1/5/2021
Print Name: Damon Fisher
Title: Principle Engineer
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

EXECUTIVE SUMMARY

Asset Management and Distribution Engineering provide ongoing analysis of distribution assets and their condition. This analysis is used to direct the Wood Pole Management (WPM) work that includes inspecting and maintaining Avista's poles, hardware, and equipment on a twenty-year cycle. The operating guidelines are documented in the Structure Specific Distribution Feeder Management Plan. Asset Maintenance collaborates with Electric Operations and contractors to coordinate and complete the work. Asset Maintenance manages and tracks the work, budget, scope, and schedule. Starting in 2020, WPM is integrating the Wildfire Urban Interface (WUI) program scope into its work plan. The goal is to complete the WUI work by 2030. The major drivers for the program are system reliability, improved cost performance, reduced customer outages, and reduction in fire risk. These drivers are achieved by replacing defective poles, associated hardware, and equipment at the end of its useful life or if the condition of the asset requires replacement. The National Electrical Safety Code (NESC) is adopted as Washington Law under WAC 296-45-045. Part 013C of this code describes the application, Part 121 defines the inspection interval, and Part 214A details documentation and correction of the pole inspection results.

WPM work encompasses Avista's electric distribution overhead facilities in Washington, Idaho, and Montana. In order to maintain a twenty-year cycle, approximately 11,400 poles need to be inspected annually. The work plan is developed to complete 66% of the poles in the state of Washington and 34% of the poles in Idaho each year. For the past three years, the spend has been approximately $10.5M; however, the anticipated spending level needs to be increased to the $17M range due to inclusion of the WUI program into the WPM work plan. This increase accelerates the twenty-year WPM inspection cycle in order to meet the required ten-year WUI cycle. In addition, with current costs, the historical $10.5M funding level does not support completing the identified component replacements on a twenty-year cycle. In 2019, the average cost to mitigate defective items identified during the inspection process was $1,093.49 per pole. As utilities become more susceptible to wildfire litigation it is imperative that the system is inspected, and the defective assets mitigated in a timely fashion. Keeping WPM on a $10.5M annual budget will push work further into the future which increases safety and fire risks to the community and the reliability to our customers.

Version	Author	Description	Date	Notes
1.0	*Mark Gabert*	*Initial draft of original business case*	*7/1/2020*	
2.0	*Mark Gabert*	*Final draft of the original business case*	*7/31/2020*	

GENERAL INFORMATION

Requested Spend Amount	$88,871,382
Requested Spend Time Period	*5 years*
Requesting Organization/Department	Asset Maintenance/WPM
Business Case Owner | Sponsor	Mark S. Gabert | Alicia Gibbs | David Howell
Sponsor Organization/Department	M51/WPM
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

The current Wood Pole Management (WPM) program inspects and maintains the existing distribution wood poles on a twenty-year cycle and the transmission poles on a fifteen-year cycle. Avista has 7,702 overhead distribution circuit miles. According to the 2017 Wood Pole Management Review and Recommendations the average age of a wood pole is twenty-eight years with a standard deviation of twenty-one years. Nearly 20% of all poles are over fifty years old and there are an estimated 230,000 distribution poles in the system. This means approximately 46,000 poles are currently over fifty years old. Our current inspection cycle allows us to reach approximately 11,400 poles each year. Starting in 2021, 14,854 poles need to be inspected each year because the Wildfire Urban Interface (WUI) program is being integrated into the inspections. This increase in inspections will ensure the poles are inspected and maintained on a twenty-year cycle. Along with inspecting the poles, WPM inspects distribution transformers, cutouts, insulators, wildlife guards, lightning arresters, crossarms, pole guying, and pole grounds. The average asset life of this equipment is fifty-five years and requires replacement along with the pole work. The inspections document the asset condition and indicate what work is required to be replaced, and assets that are damaged or near their failure point. The asset condition is observed and documented during the pole inspection process as indicated in both the S-622 Specification for the Inspection of Poles, and the Structure Specific Distribution Feeder Management Plan (DFMP) located on the Asset Maintenance Sharepoint Site Designs and work plans are then created to replace the aging infrastructure. The construction work to replace the assets is also part of this program.

1.1 What is the current or potential problem that is being addressed?

This program addresses issues such as outages, safety risks, fire risks, and unplanned maintenance. This is accomplished by inspecting, documenting, and maintaining our overhead facilities in a useful condition on a twenty-year cycle. This keeps our poles safe for employees and the general public while maintaining a high level of customer satisfaction. As of 2020, WPM is tracking on a twenty-year cycle, however, as the Grid Modernization Program (GMP) budget is reduced, there is an impact on the recommended twenty-year cycle. GMP contributes to WPM's ability to maintain the required poles needed to remain on the twenty-year cycle. The WUI Program is another impact to maintaining the twenty-year cycle. With the addition of the WUI program, WPM will need to re-inspect some poles in the system sooner than the twenty-year cycle so the required WUI work can be completed. If unfunded to expedite the plan, poles will be pushed past the twenty-year cycle in order to meet the demand from the WUI program and with the reduction of GMP budget.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* **and the benefits to the customer**

From an Asset Condition perspective, the major drivers for the program include safety, system reliability, improved cost performance, reduced customer outages, and decreased fire risk. These drivers are addressed by replacing defective poles, associated hardware, and equipment at its end of life or as required by asset condition. This program also has a mandatory and compliance component to it because the National Electrical Safety Code (NESC) is adopted as Washington Law under WAC 296-45-045. Part 013C of this code describes the application, Part 121 defines the inspection interval, and Part 214A details documentation and correction of the pole inspection results.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

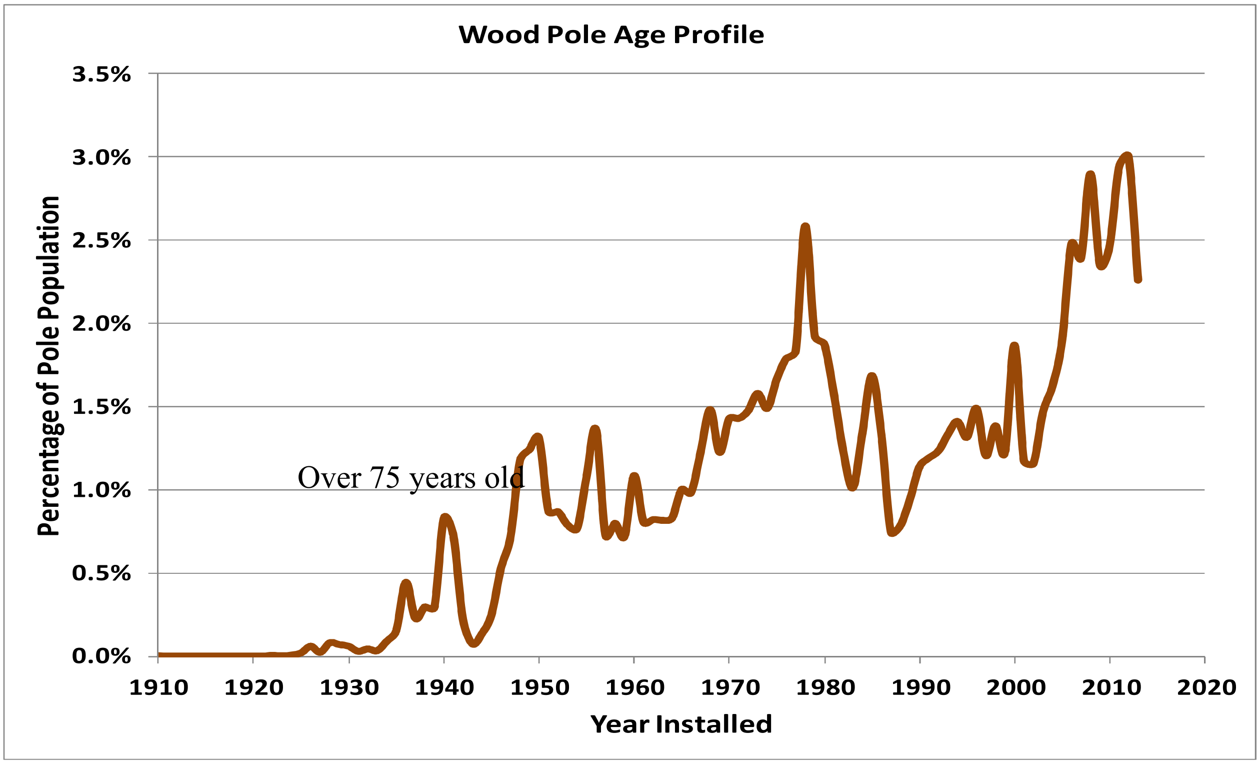
The work is required now to keep pace with the aging assets and expected failure rate. Figure 1 below shows the increased rate at which the poles are reaching the seventy-five year-end of life. If this work is not maintained, this aging infrastructure will cause an increasing number of failures leading to increased outages and higher construction costs as it is much more expensive to respond to an asset failure than to have it replaced in a planned program.

In addition to the risks of fires, outages, and failures with the aging equipment, the additional risks associated with this program pertain to the following:

Environmental: Risks include potential large volume transformer oil spill, difficult hazardous waste cleanup, impact to waterways, and repeated or moderate air emission exceedance. According to the 2017 Wood Pole Management Review and Recommendations if the program is unfunded the potential occurrence is greater than four spills per year. If funded, the potential occurrence is less than one per fifty years.

Public Safety and Health: Risks include a potential for serious injury for crews or the public, significant damage to equipment, property or businesses, public health infrastructure impact up to forty-eight hours. If the program is unfunded, the potential occurrence is less than one per ten years. If funded the potential occurrence is less than one per fifty years.

Figure 1- Pole Age Profile



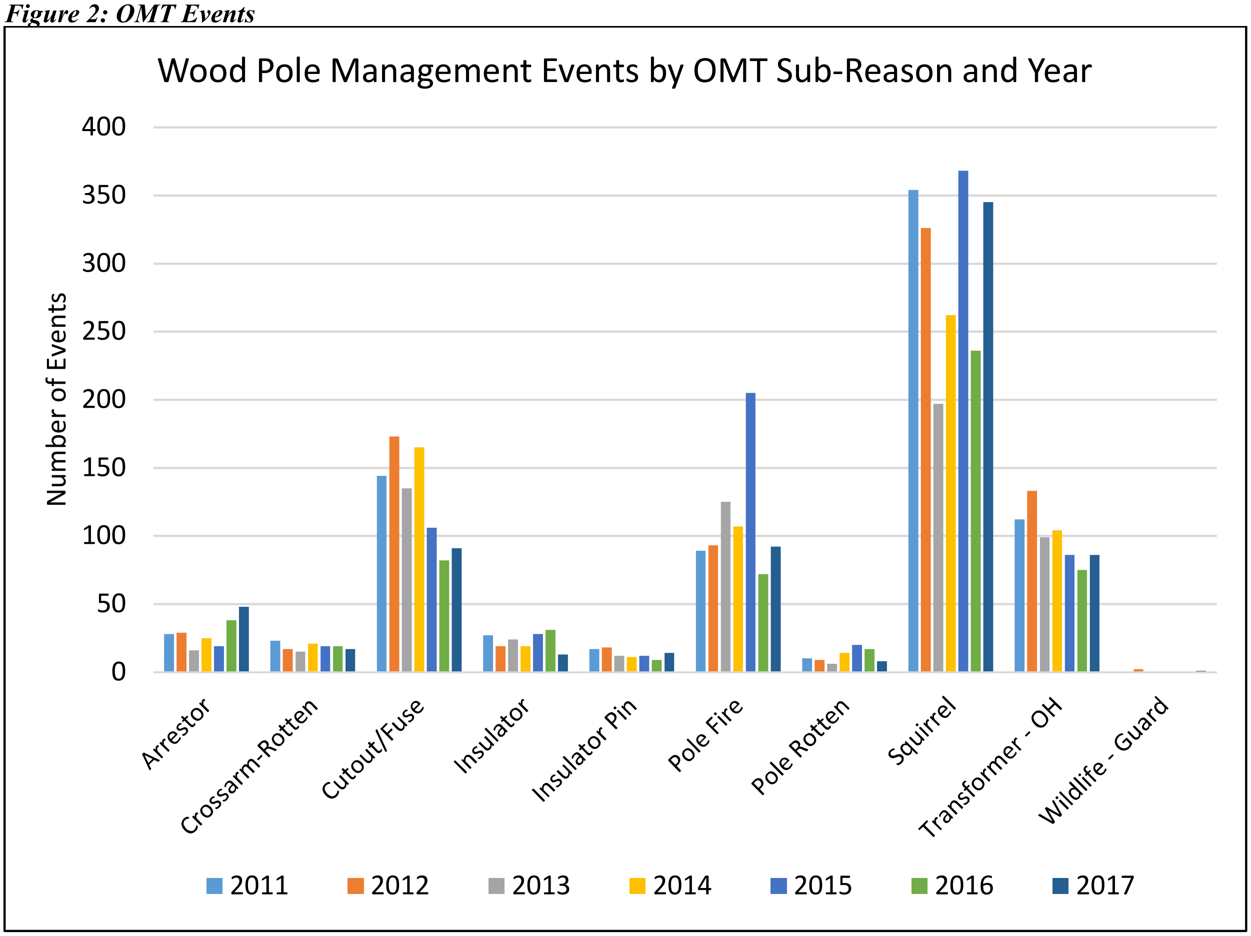
The Outage Management Tool (OMT) is used by Asset Management to track asset conditions and show trends of failures of specific equipment that should be targeted for replacement. This information is also used to track key program performance as shown in Table 1 below. The number of outage type events has been reduced by over 36% from 2009 through 2017. This reduction in outage events results in significant customer benefit. This reduction also demonstrates increased reliability and safety along with a reduction in outages. The original goal for this KPI was to stay below the number of events averaged over 2005-2009 for WPM Related OMT Events. The goal will be re-evaluated by Asset Management in the future.

Table 1: Event Reduction Results

	WPM Goal Related Number of OMT Events	Actual WPM Related Number of OMT Events	Projected Miles Follow-Up Work	Actual Miles Follow-Up Work
2009	1460	1320	500	372
2010	1460	1004	450	435
2011	1460	1004	459	333
2012	1460	1013	416	435
2013	1460	816	445	329
2014	1460	905	412	385
2015	1460	760	390	364
2016	1460	717	389	423
2017	1460	888	389	492

The type of OMT events are broken down into more detail in Figure 2. Note there are significant improvements to some events such as annual squirrel events being reduced from nearly 750 to around 240 events. This improvement has been realized by adding wildlife guards to the top of transformer bushings in order to prevent squirrels from touching exposed power connections which can result in outages. Both the transformer and cutout\fuse events have been reduced by over 50% through the replacement of aged equipment. Figure 2 also reveals a concerning upward trend of pole-rotten events that indicate the impact of the aging poles. Note that the calculated cost to customers for a pole failure is $24,400 based on an average duration of 4.8 hours for 80 customers[1]. Other key OMT events that have been significantly reduced from 2009 to 2016 include Transformer, Cutout/Fuse, and Squirrel. The combined cost impact to customers in 2015 alone for those events was $2,265,600. See Figure 2.

Figure 2: OMT Events



[1] Source: 2017 Wood Pole Management Review and Recommendation)

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Ultimately the impact of this Program can be associated with our Electric Systems Reliability metrics. The System Average Interruption Frequency Index (SAIFI) represents the average number of sustained interruptions per customer for the year across Avista's entire system. Avista reported a SAIFI score of 1.05 for the year 2015. The Asset Management group created Table 2 below to show the impact of this Program to our overall SAIFI score. The predicted contribution is about 0.211, which has a significant impact on the customer, whereas without WPM the contribution to SAIFI would be 0.57. This means the customer would experience 0.36 more outages per year without WPM. Without WPM, the contribution to SAIDI would be 1.27 (hours).

Table 2: SAIFI Metrics

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

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

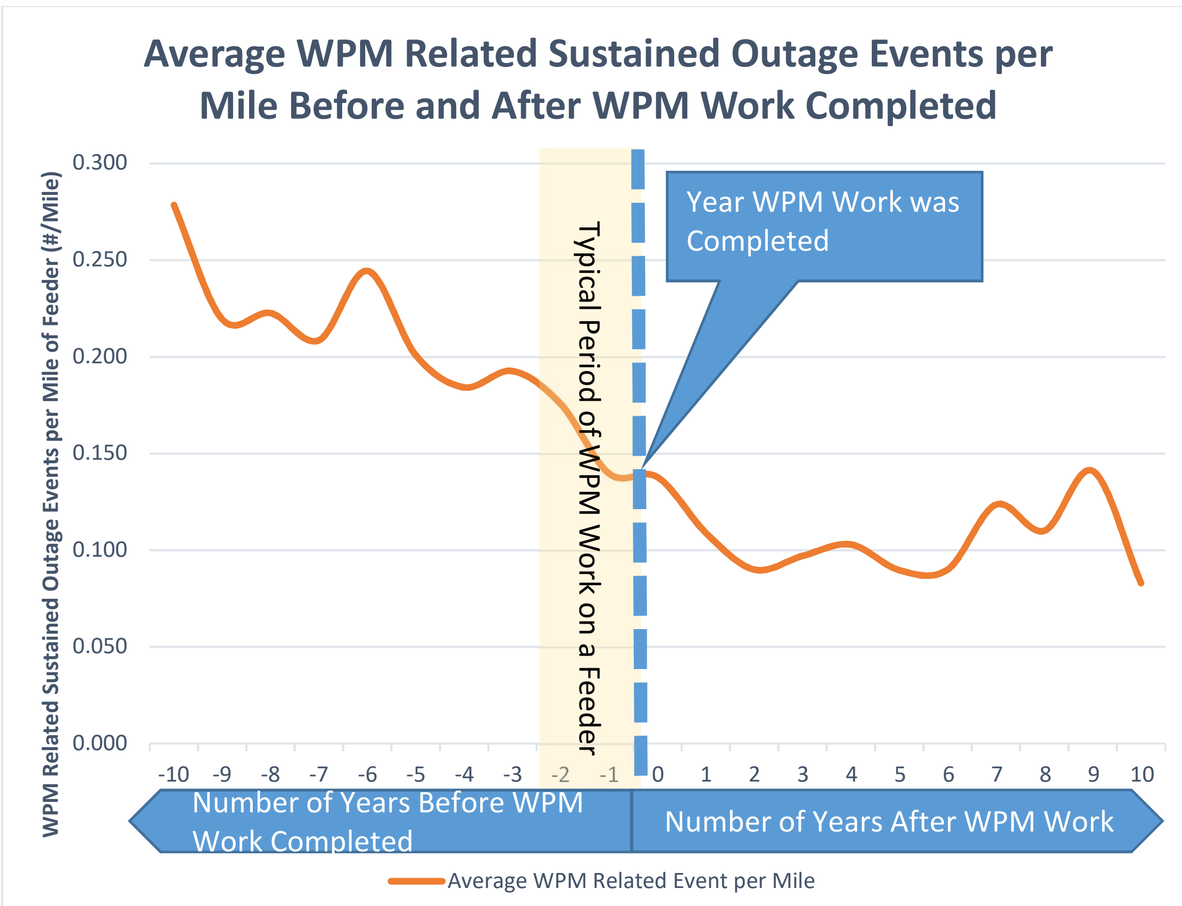
The 2017 Wood Pole Management Program and Review which is located in the c01m570 drive.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Based on the analysis in 2017, the current twenty-year WPM cycle delivers the best life cycle value for the funding level. Asset Management and Distribution Engineering monitor system reliability to determine if adjustments are needed in the future. For perspective the industry average for inspecting and maintaining distribution assets is ten years.

WPM is an ongoing cyclical program that proactively replaces aging assets. By replacing assets before they fail, outage risks are reduced, and replacement costs are reduced through planned work. Investing in the infrastructure increases life-cycle performance and is cost effective using unit-based pricing. Figure 3 below shows the significant improvement in "events per mile of feeder" resulting from this program. The peak of events per mile shown in the graph is from approximately six years ago when there were nearly 1.5 events per mile. The results after the program show performance as low as .3 events per mile of feeder, a significant improvement.

If funding were to be reduced, expected outages would increase. The team would need to prioritize which components would be replaced and which would be left. This would increase the likelihood that crews would need to revisit the same pole later if a remaining component were to fail. While the five-year cycle does provide a better Customer Internal Rate of Return of 8.85%, the five-year cycle O&M costs exceeded our historical spending constraint. The internal rate of return for a twenty-year cycle is 8.00%.



Option	Capital Cost	Start	Complete

[Recommended Solution]: Distribution Wood Pole Management Program inspects all feeders on a twenty year cycle and replaces wood poles, crossarms, missing lightning arresters, missing/stolen grounds, bad cutouts, bad insulators, leaking transformers, replace guy wires not meeting current code requirements when the pole is replaced. This includes increasing the pole inspections and replacement work for the next ten years to meet the requirements of the WUI program.	$16,739,331	01 2021	12 2030
[Alternative #1] Distribution Wood Pole Management Program inspects all feeders on a twenty year cycle and repairs and replaces wood poles, crossarms, missing lightning arresters, missing/stolen grounds, bad cutouts, bad insulators, leaking transformers, replace guy wires not meeting current code requirements when the pole is replaced. This alternative will push the WPM cycle out to twenty-three years until 2030 as WUI will compete for the same inspection and replacement costs for the next ten years.	$12,847,800	01 2021	Annually/indefinite
[Alternative #2] Do nothing-increase OMT events by 1,700 per year and increased fire risk.	$0	MMYYYY	MM YYYY

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

In Asset Management's 2017 Wood Pole Management Review and Recommendations several alternatives were examined that included a five-year, ten-year, twenty year, and twenty-five year inspection cycle time as well as the impact of GMP work on the related WPM work. While the five-year cycle did provide a better Customer Internal Rate of Return of 8.85%, the five-year cycle O&M costs exceeded our historical spending constraint.

Alternative	CIRR	NPV of Life-Cycle Costs	NPV of Risk	Benefit/ Cost Ratio	Risk Reduction Ratio
Base Case	6.03%	$1,016,381,966	$509,538,239	0.804	-0.156
WPM 20 Year Cycle without Transformer Changeout Program (TCOP)	8.00%	$817,592,755	$351,165,376	1.243	0.194
WPM 20 Year Cycle with TCOP	7.94%	$799,251,117	$304,232,511	1.272	0.257
WPM 5 Year Cycle with TCOP	8.85%	$650,557,189	$104,155,317	1.562	0.623
WPM 10 Year Cycle with TCOP	7.85%	$812,124,615	$279,737,157	1.252	0.283
WPM 25 Year Cycle with TCOP	7.46%	$894,569,506	$389,231,116	1.136	0.134
WPM 20 Year Cycle with TCOP and Grid Mod	7.10%	$922,761,015	$481,637,684	1.101	0.030

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

The WPM program is an ongoing process of inspecting, designing, and completing replacement work of assets identified for replacement during the inspection process. The poles on the feeders in the work plan are at various phases of the process throughout the year. The goal is to complete any identified work on a feeder within eighteen months of inspection, and we currently average about one year from start to finish. This work is incorporated into workplans and allows the company to efficiently utilize resources.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Additional WUI design demand, plus increasing the work to meet the twenty-year cycle goal increases the need for additional WPM design, tech, and construction resources. Material availability can also impact the ability to execute on the plan.

Additional departments the WPM program interfaces with will also see some increase in workload which includes: Distribution Engineering, Supply Chain, Environmental, Real Estate, and out-of-cycle Vegetation Management response. There is also a strong need for Asset Management to continue reviewing and analyzing the data that supports this program.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

In Asset Management's 2017 Wood Pole Management Review and Recommendations:

> *"Asset Management examined several alternatives that included a 5-year, 10-year, 20 year, and 25-year inspection cycle time as well as the impact of Grid Modernization work on the related Wood Pole Management work. While the 5-year cycle did provide a better Customer Internal Rate of Return of 8.85%, the 5-year cycle Operations and Maintenance costs exceeded our historical spending constraint. The 20-year inspection cycle provided the best Customer Internal Rate of return and our current practice of replacing transformers that functionally have failed while meeting the Operating and Maintenance budget constraints.*
>
> *Any delays in implementing the Wood Pole Management program strategy as envisioned will delay the immediate benefits and take 20 years based on the current inspection cycle to recover the long-range value of the strategy.*
>
> *We recommend continuing the Wood Pole Management program on its 20-year inspection cycle and follow-up work strategy. Any delays in the work will impact reliability and system performance. "*

Choosing the recommended solution keeps WPM and WUI on track to be completed on time. Choosing Alternative #1 pushes the cycle out further to twenty-three years which increases the risk of more OMT events, increased O&M costs, increased possibility of a fire, and reduces the overall effectiveness of how we manage our aging assets. We also add risk by underfunding our commitment of providing safe, reliable, electric service to our customers. This work has been approved and validated in previous commission responses.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

WPM is an ongoing program. The work is a continuous process of inspecting Avista's poles on a feeder basis. Each feeder represents a project within the program. There are several phases to complete each feeder including inspecting, designing, and capital follow-up. As soon as any capital follow-up work is completed, the asset can become used and useful. The transfers to plant occur on a monthly basis. In addition, our Finance Department preps the AVA_Plan system periodically for a spend and transfer to plant forecast update for the remainder of the year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This business case improves safety for our customers, employees, and the general public by responsibly mitigating safety hazards. This will also improve reliability, reduce fire risk, and decrease the number of unplanned O&M outage responses. Our company's vision is supported by building reliable infrastructure and then maintaining the assets in a safe reliable condition that improves our customers lives. The public utility commissions and our customers hold us to the highest standard of care. When we act prudently and follow through with our commitments, we demonstrate our trustworthiness.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The requested amount is a prudent investment to maintain Avista's overhead electric system on a twenty-year cycle, which is also in alignment with the NESC requirement to inspect and maintain our facilities in a timely manner. This work reduces the company's risk.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electric customers, Distribution Engineering, Environmental, Wildland Urban Interface, area offices, line crews, Asset Management, and Grid Modernization. Please note that with the sunsetting of the TCOP program the internal crews incorporate WPM as part of their workplan.

2.8.2 Identify any related Business Cases

Grid Modernization Program, WSDOT Control Zone Mitigation, and WUI-Wildfire Urban Interface Program.

3.1 Steering Committee or Advisory Group Information

Asset Management and Distribution Engineering provide ongoing analysis of distribution asset condition. The analysis is used to direct the WPM work that includes inspecting and maintaining Avista's poles, hardware, and equipment on a twenty-year cycle. The twenty-year cycle is documented in the 2017 Wood Pole Management Review and Recommendations. The operating guidelines are documented in the Structure Specific DMFP.

3.2 Provide and discuss the governance processes and people that will provide oversight

The governance process is a collaborative process that includes leadership from: Asset Management Asset Maintenance, Distribution Engineering, the Director of Operations, and the WPM Program Manager and WPM inspectors . The operating guidelines are documented in the Structure Specific Distribution Feeder Management Plan. The yearly goals are documented and updated on the annual one pager.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

WPM is a long-standing program that is well established. There are few change orders, but they are documented by the inspectors during the audit process. All significant change requests are reviewed by the Program Manager for approval. In cases where scope is re-evaluated, changes are agreed to prior to construction.

The undersigned acknowledge they have reviewed the *Wood Pole Management Business Case* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Mark S. Gabert	Date:	7/30/20
Print Name:	Mark S Gabert		
Title:	WPM/WSDOT Program Manager		
Role:	Business Case Owner		

Signature:	David Howell	Date:	8/2/20
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Sponsor		

Signature:	Alicia Gibbs	Date:	8/2/2020
Print Name:	Alicia Gibbs		
Title:	Asset Maintenance Manager		
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

The threat of wildfires poses a significant risk to utilities across the western United States. In May of 2020, Avista published its "**2020 Wildfire Resiliency Plan**" which details twenty-eight actions to mitigate the risk of wildfire. The Plan includes upgrades to infrastructure aimed at reducing spark-ignition events and protecting critical infrastructure from the threat of wildfires. The Plan details a 10-year time horizon. The $268,965,000 Plan includes investments in the four categories:

Enhanced Vegetation Management
Widen Transmission R/Ws ($5,000,000)
Vegetation management incorporated into CPC designs ($100,000)

Situational Awareness
Fire-Weather Dashboard & TROVE risk analysis ($425,000)
Midline Reclosers Communications ($540,000)
100% Substation SCADA ($17,000,000)

Operations and Emergency Response
Transmission Design Review of Major Events ($100,000)
Fire Ignition Tracking System ($200,000)

Grid Hardening & Dry Land Mode
Transmission Fire Inspection ($3,000,000)
Transmission Grid Hardening ($44,000,000)
Midline Reclosers ($5,400,000)
Distribution Grid Hardening (193,200,000)

Wildfire Plan (CapX 2020-2029) $268,965,000

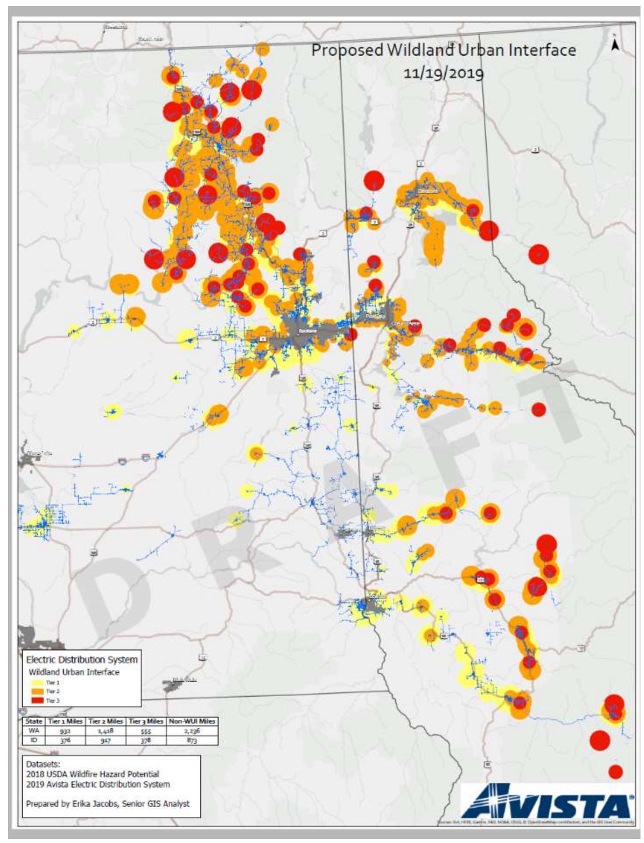
The 10-year accumulated inherent risk of wildfire is estimated between $8.05 and $18.2 billion dollars. The mitigated risk (with controls) is estimated between 0.5 and $2.3 billion dollars. Again, accumulated over a 10-year period. The risk reduction is estimated at between 8X and 16X with a cost – benefit ratio between 22.9 and 48.6 including $60 million dollars of O&M expense.

VERSION HISTORY

Version	Author	Description	Date	Notes
0	David James	Initial Submission to Capital Planning	April 1, 2020	Initial submission
1	David James	Refresh using 2020 BC narrative template	July 29, 2020	No revision to capital requirements

GENERAL INFORMATION

Requested Spend Amount	$268,965,000 (2020-2029) CAPX $59,586,000 (2020-2029 OPX) *for information*
Requesting Organization/Department	Electric Operations
Business Case Owner	David Howell
Business Case Sponsor	Heather Rosentrater
Sponsor Organization/Department	Electric Operations
Category	Program
Driver	Customer Service Quality & Reliability



1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed? The risk of wildfires is increasing throughout the western United States. Data from the U.S. Forest service indicates a 300% increase in the number of wildfires since 1970 Data specific to fires in Washington and Idaho fires suggest that fire size has increased 400-500% over the last several decades. Though the number of powerline involved wildfires remains relatively low (5-7% WA DNR statistics, 1990-2015), wildfire is differentiated from natural disasters in that 'cause and origin' investigations often lead to claims for fire suppression costs, property damage, timber loss, and personal injury. In the fall of 2018, a small team of Avista employees was assembled to assess the risks, develop defensive strategies, and implement a Wildfire Resiliency Plan. This business case reflects the 10-year strategy to build defense strategies against wildfire.

1.2 Discuss the major drivers of the business case and the benefits to the customer? Wildfire does not align well with the existing business case drivers. Unlike most asset replacement programs, Wildfire Resiliency is a risk-based, not a condition-based program. Therefore, it is best aligned with Customer Service Quality & Reliability and is expected to reduce risk exposure by at least $7.5 billion dollars over a 10-year period.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred – Avista has published a "2020 Wildfire Resiliency Plan" and have committed to implementation at the highest levels of the Company including the Board of Directors. It is a Tier 1 Enterprise Level risk.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above – As part of Wildfire Resiliency, performance metrics will be tracked including, fire ignition events, to measure the efficacy of the program. Transmission and Distribution Operations tracks system outages including cause-code, duration, and impacted customers. The primary goal of the program is to limit the number of spark-ignition events and the reduction in outages will enhance customer experience.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Several supporting documents are available for review:

2020 Avista Wildfire Resiliency Plan (June 2020)
Wildfire Resiliency Cost Plan (January 2020)
Wildfire Risk Assessment (September 2019)
Wildfire Plan Charter (May 2019)

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Wildfire Resiliency is a comprehensive, risk-based program and includes targeted equipment replacement. Condition based metrics are not considered.

In May and June of 2019, a series of risk workshops were held to identify potential defensive strategies to reduce the risk of wildfire. These workshops were facilitated by the Business

Process Improvement team with support from Senior Risk Manager, Bob Brandkamp, and Asset Management Analyst, Jeff Smith. Over the course of 6-workshops, 160 mitigation strategies were identified. 60 of those were analyzed in detail and ultimately, 28 strategies were adopted into the plan including transmission and distribution grid hardening, a comprehensive review of dry land mode operating strategies, and systems to actively monitor fire-risk. In addition to internal processes, Avista participated in several utility forums sponsored by the Western Energy Institute including the Wildfire Planning & Mitigation workshop. In general, the approach to fire mitigation is consistent throughout the utility sector.

Option	Capital Cost	Start	Complete
Wildfire Resiliency Plan	*$268,965,000*	*07 2020*	*12 2029*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Wildfire Resiliency is a risk-based plan. Inherent (existing) and mitigated (future) risks were assessed in three categories:

- Financial (the cost of replacing T&D infrastructure associated with wildfire events and response to third party and other claims for fire suppression and damages)
- Customer (the cost impact to customers including outage duration and societal disruption)
- Safety (costs associated with worker and public injuries)

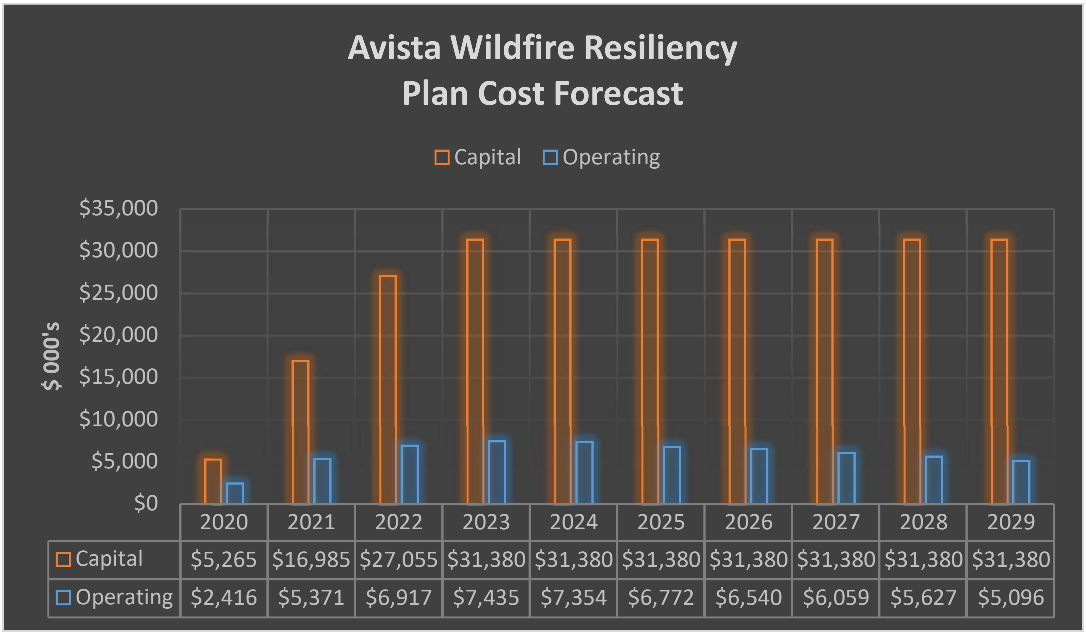
The following is a list of the 28 recommended actions indicating a range of inherent and mitigated risk costs. Note that not all the actions reflect capital investments (e.g. vegetation management). Monetized risk values represent a 10-year operating time horizon.

	Inherent Risk ($M)		Managed Risk ($M)		Cost: Benefit		Risk Red
System & Transmission	Low	High	Low	High	Low	High	%
EOP & Fire ICS Representation	9.6	17.7	9.6	17.6	0.0	2.0	0%
Fire-Weather Dashboard	4.8	8.8	4.3	4.8	0.5	3.7	33%
Engineering Review Major Events	1	6.9	0.9	2.4	1.0	45.0	58%
Wildfire Compliance Tracking	9.6	18	2.2	2.7	49.3	102.0	82%
Digital Data Collection	9.6	17.7	0.9	2.4	1.3	2.2	88%
Wood Pole FR Mesh Protection	9.6	28	4.3	4.8	2.2	9.5	76%
Fuel Reduction Partner	15	29	3	29	8.0	0.0	27%
Emergency Responder Training	1.8	2.3	0.3	0.9	1.2	1.1	71%
Conforming Rights-of-Way	4.8	8.8	0.2	1.4	0.9	1.5	88%
Transmission Inspection Pym	4	59	1.1	2.6	0.6	11.3	94%
Expedited Fire Response	-	-	-	-			n/a
Transmission Grid Hardening							n/a
Transmission Total	**$70**	**$196**	**$27**	**$69**	**0.6**	**1.9**	**64%**

	Inherent Risk ($M)		Managed Risk ($M)		Cost: Benefit		Risk Red
Electric Distribution	Low	High	Low	High	Low	High	%
Fuse Coordination Study	41	107	1.6	8.2	197.0	494.0	93%
Recloser Event Reporting	21	82	1.3	8.4	49.3	184.0	91%
Fire Ignition Tracking System	132	547	46	213	286.7	1113.3	62%
Veg Mngt in CPC designs	20	278	10	21	100.0	2570.0	90%
Fire Suppression 'wetting' agent	53	582	11	66	840.0	10320.0	88%
Dry Land Mode 'effectiveness' study	21	57	0.6	4.2	204.0	528.0	94%
WUI layer in GIS	0	0.11	0	0.11	0.0	0.0	0%
Dry Land Mode 'trigger'	-	-	-	-			n/a
Arcos Wildfire Notification	-	-	-	-			n/a
Distribution Annual Risk Tree	2,816	5,722	264	1,226	100.1	176.3	83%
Public Safety Initiative 'Right Tree-Right Place'	563	1,145	2.25	28.2	58.4	116.3	98%
Midline Recloser Communication	14.6	29	0.25	0.28	17.7	35.4	99%
Additional Midline Reclosers	22.6	39	5.63	13.2	2.9	4.4	69%
Digital Data Collection	2,816	5,722	132	564	346.3	665.5	92%
100% Substation Scada	132	547	0	1.6	7.7	31.9	100%
WA Grid Hardening in WUI Tier 2-3	823.6	1980.75	6.83	41	6.8	16.2	98%
ID Grid Hardening in WUI Tier 2-3	502.4	1208.25	4.17	25	6.8	16.2	98%
Distribution Total	**$7,978**	**$18,046**	**$486**	**$2,220**	**28.7**	**60.6**	90%

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

The illustration indicates the estimated capital and operating investments. Though we do expect outage rates associated with vegetation and equipment failures to trend downward, O&M ‘offsets’ are not a significant factor. The primary focus of this plan is risk reduction and to protect the financial viability of the Company.



Capital cost breakdown by year and project (values in $000’s).

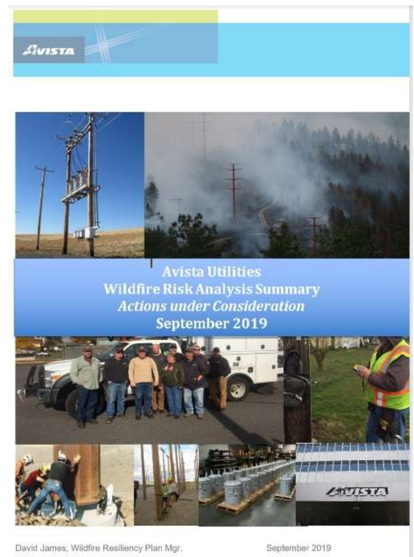
		Capital										
	System & Transmission	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	10-yr
ST-1	EOP & Fire ICS Representation											0
ST-2	Fire-Weather Dashboard	200	150	75								425
ST-3	Engineering Review Major Events	10	10	10	10	10	10	10	10	10	10	100
ST-4	Wildfire Compliance Tracking											0
ST-5	Digital Data Collection											0
ST-6	Wood Pole FR Mesh Protection											0
ST-7	Fuel Reduction Partner											0
ST-8	Emergency Responder Training											0
ST-9	Conforming Rights-of-Way	500	500	500	500	500	500	500	500	500	500	5,000
ST-10	Transmission Inspection Pgm	300	300	300	300	300	300	300	300	300	300	3,000
ST-11	Expedited Fire Response											0
ST-12	Transmission Grid Hardening	1,000	3,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	44,000
	Transmission Total	**$2,010**	**$3,960**	**$5,885**	**$5,810**	**$5,810**	**$5,810**	**$5,810**	**$5,810**	**$5,810**	**$5,810**	**$52,525**

		Capital										
	Electric Distribution	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	10-yr
D-1	Fuse Coordination Study											0
D-2	Recloser Event Reporting											0
D-3	Fire Ignition Tracking System	25	75	100								200
D-4	Veg Mngt in CPC designs	10	10	10	10	10	10	10	10	10	10	100
D-5	Fire Suppression 'wetting' agent											0
D-6	Dry Land Mode 'effectiveness' study											0
D-7	WUI layer in GIS											0
D-8	Dry Land Mode 'trigger'											0
D-9	Arcos Wildfire Notification											0
D-10	Distribution Annual Risk Tree											0
D-11	Public Safety Initiative 'Right Tree-Right Place'											0
D-12	Midline Recloser Communication	20	40	60	60	60	60	60	60	60	60	540
D-13	Additional Midline Reclosers	200	400	600	600	600	600	600	600	600	600	5,400
D-14	Digital Data Collection											0
D-15	100% Substation Scada	0	1,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	17,000
D-16	WA Grid Hardening in WUI Tier 2-3	2,000	6,500	10,000	14,500	14,500	14,500	14,500	14,500	14,500	14,500	120,000
D-17	ID Grid Hardening in WUI Tier 2-3	1,000	5,000	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400	73,200
	Distribution Total	**$3,255**	**$13,025**	**$21,170**	**$25,570**	**$25,570**	**$25,570**	**$25,570**	**$25,570**	**$25,570**	**$25,570**	**$216,440**
	D-10 - $500k/per year added to the above for budget											
	Plan Total	**$5,265**	**$16,985**	**$27,055**	**$31,380**	**$31,380**	**$31,380**	**$31,380**	**$31,380**	**$31,380**	**$31,380**	**$268,965**

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Implementation has and will impact many areas of the Company including electric operations, engineering, supply chain, IT, asset management, finance and accounting. However, great care has been taken to leverage existing workflow processes and technologies to minimize disruption to the organization. This is an enterprise level program.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.



A complete list of alternatives is included in the September 2019 publication entitled, "Wildfire Risk Analysis Summary – actions under consideration". This document focuses on the risks and costs of viable alternatives and laid the groundwork for actions adopted in the Resiliency Plan.

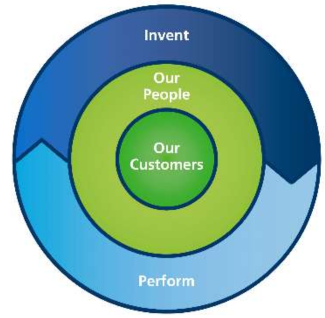
2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

The scope of this plan is considerable. Both transmission and distribution grid hardening projects will be ramped from 2020 through 2023 and then levelized through 2029. Other efforts including technology projects such as the fire-weather dashboard and the TROVE risk analysis will be conducted on the front end of the ten-year horizon. The following table indicates the capital spend levels, by year. This is a surrogate for activity.

Capital										
2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	10-yr
$5,265	**$16,985**	**$27,055**	**$31,380**	**$31,380**	**$31,380**	**$31,380**	**$31,380**	**$31,380**	**$31,380**	**$268,965**

Values in $000's.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.



The stated goals of the resiliency plan are:

- Protect lives and property
- Ensure emergency preparedness and align operating practices with fire threat conditions
- Protect Avista's energy delivery infrastructure

The effort to develop a comprehensive wildfire mitigation strategy has been fully embraced by Avista's Board of Directors and executive management. The Board has requested quarterly updates since early 2020 and will receive another briefing on August 5, 2020 (D. Howell and D. James).

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Prudency is a fundamental tenant of cost recovery. Avista has engaged directly with Idaho and Washington Utility Commissioners and their staffs. Avista's rates department recently petitioned the IPUC for deferral treatment of all wildfire related costs (capital and O&M). Discussions continue with Washington Commissioners. Events surrounding the November 2018 'Camp Fire' lead to the bankruptcy of PG&E and served as the catalyst for many utilities to assess their systems and defenses associated with wildfire.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Avista electric customers located in Wildland Urban Interface zones 2 & 3 will be directly engaged via the process. Grid hardening and enhanced vegetation management strategies will be focused in those areas. In addition, Avista is coordinating with local and regional stakeholders including fire protection agencies, electric utilities, the Washington department of natural resources (DNR), the Idaho department of lands (IDL), and groups with an interest in or impacted by Avista's plan.

2.8.2 Identify any related Business Cases

N/A

3.1 Steering Committee or Advisory Group Information

Since February of 2019, a Wildfire Steering Committee has actively engaged in the formation and adoption of the Plan. That committee remains active and will guide efforts throughout the life of the program. Members include:

Name	Title
David Howell	Director, Electric Operations (Business Case Owner)
Bruce Howard	Sr. Director, Environmental Affairs and Real Estate
Greg Hesler	Vice President, General Counsel & Chief Compliance Officer
Alicia Gibbs	Manager, Asset Maintenance
Elizabeth Andrews	Sr. Manager, Revenue Requirements
Bob Brandkamp	Sr. Manager, Risk
Annie Gannon	Manager, Communications
Casey Fielder	Manager, Corporate Communications

3.2 Provide and discuss the governance processes and people that will provide oversight

The Wildfire Resiliency Plan will adapt and evolve to align with risk conditions and available technologies to mitigate those risks. Governance and oversight will be a consistent element throughout the life of the Plan including direct involvement by senior management and oversight via the Board of Directors.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Program management is a prescribed function of the Wildfire Plan Manager position. Monthly status reports will include status of costs, production, and forecasts including resource requirements. This plan will adapt over time as we gain experience with new elements including risk-based vegetation management, digital data collection, grid hardening, and emergency operations tactics specific to fire response.

The undersigned acknowledge they have reviewed the ***__Wildfire Resiliency Plan business case__*** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	David Howell	Date:	8/2/20
Print Name:	David Howell		
Title:	Director, Electric Operations		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	Heather Rosentrater		
Title:	Sr Vice President, Energy Delivery & Shared Services		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	David Howell (on behalf of WFRES Steering Group)		
Title:			
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

Avista's electric distribution system is the largest part of the company's infrastructure. It consists of poles, wires, underground cable, transformers and a variety of other equipment. In addition, Avista's electric distribution system has the largest footprint of any other infrastructure within the company's service territory. This creates a unique challenge for the company. The distribution system is the largest contributor to a customer's reliability and the overall safety of the public, mostly from the sheer volume of exposure it establishes. This business case is one of several such as, Minor Rebuilds, Wood Pole Management, Grid Modernization, etc., that creates a direct customer benefit by completing projects that improve the electric distribution system's safety, performance and reliability. The jobs for this business case are identified by our area engineers for their regional areas within Washington, Idaho, and Montana and they are prioritized against each other with input from the distribution planner.

Most of the funds provided by this business case are used to complete projects that solve performance and capacity issues driven by system wide electric load growth. Other projects address power quality mitigation, reliability improvements, operational flexibility, system protection improvements, and safety enhancements. As such, the risk in not funding this business case is the inevitable decline in the overall health and operation of Avista's electric distribution system, e.g. overloading conductor to the point of failure. The ongoing nature of issues that arise within the electric distribution system coupled with the large amount of work drives the need for this business case to be funded on a yearly basis.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.1	*David James*	*Initial draft of original business case.*	*04/07/2017*	
1.2	*Cesar Godinez*	*Updated to include voltage/transformer mitigation work.*	*07/03/2019*	*Addition of voltage and transformer mitigation work identified by AMI data.*
2.0	*Cesar Godinez*	*Updated narrative and business case template.*	*07/01/2020*	*Business case refresh and name change to "Distribution System Enhancements" from "Segment Reconductor and FDR Tie."*

GENERAL INFORMATION

Requested Spend Amount	$7,500,000
Requested Spend Time Period	*5 years (on-going)*
Requesting Organization/Department	C51 / Electric Distribution Design
Business Case Owner | Sponsor	Cesar Godinez | Josh DiLuciano
Sponsor Organization/Department	T08 / Electrical Engineering
Phase	Monitor/Control
Category	Program
Driver	Performance & Capacity

1. BUSINESS PROBLEM

Avista's electric distribution system consists of three hundred and fifty seven (357) discrete primary electric circuits encompassing over 19,000 miles of overhead conductors and underground cables. The distribution grid is managed by division or 'area engineers' and centralized distribution planning.

Load Demands on the grid are dynamic with load patterns changing as a result of many factors including weather, temperature, economic conditions, conservation efforts, and seasonal variations. Avista operates a radial distribution system using a trunk and lateral configuration (industry standard). Though many circuits are monitored at the source substation (SCADA), downstream trunk and lateral branch circuits loading are analyzed via computer simulation. At Avista, distribution analysis is performed with the **Synergi** load flow program. AMI data is also used to analyze service voltages and transformer loading. AMI data has shown system issues in the form of service voltage problems and transformer overloading. In the near future AMI load data will be exported to Synergi and used in the computer simulation.

Additionally, power quality investigation and subsequent mitigation projects are initiated by customer inquiries or analysis work. Work is also driven by reliability and safety concerns that are identified by our engineers and/or operation personnel. Operational flexibility can also drive the need to upgrade electric circuits, install switching equipment, and other infrastructure as needed.

In a manner similar to substation rebuilds, expansions, and additions that are planned for and scheduled years in advance, the distribution system also requires rebuilds, expansions, and additions. The Distribution System Enhancements Business Case allows for a methodical and planned out approach to needed feeder enhancements. Secured funding for future years allows for planning large projects in a multi-year approach, with completion of a portion of the overall project happening over a series of years. In absence of this business case, critical issues would be resolved in a reactionary and haphazard fashion, funded through the Minor Blanket, and completed outside the confines of a "big picture" plan and approach to feeder management.

Avista's electric distribution system analysis and mitigation strategies are informed by several internal documents and data repositories. These are listed below for reference:

1. Distribution Planning Standard "500 Amp FDR" – internal document that defines the performance criteria and limits for both urban FDR tie systems and rural pure radial circuits. This document is maintained by Distribution System Planning (Damon Fisher).
2. FDR Status Report – distribution engineering publishes an annual report indicating peak circuit demand by season, reliability outage statistics, circuit health check, and other logistic information.
3. Distribution Standards – distribution engineering maintains construction standards for both overhead and underground primary circuits. It also maintains standards for all electrical material and apparatus.
4. PI Database – operating data retrieved by either the SCADA or DMS system is stored in the PI historian. This allows direct access by engineers and planners to help inform both operating and design strategies. (Distribution Operations)
5. Distribution FDR Management Plan – a design guide to assist the CPC/Engineer when making decisions related to reinforcements or reconstruction of distribution assets (Asset Management).
6. Feeder Automation Strategy – a design guide to assist the CPC/Engineer when making decisions involving automated devices (Distribution Engineering).
7. Synergi Computer Program – the load flow program derives topology information from Avista's GIS system. Updates to the Synergi database are performed by Distribution Planning.
8. SCADA Variable Limit (SVL) – Avista uses temperature compensated program to monitor conductors, cables, and series connected major equipment (e.g. transformers, breakers, switches, regulators, and etc.). This system is deployed on Avista's EMS/SCADA system. The program is SME supported by Substation Engineering.
9. AMI Data – AMI service voltage data is used to identify services that are out of compliance with the ANSI C84.1 standard of +/- 5% of 120 volts. AMI service load data is used to identify transformers that are overloaded according to the standards set by distribution engineering.

A typical distribution circuit is illustrated on the next page. Similar to municipal water systems, grid capacity decreases with distance away from the source substation. This leads to system 'constraints' as loads are added to the system through direct customer action or load shifting between circuits (Avista).

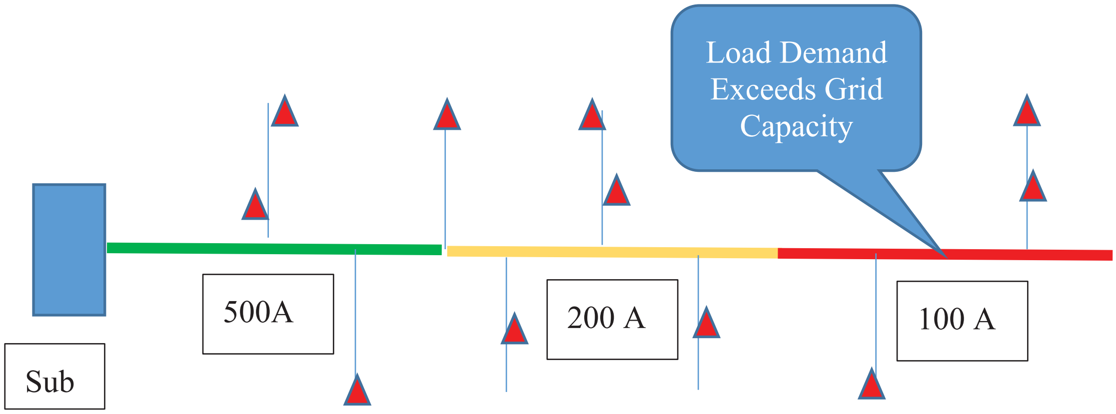


Illustration of Distribution Grid Capacity Constraint

Avista's Distribution System contains over 75 different wires and cables

2020 Avista Standard OH Primary Conductors

556 All-Aluminum (AAC) – 601 Amps (main trunk, urban)

336 All-Aluminum (AAC) – 442 Amps (main trunk, rural)

2/0 Aluminum Conductor, Steel Reinforced (ACSR) – 238 Amps (gen purposes, rural)

#4 Aluminum Conductor, Steel Reinforced (ACSR) – 119 Amps (lateral circuit)

Legacy Conductors

2/0-3/0 Copper – 319-369 Amps (main trunk)

#2 Copper – 197 Amps (main trunk)

#6 Copper - 110 Amps (lateral circuit)

Avista's distribution grid contain over 1,000 miles of conductor equivalent or smaller than #6 Copper.

Option	Description	Consequence
Do-Nothing	No Action to mitigate thermal overloads, power quality issues, reliability and safety issues.	Conductor will 'sag' down beyond design limits and contact joint-use telecom circuits or violate NESC prescribed limits. In extreme situations, conductor failure will occur. Service quality will degrade below acceptable levels and customer outages will increase. System enhancements (if they occur at all) will be done in a "scattered" approach and not guided by engineered plans and solutions.
Select DSM treatment	Target homes and businesses with demand side management solutions to effect peak load demand reduction.	This option would be a viable, however, State Commissions do not allow DSM treatment in localized areas.
Load Shifting	FDR Tie	This action is represented in the Distribution System Enhancements program. By extending lines to adjacent circuits, load can be shifted to underutilized circuits and mitigate overloads. This action requires capital investment.
Capacity Increase	Reconductor overloaded 'segments' to increase line capacity, mitigate identified low voltage issues, and correct system protection issue. Install voltage regulators to mitigate feeder level low voltage issues. Replace Transformers (or install additional transformers) to mitigate overloaded transformers and service voltage issues.	All electric components are thermally limited. Reconductoring is the <u>most direct approach</u> to mitigating overloaded circuits and low voltage issues.
System Enhancements	Mitigate power quality issues, as well as, reliability and safety issues. Add operational flexibility to the electric distribution system. Expand distribution automation by adding targeted "smart" devices.	Accomplishing this type of work ensures that our electric distribution system is operated efficiently, reliably, and safe.

Recommendation:

1. Do Nothing is unacceptable. Violates NESC/WAC regulations and industry standards. It also represents an unacceptable level of risk to public safety and infrastructure.
2. Targeted DSM is not allowed.
3. FDR Tie – represented in the program (indirect solution).
4. Segment Reconductor – represented in the program (direct solution).
5. System Enhancements – represented in the program.

Projects listed in the current 5-year "Distribution System Enhancements" program are summarized on the Distribution Engineering SharePoint site. The following is a summary of those projects listings as of June 2, 2020.

https://sp2016.corp.com/sites/sp/enso/dist/_layouts/15/start.aspx

Region	2021	2022	2023	2024	2025
Spokane	2,946,400	2,946,400	2,946,400	2,946,400	2,946,400
East	2,142,900	2,142,900	2,142,900	2,142,900	2,142,900
South	1,339,300	1,339,300	1,339,300	1,339,300	1,339,300
Big Bend	1,071,400	1,071,400	1,071,400	1,071,400	1,071,400
Total	**7,500,000**	**7,500,000**	**7,500,000**	**7,500,000**	**7,500,000**

One of the planning objectives is to levelize the resource demands and avoid significant upswings or downturns in crew resource forecasting. Distribution Engineering works closely with the Operating Divisions and Asset Maintenance to develop a resource balanced work plan and maximize the effectiveness of Avista craft resources. In addition, reductions in funding of this business case typically result in increase spend in our Minor Blanket business case.

Distribution assets are fixed resources and therefore, project alternatives are generally dominated by supply side solutions. Operating limitations are codified in Avista internal standards (as listed) but derived through industry and regulatory policies including: Washington Administrative Code (WAC), National Electric Safety Code (NESC), National Electric Code (NEC), and IEEE/ANSI standards & manufacturer recommendations specific to equipment ratings and operating limits.

Steering Committee or Advisory Group Information

Distribution Area Engineers and Distribution System Planning.

Tim Figart & Jon Gilrein – Spokane and Deer Park

Marshall Law – East Region (CDA, Kellogg, St. Maries, Sandpoint)

Dan Knutson – Othello, Davenport

Marc Lippincott – Colville

Chris Dux – South Region (Pullman, Clarkston, Grangeville)

Damon Fisher – Distribution System Planning

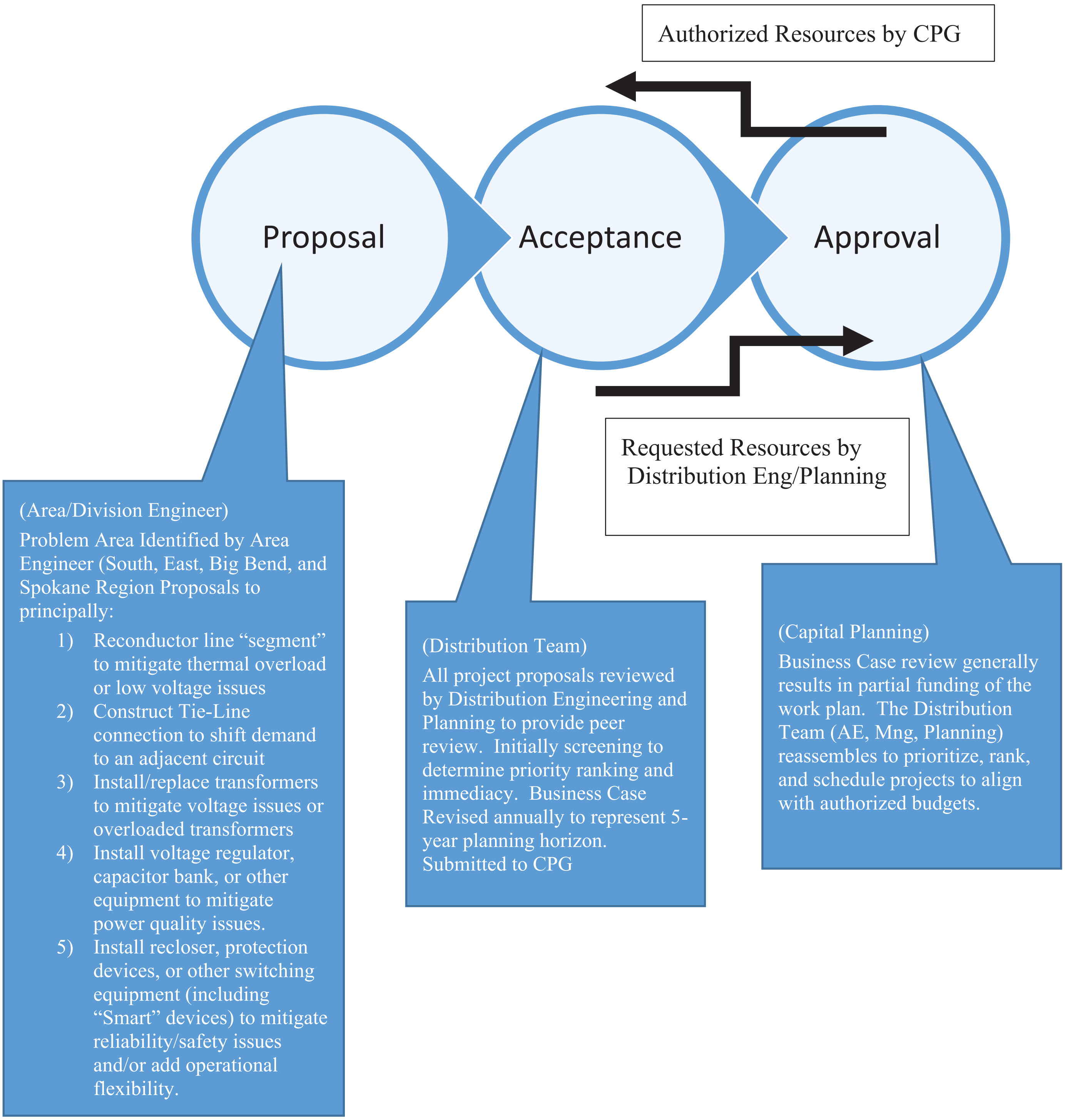
Cesar Godinez – Distribution Engineering Manager

The steering committee meets monthly to review projects and construction processes and discuss near term operating conditions. The team also meets quarterly to focus attention and resources on the system planning needs for grid capacity, service revisions, and substation capacity.

Decision Making Process

The decision model is represented by individual ‘proposals’ coupled with joint review and acceptance by distribution engineering and distribution system planning. The project ‘proposals’ typically consist of a Project Requirement Diagram (PRD) that outlines the scope of the project and includes supporting calculations and documentation. The program’s business case is modified annually to reflect the 5-year work plan. The Capital Planning Group then reviews all of the submitted business cases and prioritizes and allocates resources across the organization. *Distribution infrastructure is not part of the “Engineering Roundtable” with the exception of distribution substations.*

The Distribution System Enhancements business case decision model is illustrated on the next page.


Authorized Resources by CPG
Proposal
Acceptance
Approval
Requested Resources by Distribution Eng/Planning
(Area/Division Engineer)
Problem Area Identified by Area Engineer (South, East, Big Bend, and Spokane Region Proposals to principally:
1) Reconductor line "segment" to mitigate thermal overload or low voltage issues
2) Construct Tie-Line connection to shift demand to an adjacent circuit
3) Install/replace transformers to mitigate voltage issues or overloaded transformers
4) Install voltage regulator, capacitor bank, or other equipment to mitigate power quality issues.
5) Install recloser, protection devices, or other switching equipment (including "Smart" devices) to mitigate reliability/safety issues and/or add operational flexibility.
(Distribution Team)
All project proposals reviewed by Distribution Engineering and Planning to provide peer review. Initially screening to determine priority ranking and immediacy. Business Case Revised annually to represent 5-year planning horizon. Submitted to CPG
(Capital Planning)
Business Case review generally results in partial funding of the work plan. The Distribution Team (AE, Mng, Planning) reassembles to prioritize, rank, and schedule projects to align with authorized budgets.

The undersigned acknowledge they have reviewed the *Distribution System Enhancements* business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Cesar Godinez
Digitally signed by Cesar Godinez
DN: C=US, E=cesar.godinez@avistacorp.com, O=Avista Utilities, OU=Distribution Engineering, CN=Cesar Godinez
Reason: I attest to the accuracy and integrity of this document
Date: 2020.07.08 12:23:28-07'00'
Date:
Print Name: Cesar Godinez
Title: Distribution Engineering Manager
Role: Business Case Owner

Signature: Date:
Print Name: Josh DiLuciano
Title: Director of Electrical Engineering
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

EXAMPLES SHOWN FOR ILLUSTRATION:

FDR Status Report (provides baseline circuit performance and logistics information) Warning Level (yellow highlight),

Third & Hatch

3HT12F1

Service Area	Spokane		
Trunk [Mi]	2.11		
Lat. [Mi]	7.12		
Predom. Conductor	556AAC		
Nom. Volt. [kV]	13.2	Per Phase KVA	
# Customers	642	A:	9956
Conn. kVA	29173	B:	9219
Peak KVA	11411	C:	9998
Utilization factor	0.391		
Scada Status	3-Phase		
Pri. Meter Customer			

Notes

2015	Feeder Demand (A) AΦmax	BΦmax	CΦmax	BΦavg	Imbal. (%)	Peak Reactive (KVAR)	Station Regs (Buck Boost) AΦ		BΦ		CΦ	
Winter	326	272	292	199.2	7.5%	-35.50	-9	-2	-10	-2	-9	-1
Spring	318	294	322	142.7	7.9%	110.46	-10	-1	-10	0	-9	-1
Summer	387	380	394	212.8	7.7%	753.85	-9	4	-9	2	-9	4
Fall	395	347	377	215.6	9.1%	351.60	-10	3	-10	2	-9	3

Year	Historical Demand (A) Summer	Winter
13	336	272
14	372	302
15	380	298

Capacitor Information

Cap ID	KVAR Rating	Status	Smart ID	Location
71378	600	ON	Z906F	(126 - 149) S Scott
82259	600	ON	Z907F	(1 - 99) E Main

Year	Reliability SAIFI	CAIDI
10	0.18	1:10:09
11	1.23	1:22:32
12	2.11	1:34:54
13	0.06	6:10:04
14	0.09	3:31:01
15	0.45	6:47:31

(Reliability data disregards major event days)

Feeder Health Check

	Value	Cond.	Section ID
Max Loading (%)	62.02	556AAC	389-445931-0
Location:	Pacific-2nd and Scott		
Min. Volts (V)	123.08	1CN15	394-2660217-0
Location :	Under the WSU Riverpoint Campus		

2015 5 Worst Outages

Incident ID	Date	Cust. Hrs.	# Eff Cus.	Dur.	Cause	Location
866563	7-Dec	1014:46:08	152	6:40	Pole Fire	1036 E DESMET AVE UNIT 8
867075	8-Dec	593:50:08	53	11:12	Car Hit Pole	523 E 3RD AVE
868558	15-Dec	222:48:45	25	8:54	Maint/Upgrade	902 E BOONE AVE
790350	8-May	54:22:14	22	2:28	Maint/Upgrade	(1000 - 1098) E Sharp-Sinto
786456	19-Mar	24:11:30	5	4:50	Maint/Upgrade	(800 - 929) E Sprague

Distribution "500 Amp" Plan (System Planning)

Company standard for the operation and load service planning associated with Avista's electric distribution grid.

Key elements-- Urban "FRD Tie" system. Requires that reserve capacity margins be maintained so that adjacent circuits can restore service to customers in the event of a planned or forced outage. In summary, no urban circuit should be loaded above its 67% capacity limit.

System Limits - Operating & Design

The following set of proposed service limits are based on traditional company service reliability and practices, as well as appropriate state and federal rules and regulations. These are guidelines only, specific situations will arise where these limits must be exceeded because of physical or economic problems.

1. Maximum Outage - 3 hrs.

   This is an approximate number heavily weighted by the political influence of "Keeping the Customer Happy". Avista urban customer service record has been quite good in the past and should be maintained at a high level.

2. Maximum Portion of Customers Served to See Full Length of Outage - 50%

   For example: Feeder outage - 50% of customers on that feeder)
   Substation outage - 50% of customers served by that substation)

   This again is an arbitrary number. However, it is the worst case possibility using the substation connections and feeder sectionalizing practice that is being recommended as General Design Criteria for the future. Most cases would result in a smaller number of customers seeing full outage duration.

Excerpt from "500 Amp" Plan. Source: Distribution SharePoint (3/15/17)

Avista's SCADA monitoring system incorporates a temperature compensated thermal ampacity rating system known internally as SVL (Scada Variable Limit). SVL has been in use since 1993. The following indicates a summary screen indicating the top ten most heavily loaded (by % capacity) transmission lines, substation power transformers, and distribution circuits. This screen is continuously monitored by System Operators but also used by Area Engineers to capture data during peak load conditions. It provides additional data to aid with project planning for the distribution system enhancements program.

SCADA Variable Limits

Top 10 Lists

Note 1: It may be necessary to manually refresh this display to update the sort order.

Last Ran: 02-Jul-2013 15:39:49

BEACON Temperature Was: 98.1 F

Recalc

Top 10 (% Of Rated) Transmission Breakers

				Reading At Last Run	Rated Limit	% Of Rated
1	OROFINO	CB	A343	451.0	563.2	80.1
2	STRATFRD	CB	A46	435.1	571.5	76.1
3	STRATFRD	CB	A50	455.4	600.0	75.9
4	WARDEN	CB	A310	521.0	711.1	73.3
5	WARDEN	CB	A253	212.0	291.6	72.7
6	PINE_PUD	CB	RATHDRUM_LINE	424.0	596.4	71.1
7	CLEARWTR	CB	A217	383.6	575.5	66.7
8	NLEWISTN	CB	A588	382.5	575.5	66.5
9	NOXON	CB	R316	674.4	1177.2	57.3
10	RATHDRUM	CB	CAB_LINE	676.5	1183.5	57.2

Top 10 (% Of Rated) Transformers

				Reading At Last Run	Rated Limit	% Of Rated
1	NRTHEAST	XFMR	#2	834.7	983.5	84.9
2	CDALENE	XFMR	#2	1221.0	1467.7	83.2
3	10TH_STW	XFMR	#1	773.7	960.9	80.5
4	BARKERRD	XFMR	#1	780.6	983.5	79.4
5	COLBERT	XFMR	BPAT_COLBERT	767.0	983.5	78.0
6	DALTON	XFMR	#2	754.3	978.5	77.1
7	AIRWYHGT	XFMR	#2	752.4	983.5	76.5
8	PRAIRIE	XFMR	#2	669.1	875.6	76.4
9	WAIKIKI	XFMR	#1	746.7	983.5	75.9
10	POUNDLN	XFMR	#1	709.7	960.9	73.9

Top 10 (% Of Rated) Feeders

				Reading At Last Run	Rated Limit	% Of Rated
1	MILLWOOD	CB	12F4	471.0	537.6	87.6
2	CDALENE	CB	124	457.2	532.9	85.8
3	POUNDLN	CB	1201	420.8	516.5	81.5
4	WAIKIKI	CB	12F2	430.0	537.6	80.0
5	ROSSPARK	CB	12F5	429.0	537.6	79.8
6	WAIKIKI	CB	12F3	422.8	537.6	78.7
7	9TH_CENT	CB	12F4	340.0	435.0	78.2
8	SANDPNT	CB	4S23	238.0	307.7	77.4
9	CRTCHFLD	CB	1210	396.0	516.5	76.7
10	10TH_STW	CB	1256	392.4	516.5	76.0

FDR by Area. Shown only to illustrate the scale of the effort to monitor our distribution system.

REV	6/20/2019		FDR BY AREA ENGINEER -- DISTRIBUTION ENG. SHAREPOINT									
Tim Figart, Jon Gilrein			Chris Dux			Marshall Law			Marc Lippincott	Dan Knutson		Brian Chain
Spokane	Spokane	Deer Park	Mos/Pull	L/C	Grangeville	CDA	Kell/St. M	Sandpoint	Colville	Davenport	Othello	DT NTWK
3HT12F1	L&S12F1	CLA56	DER651	CFD1210	COT2401	APW111	BIG411	BLA311	ARD12F2	DVP12F1	L&R511	PST13521
3HT12F2	L&S12F2	COB12F1	DER652	CFD1211	COT2402	APW112	BIG412	CGC331	CHW12F2	DVP12F2	L&R512	PST13522
3HT12F3	L&S12F3	COB12F2	DIA231	DRY1208	CRG1260	APW113	BIG413	CKF711	CHW12F3	FOR12F1	L&R516	PST13523
3HT12F4	L&S12F4	DEP12F1	DIA232	DRY1209	CRG1261	APW114	BUN422	CKF712	CHW12F4	FOR2.3	LIN711	PST13524
3HT12F5	L&S12F5	DEP12F2	ECL221	HOL1205	CRG1263	APW115	BUN423	NRC351	CLV12F1	HAR12F1	LIN712	PST13526
3HT12F6	LIB12F1	LOO12F1	ECL222	HOL1206	GRV1271	APW116	BUN424	ODN731	CLV12F2	HAR12F2	OTH501	PST13527
3HT12F7	LIB12F2	LOO12F2	EWN241	HOL1207	GRV1272	AVD151	BUN426	ODN732	CLV12F3	LF34F1	OTH502	PST13528
3HT12F8	LIB12F3	MLN12F1	GAR461	LMR1530	GRV1273	AVD152	LKY551	OLD721	CLV12F4	LL12F1	OTH503	PST13529
9CE12F1	LIB12F4	MLN12F2	JUL661	LMR1531	GRV1274	BLU321	LKY552	OLD722	CLV34F1	ODS12F1	OTH505	MTR13632
9CE12F2	MEA12F1		JUL662	LMR1532	KAM1291	BLU322	MIS431	PRV751	GIF12F1	RDN12F1	RIT731	MTR13633
9CE12F3	MEA12F2		LAT421	LOL1266	KAM1292	CDA121	OGA611	PRV752	"GIF34F1	RDN12F2	RIT732	MTR13634
9CE12F4	MIL12F1		LAT422	LOL1359	KAM1293	CDA122	OSB521	SAG741	GIF34F2	WIL12F1	ROX751	MTR13636
9CE12F5	MIL12F2		LEO611	NLW1222	KOO1298	CDA123	OSB522	SAG742	GIF12F1	WIL12F2	SOT521	MTR13637
9CE12F6	MIL12F3		LEO612	NLW1321	KOO1299	CDA124	PIN441	SPT4S21	GRN12F1	"GIF34F1	SOT522	MTR13638
AIR12F1	MIL12F4		M15511	PDL1201	NEZ1267	CDA125	PIN442	SPT4S22	GRN12F2		SOT523	
AIR12F2	NE12F1		M15512	PDL1202	ORO1280	DAL131	PIN443	SPT4S23	GRN12F3		SPR761	
AIR12F3	NE12F2		M15513	PDL1203	ORO1281	DAL132	STM631	SPT4S30	KET12F1		WAS781	
BEA12F1	NE12F3		M15514	PDL1204	ORO1282	DAL133	STM632		KET12F2			
BEA12F2	NE12F4		M15515	SLW1316	WEI1289	DAL134	STM633		ORI12F1			
BEA12F3	NE12F5		M23621	SLW1348	WIK1278	HUE141	WAL542		ORI12F2			
BEA12F4	NW12F1		NMO521	SLW1358	WIK1279	HUE142	WAL543		ORI12F3			
BEA12F5	NW12F2		NMO522	SLW1368		LKV341	WAL544		SPI12F1			
BEA12F6	NW12F3		PAL311	SWT2403		LKV342	WAL545		SPI12F2			
BEA13T09	NW12F4		PAL312	TEN1253		LKV343			VAL12F1			
BKR12F1	NW13T23		POT321	TEN1254		IDR251			VAL12F2			
BKR12F2	OPT12F1		POT322	TEN1255		IDR252			VAL12F3			
BKR12F3	OPT12F2		TUR 111	TEN1256		IDR253						
C&W12F1	PST12F1		TUR 112	TEN1257		PF211						14
C&W12F2	PST12F2		TUR 113			PF212					SEC. NETWORK	
C&W12F3	ROS12F1		TUR115			PF213						
C&W12F4	ROS12F2		TUR 116			PRA221						
C&W12F5	ROS12F3		TUR 117			PRA222						
C&W12F6	ROS12F4		ROK451			PVW241						
CHE12F1	ROS12F5		RSA431			PVW243						
CHE12F2	ROS12F6		SPA442			RAT231						
CHE12F3	SE12F1		SPU121			RAT233						
CHE12F4	SE12F2		SPU122			SPL361						
EFM12F1	SE12F3		SPU123									
EFM12F2	SE12F4		SPU124									
F&C12F1	SE12F5		SPU125									
F&C12F2	SIP12F1		TKO411									
F&C12F3	SIP12F2		TKO412									
F&C12F4	SIP12F3		TVW131									
F&C12F5	SIP12F4		TVW132									
F&C12F6	SIP12F5		WOR471									
FWT12F1	SLK12F1											
FWT12F2	SLK12F2											
FWT12F3	SLK12F3											
FWT12F4	SUN12F1											
GRA 12F1	SUN12F2											
GRA 12F2	SUN12F3											
GRA 12F3	SUN12F4											
GLN12F1	SUN12F5											
GLN12F2	SUN12F6											
H&W12F1	WAK12F1											
H&W12F2	WAK12F2											
H&W12F3	WAK12F3											
H&W12F4	WAK12F4											
H&W12F5												
H&W12F6												
INT12F1												
INT12F2												

"GIF34F1 shared by Colville and Davenport offices

Non-Avista & Customer dedicated FDRs omitted

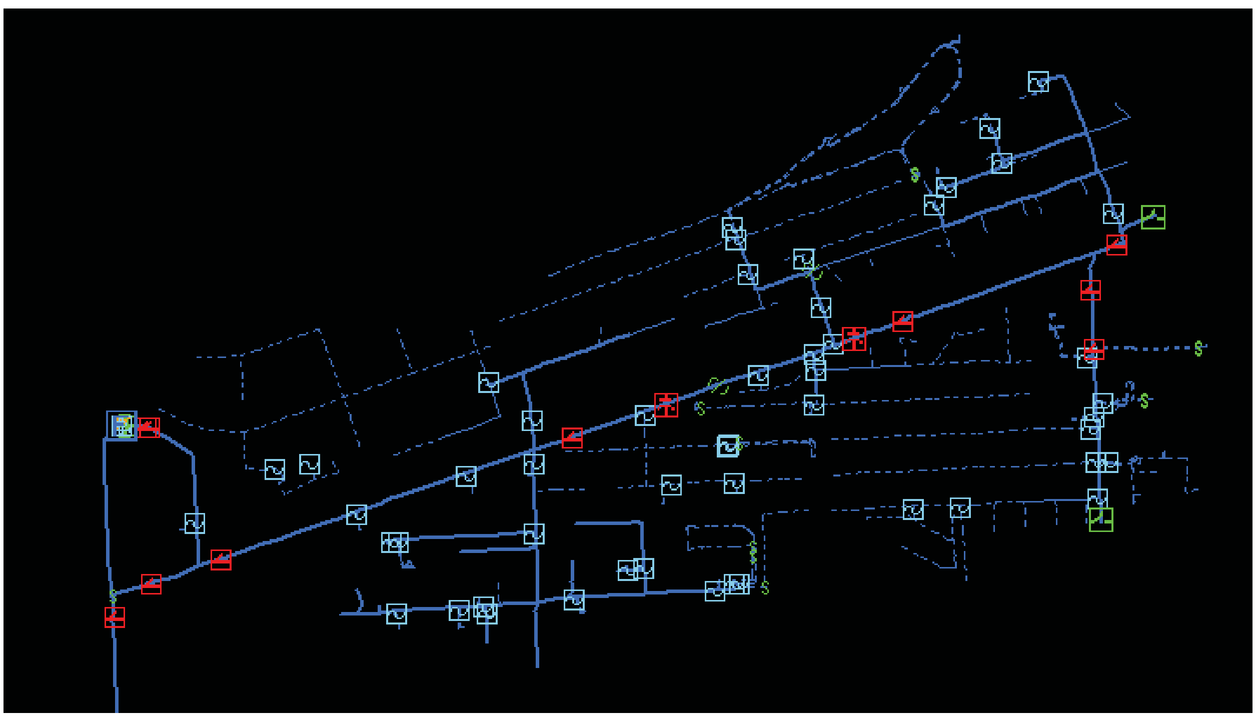
# by Area Engr	FDR Count	
Spokane	129	DMS
South	94	3PH SCADA
East	77	1PH SCADA
Colville	26	
Big Bend	31	
Total	**357**	

REV NOTES	LMR	LEWISTON MILL ROAD ENERGIZATION FALL 2014
12/10/2013	NLW	N LEW 13 KV SUB MOVED TO N LEWISTON 230 KV 2014
12/10/2013	GRA	NEW GREENACRES SUB 2015
9/23/2014	GIF	ADD 13 KV AT GIFFORD IN 2015
9/24/2014	RAT	231 and 233 DMS
7/20/2016	HAR	4KV CONVERSION, ASSIGN DAV TO BB
8/26/2016	HER	HERN DEL
6/1/2018	9CE	ADD 12F5&6
6/1/2018	DEP	3 PHASE SCADA
6/1/2018	KAM	SUB RB DMS RD
6/1/2018	GIF	ADD 12F1
6/1/2018	LINESCOPE	ADD NOTATION (RED FONT)
6/1/2018	NTWK	ADD NTWK FDR LIST
6/20/2019	LIN	ADDED 712 and DMS
6/20/2019	L&R	ADDED 516 and DMS

Synergi Computer Modeling (Millwood 12F4 screen shot)

Computer simulation is the primary tool used to identify and develop strategies to mitigate a thermal overload condition. Note, that Avista's electric distribution system has been developed over the full course of the Company's operating history and infrastructure installed near the turn of the century (1900) is still in-service. Though current Avista construction standards limit the number of overhead primary wires to four (4): #4 ASCR, 2/0 ACSR, 336 AAC, 556 AAC; Avista maintains a fleet of seventy five (75) different primary wires and cables. Many are no longer available commercially and we maintain 'hand coils' salvaged from project work in order to effect maintenance repairs on those conductor segments. We ceased to install overhead copper conductors in the 1950's though today, thousands of miles of #6A, #6CW, and other copper conductors remain in service.

Synergi Computer System: Millwood 12F4 Circuit



Rattlesnake Flat Wind 115kV Integration Project

1 GENERAL INFORMATION

Requested Spend Amount	$19,789,874
Requesting Organization/Department	Transmission Services
Business Case Owner	Josh DiLuciano
Business Case Sponsor	Heather Rosentrater
Sponsor Organization/Department	T&D
Category	Project
Driver	Customer Requested

1.1 Steering Committee or Advisory Group Information

- Ken Sweigart – Manager, Transmission Line Design Engineering
- Glenn Madden – Manager, Substation Engineering
- Project Engineer/Project Manager – Aaron Tremayne and Adam Newhouse
- Randy Gnaedinger – Transmission Contracts Analyst

The assigned PE/PM holds stakeholder meetings to develop/confirm scope, schedule and costs. Also meets at time of pre-construction. Other meetings held as necessary.

2 BUSINESS PROBLEM

The Interconnection Customer representing the Rattlesnake Flat Wind Farm Development (Avista Interconnection Project #49) has proposed construction of a new 144MW nameplate capacity wind generation facility, and has chosen an interconnection to Avista's Lind-Washtucna 115kV Transmission Line at a point approximately 4.5 miles southeast of Avista's Lind Substation. The Point of Interconnection (POI) will be the new 3-position ring bus Neilson Substation with a line position dedicated to the Interconnection Customer. The Interconnection Customer chose the POI from a number of options developed by Avista's Transmission Planning Group during the FERC-mandated interconnection study process. Per the FERC process, the Interconnection Customer and Avista have signed an Interconnection Agreement that include required milestones for completion of this project.

These milestones include, the Interconnection Customer providing deposits totaling $1,041,500 (equivalent to the project's associated Direct Assigned Costs) in the 2018-2019 time frame, and Avista's completion of the project with an in service date prior to September 30, 2020.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alt 1: Status Quo: Do nothing.			
Alt 2: Build Network Upgrade Facilities required to support the Rattlesnake Flat Wind Farm nameplate output of 144MW.	*$19,789,874*	*2018*	*2020*

Due to the nature of the rules governing the Interconnection Process the POI location is selected by the Interconnection Customer, therefore only one alternative is shown.

Alternative 1:

This alternative is not recommended because it does not comply with rules set forth by FERC governing interconnection requests. Options are available for funding, design, and construction, but not as to whether the project can be avoided.

Alternative 2:

This alternative meets the requirements of the Interconnection Customer's request, and best satisfies the integration requirements of the wind project. This alternative also addresses a Transmission Line Asset Condition project (Lind-Warden) previously identified and prioritized to construct in the 2018-2019 time frame. This alternative is the best solution for the long term.

Solution:

Alternative 2: The scope recommended consists of the following:

Transmission Provider Network Upgrades	
Rebuild 22 miles of 115 kV transmission with OPGW from Lind-Warden – permitting, engineering, design, procurement and construction (includes Distribution Underbuild)	$11,150,000
Rebuild 4.5 miles of 115 kV transmission with Optical Ground Wire (OPGW) from Neilson to Lind – permitting, engineering, design, procurement and construction (includes Distribution Underbuild)	$ 2,900,000
Point of Interconnection 115 kV Substation (Neilson) – engineering, design, procurement and construction of (2) line positions, protection and control of a 3-position ring bus station	$ 2,500,000
Construct Communications Path(s) for Operation of the (POI) 115 kV Neilson switching station, Lind Substation, and Warden Substation – engineering, design, licensing, land acquisition, building construction, and installation	$ 689,874
Lind Substation capacity upgrades 115 kV substation –engineering, design, procurement and installation of protection and control (two relay upgrades and mobile installation)	$ 550,000
Replacement of the Roxboro circuit switcher - engineering, design, procurement and installation of protection and control (includes mobile installation)	$ 250,000
Warden Substation capacity upgrades - engineering, design, procurement and installation of protection and control (two breaker replacements, two relay upgrades, and one relay modification)	$ 1,250,000
Othello Switching Station capacity upgrades - engineering, design, procurement and installation of protection and control construction (two relay upgrades)	$ 500,000

Subtotal Network Upgrades	**$ 19,789,874**

IN SERVICE: 8/31/2020

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Rattlesnake Flat Wind 115kV Integration Project* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 4/22/19
Print Name: Josh DiLuciano
Title: Director
Role: Business Case Owner

Signature: [signature] Date: 4-22-19
Print Name: Heather Rosentrater
Title: VP, Energy Delivery
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*<Author name>*	*mm/dd/yy*	*<name>*	*mm/dd/yy*	*Initial version*

Template Version: 03/07/2017

EXECUTIVE SUMMARY

Avista is a joint owner in the 500kV Colstrip Transmission System and party to the Colstrip Project Transmission Agreement ("Agreement"). Under Federal Energy Regulatory Commission ("FERC") rules and the Agreement, Avista must comply with all rules and procedures governing the interconnection of new generation facilities with the Colstrip Transmission System. Pursuant to the Agreement, Clearwater Energy Resources, LLC requested interconnection of a 750MW wind project at Broadview ("Clearwater Wind Project"), all required study processes were completed, and Avista executed a Large Generator Interconnection Agreement with the developer on May 22, 2019 ("LGIA").

Avista and the joint owners of the Colstrip Transmission System are obligated to fund their respective shares of all Transmission Provider Interconnection Facilities and Network Upgrades applicable to the interconnection of a Large Generator Interconnection project. Failure to fund this project will result in Avista being in breach of both the Agreement and the LGIA, and would be a violation of FERC rules governing generation interconnection. Such obligations arise from Avista's ownership in the Colstrip Transmission System, which has benefited Avista retail native load customers over the life of the Colstrip Project.

Avista's allocation of costs for the construction of required facilities for the Clearwater Wind Project was originally estimated to be $650,600, in 2018 dollars. The original Business Case was submitted and approved, July, 2019. Overall project cost was reduced to $570,000 per the in-year adjustment request approved June 17, 2020. Applicable service code and jurisdiction are 098-ED, common system-wide, electric direct.

VERSION HISTORY

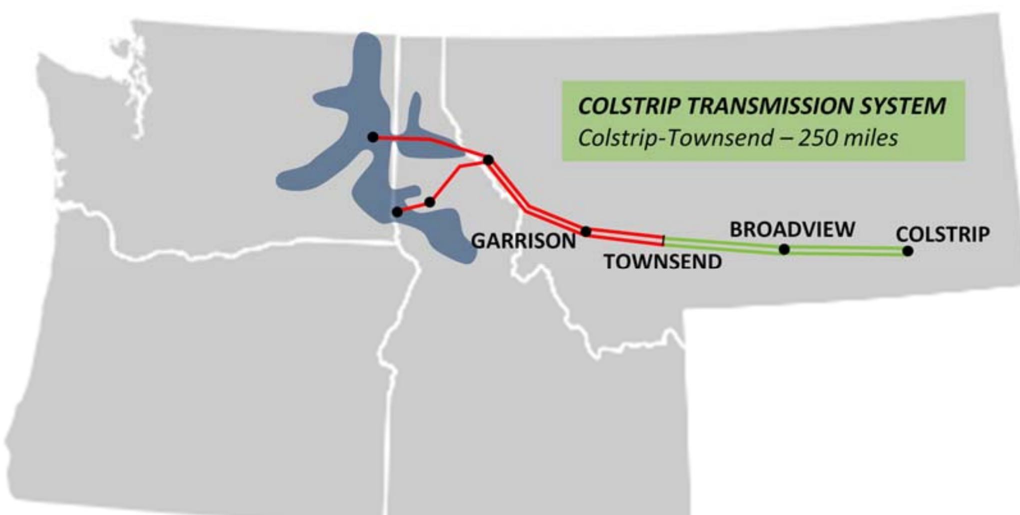
Version	Author	Description	Date	Notes
1.0	*Jeff Schlect*	*Initial narrative drafted from pre-existing approved case*	*7/30/2020*	*Existing Approved Case*

GENERAL INFORMATION

Requested Spend Amount	$570,000
Requested Spend Time Period	*2 years (2020-2021)*
Requesting Organization/Department	Energy Delivery / Transmission Services
Business Case Owner | Sponsor	Jeff Schlect | Heather Rosentrater / Mike Magruder
Sponsor Organization/Department	Energy Delivery / Transmission Services
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

Per the Agreement, Avista is a joint owner (joint tenants in common) of the Colstrip Transmission System, which consists of approximately 250 miles of double circuit 500kV transmission facilities extending from the Colstrip Project westward to the Broadview 500kV Substation and the Townsend point of interconnection between the Colstrip Transmission System and the Bonneville Power Administration's Eastern Intertie 500kV facilities[1]. Under FERC rules and the Agreement, Avista must comply with all rules and procedures governing the interconnection of new generation facilities with the Colstrip Transmission System. Pursuant to the Agreement, Clearwater Energy Resources, LLC requested interconnection of its 750MW Clearwater Wind Project to the Colstrip Transmission System at Broadview. All required study processes were completed and Avista executed a Large Generator Interconnection Agreement with the developer on May 22, 2019 ("LGIA").



[1] Avista owns a 10.2% share in the Colstrip-Broadview segment and a 12.1% share in the Broadview-Townsend segment.

Avista and the joint owners of the Colstrip Transmission System are obligated to fund their respective shares of all Transmission Provider Interconnection Facilities and Network Upgrades applicable to the interconnection of a Large Generator Interconnection project. NorthWestern Energy ("NWE") performs all Transmission Operator functions under the Agreement, including construction budgeting and forecasting for Colstrip Transmission System facilities. Avista's allocation of costs for the construction of required facilities for the Clearwater Wind Project was originally estimated to be $692,000 to be split equally between 2020 and 2021. An updated forecast received from NorthWestern Energy on June 1, 2020, outlined an overall project decrease (from $692,000 to $570,000) along with a timing adjustment between 2020 and 2021 (2020 - $110,000; 2021 - $460,000).

1.1 What is the current or potential problem that is being addressed?

Pursuant to the Agreement and its mandatory compliance requirements with FERC generation interconnection rules, the Company must fund its applicable ownership share of constructions costs associated with generation interconnection projects, including the Clearwater Wind Project.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer.

The applicable driver for the Company's construction investment in FERC jurisdictional generation interconnection projects *Mandatory & Compliance.*

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

Failure by the Company to provide construction funding for this project would be: (i) an act of default under Section 25 of the Agreement, (ii) an act of default under the LGIA, and (iii) a violation of FERC rules pursuant to which the Company could incur compliance penalties of up to $1 million per day. The Clearwater Wind Project is currently planned for completion in 2021 but, depending upon action or inaction by the developer under the LGIA, the project and related funding may be delayed.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Appendix B to the LGIA incorporates construction milestones for the project.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

Clearwater Wind Project #234 Feasibility Study Report (NWE)
Clearwater Wind Project #234 System Impact Study Report (NWE)
Clearwater Wind Project #234 Facilities Study Report (NWE)

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Not applicable

The Company must fund its allocated share of capital improvements under the Colstrip Transmission Agreement, the LGIA and FERC rules.

Option	Capital Cost	Start	Complete
Fund Network Upgrades under LGIA	*$570,000*	*01 2020*	*12 2021*
Default on agreements and violate FERC rules	*N/A*	*N/A*	*N/A*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Not applicable – Mandatory and Compliance driver

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

2020 – Design, engineering and procurement

2021 – Construction

No related O&M reductions are expected with this project

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Capital funding only; no engineering or construction labor impacts to the Company. NWE performs all construction and administration activities as Transmission Operator under the Agreement.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Not applicable (only alternative is to not fund as outlined under 1.3 above)

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

NWE, as the Transmission Operator under the Agreement, manages the Colstrip Transmission System construction program. Investments become used and useful and are placed in service following construction completion and energization.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Business Case investment upholds the Company's Code of Conduct and is consistent with its lasting values. Such investment complies with applicable contract obligations and FERC rules.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project.

Capital investment under this Business Case is mandatory – required by contract and FERC rules. As outlined in 1.3 above, failure by the Company to provide construction funding for this project would be: (i) an act of default under Section 25 of the Agreement, (ii) an act of default under the LGIA, and (iii) a violation of FERC rules pursuant to which the Company could incur compliance penalties of up to $1 million per day.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Counterparties to the Colstrip Transmission Agreement, joint owners of the Colstrip Transmission System, and joint parties to the LGIA – NorthWestern Energy, PacifiCorp, Portland General Electric and Puget Sound Energy

LGIA Counterparty – Clearwater Energy Resources, LLC

Bonneville Power Administration – Transmission entity interconnecting with the Colstrip Transmission System at the point of change of ownership near Townsend, MT

2.8.2 Identify any related Business Cases

Colstrip Transmission

3.1 Steering Committee or Advisory Group Information

The Colstrip Transmission Committee, of which the Company is a member, meets periodically to review construction funding associated with the Colstrip Transmission System, including generation interconnection projects. The Company's Transmission Services department administers the LGIA.

3.2 Provide and discuss the governance processes and people that will provide oversight

Pursuant to Section 22 of the Agreement, the Colstrip Transmission Committee is established to facilitate cooperation, interchange of information and efficient management of the Colstrip Transmission System. The Colstrip Transmission Committee consists of five members, each designated by one of the parties to the Agreement. Each committee member has the right to vote their party's ownership share in the Colstrip Transmission System. The Company's Transmission Services department participates on the Colstrip Transmission Committee and administers the LGIA.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Such items are reviewed by the Colstrip Transmission Committee and documented by NWE as the Transmission Operator under the Agreement.

The undersigned acknowledge they have reviewed the Clearwater Wind Generation Interconnection Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	
Print Name:	Jeff Schlect		
Title:	Senior Manager, FERC Policy and Transmission Services		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	Mike Magruder		
Title:	Director, Transmission Operations and System Planning		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

The undersigned acknowledge they have reviewed the Clearwater Wind Generation Interconnection Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeff Schlect Digitally signed by Jeff Schlect Date: 2020.07.30 17:30:45 -07'00'	Date:	7/30/2020
Print Name:	Jeff Schlect		
Title:	Senior Manager, FERC Policy and Transmission Services		
Role:	Business Case Owner		

Signature:	Michael A. Magruder Digitally signed by Michael A. Magruder Date: 2020.07.31 12:22:28 -07'00'	Date:	7/31/2020
Print Name:	Mike Magruder		
Title:	Director, Transmission Operations and System Planning		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

Avista is a joint owner in the 500kV Colstrip Transmission System and party to the Colstrip Project Transmission Agreement ("Agreement"). Avista and the joint owners are obligated to fund their respective shares of the Colstrip Transmission System construction and maintenance budgets, as approved by the Colstrip Transmission Committee, which consists of representatives of each of the parties to the Agreement. The Colstrip Transmission Committee reviews and approves, on an annual basis, the capital and O&M expense program proposed by NorthWestern Energy ("NWE") (the designated Transmission Operator under the Agreement). Pursuant to Section 22 of the Agreement, Avista provides annual input to, and approval for, the Colstrip Transmission System capital and O&M expense program commensurate with its ownership shares in the Colstrip Transmission System.[1]

In conjunction with the Company's ownership interest in Colstrip Project Units 3 and 4, the Colstrip Transmission System has benefited the Company's retail native load customers since the early 1980's. To continue to reliably integrate the Company's Colstrip Project resources to native load and to meet applicable NERC transmission planning and operational reliability standards, the Colstrip Transmission System must be maintained. Examples of recent and pending capital expenditures in the Colstrip Transmission System include end-of-life replacement of 500kV power circuit breakers at the Colstrip 500/230kV Station and 500kV structure relocation to mitigate erosion risk caused by high runoff in the Little Big Horn River.

Colstrip Transmission program expenditures have averaged $348,000 over the past ten years. NWE's latest draft plan was released in July, 2020, outlining a five-year (2020-2024) average program expense of $516,000. The original Business Case was submitted and approved in April, 2017. Applicable service code and jurisdiction are 098-ED, common system-wide, electric direct.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Jeff Schlect*	*Initial narrative drafted from pre-existing approved case*	*7/28/2020*	*Existing Approved Case*

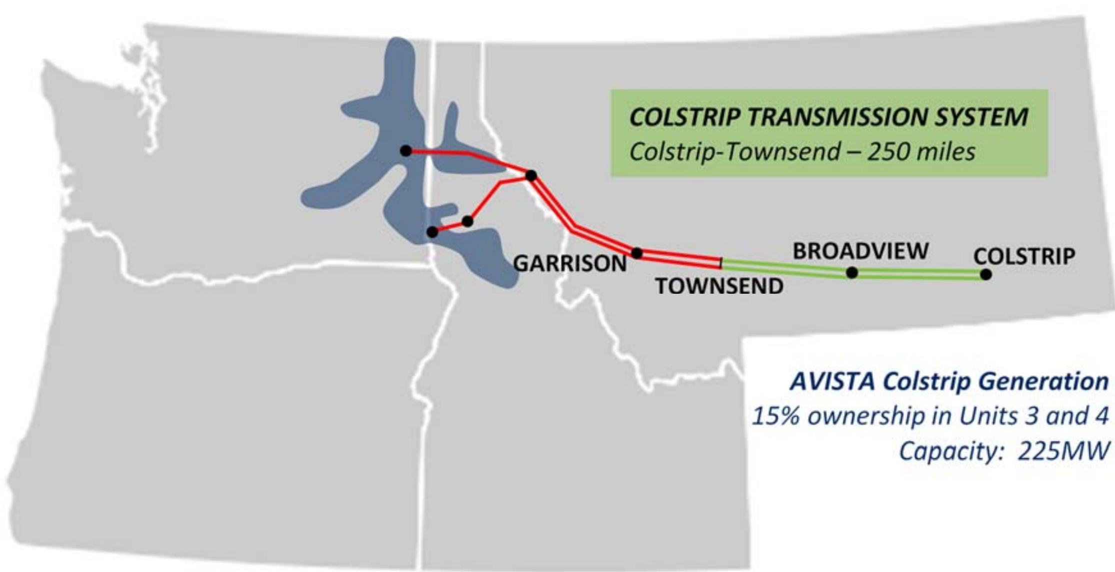
[1] Avista owns a 10.2% share in the Colstrip-Broadview segment and a 12.1% share in the Broadview-Townsend segment.

GENERAL INFORMATION

Requested Spend Amount	$724,000 (2021)
Requested Spend Time Period	*Ongoing Annual Program*
Requesting Organization/Department	Energy Delivery / Transmission Services
Business Case Owner | Sponsor	Jeff Schlect | Heather Rosentrater / Mike Magruder
Sponsor Organization/Department	Energy Delivery / Transmission Services
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

As part of the construction and integration of Colstrip Units 3 and 4 in the early 1980s for the benefit of the Company's native load retail customers, the Colstrip project participants constructed the Colstrip Transmission System, approximately 250 miles of double circuit 500kV transmission facilities extending from the Colstrip Project westward to the Broadview 500kV Substation and the Townsend point of interconnection between the Colstrip Transmission System and the Bonneville Power Administration's Eastern Intertie 500kV facilities.



Avista owns a 15% share of Colstrip Units 3 and 4 (approximately 225MW). Reliable operation of the Colstrip Transmission System is necessary to transfer Colstrip output to the respective systems of each joint project owner, including Avista (other project owners are: NorthWestern Energy, PacifiCorp, Portland General Electric and Puget Sound Energy). Avista and the other joint project owners are party to the Colstrip Project Transmission Agreement which, among other things, obligates Avista to fund its commensurate share of all construction and maintenance expenses for the ongoing operation, maintenance, renewal and replacement of the jointly owned Colstrip Transmission System facilities.

Examples of recent expenditures in the Colstrip Transmission System are noted in Section 2.2 below.

As NERC transmission planning and operational reliability standards[2] evolve, compliance with both operational and planning standards may require replacement of, or upgrades to, Colstrip Transmission System facilities.

1.1 What is the current or potential problem that is being addressed?

Pursuant to the Agreement, the Company must fund its applicable ownership share of capital improvements to the jointly owned Colstrip Transmission System.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer.

The Company's capital investment in the Colstrip Transmission System is driven by its contractual obligations under the Agreement (*Mandatory & Compliance*). Related drivers include *Asset Condition* and *Failed Plant & Operations.*

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

Failure to fund its allocated share of costs under the Agreement will put the Company into default and would eliminate the Company's right to use the Colstrip Transmission System to integrate its resources for service to its bundled retail native load customers.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Not applicable

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

Not applicable

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Not applicable

The Company must fund its allocated share of capital improvements under the Colstrip Transmission Agreement.

[2] Among its other provisions, the U.S. Energy Policy Act of 2005 provided for the establishment of mandatory reliability standards and authorized the Federal Energy Regulatory Commission (FERC) to assess penalties of up to $1 million per day per violation for non-compliance with these standards and other FERC regulations. FERC has certified the North American Electric Reliability Organization (NERC) to establish and enforce these reliability standards. The Company has a statutory obligation to plan, improve, upgrade, and operate its transmission system, including the Colstrip Transmission System, to maintain compliance with these standards and is required to self-certify its compliance with these standards on an annual basis.

Option	Capital Cost	Start	Complete
Fund capital program under the Agreement	*$516,000*	*1981*	*Ongoing*
Do not fund – Contract default	*Undetermined*	---	---

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Additional Information – In addition to upholding the Company's contractual obligations and maintaining the ability to integrate its Colstrip generation output for service to its bundled retail native load customers, Colstrip Transmission program funding also provides the Company a future transmission alternative for consideration under the Company's Integrated Resource Planning process, to integrate potential renewable resources located in Montana.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

Capital amounts are used for improvements, renewals and replacements of Colstrip Transmission System assets. Examples of recent expenditures in the Colstrip Transmission System include:

- End-of-life replacement of 500kV power circuit breakers at the Colstrip 500/230kV Substation
- Erosion mitigation caused by record high runoff in the Big Horn River, threatening the stability of two 500kV structures
- Construction of optical ground wire (OPGW) communication facilities between Broadview and Colstrip to meet dual communication path requirements under North American Electric Reliability Corporation (NERC) standards
- 500kV relay replacements
- Hardware, software and operating system upgrades to maintain compliance with applicable operating standards

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Capital funding only; no engineering or construction labor impacts to the Company. NWE performs all construction and construction administration activities as Transmission Operator under the Agreement.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Not applicable (only alternative is to not fund and default on contract)

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

NWE, as the Transmission Operator under the Agreement, manages the Colstrip Transmission System construction program. Program investments, as improvements, renewals and replacements for the existing Colstrip Transmission System, become used and useful each year upon being placed in-service.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Program investment upholds the Company's Code of Conduct and is consistent with its lasting values. Colstrip Transmission System investment maintains the Company's ability to integrate its Colstrip generation assets for service to bundled retail native load customers and provides the Company with a future transmission alternative to integrate potential renewable resources located in Montana.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project.

Capital investment under the program is mandatory – required by contract – pursuant to the Agreement. The Company's ongoing ownership in the Colstrip Transmission System may be evaluated consistent with its assessment of potential future resource acquisitions in Montana under the Company's Integrated Resource Planning activities.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Avista Power Supply – Internal customer for the integration of resources designated for service to bundled retail native load customers

Counterparties to the Colstrip Transmission Agreement and joint owners of the Colstrip Transmission System – NorthWestern Energy, PacifiCorp, Portland General Electric and Puget Sound Energy

Bonneville Power Administration – Transmission entity interconnecting with the Colstrip Transmission System at the point of change of ownership near Townsend, MT

2.8.2 Identify any related Business Cases

Clearwater Wind Generation Integration

3.1 Steering Committee or Advisory Group Information

Pursuant to Section 22 of the Agreement, Avista provides annual input to, and approval for, the Colstrip Transmission System capital and O&M expense program commensurate with its ownership shares in the Colstrip Transmission System. The Colstrip Transmission Committee, of which the Company is a member, meets periodically to review, and provide recommendations for, the annual capital program administered by NWE. The Colstrip Transmission Committee provides approval for each year's capital program.

3.2 Provide and discuss the governance processes and people that will provide oversight

Pursuant to Section 22 of the Agreement, the Colstrip Transmission Committee is established to facilitate cooperation, interchange of information and efficient management of the Colstrip Transmission System. The Colstrip Transmission Committee consists of five members, each designated by one of the parties to the Agreement. Each committee member has the right to vote their party's ownership share in the Colstrip Transmission System. Section 22(f) of the Agreement outlines all matters that shall be submitted to the committee by NWE for approval, including Colstrip Transmission System construction and operating budgets.

With respect to long-term continuing ownership and participation in the Colstrip Transmission System, the Company's Power Supply and Transmission Services groups will, under the Company's Integrated Resource Planning process, analyze and assess such costs and benefits related to the integration of potential renewable resources located in Montana.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Such items are reviewed by the Colstrip Transmission Committee and documented by NWE as the Transmission Operator under the Agreement.

The undersigned acknowledge they have reviewed the Colstrip Transmission Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	
Print Name:	Jeff Schlect		
Title:	Senior Manager, FERC Policy and Transmission Services		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	Mike Magruder		
Title:	Director, Transmission Operations and System Planning		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

The undersigned acknowledge they have reviewed the Colstrip Transmission Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeff Schlect Digitally signed by Jeff Schlect Date: 2020.07.30 17:22:00 -07'00'	Date:	7/30/2020
Print Name:	Jeff Schlect		
Title:	Senior Manager, FERC Policy and Transmission Services		
Role:	Business Case Owner		

Signature:	Michael A. Magruder Digitally signed by Michael A. Magruder Date: 2020.07.31 12:21:25 -07'00'	Date:	7/31/2020
Print Name:	Mike Magruder		
Title:	Director, Transmission Operations and System Planning		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

NERC reliability standard PRC-002-2 defines the disturbance monitoring and reporting requirements to have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances. The methodology of Attachment A of the NERC standard was performed to identify the affected buses within the Avista BES. The Protection Systems must be capable of recording electrical quantities for each BES Elements it owns connected to the BES buses identified.

Non-compliance can carry a fine of up to a million dollars per day based on severity. This business case is important to customers because it allows analysis of system faults for the BES that can lead to continued stability and reliability of the electric system.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2016-07

Cost of Solution: $12,000,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Randy Spacek	Initial Version	7/11/2017	Initial Version
2.0	Glenn Madden	Revised to remove DRAFT watermark	5/28/2019	
3.0	Karen Kusel / Glenn Madden	Update to 2020 Template	06/2020	

GENERAL INFORMATION

Requested Spend Amount	$12,000,000
Requested Spend Time Period	5 Years
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | Josh Diluciano
Sponsor Organization/Department	Electrical Engineering
Phase	Execution
Category	Project
Driver	Mandatory & Compliance

1 BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

NERC reliability standard PRC-002-2 defines the disturbance monitoring and reporting requirements to have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances. The methodology of Attachment A of the NERC standard was performed to identify the affected buses within the Avista BES. The Protection Systems must be capable of recording electrical quantities for each BES Elements it owns connected to the BES buses identified.

The present Protection Systems are either electromechanical or first generation relays not capable of meeting the NERC PRC-002-2 standard requirements of fault recording. The scope of the project is to upgrade the existing Protection Systems on various 230 kV and 115kV terminals to Fault Recording (FR) capability per PRC- 002 requirements at Beacon, Boulder, Rathdrum, Cabinet Gorge, North Lewiston, Lolo, Pine Creek, Shawnee, and Westside Substations. Implementation is a phased approach with 50% compliaint within 4 years and fully compliant within 6 years of the effective date 7/1/16. The total number of affected terminals is 49.

Non-compliance can carry a fine of up to a million dollars per day based on severity.

1.1 What is the current or potential problem that is being addressed?

PRC-002-2 went into effect on 7/1/2016, we have six years to bring our protection system into compliance with this updated standard.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Mandatory & Compliance is the main driver for this project. But this will also allow more information to be collected to facilitate analysis of BES disturbances.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Avista is required to comply with PRC-002 by July 1, 2022.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

System Planning Assessments, Relay & Protection Design Reporting for PRC-002.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

NERC Reliability Standard PRC-002-2

NERC Project 200711 Disturbance Monitoring:

DL-2007-11_DM_Imp_Plan_2014Sep01_clean

PRC-002 Bus Fault Summary & Anaylsis 2016.xlsx

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The present Protection Systems are either electromechanical or first generation relays not capable of meeting the NERC PRC-002-2 standard requirements of fault recording.

2 PROPOSAL AND RECOMMENDED SOLUTION

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

The Protection System upgrade of 49 terminals impacts the resources of Engineering and GPSS over a 5 year period. The NERC standard requires compliance by specific dates. By missing the compliance date set forth by NERC, Avista not only risks monetary penalties based on severity but reputational damage as well.

Cost estimates per terminal from previous Protection System upgrades at a total installed cost of $150k.

Protection System upgrades is the preffered solution. The relay replacement will not only provide the recording capability but will improve system reliability, reduce maintenance and support other NERC standard requirements (PRC-023, PRC-004).

In the past, Avista has attempted to put in a single digital fault recorder that complicated the wiring and CT circuits within a station. All recorders have since been removed.

Option	Capital Cost	Start	Complete
Upgrade Protection Systems	$4.86M	02 2017	10 2022
Do Nothing	$0M		
Installation of a digital recorder on each BES bus to provide the SER and FR data.			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

Since this is a compliance mandate, we also looked at other standards and relay options.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

2020 - $3,200,000

2021 – $5,420,000

2022 – $2,480,000

2023 – $150,000

O&M costs may be reduced with this equipment replacement.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

Delay of the other projects due to resource scarcity.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See Section 2.0 for alternative discussion.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Project is currently underway, construction is in progress at multiple sites and will conclude in 2022 and closeout of project will occur in 2023. Transfers to plant are completed when the work at each location is completed.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

Fault recording at substations enables root cause analysis, which can lead to improved reliability. Additionally the work is mandatory from NERC.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

NERC required projects are vetted through NERC as to the viability of requiring the work to be done and the associated benefit. The investment is likely to result in improved reliability to the BES.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Not Applicable.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

The Engineering Roundtable process is used to identify projects requmng Transmission, Substation, or Protection (TS&P) engineering support. The committee is responsible to track TS&P project requests, facilitate prioritization of TS&P capital projects across Engineering, Operations, and Planning), and to ensure projects are completed consistent with the company's mission and corporate strategies.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Protection System Upgrades for PRC-002 and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Glenn Madden	Date:	12-23-20
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	Josh DiLuciano	Date:	1/5/2021
Print Name:	Josh DiLuciano		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:	Damon Fisher	Date:	1/5/2021
Print Name:	Damon Fisher		
Title:	Principle Engineer		
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

1 GENERAL INFORMATION

Requested Spend Amount	$38,000,000
Requesting Organization/Department	Transmission Planning
Business Case Owner	Scott Waples
Business Case Sponsor	Heather Rosentrater
Sponsor Organization/Department	T&D
Category	Project
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

- Ken Sweigart – Manager, Substation Engineering
- Project Engineer/Project Manager – Brian Chain

The assigned PE/PM holds stakeholder meetings to develop/confirm scope, schedule and costs. Also meets at time of pre-construction. Other meetings held as necessary.

2 BUSINESS PROBLEM

In the fall of 2013, Grant employees contacted Avista System Planning about performance issues within Grant's system that are exacerbated by Avista's load in the Othello area. The issue was escalated to Columbia Grid through the Regional Planning process. It was identified through this process and Avista System Planning that the system performance analysis indeed indicates an inability of the System to meet the performance requirements P1, P2 and P6 categories in Table 1 of NERC TPL-001-4 in current heavy summer scenarios, and P6 categories in heavy winter scenarios.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alt 1: Status Quo			
Alt 2: Build new 115kV Transmission Line			
Alt 3: Close "Star" Points			
Alt 4: Install Generation			
Alt 5: Build Saddle Mountain 230/115kV Substation Phase 1 Project with associated support projects	*$38M*	*2017*	*2021*

Alternative 1:

This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not adhere to NERC Compliance regulations.

Alternative 2:

This alternative is not recommended as it does not mitigate the low voltage issues in the Othello area.

Alternative 3:

This alternative is not recommended due to its high cost. It is anticipated that $75M of reconductoring would be needed to mitigate any potential violations comparable to the preferred alternative.

Alternative 4:

This alternative is not recommended due to its high financial costs, the potential for must run operation and the lead time on this project will be well beyond the time this project is needed per NERC requirements.

Alternative 5:

This alternative is the most cost effective option considered and provides enough voltage support and capacity into the area for the next 50 years. This alternative mitigates all identified deficiencies in the Othello area documented in the 2016 Planning Annual Assessment. This alternative is the best solution for the long term.

Solution:

Alternative 5: The scope recommended consists of two phases:

PHASE 1:

1) Construct a 3 – position 230 kV double bus double breaker arrangement with space for 2 future positions at the line crossing of the Walla Walla – Wanapum 230 kV and Benton – Othello 115 kV transmission lines.
2) Construct a 3 position 115 kV breaker and a half arrangement with space for 3 future positions.
3) Install 250 MVA Transformer
4) Rebuild entire 8.28 miles of Othello – Warden No.1 115 kV line with minimum 205 MVA capacity
5) Rebuild 2.88 miles of Othello – Warden No. 2 115 kV line with minimum 205 MVA capacity

COST: $38M

IN SERVICE: 12/31/2020

PHASE 2: See Associated Phase 2 BC Narrative

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Saddle Mountain 230/115kV Station (New) Integration Business Case* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 8/11/2017

Print Name: Scott Waples

Title: Director of Planning & AM

Role: Business Case Owner

Signature: [signature] Date: 8/14/17

Print Name: Heather Rosentrater

Title: VP Energy Delivery

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*<Author name>*	*mm/dd/yy*	*<name>*	*mm/dd/yy*	*Initial version*

Template Version: 03/07/2017

EXECUTIVE SUMMARY

The Transmission Construction – Compliance Business Case covers the Transmission rebuild and reconductor work necessary to maintain compliance with the NERC Reliability Standard TPL-001-4 – Transmission System Planning Performance Requirements ("Standard"). It has 8 requirements and 57 sub-requirements related to planning and analysis, including the requirement for robust system models to determine system stability, voltage levels and system performance under various scenarios. This standard mandates that an annual planning assessment be conducted and corrective actions be identified and implemented to remedy any system performance deficiencies In addition, when Avista's system planning studies indicate any kind of problem that could arise in the transmission system, it must be remedied within specific timeframes. The Transmission Construction - Compliance Program provides funding to mitigate any identified reliability issues in order to remain in compliance with NERC requirements.

The implementation of this business case will be considered successful if these projects are all completed prior to the required compliance dates identified in the Engineering Roundtable Project List, which are copied from the Corrective Action Plans (within the annually published Avista System Planning Assessment).

The Transmission Construction – Compliance Business Case also covers the Transmission line rebuild for lines not meeting National Electric Safety Code (NESC) physical capacities for appropriate loading cases. These code minimums have also been adopted into the State of Washington's Administrative Code (WAC). These lines may have met the NESC criteria at the time of their original construction, but have been found to not be up to standards through anaysis either as a result of requests for facility additions, or identified past additions not analyzed at the time of installation.

The recommended solution is to build, rebuild, or reconductor transmission lines as identified in the Corrective Action Plans to stay in compliance with NERC mandatory and enforceable Reliability Standards (most notably TPL-001-4) and the NESC code (via WAC).

If Avista does not implement this business case, the company is at risk of violating NERC Reliability Standard Requirements and could be subject to penalties of up to $1M per day for the duration of any such violation. Following a "do nothing" option for this business case would likely be treated as an aggravating factor by the regulatory authority when assessing enforcement actions. If Avista does not fully implement this business case, it also runs the risk of being fined for not staying in compliance with the NESC code and WAC rules. There are no expected business impacts to continuing this program in place. A spend of $5,050,000 is needed to complete the planned 2021-2025 projects . This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North.

The Business Case contains four projects:

- KEC Rimrock Substation Interconnection
- Beacon-Ross Park 115kV Rebuild
- Beacon-Boulder #1 115kV Rebuild (east of Irvin)
- Ninth & Central-Sunset 115kV Partial Rebuild (Upgrade to 795 ACSS)

The customer benefits from this Business Case through increased service reliability.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Ken Sweigart	Initial draft of original business case	7/10/2020	

GENERAL INFORMATION

Requested Spend Amount	$5,050,000
Requested Spend Time Period	5 years
Requesting Organization/Department	TLD Engineering
Business Case Owner | Sponsor	Josh DiLuciano/Heather Rosentrater
Sponsor Organization/Department	Energy Delivery/Electrical Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 The Transmission Construction – Compliance Business Case covers the Transmission rebuild and reconductor work necessary to maintain compliance with the NERC Reliability Standard TPL-001-4 – Transmission System Planning Performance Requirements ("Standard"). This standard mandates that an annual planning assessment be conducted and corrective actions be identified and implemented to remedy any system performance deficiencies. Corrective Action Plans must be completed within the required timeframe to meet the system performance requirements dictated by the Standard.

The Transmission Construction – Compliance Business Case also covers the Transmission line rebuild for lines not meeting National Electric Safety Code (NESC) physical capacities for appropriate loading cases. These code minimums have also been adopted into the State of Washington's Administrative Code (WAC). These lines may have met the NESC criteria at the time of their original construction, but have been found to not be up to standards through anaysis either as a result of requests for facility additions, or identified past additions not analyzed at the time of installation.

1.2 What is the current or potential problem that is being addressed? NERC Reliability Standards and NESC loading capacities.

1.3 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset* Condition, or Failed Plant & Operations) **and the benefits to the customer** Mandatory & Compliance: Customer benefits by having a Transmission System in compliance with Federal Code and State Law.

1.4 Identify why this work is needed now and what risks there are if not approved or is deferred Relevant sections of the NERC Sanction Guidelines are cited below:

2.9 Concealment or Intentional Violation

NERC or the Regional Entity shall always consider as an aggravating factor any attempt by a violator to conceal the violation from NERC or the Regional Entity, or any intentional violation incurred for purposes other than a demonstrably good faith effort to avoid a significant and greater threat to the immediate reliability of the Bulk Power System.

2.10 Economic Choice to Violate

Penalties shall be sufficient to assure that entities responsible for complying with Reliability Standards do not have incentives to make economic choices that cause or unduly risk violations of Reliability Standards, or incidents resulting from violations of the Reliability Standards. Economic choice includes economic gain for, or the avoidance of costs to, the violator. NERC or the Regional Entity shall treat economic choice to violate as an aggravating factor when determining a Penalty.

2.15 Maximum Limitations on Penalties

In the United States, the maximum Penalty amount that NERC or a Regional Entity will assess for a violation of a Reliability Standard Requirement is $1,000,000 per day per violation. NERC and the Regional Entities will assess Penalties amounts up to and including this maximum amount for violations where warranted pursuant to these Sanction Guidelines.

In the case of projects addressing NESC capacity inadequacies, Avista will be cognisant of not meeting the WAC.

.**Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.** As-Built confirmation of mitigation measures.

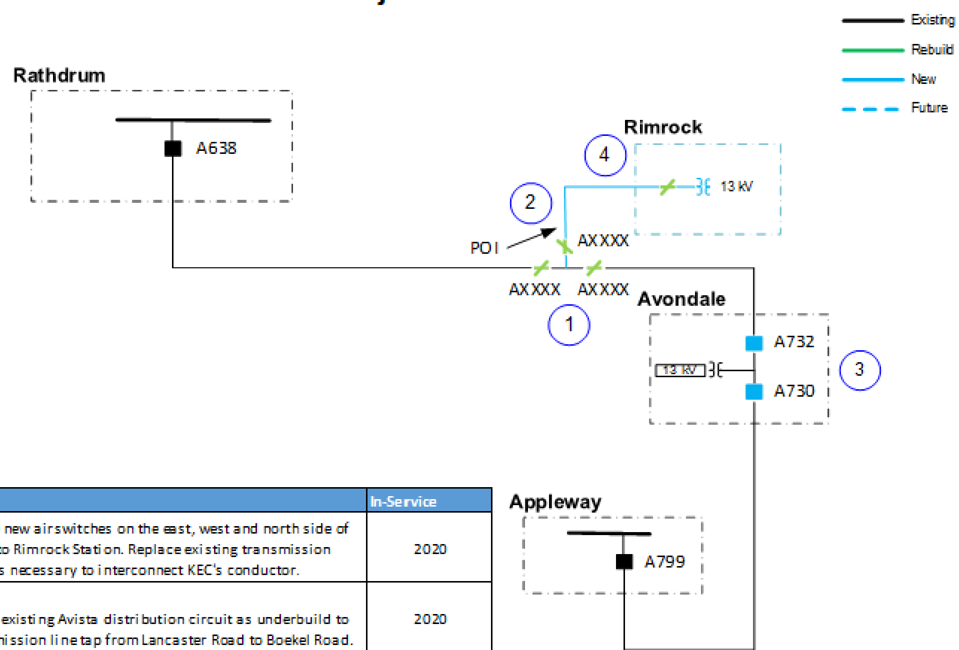
1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

KEC Rimrock System Impact Study.docx
CAI Structure Analysis Results_BEA-BLD.xlsx
CAI Structure Analysis Results_BEA-ROS.xlsx
2019 Avista System Planning Assessment

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Rimrock Station Interconnection Project



Item	Description	In-Service
1	Install three new airswitches on the east, west and north side of the KEC tap to Rimrock Station. Replace existing transmission structures as necessary to interconnect KEC's conductor.	2020
2	Reconstruct existing Avista distribution circuit as underbuild to KEC's transmission line tap from Lancaster Road to Boekel Road.	2020
3	Replace switches A732 and A730 within Avondale Station with new circuit breakers and associated station upgrades.	Within 1 year of Rimrock
4	KEC will build, own and maintain their facilities from the POI to the Rimrock Station.	2020

FIGURE 3: RIMROCK INTERCONNECTION PROJECT DIAGRAM

Engineering Project Request

Instructions: If this is a new request, save this template to your local drive, complete the form, then upload it to ENSO Sharepoint.

Project Title *(e.g. "Benewah-Moscow 230kV Rebuild")*	Beacon – Boulder #1 115 kV Rebuild	**Request Number**	ERT_2020-xx
Enterprise Project Driver *Reason for initiating the project*	Mandatory & Compliance	**Primary Asset Class**	Transmission
Requested By *The person filling out this form*	Ken Sweigart	**Project Sponsor** *Director sponsoring the project*	Josh DiLuciano
Proposed In-Service Date *Date that the project should be completed*	12/30/2022	**VROM** *Very Rough Order of Magnitude (Cost Estimate)*	$3.60 million

Problem Statement *Provide a brief explanation of the problem that needs to be addressed*	Under the present existing circumstances, most of the wood structures along the 3+ mile alignment will not pass the structural analysis requirements outlined in the 2017 National Electric Safety Code (Adopted by Washington Statute).
Alternatives Considered *Provide a list of potential alternatives, including non-wires alternatives*	1. Do Nothing – This alternative would not bring us into compliance with the National Electric Safety Code (NESC). By not complying with the NESC, we would be out of compliance with the State of Washington. 2. Rebuild parts of the Beacon – Ross Park 115 kV transmission line within the existing alignment. Work up a design to top existing transmission structures and leave any distribution or joint use on old wood transmission structures. This may require less overall steel, due to the existing wood that would be left along the alignment, but it may require taller steel structures to provide enough height clearance to extend above existing already topped wood structures. Based on previous experience with the public perception in this area, this may not be the preferred option from the public's perspective. Additionally, this option would forego the opportunity to shift the line outside of railroad r-o-w on to provate easement which would eliminate annual permit fees. Parts of this line section are already on Provate easement. 3. Rebuild the Beacon – Boulder #1 115 kV line between Irvin Substation and to our current high capacity standard of 200 degrees C. This option accommodates the following stakeholders: a. Planning and System Operations: Increased line capacity will add flexibility. b. ET: Structures will be built ready for Network Communications needs. c. Real Estate: One-time easement costs will eliminate annual permit fees and real-time the access permitting process. d. Operations: This project will accommodate and coordinate with Distribution and Grid Mod needs.
Recommendation *Indicate which alternative is recommended and why. List specific project details and assets to be installed or replaced as well as project phasing.*	Rebuild the Beacon – Boulder #1 115 kV line to meet code and comply with rules and regulations outlined in the National Electric Safety Code. During the design, we will ensure all stakeholders' needs are met from the public eye externally to those internally. The Beacon-Boulder #1 and #2 115kV Lines serve Otis Orchard, Spokane Valley, and the City of Spokane at the Distributive Transmission level. This line supports distribution feeders. Rebuilding this line will provide customer benefit through an increase in reliability/resiliency and benefit internal Avista Stakeholder groups.
Supporting Documentation *Provide links to studies, lifecycle analyses, etc. that support this request.*	1. CAI Structure Analysis Results_BEA-BLD.xlsx – A structural analysis report performed by Commonwealth Associates.

Engineering Project Request

Instructions: If this is a new request, save this template to your local drive, complete the form, then upload it to ENSO Sharepoint.

Project Title *(e.g. "Benewah-Moscow 230kV Rebuild")*	Beacon – Ross Park 115 kV Rebuild	**Request Number**	ERT_2018-08
Enterprise Project Driver *Reason for initiating the project*	Mandatory & Compliance	**Primary Asset Class**	Transmission

Requested By *The person filling out this form*	Ken Sweigart	**Project Sponsor** *Director sponsoring the project*	Josh DiLuciano
Proposed In-Service Date *Date that the project should be completed*	4/2/2021	**VROM** *Very Rough Order of Magnitude (Cost Estimate)*	$1.25 million
Problem Statement *Provide a **brief** explanation of the problem that needs to be addressed*	Under the present existing circumstances, most of the wood structures along the 2 mile alignment will not pass the structural analysis requirements outlined in the 2017 National Electric Safety Code (Adopted by Washington Statute).		
Alternatives Considered *Provide a list of potential alternatives, including non-wires alternatives*	1. Do Nothing – This alternative would not bring us into compliance with the National Electric Safety Code (NESC). By not complying with the NESC, we would be out of compliance with the State of Washington. 2. Rebuild parts of the Beacon – Ross Park 115 kV transmission line. Work up a design to top existing transmission structures and leave any distribution or joint use on old wood transmission structures. This may require less overall steel, due to the existing wood that would be left along the alignment, but it may require taller steel structures to provide enough height clearance to extend above existing already topped wood structures. Based on previous experience with the public perception in this area, this may not be the preferred option from the public's perspective. 3. Rebuild the entire Beacon – Ross Park 115 kV line to accommodate the lines current capacity ratings at 130 degrees C or rebuild the line to our current high capacity standard of 200 degrees C. We will also accommodate the needs of the IT communication folks and install an OPGW communication cable at the top of the structures if deemed necessary.		
Recommendation *Indicate which alternative is recommended and **why**. List specific project details and assets to be installed or replaced as well as project phasing.*	Rebuild the Beacon – Ross Park 115 kV line to meet code and comply with rules and regulations outlined in the National Electric Safety Code. During the design, we will ensure all stakeholders' needs are met from the public eye externally to all operations folks internally. The Beacon-Ross Park 115kV Line is one of the more heavily loaded in the Avista System, as evidenced by an earlier Reconductor to 795 ACSS, and the limitation on available outage windows. Additionally, this line supports two distribution feeders. Rebuilding this line will not only provide customer benefit through an increase in reliability/resiliency, but will also allow the removal (aesthetic improvement) of span guys (3 locations). Lastly, Avista Network Communications will benefit through a newly available fiber communications pathway.		
Supporting Documentation *Provide links to studies, lifecycle analyses, etc. that support this request.*	1. CAI Structure Analysis Results_REV 2_Arbutus and Dahlia AAC_UB.xlsx – A structural analysis report performed by Commonwealth Associates. 2. beacon-ross park 115 1-23-19.kmz – A preliminary Google Earth KMZ file of the line design.		

Engineering Project Request

***Instructions:** If this is a new request, save this template to your local drive, complete the form, then upload it to ENSO Sharepoint.*

Project Title *(e.g. "Benewah-Moscow 230kV Rebuild")*	Ninth and Central - Sunset Transmission Line Rebuild	**Request Number**	ERT_2017-49

Enterprise Project Driver *Reason for initiating the project*	Performance & Capacity	**Primary Asset Class**	Transmission
Requested By *The person filling out this form*	Transmission Planning	**Project Sponsor** *Director sponsoring the project*	Scott Waples
Proposed In-Service Date *Date that the project should be completed*	12/31/2023	**VROM** *Very Rough Order of Magnitude (Cost Estimate)*	$1,300,000
Problem Statement *Provide a **brief** explanation of the problem that needs to be addressed*	An outage of the Garden Springs – Westside 115 kV Transmission Line (created with completion of the 115 kV phase of the Garden Springs 230 kV Station Integration project) combined with another outage of Metro – Post Street, Metro – Sunset, or Post Street – Third & Hatch 115 kV transmission lines causes the Ninth & Central – Sunset 115 kV Transmission Line to exceed its applicable facility rating. System performance analysis indicates an inability of the System to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2021 Heavy Summer scenarios for the P6 events.		
Alternatives Considered *Provide a list of potential alternatives*	**Alt1: Status Quo** This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not adhere to NERC Compliance regulations. Operating Procedures can be used to defer the System Deficiencies.		
	Alt2: Ninth & Central – Sunset 115 kV Transmission Line Rebuild Replace the 795 AAC conductor on the Ninth & Central – Sunset 115kV Transmission Line with 795 ACSS with E3X coating to match the rest of the line. All System deficiencies are mitigated. **Alt3: Garden Springs 230 kV Station Integration** The proposed Garden Springs 230 kV Station Integration project could be advanced in the schedule. The project has its own Engineering Round Table project request. All System deficiencies are mitigated.		
Recommendation *Indicate which alternative is recommended and why. List specific project details and assets to be installed or replaced as well as project phasing.*	Alternative 2, replace the 795 AAC conductor on the Ninth & Central – Sunset 115kV Transmission Line with 795 ACSS with E3X coating to match the rest of the line is the recommended alternative. $800,000 – Transmission		
Supporting Documentation *Provide links to studies, lifecycle analyses, etc. that support this request.*	Under development.		

This is the continuation of a Program first started in 2012 (execution phase), and requires the mitigation of clearances violations.

Option	Capital Cost	Start	Complete
Maintain Compliance	$5.05M	01-2021	12-2025
[Alternative #1] See 1.5.2	$M	MM YYYY	MM YYYY
[Alternative #2] See 1.5.2	$M	MM YYYY	MM YYYY

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:
- Samples of savings, benefits or risk avoidance estimates
- Description of how benefits to customers are being measured
- Comparison of cost ($) to benefit (value)
- Evidence of spend amount to anticipated return

Reference key points from external documentation, list any addendums, attachments etc.

See 1.5.2

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

This program is in the various stages based on individual project.

[Offsets to projects will be more strongly scrutinized in general rate cases going forward (ref. WUTC Docket No. U-190531 Policy Statement), therefore it is critical that these impacts are thought through in order to support rate recovery.]

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Primary impacts are in the area of obtaining Transmission system outages and construction resources. Although Transmission Line Design has the ability to Contract for construction services on the large projects, internal construction resources typically perform Spokane area jobs.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See 1.5.2.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

KEC Rimrock Substation Interconnection: 2020-2022
Beacon-Ross Park 115kV Rebuild: 2020-2021
Beacon-Boulder #1 115kV Rebuild (east of Irvin): 2020-2022
Ninth & Central-Sunset 115kV Partial Rebuild (Upgrade to 795 ACSS): 2022-2023

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Aligns with Avista's Culture of Compliance.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Design solution performed within PLS-CADD, which is the industry leader in providing Transmission Line Design computer based programs. Designs are reviewed at multiple stages to ensure prudency and maximum Stakeholder value.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Many and varied throughout Avista.

2.8.2 Identify any related Business Cases

None.

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

Provide and discuss the governance processes and people that will provide oversight

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

3.2 HOW WILL DECISION-MAKING, PRIORITIZATION, AND CHANGE REQUESTS BE DOCUMENTED AND MONITORED

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

The undersigned acknowledge they have reviewed the Transmission Construction – Compliance Business Case Justification Narrative and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ______________________________ Date: ____________

Print Name: ______________________________

Title: ______________________________

Role: Business Case Owner

Signature: ____________________ Date: ____________

Print Name: ____________________

Title: ____________________

Role: Business Case Sponsor

Signature: ____________________ Date: ____________

Print Name: ____________________

Title: ____________________

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

EXECUTIVE SUMMARY

The Transmission NERC Low Priority Lines Mitigation Business Case covers the work to reconfigure insulator attachments, and/or rebuild existing transmission line structures, or remove earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2012 North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings". This Capital Program covers mitigation work on Avista's "Low Priority" 230kV and 115kV transmission lines. Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have also been adopted into the State of Washington's Administrative Code (WAC). This program is expected to be completed in 2023.

The recommended solution is to correct the issues found in the LiDAR studies to stay in compliance with the NESC code and WAC. There are no expected business impacts to continuing this program in place. If Avista does not fully implement this business case, it runs the risk of being fined for not staying in compliance with the NESC code and WAC rules. A spend of $6,700,000 is needed to complete the mitigations by 2023. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North.

The customer benefits from this Business Case through increased service reliability.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Ken Sweigart	Initial draft of original business case	7/10/2020	

GENERAL INFORMATION

Requested Spend Amount	$6,700,000
Requested Spend Time Period	3 years
Requesting Organization/Department	TLD Engineering
Business Case Owner | Sponsor	Josh DiLuciano/Heather Rosentrater
Sponsor Organization/Department	Energy Delivery/Electrical Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 The Transmission NERC Medium Priority Lines Mitigation Business Case covers the work to reconfigure insulator attachments, and/or rebuild existing transmission line structures, or remove earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2012 North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings". This Capital Program covers mitigation work on Avista's "Low Priority" 230kV and 115kV transmission lines. Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have also been adopted into the State of Washington's Administrative Code (WAC).

1.2 What is the current or potential problem that is being addressed? Clearance violations.

1.3 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* **and the benefits to the customer** Mandatory & Compliance: Customer benefits by having a Transmission System in compliance with Federal Code and State Law.

1.4 Identify why this work is needed now and what risks there are if not approved or is deferred The North American Electric Reliability Corporations (NERC) "NERC Alert" originally identified Low Priority Transmission Line assessments to complete by December 31, 2013. Although a mitigation timeline did not include a penalty threat, we have been operating under a grace period that requires us to report progress every six months. Completing the program by 2023 will show us taking ten years to complete the effort. Deferring completion is tempting greater scrutiny from NERC and delays mitigation of a compliance violations recognized by Washington State Law.

1.5 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above. As-Built confirmation of mitigation measures.

1.6 Supplemental Information

1.6.1 Please reference and summarize any studies that support the problem

CAN-0009_FAC-008 FAC-009.pdf

1.6.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility Ratings

On November 30, 2010, NERC provided an update to the October 7, 2010 Recommendation to Industry entitled "Consideration of Actual Field Conditions in Determination of Facility Ratings." Transmission Owners and Generator Owners of bulk electric system facilities should review their current facility ratings methodology for their transmission lines to verify the methodology used is based on actual field conditions and determine if their ratings methodology will produce appropriate ratings when considering differences between design and field conditions. If entities have not previously verified that the facility design, installation, and field conditions are within design tolerances when the facilities are loaded at their ratings, entities are required by January 18, 2011, to describe its plans to complete such an assessment of all its transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority by December 31, 2013. At the conclusion of each year, each Transmission Owner and Generator Owner must report to its Regional Entity a summary of the assessments and identification of all transmission facilities where as-built conditions are different from design conditions, resulting in incorrect ratings, and their associated mitigation timelines. Remediation is expected within one year from identification of the issue or on a schedule approved by the Regional Entity if longer than a year. Owners are also expected to coordinate with their respective operating and planning organizations to coordinate interim mitigation strategies.

Owner Information	
Entity Name	Avista Utilities
NCR#	
Region	WECC
Owner Type	Transmission Owner
Total High Priority	
Miles	227.50
Circuits	6.00
Total Medium Priority	
Miles	760.00
Circuits	54.00
Total Low Priority	
Miles	1270.00
Circuits	67.00
Grand Totals	
Miles	2257.50
Circuits	127.00

Overall Comments

1/16/2020 Update: Continue multi-phase rebuild projects with LiDAR NERC Alert components.

This is the continuation of a Program first started in 2012 (execution phase), and requires the mitigation of clearances violations.

Option	Capital Cost	Start	Complete
Mitigate Violations	$6.7M	01-2021	12-2023
[Alternative #1]	$M	MM YYYY	MM YYYY
[Alternative #2]	$M	MM YYYY	MM YYYY

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- Samples of savings, benefits or risk avoidance estimates
- Description of how benefits to customers are being measured
- Comparison of cost ($) to benefit (value)
- Evidence of spend amount to anticipated return

Reference key points from external documentation, list any addendums, attachments etc.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

This program is in the Execution Stage with spend directed primarily at structure change-outs resulting in greater ground clearance.

[Offsets to projects will be more strongly scrutinized in general rate cases going forward (ref. WUTC Docket No. U-190531 Policy Statement), therefore it is critical that these impacts are thought through in order to support rate recovery.]

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Primary impacts are in the area of obtaining Transmission system outages and construction resources. Although Transmission Line Design has the ability to Contract for construction services on the large projects, internal construction resources typically perform the smaller jobs.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Raising structure heights is by far the go to alternative. In one instance the removal of earth was used. Earth removal can trigger permitting, which otherwise would not be necessary.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

Smaller projects can take place throughout the year. Most of the large projects take place in the Fall months and Transfer to Plant in the November time frame.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Aligns with Avista's Culture of Compliance.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Mitigation design solution performed within PLS-CADD, which is the industry leader in providing Transmission Line Design computer based programs. Designs are reviewed at multiple stages to ensure prudency and maximum Stakeholder value.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Many and varied throughout Avista.

2.8.2 Identify any related Business Cases

None.

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

Provide and discuss the governance processes and people that will provide oversight

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

3.2 HOW WILL DECISION-MAKING, PRIORITIZATION, AND CHANGE REQUESTS BE DOCUMENTED AND MONITORED

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

The undersigned acknowledge they have reviewed the Transmission NERC Low Priority Ratings Mitigation Business Case Justification Narrative and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ____________________ Date: __________
Print Name: ____________________
Title: ____________________
Role: Business Case Owner

Signature: ____________________ Date: __________
Print Name: ____________________
Title: ____________________
Role: Business Case Sponsor

Signature: ____________________ Date: __________
Print Name: ____________________
Title: ____________________
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

EXECUTIVE SUMMARY

This business case is driven by compliance – the legal requirement to obtain and maintain permits/leases for Avista's facilities located on Tribal reservations. Land ownership on Tribal reservations is complex. Much of the land is held in trust by the federal government on behalf of either Tribes or individual Tribal members. Permits for Avista's transmission and distribution facilities were originally obtained pursuant to 25 CFR 169. Business leases required for substations are obtained pursuant to 25 CFR 162. However, the federal regulations do not typically allow for perpetual easements. Rather, permits/leases can be issued up to 50 years and then these permits need to be renewed. The majority of Avista's permits have reached the 50 year expiration and need to be renewed. In addition, new facilities placed on Trust lands need new permits. In order to acquire a renewed or new permit, a time-consuming federal regulatory process needs to be followed and permission needs to be obtained from the Tribe and/or the majority of individual Tribal landowners who have an interest in the relevant parcel of land. The permit is issued by the Bureau of Indian Affairs after they determine all steps of the process have been achieved. Most of the land on Reservations is divided into parcels of 80 acres or less. Therefore, a transmission or distribution line usually crosses numerous parcels of land – each of which requires its own permit.

Avista has facilities on the following Tribal reservations: Spokane, Colville, Nez Perce, Coeur d'Alene, Flathead, and Kalispel trust lands in Airway Heights. Avista maintains approximately 82 miles of transmission lines on Tribal trust lands. Over the last 10 years, we have renewed permits on the Coeur d'Alene, Flathead, and Nez Perce reservations. The current focus is renewals on the Spokane and Colville Reservations. Approximately 300 new permits are needed on the Spokane Reservation and 130 on the Colville Reservation.

Failure to obtain necessary new permits and maintain existing permits would put us in immediate violation of Federal Law. Without a valid permit, the Bureau of Indian Affairs would require us to remove our facilities from Tribal trust lands. Avista has an obligation to serve its customers on these reservations. To ensure Avista can serve its customers and transmit power on and across Tribal reservations, we need to complete the process of renewing permits that have and/or are expiring.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Toni Pessemier*	*Initial draft of original business case*	*7/8/20*	
1.0		*Updated Approval Status*		*Full amount approved*
1.1		*Budget change*		
2.0				

GENERAL INFORMATION

Requested Spend Amount	$1,250,000
Requested Spend Time Period	*5+ years*
Requesting Organization/Department	American Indian Relations
Business Case Owner | Sponsor	Toni Pessemier /Jason Thackston |
Sponsor Organization/Department	Energy Resources
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed? *Avista has a federal regulatory requirement to obtain and maintain permits/leases for its facilities located on Tribal reservations, specifically for the land held in trust by the Federal government on behalf of either Tribes or individual Tribal members ("trust lands"). Permits for Avista's transmission and distribution facilities were originally obtained from the Bureau of Indian Affairs pursuant to 25 CFR 169. Business leases required for substations are obtained from the BIA pursuant to 25 CFR 162. The Federal regulations do not allow for perpetual easements. Rather, permits/leases were issued up to 50 years. The majority of Avista's permits on Tribal reservations have reached the 50 year expiration and need to be renewed.*

1.2 Discuss the major drivers of the business case – *Mandatory and Compliance – Avista needs to obtain and maintain active permits for all of its encroachments on Trust lands on Tribal reservations. Avista has facilities on the following reservations: Spokane, Colville, Nez Perce, Coeur d'Alene, Flathead, and Kalispel trust lands in Airway Heights. Avista maintains approximately 82 miles of transmission lines on Trust lands and extensive distribution systems. To-date, we have renewed permits on the Nez Perce, Coeur d'Alene and Flathead reservations. Avista's current focus is to renew permits for facilities on the Spokane and Colville Reservations.*

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred *Avista is the only electric provider on the Spokane Reservation and is the electric provider in the Inchelium area of the Colville Reservation. Avista has an obligation to serve its customers. Approximately 300 permits are needed on the Spokane Reservation and 130 on the Colville Reservation. To ensure Avista can continue to serve its customers, and transmit power to serve customers on and off the reservations, we need to continue the process of renewing permits that have and/or are expiring. Avista does not have the ability to condemn on Tribal trust lands. If Avista is not actively pursuing these renewals, we would be in violation of Federal law, and the Bureau of Indian Affairs could demand that we immediately remove our facilities from Tribal trust lands. There are examples across the United States where businesses have been required to remove their facilities when permits have expired. Although Avista has now renewed many of the transmission related permits for 20-50 years, it has been estimated that it would cost at least $61 million to relocate all transmission lines off of Tribal land. Because of our obligation to serve, we need to continue obtaining the required permits for distribution facilities on the reservations.*

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above. *Over the last 10 years, Avista has successfully delivered on the objectives and renewed all of the expired permits for facilities on the Nez Perce, Coeur d'Alene and Flathead reservations so we have a successful track record and are extensively familiar with the process and estimated costs. However, each Tribe, reservation, and Tribal member is unique so costs can vary depending on individual negotiations and resolutions.*

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Continue the process to obtain renewed permits for Avista's facilities located on Trust lands on Tribal reservations which are required by law to transmit power and continue serving our customers. Relocating transmission lines would include longer distances and the risk of obtaining satisfactory easements on non-Tribal land. For distribution assets on Trust lands, there is no immediate viable option, due to obligation to serve.

Option	Capital Cost	Start	Complete
Continue to negotiate permits/leases as required	*250,000 annually*	*01 2021*	*12 2025*

Do nothing, - not in compliance with federal regulations and leads to next alternative	*$0*		
Relocate transmission lines off of Tribal land	*$61,190,000*	*01 2021*	*12 2023*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The 250,000 is a placeholder for permitting costs which has run historically:

Project Description	2017	2018	2019
2015 CDA 230kV TransPermits	5,777	5,311	4,832
2015 Colville Tribe DistPermit	103,660	43,792	84,971
2015 CSKT 230kV Tran Permits	2,963	63,816	
2015 NezPerce 230kV T-Permits	(4,952)		
2015 Spokane Tribe DistPermits	62,870	73,911	77,144
2015 SpokaneTribe 115kV Permit	38,677	103,083	205,060
2016 ID Dist Tribal Permits	4,823		
2017 Nez Perce Dist Permits	177,710	39,944	26,256
2020 CDA 230kV TransPermits			502
2020 Colville Tribe DistPermit			14,961
2020 Nez Perce Dist Permits			2,228
2020 Spokane Tribe DistPermits			2,919
Kamiah Nez Perce 115kV Easmt	23,491		
Grand Total	**415,020**	**329,857**	**418,873**

Costs can vary depending on the Tribe, Bureau of Indian Affairs personnel on the reservation, and individual Tribal members when trying to reach a settlement. Additionally the federal regulations were updated in 2017 and the costs associated with the renewal process (e,g, individual surveys, appraisal reports, process to obtain consent from landowners) have the potential to increase.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

The costs are associated with following 25 CFR 169 and 162 regulatory processes, and negotiating settlements with Tribe and/or individual Tribal members as needed. The objective is to renew all of the remaining expiring permits. Avista maintains a Native American Relations department for the express purpose of working closely with Tribes on a variety of issues. The annual O&M expenditure for this department is approximately $300,000. The Tribal Rights of Way Specialist devotes 90% of her time to this capital business case.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

By renewing the permits, transmission and distribution engineering will not need to evaluate options and costs associated with relocating our facilities.

Operations staff will have rights for ingress and egress to maintain our facilities and service to customers will not be negatively impacted.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative. *See 2.0*

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

This work is ongoing. Transfer to plant is reviewed quarterly. When permits have been obtained, related costs can be transferred.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Being able to serve our customers is critical and our customers trust we will do so. Obtaining the required permits allows us to demonstrate our focus on compliance. Avista's commitment to Tribal relations demonstrates accomplishing this in a collaborative manner.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project *Costs are directly associated with compliance and adhering to federal law and regulations 25 CFR 169 and 162. When settlement discussions are necessary to obtain a permit, each situation and scenario is evaluated for possible alternatives and related costs. In all cases to-date, the settlement costs have been lower than alternatives such as relocating facilities.*

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

2.8.2 Identify any related Business Cases

3.1 Steering Committee or Advisory Group Information

There is no specific Steering Committee for this Business Case. The Advisory

Group is the American Indian Relations department in consultation with others including the Realty Department, Legal, District Managers, Transmission and Distribution Engineers as needed.

3.2 Provide and discuss the governance processes and people that will provide oversight *American Indian Relations department is responsible for day to day activities. The Tribal R/W specialist works with other Real Estate representatives and utilizes multiple systems. The Sr. VP of Energy Resources provides oversight along with VP General Counsel and VP Chief Regulatory Counsel.*

3.3 How will decision-making, prioritization, and change requests be documented and monitored *Decision making will occur as outlined in 3.2. Change requests and documentation will be initiated and monitored by American Indian Relations with support from Financial Planning & Analysis Operations Analytics Manager.*

The undersigned acknowledge they have reviewed the *Tribal Permits and Settlements Business Case* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Toni Pessemier	Date:	7/9/20
Print Name:	Toni Pessemier		
Title:	American Indian Relations Advisor		
Role:	Business Case Owner		

Signature:	Jason Thackston	Date:	7/10/20
Print Name:	Jason Thackston		
Title:	Sr. VP Energy Resources		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

Avista owns and maintains electric transmission, distribution, and natural gas facilities which cross public lands managed by a variety of state, federal and local agencies, as well as entities who own extensive tracts, such as railroads. Traditionally, we have secured long-term rights-of-way permits for these facilities, but have been required to renew them through an annual billing process. The cost of renewing these permits continues to increase each year, ranging from 3% to 10% annually, depending on the agency, thereby increasing annual O&M expenses to the company and our customers. This business case proposal is to secure long-term agreements with lump-sum payments in order to reduce overall expenses related to labor of tracking, research, and processing these annual permits. In some cases, we have been able to negotiate a lower annualized cost over the term of the permit by paying a lump sum up front. In either case, we reduce costs to the company and our customers. Making long-term lump sum payments allows us to capitalize these costs, as the permit is a long-term asset.

Without capital funding, we will continue to incur increasing annual permitting fees and related internal costs as an O&M expense. These costs affect all customers, electric and gas, in the entire Avista service territory.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Rod Price*	*Initial draft of original business case*	*6/30/2020*	
1.0	*Rod Price*	*Completed business case*	*7/28/2020*	
1.1				
2.0				

GENERAL INFORMATION

Requested Spend Amount	$50,000
Requested Spend Time Period	*annually.*
Requesting Organization/Department	V08 / Real Estate
Business Case Owner | Sponsor	Rod Price | Bruce Howard
Sponsor Organization/Department	A04 / Environmental Affairs
Phase	Execution
Category	Productivity
Driver	Performance & Capacity

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Avista owns and maintains electric transmission, distribution, and natural gas facilities which cross public lands managed by a variety of state, federal and local agencies, as well as entities who own extensive tracts, such as railroads. As these rights of way permits renew, we've been paying annually increasing fees, leading to increased O&M expenses associated with both the permit costs and the labor to process them.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

This business case is directly tied to Reliability, Mandatory & Compliance, Performance & Capacity, and Failed Plant & Operations. In order to legally construct, maintain and upgrade our facilities on agency owned lands, we must acquire and renew rights of way permits. While we would continue doing this work without this business case, the main benefits to the customer are being able to negotiate lower fixed permit costs through lump sum payments, as well as securing long term permits which will allow us to maintain reliability in our infrastructure. In addition, we will reduce our labor costs for managing these permits. We also reduce the risk of annual permits not being renewed, or being modified unilaterally.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Right of way permitting on agency-owned lands is an ongoing and necessary scope of work. We will continue doing this work without an approved capital business case. This business case is based on our potential of saving the company and our customers money over the long term by capitalizing permit fees and negotiating lower costs through long term, lump sum payments.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Annual tracking of all agency permits costs, and then completing a comparative analysis against past years.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

We propose that through this business case, we will work with agencies to negotiate lump sum payments for our rights of way permits, thereby securing long-term, and lower fixed costs associated with acquiring and renewing these permits.

Option	Capital Cost	Start	Complete
Capitalize and negotiate lump sum payments	*$50,000*	*01/2021*	*12/2021*
Keep paying annually increasing permit fees through O&M dollars	*$0*	*01/2021*	*12/2021*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request

Review of past years permit costs, we feel that $50k annually will be enough to cover renewals.

Company Name	2014	2015	2016	2017	2018	2019
IDAHO DEPARTMENT OF PARKS AND RECREATION	$ 7,604.20	$ 4,199.60	$10,983.00		$ 1,266.80	$ 12,572.00
LINCOLN COUNTY					$ 687.69	
Multi-party Agreement Bonneville, Avista and Inland Power and Light			$ 500.00			
SPOKANE COUNTY DEPT OF PUBLIC WORKS					$ 500.00	
SPOKANE COUNTY ENGINEERS	$ 5,000.00	$ 5,000.00	$ 5,564.20	$ 5,500.00	$ 5,500.00	$ 5,000.00
STATE OF IDAHO DEPARTMENT OF PARKS & RECREATION	$ 3,520.30	$ 1,244.80	$ 817.67	$ 12,019.00	$ 11,014.00	$ 242.00
STATE OF WASHINGTON DEPARTMENT OF NATURAL RESOURCES		$ 154.40				
UNITED STATES DEPARTMENT OF INTERIOR, BUREAU OF LAND MANAGEMENT	$ 25,855.44	$ 36,680.40	$22,361.24	$ 46,640.84	$ 29,666.54	$ 42,844.37
UNITED STATES DEPARTMENT OF INTERIOR, BUREAU OF RECLAMATION		$ 800.00				
	$ 41,979.94	$ 48,079.20	$40,226.11	$ 64,159.84	$ 48,635.03	$ 60,658.37

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

Starting in 2021, the capital cost amount will be used primarily to cover the costs of agency right of way fees. There should be minimal labor costs associated with this activity, and the annual labor costs should reduce slightly if the number of annual renewals is reduced through the negotiation of long-term permits.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

By taking annually renewing permits, and converting them to longer-term permits, we should positively impact the labor associated with processing annual permits.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The only other alternative is to continue processing annual permits and paying the annually increasing fees, which is a charge to company O&M.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

This is a program and the work is completed throughout the year based on when agency permits are received. They will become used and useful once the fully executed permit is in place.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Our proposed investment is aligned with Avista's mission of delivering reliable power to our customers at the most affordable price we can deliver. Rights of way permits are required for Avista to construct, maintain, and upgrade electric and gas infrastructure on agency owned land. Without these rights of way, we cannot meet our objectives.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Without this business case, we will still be required to do the same work, thereby continuing to pay increasing O&M costs. This program proposal is prudent, as it will help mitigate long-term expenses for the company and our customers.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electric and Gas operations are impacted by this business case as we are securing rights of way for these facilities. Avista's electric and gas customers are also affected by our ability to provide reliable and low-cost power.

2.8.2 Identify any related Business Cases

3.1 Steering Committee or Advisory Group Information

This program will be monitored by the Real Estate Manager, Sr. Director of Environmental Affairs, and Department Financial & Budget Specialist.

3.2 Provide and discuss the governance processes and people that will provide oversight

This program will be monitored by the Real Estate Manager, Sr. Director of Environmental Affairs, and Department Financial & Budget Specialist. We will evaluate the annual costs and savings to ensure the program is on track.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The undersigned acknowledge they have reviewed the *Use Permits* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Rod Price	Date:	07/29/2020
Print Name:	Rod Price		
Title:	Mgr Real Estate		
Role:	Business Case Owner		

Signature:	Bruce Howard	Date:	7/29/20
Print Name:	Bruce Howard		
Title:	Sr Dir Environmental Affairs		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

The 2010 Spokane Area Regional Assessment identified specific transmission system performance issues in the five and the ten-year planning horizons. Many of the issues are caused by inadequate 230/115 kV transformation in the area.

Additionally, the distribution stations in this area are connected to radial transmission lines. Manual operator action is necessary to restore service to customers following automatic circuit breaker operation to isolate a fault. This business case is important to customers because it will more easily allow planned outages to occur that will enable maintenance and replacement of substation equipment before it causes unplanned outages and reduces the electric system reliability that customers have become accustomed to receiving.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2017-54

Cost of Solution: $9,000,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart / Jeff Schlect	Initial Version	04/14/2017	Initial Version
2.0	Karen Kusel / Glenn Madden	Update to 2020 Template	6/2020	

GENERAL INFORMATION

Requested Spend Amount	$9,000,000
Requested Spend Time Period	2 Years
Requesting Organization/Department	Transmission / System Planning
Business Case Owner | Sponsor	Glenn Madden | Josh Diluciano
Sponsor Organization/Department	T&D
Phase	Initiation
Category	Project
Driver	Mandatory & Compliance

1 BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

The 2010 Spokane Area Regional Assessment identified specific transmission system performance issues in the five and the ten-year planning horizons. Many of the issues are caused by inadequate 230/115 kV transformation in the area. Presently there are four substations in the Spokane Area providing 230/115 kV transformation: Beacon (500 MVA), Bell (250 MVA), Boulder (500 MVA), and Westside (250 MVA). The concept of constructing the West Plains New 230kV Substation is to add 500 MVA of transformation capacity. This project is required to mitigate NERC TPL-001-4 standard violations for P2 and P6 events.

Additionally, the distribution stations in this area are connected to radial transmission lines. Manual operator action is necessary to restore service to customers following automatic circuit breaker operation to isolate a fault. Currently the Sunset-Westside 115kV Transmission Line includes the South Fairchild 115 kV Tap, to which the Four Lakes 115 kV Tap is connected, leaving a total exposure of 31 miles for all customers served by the Cheney, Fairchild South, Four Lakes, Hayford and Hallett & White substations.

There are a minimum of seven (7) thermal or voltage limit violations identified to take place within the 10-year planning horizon if this project is not constructed. Additional supporting documentation may be found in the Garden Springs Integration Project Feasibility Study report authored by John Gross.

1.1 What is the current or potential problem that is being addressed?

This project is required to mitigate NERC TPL-001-4 standard violations for P2 and P6 events.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

There are a minimum of seven (7) thermal or voltage limit violations identified to take place within the 10-year planning horizon if this project is not constructed.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This project is required to mitigate NERC TPL-001-4 standard violations for P2 and P6 events.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Future System Planning Assessment reports.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

System Planning Assessments located on the System Planning Department Sharepoint site.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Not Applicable.

2 PROPOSAL AND RECOMMENDED SOLUTION

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

Alternative 1 – Do Nothing / Status Quo:
This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not comply with applicable NERC transmission planning standards. Operating Procedures may be used to defer some system deficiencies.

Alternative 2 – Construct the West Plains New 230kV Substation:
This alternative constructs a new 230 kV station in the West Plains area. The 230 kV station (Phase 2) would be sourced through a new 230 kV transmission line interconnection with the Bonneville Power Administration (BPA) and/or with connections to Westside Substation. The 115 kV portion of the new station (Phase 1) is a part of the West Plains Transmission Reinforcement Plan which addresses reliability issues and provides operational flexibility. All system deficiencies identified will be mitigated.

Alternative 3 – Airway Heights-Westside 115 kV Transmission Line:
Constructing a new 9.5-mile 115 kV transmission line from Airway Heights to Westside was considered as an alternative. Outages at the Westside station, including the P6 outage of both 230/115 kV transformers and P7 outage of the 230 kV double circuit into Westside, continue to cause performance issues. A new 230 kV source to the Spokane area provides a more robust long term solution.

Alternative 4 – Garden Springs 230 kV Station with 230 kV Transmission Line to Westside:
Constructing a 7.9-mile 230 kV transmission line from Westside to a new Garden Springs station was considered instead of the proposed Bluebird-Garden Springs 230 kV Transmission Line interconnection with BPA. Performance issues are not fully mitigated with this alternative. Specifically, the P7 outage of the 230 kV double circuit into Westside continues to be an issue and right-of-way events between Westside and Garden Springs stations do not meet performance criteria.

Alternative 5 – No New 230 kV Infrastructure – 115 kV Transmission Line Rebuilds: Rebuilding several 115 kV transmission lines in the Spokane area instead of constructing any new 230 kV infrastructure was considered. The alternative does not provide the necessary redundancy but instead creates a higher dependence upon existing facilities.

Option	Capital Cost	Start	Complete
Construct the West Plains New 230kV Substation (2 Phases)	$33M	01 2022	12 2028
Alternative 1 – Do Nothing / Status Quo	$0M		
Alternative 3 – Airway Heights-Westside 115 kV Transmission Line			
Alternative 4 – Garden Springs 230 kV Station with 230 kV Transmission Line to Westside			
Alternative 5 – No New 230 kV Infrastructure – 115 kV Transmission Line Rebuilds			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

System Planning Assessments.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

2022 - $9,000,000 (Construction may spread into 2023)

O&M will increase with the addition of this new substation due to inspection and maintenance on the substation, transmission and distribution equipment.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See Section 2.0 for alternative discussion.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Design and Construction are scheduled for 2022. Transfers to Plant will occur when the substation is commissioned and in-service.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

Additional transformation capabilities in the area will alleviate the threat of customer outages.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The scope for the project, which is to increase transformation capacity in the Spokane station is the least cost option that provides the needed functionality. Adhering to the scope and project objectives will be reviewed regularly by the project team including the project engineer and the project manager.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Westside 230/115kV Station Rebuild also provides stability to the Spokane area.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

The Engineering Roundtable initially is designated as the Steering Committee for this project, with a more project-specific Steering Committee to be potentially identified at a later date.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the West Plains New 230kV Substation and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	Josh DiLuciano		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	Damon Fisher		
Title:	Principle Engineer		
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

The existing Westside #1 230/115 kV transformer exceeds its applicable facility rating for the P1 event of the Westside #2 230/115 kV transformer. System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events. While Avista intends to avoid proactively shedding customer load, an operating procedure to shed non-consequential load can be used until 2021 to mitigate system deficiencies (non-consequential load shedding is considered acceptable through the 84 month implementation of TPL-001-4).

Westside Transformer Replacement is the recommended solution. Replace the existing Westside transformers with 250 MVA rated transformers and reconstruct both the 230 kV and 115 kV buses at the station to double bus, double breaker. All associated system deficiencies will be mitigated.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2017-47

Cost of Solution: $32,000,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart	Initial Version	4/14/2017	Initial Version
2.0	Karen Kusel / Glenn Madden	Update to 2020 Template	6/2020	

GENERAL INFORMATION

Requested Spend Amount	$32,000,000
Requested Spend Time Period	15 Years
Requesting Organization/Department	Transmission/System Planning
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Execution
Category	Project
Driver	Mandatory & Compliance

1 BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

The existing Westside #1 230/115 kV transformer exceeds its applicable facility rating for the P1 event of the Westside #2 230/115 kV transformer. System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events. While Avista intends to avoid proactively shedding customer load, an operating procedure to shed non-consequential load can be used until 2021 to mitigate system deficiencies (non-consequential load shedding is considered acceptable through the 84 month implementation of TPL-001-4).

1.1 What is the current or potential problem that is being addressed?

System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Mandatory & Complaince - All associated system deficiencies will be mitigated with the completion of this project.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

While Avista intends to avoid proactively shedding customer load, an operating procedure to shed non-consequential load can be used until 2021 to mitigate system deficiencies (non-consequential load shedding is considered acceptable through the 84 month implementation of TPL-001-4).

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Future System Planning Assessments which show mitigation of all prior deficiencies.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

System Planning Assessments.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Not Applicable.

2 PROPOSAL AND RECOMMENDED SOLUTION

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

Westside Transformer Replacement is the recommended solution. Replace the existing Westside transformers with 250 MVA rated transformers and reconstruct both the 230 kV and 115 kV buses at the station to double bus, double breaker. All associated system deficiencies will be mitigated.

Project scope includes the following:

Phase 1: Replace the existing Westside #1 230/115 kV transformer and construct necessary bus work and breaker positions. $11 million, energize 2018

Phase 2: Continue bus work and breaker replacement: $8 million, energize 2019

Phase 3: Replace the existing Westside #2 230/115 kV transformer and complete bus work to single bus configuration: $6 million, energize 2020

Phase 4: Complete bus work to double bus, double breaker on both the 230 kV and 115 kV buses: $7 million, energize 2022

Alternative 1 - Status Quo/Do Nothing: This alternative is not recommended because it does not mitigate the expected capacity constraints and does not adhere to NERC transmission planning standards.

Solution/Alternative 2 - Westside Transformer Replacement: Replace the existing Westside transformers with 250 MVA rated transformers and reconstruct both the 230 kV and 115 kV buses at the station to double bus, double breaker. All associated system deficiencies will be mitigated.

Alternative 3- Garden Springs 230kV Station Integration: The Garden Springs 230 kV Station Integration project includes the installation of new 230/115 kV transformation in the Spokane area. The additional transformation will offload the Westside #1 and #2 230/115 transformers. In the future, the Garden Springs 230 kV Station Integration project will be necessary in addition to the Westside Transformer Replacement project.

Alternative 4 - Replace Westside Transformers without Station Rebuild: Replacing the existing Westside transformers to 250 MVA rated transformers will mitigate the transformer overload system deficiencies but will create a short circuit breaker rating exceedance. Additional P2 bus outage system deficiencies will exist.

Option	Capital Cost	Start	Complete
[Recommended Solution] Westside Transformer Replacement	$32M	2015	2022
Alternative #1 Status Quo	$0M		
Alternative #3 Garden Springs 230kV Station Integration			
Alternative #4 Replace Westside Transformers without Station Rebuild			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

System Planning Assessments.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

2020 – $3,000,000

2021 - $3,500,000

2022 - $2,800,000

2023 - $2,000,000

2024 – $1,000,000

O&M costs will be comparible to what they were before this project.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See Section 2.0 for alternative discussion.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Construction will continue through 2024. Transfers to Plant will be at the close of each Phase.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

The completion of this project leads directly to a dimished threat of customer outages.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The scope for the project, which is to increase transformation capacity in the Spokane area is the least cost option that provides the needed functionality. Adhering to the scope and project objectives will be reviewed regularly by the project team including the project engineer and the project manager.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Not Applicable.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

- Project Engineer/Project Manager (PE/PM)- Dana Gerbing/Zachary Curry
- Engineering Roundtable Committee

The assigned PE/PM holds stakeholder meetings to develop/confirm scope, schedule and costs. Also meets at time of pre-construction. Other meetings held as necessary.

This project has also been reviewed by the Engineering Roundtable.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Westside 230/115kV Station Rebuild and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	Josh DiLuciano		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	Damon Fisher		
Title:	Principle Engineer		
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Exhibit No. 11
Case Nos. AVU-E-21-01 & AVU-G-21-01
H. Rosentrater, Avista
Schedule 9, Page 190 of 414

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

Local load growth, specifically at the local paper mill occurring in 2007 is a strong driver for a transmission system expansion in the Spokane Valley area. Additionally, there are NERC TPL-001-4 events not meeting performance requirements that are mitigated by completing the project. The worst performance issue mitigated by the completion of the project is the NERC TPL-001-4 category P2.4 event of an internal Breaker Fault (Bus-tie Breaker) on A717 at Boulder Station. System performance analysis indicates an inability of the System to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer Scenarios for the P2 contingency. An Operating Procedure to open Boulder A717 can be used to mitigate the system deficiencies. Portions of the project have been completed prior to 2016.

The remaining portions of the Spokane Valley Transmission Reinforcement project are constructing the Irvin Substation and rebuilding a portion of the Beacon – Boulder #2 115 kV Transmission Line. All system defeciencies are mitigated and the desired operational flexibility to serve large industrial customers is realized. This business case is important to customers because its completion likely allows customers to continue to receive electrical service with the reliability that they have grown accustom to receiving.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2017-48

Cost of Solution: $19,00,000 (includes completed projects) over $15 years

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart	Initial Version	4/14/2017	Initial Version
2.0	Karen Kusel / Glenn Madden	Update to 2020 Template	06/2020	

GENERAL INFORMATION

Requested Spend Amount	$6,800,000 (Remaining Projects)
Requested Spend Time Period	3 Years
Requesting Organization/Department	Transmission/System Planning
Business Case Owner | Sponsor	Glenn Madden | Josh Diluciano
Sponsor Organization/Department	T&D
Phase	Execution
Category	Project
Driver	Mandatory & Compliance

1 BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

Completion of this project is required to mitigate a NERC TPL-001-4 system deficiency. The transmission system in the Spokane Valley currently fails TPL-001-4(P2.4), which is an internal Breaker Fault (Bus-tie Breaker) on A717 at the Boulder Station. In addition the system fails the NERC TPL-001-4 P2 Contingency for the 2017 Heavy Summer Scenario. Completion of this project is required to ensure Avista maintains compliance with NERC regulations and Avista's planning documents.

1.1 What is the current or potential problem that is being addressed?

Being currently out of compliance of NERC TPL-001-4 and potential breaker faults which could lead to large customer outages.

1.2 Discuss the major drivers of the business case (Customer Requested, Customer *Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The major driver of the business case is Mandatory & Compliance. Completion of this project is required to ensure Avista maintains compliance with NERC regulations and Avista's planning documents.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

There are risks to the reliability of electric service with delays to the completion of this project.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Future System Planning Assessments will show the BES improvements made by completing this project.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

2016 Avista System Planning Assessment.pdf

Irvin Project Final.pdf

IrvinvSubstationvProject - Rev C.pdf

SP-2009-03 Summary of Work - Irvin Project.pdf

SP-2011-07 2011 Spokane Valley Transmission Reinforcement.pdf

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Not Applicable.

2 PROPOSAL AND RECOMMENDED SOLUTION

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

Recommendation: Alternative 2, complete the Spokane Valley Transmission Reinforcement project. Remaining project scope includes the following:

Construct the Irvin Station terminating the Beacon – Boulder #1 and #2, Irvin – IEP, and Irvin – Opportunity 115 kV transmission lines as a breaker and a half configuration: $5 million.

Rebuild the existing Beacon – Boulder #2 115 kV Transmission Line from Beacon to Millwood to 795 ACSS conductor: $2 million.

Alternative 1: Status Quo

This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not adhere to NERC Compliance regulations.

Alternative 2: Revert to before the CDA Reconfiguration Project

Revert the system to the condition prior to the Coeur d'Alene Reconfiguration Project creating the Boulder-Rathdrum and Post Falls –Ramsey 115 kV transmission lines. Operational concerns will present themselves specifically with a P2.1 planned outage followed by a forced Pl event in the Coeur d'Alene area. (The P2.1 and Pl event combination is not a TPL-001-4 event.) Operational flexibility constrained by large industrial customers will continue to persist.

Option	Capital Cost	Start	Complete
Complete Project (Irvin Substation and BEA-BLD #2 115kv Line Rebuild)	$6.8M	01 2020	12 2021
Alt 1: Status Quo	$0M		
Alt 3: Revert to before the CDA Reconfiguration Project			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:
- Samples of savings, benefits or risk avoidance estimates
- Description of how benefits to customers are being measured
- Comparison of cost ($) to benefit (value)
- Evidence of spend amount to anticipated return

Reference key points from external documentation, list any addendums, attachments etc.

Load Growth, changes to compliance standards and System Planning Assessments were considered.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

2020 - $3.9M

2021 - $2.9M

O&M will be reduced by replacing the transmission line which will help offset the cost of O&M of inspection and maintenance requirements of the substation and its equipment.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system in the Spokane Valley area.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Status Quo would possibly lead to NERC fines and large customer outages. Reverting to before the CDA Reconfiguration project would negate the benefits of having completed that project.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Construction at Irvin Substation will continue in the Fall of 2020 and be complete in the Spring of 2021. The Beacon – Boulder #2 transmission rebuild will be completed in late 2021.

Transfers to Plant will occur as the substation and transmission line are deemed in-service and energized.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

This project will provide a solid foundation for customer reliability in the Spokane Valley.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The scope for the project, which is to increase reliability in the Spokane Valley by creating the switching station is the least cost option. Adhering to the scope and project objectives will be reviewed regularly by the project team including the project engineer and the project manager.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Not Applicable.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

•Glenn Madden - Manager, Substation Engineering

•Project Engineer/Project Manager (PE/PM)- Various

The assigned PE/PM holds stakeholder meetings to develop/confirm scope, schedule and costs. Also meets at time of pre-construction. Other meetings held as necessary.

This project has been reviewed by the Engineering Roundtable.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and upcoming project.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Spokane Valley Transmission Reinforcement Project and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	Josh DiLuciano		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	Damon Fisher		
Title:	Principle Engineer		
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

SCADA - SOO and BuCC

EXECUTIVE SUMMARY

This business case provides for replacement of existing technology, as well as for deployment of new applications and technology as required to address expanding regulatory and business requirements. This program (Supervisory Control and Data Acquisition - System Operations Office and Backup Control Center) replaces and upgrades existing electric and gas control center telecommunications and computing systems as they reach the end of their useful lives, require increased capacity, or cannot accommodate necessary equipment upgrades due to existing constraints. Some system upgrades may be necessitated by other requirements, including NERC reliability standards, federal gas standards, system growth, and external projects (e.g. Smart Grid). The customers who benefit are all electric and gas residential, commercial, and industrial customers (CD.AA).

The estimated costs for the upcoming five years are $4.3M. The amount requested is based partially upon historical spending needs, and partially on known upcoming major projects. Within the program's yearly authorized spend amount, specific budgetary items to be implemented are determined based upon requests by affected stakeholders including System Operations, Distribution Operations, and Power Supply, and are documented in the Director of Transmission & Distribution System Operations' annual goals and priorities list.

There are multiple risks if this program is not adequately funded. The clearest risk would be to public and personnel safety. The control systems supported by this business case provide real-time visibility, situational awareness, and control of Avista's electric and gas systems. Degradation of these capabilities due to lack of capacity, capability, or aging systems would present increased safety risk. Additionally there is significant compliance risk. These control systems provide the capabilities required to achieve compliance with numerous reliability standards and requirements. For the electrical system these include the NERC standards BAL, COM, CIP, EOP, INT, PER, PRC, TOP, and VAR. For the gas system these include the PHMSA "Pipeline Safety: Control Room Management/Human Factors" rule (49 CFR Parts 192 and 195.) The expenditure of these funds is necessary to operate Avista's electric and gas systems in a safe, reliable, and compliant manner.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Craig Figart	Initial draft of original business case	07.1.2020	
1.0	Craig N Figart	Final version of 2020 business case	07.17.2020	Updated Executive Summary

GENERAL INFORMATION

Requested Spend Amount	$4.3M
Requested Spend Time Period	*5 years*
Requesting Organization/Department	T&D - SCADA/EMS/DMS - System Operations
Business Case Owner | Sponsor	Craig N Figart | Mike Magruder
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

1.1 What is the current or potential problem that is being addressed?

In order to effectively operate the Transmission & Distribution (T&D) Systems, sufficient business and computing hardware and software is necessary. This business case provides for replacement of existing technology in alignment with manufacturer product roadmaps for application and technology lifecycles, as well as for deployment of new applications and technology as required to address expanding regulatory and business requirements. Technology continues to change and T&D Systems continue to incorporate improved technology.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Asset Condition is the major driver of the business case. Another driver is Customer Service quality and reliability. This business case is crucial in a key aspect of Our Vision; "Delivering reliable energy service…" It is essential in providing sufficient control center technology tools, situational awareness, and monitor/control capabilities to achieve reliable energy service.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

There are multiple risks if this program is not adequately funded. The clearest risk would be to public and personnel safety. The control systems supported by this business case provide real-time visibility, situational awareness, and control of Avista's electric and gas systems. Degradation of these capabilities due to lack of capacity, capability, or aging systems would present increased safety risk. Additionally there is significant compliance risk.

These control systems provide the capabilities required to achieve compliance with numerous reliability standards and requirements. For the electrical system these include the NERC standards BAL, COM, CIP, EOP, INT, PER, PRC, TOP, and VAR. For the gas system these include the PHMSA "Pipeline Safety: Control Room Management/Human Factors" rule (49 CFR Parts 192 and 195.)

The expenditure of these funds is necessary to operate Avista's electric and gas systems in a safe, reliable, and compliant manner.

In addition to the risks related to public and personnel safety, compliance risk would be increased without this investment. Non-compliant operational capabilities and practices would result in negative audit findings, significant financial penalties, and litigation expenses. Obsolete equipment would remain in service until failure. Additional capacity for growth may or may not be suitable for required expansions to meet other needs (e.g. Regulatory, Smart Grid.)

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

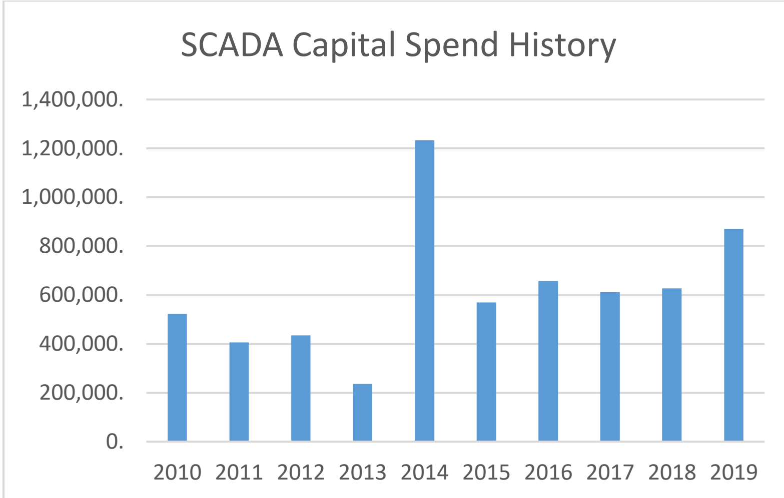
Option	Capital Cost	Start	Complete
Fully Funded "SCADA – SOO and BuCC" business case	*$1.3M*	*01/2021*	*12/2021*
Cancel Dispatcher Training Simulator (DTS) replacement	*$1.15M*	*01/2021*	*12/2021*
Do not complete EMS Upgrade project, nor DTS	*$0.65M*	*01/2021*	*12/2021*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.



2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

The EMS upgrade project is required to be completed in order to upgrade hardware and software that is no longer supported. The EMS upgrade project will also better accommodate operation under the Energy Imbalance Market.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

This is a continuous program. Work is started and completed throughout each year, and in some cases, such as major upgrades, spans multiple years. Technology continues to change and T&D Systems continue to incorporate improved technology.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

This business case is crucial in a key aspect of Our Vision; "Delivering reliable energy service…" It is essential in providing sufficient control center technology tools, situational awareness, and monitor/control capabilities to achieve reliable energy service.

This business case is key in accomplishing the Our Focus item of "Safe & Reliable Infrastructure." Providing remote monitor and control capabilities to operators is essential in achieving "optimum life-cycle performance - safely, reliably, and at a fair price."

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

- Our Stakeholders include:
  - Operations
    - System Operators
    - Power Schedulers
    - Distribution Dispatchers
    - Gas Controllers
    - Energy Accounting & Risk Management
    - Neighboring utility control centers
    - Peak Reliability Coordinator
  - Technicians
    - Protection/Control/Metering Technicians
    - Telecommunication Technicians
  - Engineering
    - Protection/Integration Engineering
    - Substation Engineering
    - Generation Engineering
    - Distribution System Operations
  - Enterprise Technology
    - Oracle Database Administrators
    - Security Engineering
    - Network Engineering
    - Network Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

3.2 Provide and discuss the governance processes and people that will provide oversight

Within the program's yearly authorized spend amount, specific budgetary items to be implemented are determined based upon requests by affected stakeholders including System Operations, Distribution Dispatch, and Power Supply, and are documented in the Director of Transmission & Distribution System Operations' annual goals and priorities list.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The undersigned acknowledge they have reviewed the *Business Case Justification Narrative – SCADA -SOO and BuCC – 2020* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Craig N Figart	Date:	July 17, 2020
Print Name:	Craig N Figart		
Title:	Manager of SCADA/EMS		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	Mike Magruder		
Title:	Energy Delivery Director, Transmission & Distribution System Operations		

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

EXECUTIVE SUMMARY

The Transmission Minor Business Case covers the Transmission rebuild and reconductor work necessary to maintain compliance with the North American Electric Reliability Corporation (NERC) Reliability Standard FAC-501-WECC-1 as applied through Avista's Transmission Maintenance Inspection Program (TMIP) This standard mandates that specific Transmission lines be inspected annually and assessed for corrective actions to be implemented to remedy any system performance deficiencies. The TMIP applies the same inspection methodology to the entire Avista system with the understanding that only a portion of the mitigation work is recognized as Mandatory and Compliance. The remaining work undertaken within this Business Case is recognized as Failed Plant and Asset Condition.

The implementation of this business case will be considered successful if these projects are all completed on an annual basis or the dates identified in the Engineering Roundtable Project List.

The Transmission Minor Rebuild Business Case covers the follow-up work to Wood Pole Inspections, Aerial Patrol inspections, and Ad Hoc ground inspections and Air Switch Replacements.

During routinely scheduled inspections, issues are discovered regarding the condition of assets, including items such as rotten poles, broken/split/rotten crossarms, broken conductor or ground/shield wire, and air switches that no longer operate safely or reliably.

The recommended solution is to correct the issues found by these inspections either in the same year, or within 1-2 years afterwards. There are no expected business impacts to continuing this program in place. If Avista does not fully implement this business case, it runs an increased risk of system failures, customers outages, and wildfires. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North. An annual spend of $3,343,420 is needed to complete the mitigations as follows:

- ER 2057, BI AMT12 and AMT13 ($1,613,420): Wood and Steel Pole Inspections (FAC-501-WECC-1, TMIP)
- ER 2057, BI XT902 ($1,500,000): Aerial and ground inspections (FAC-501-WECC-1, TMIP, and Ad Hoc)
- ER 2254, BI AMT10 ($230,000): Planned/unplanned replacements based on failure or upgrade needs

The customer benefits from this Business Case through increased service reliability.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Ken Sweigart	Initial draft of original business case	7/10/2020	

GENERAL INFORMATION

Requested Spend Amount	$16,717,100
Requested Spend Time Period	5 years
Requesting Organization/Department	TLD Engineering
Business Case Owner | Sponsor	Josh DiLuciano/Heather Rosentrater
Sponsor Organization/Department	Energy Delivery/Electrical Engineering
Phase	Execution
Category	Program
Driver	Multiple (see Executive Summary)

1. BUSINESS PROBLEM

1.1 The Transmission Minor Business Case covers the Transmission rebuild and reconductor work necessary to maintain compliance with the North American Electric Reliability Corporation (NERC) Reliability Standard FAC-501-WECC-1 as applied through Avista's Transmission Maintenance Inspection Program (TMIP) This standard mandates that specific Transmission lines be inspected annually and assessed for corrective actions to be implemented to remedy any system performance deficiencies. The TMIP applies the same inspection methodology to the entire Avista system with the understanding that only a portion of the mitigation work is recognized as Mandatory and Compliance. The remaining work undertaken within this Business Case is recognized as Failed Plant and Asset Condition.

The Business Case also covers aerial, ground and Ad Hoc patrols intended to pro-actively replace structures and structure components as riak on near term failure. This work (BI XT902: $1.5M) in previous years was funded through the Operations Storms blanket Business Case.

1.2 What is the current or potential problem that is being addressed? . Avoidance of failure conditions; that, if left unaddressed in the near-term (<1-2 years) will result in an increased risk of system failures, customers outages, and wildfires.

1.3 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* **and the benefits to the customer** Mandatory & Compliance, combined with Failed Plant and Asset Condition: Customer benefits by having a Transmission System in compliance with Federal Standards, and one where identified near-term failure risks are proacitively addressed.

1.4 Identify why this work is needed now and what risks there are if not approved or is deferred Unlike Asset Management studies and analysis that develop long-term facility failure models, the inspection protocols associated with this Business Case identify asset problems; that, if left unaddressed, will lead to near-term catastrophic structural failures.

1.5 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

As-Built confirmation of mitigation measures.

1.6 Supplemental Information

1.6.1 Please reference and summarize any studies that support the problem

Asset Maintenance Wood Pole Management annual inspection reports
Transmission Line Design annual aerial patrol reports
Ad hoc inspections and or real-time notifications from area offices

1.6.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Below are a few examples of the metric documents developed for this Business Case.

	A	B	C	D	E	F	G	H	I
1	STRUCTURENUM	FEEDERID	Severity	STATUS	Condition 1	Condition	DESCRIPTION	PATROLLEDBY	DATEPATROLLED
2	11/4	Pine St.-Rathdrum	No defect	OK	Bird Nest	-		wss3058	6/26/2019
3	5/6	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
4	3/4	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
5	22/3	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
6	20/6	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
7	19/3	Pine St.-Rathdrum	Moderate defect to be monitored	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/3/2018
8	19/2	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Phase Insulator - Broken	-	Repair next outage on the line - both	wss3058	6/26/2019
9	15/2	Pine St.-Rathdrum	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
11	18/2	Pine St.-Rathdrum	Serious defect, repair immediately	Remediation Required	Crossarm - Broken	-	south arm busted open pretty good	wss3058	6/26/2019
12	27/3	Pine St.-Rathdrum	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
13	26/4	Pine St.-Rathdrum	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
14	26/2	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
15	25/3	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
17	24/3	Eighth & Fancher-Latah	Moderate defect to be monitored	Remediation Required	Pole - Split	-	roadside pole hollow top	wss3058	6/17/2019
18	27/10	Eighth & Fancher-Latah	Minor defect to be noted	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
19	28/2	Eighth & Fancher-Latah	Minor defect to be noted	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
20	14/12	Eighth & Fancher-Latah	Serious defect, repair inside 6 mo	Remediation Required	crossarm - HW loose	Pole - Split	guy need insulation	wss3058	6/17/2019
21	18/9	Eighth & Fancher-Latah	No defect	Remediation Required	Pole - Split	-		wss3058	5/24/2018
22	17/8	Eighth & Fancher-Latah	Serious defect, repair inside 6 mo	Needs Inspection	Pole - Split	-	rotten pole top	wss3058	6/17/2019
23	10/7	Eighth & Fancher-Latah	Moderate defect to be monitored	Remediation Required	Crossarm - Broken	-	split on north side	wss3058	6/17/2019
24	10/12	Eighth & Fancher-Latah	Minor defect to be noted	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
25	4/9	Eighth & Fancher-Latah	No defect	OK	Crossarm - Split	-		wss3058	6/17/2019
26	4/10	Eighth & Fancher-Latah	Moderate defect to be monitored	Needs Inspection	Crossarm - Split	-		wss3058	6/17/2019
27	5/5	Eighth & Fancher-Latah	Moderate defect to be monitored	Remediation Required	Crossarm - Split	-		wss3058	6/17/2019
28	8/10	Beacon-Boulder #1	Moderate defect to be monitored	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
30	10/7	Beacon-Boulder #2	No defect	Remediation Required	Pole - Split	-		wss3058	5/24/2018
31	5/7	Beacon-Boulder #1	Moderate defect to be monitored	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
32	3/5	Beacon-Boulder #1	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Broken	-		wss3058	6/17/2019
35	18/2	Lind-Warden	No defect	OK	Misc	-	REPLACE BEAR ONPOLE	wz74pk	6/13/2017
36	20/11	Lind-Warden	Moderate defect to be monitored	OK	Pole - Split	-		wz74pk	6/13/2017

	A	B	C	D	E	F	G
1	PM Work						
2	0	6	Replace		Confirmed, G Str 2 DG, 2 SG	3	str
3	0	8	Replace		Confirmed, H w 1 SG	3	str
4	9	5	PM Xarm	PM 2020	Replace arm	3	arm
5	11	3	Split Xarm	PM 2020	Replace arm, 11/4 restaple gnd	3	arm
6	11	6	Split Xarm	PM 2020	Dbl arm, wise to replace str	3	str
7	12	5	replace		confirmed	3	str
8	18	2	split Xarm	PM 2020	Confirmed, high priority	3	arm
9	19	4	stub + PM Xarm	PM 2020	H str	3	str
10	39	4	bad xarm	PM 2020	Y - high priority	3	arm
11	40	3	PM Xarm	PM 2020	confirmed, str	3	str
12	43	8	bad xarm	PM 2020	confirmed	3	arm
13	43	10	stub both		confirmed, bad shape str	3	str
14	53	10	stub both		confirmed, str this year	3	str
15	55	1	stub both, bad top		Confirmed, str, move 60' ahead to get out of creek?	3	str
16	56	5	replace, broken guy wire	guy, PM 20	confirmed - GDA, w side guy	3	str
17	62	11	addded		in bad shape	3	str
18	65	7	Low band, restub, and stub R	Xarm PM 2	yep, rough	3	str
19	65	10	replace		yep, rough	3	str
20	66	12	stub both, bad xarm, broken guy		hot mess, easy access though	3	str
21							
22	Reinforcement						
23	1	9	Stub/PWT - stub/replace	1		60 locations, 72 stubs	

This is the continuation of an ongoing Program, and requires the mitigation of structure deficiencies.

Option	Capital Cost	Start	Complete
Mitigate Deficiencies	$16.7M	01-2021	12-2025
[Alternative #1]	$M	MM YYYY	MM YYYY
[Alternative #2]	$M	MM YYYY	MM YYYY

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- Samples of savings, benefits or risk avoidance estimates
- Description of how benefits to customers are being measured
- Comparison of cost ($) to benefit (value)
- Evidence of spend amount to anticipated return

Reference key points from external documentation, list any addendums, attachments etc.

The benefits of this Business Case are seen in something not happening. Pro-actively addressing near-term failures results in avoiding public safety risks including physical, electrical, and fire. A portion of this Business Case was previously funded through an Operations Business Case.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

This program is in the Execution Stage with spend directed primarily at structure and structure component change-outs resulting in facility failure avoidance.

[Offsets to projects will be more strongly scrutinized in general rate cases going forward (ref. WUTC Docket No. U-190531 Policy Statement), therefore it is critical that these impacts are thought through in order to support rate recovery.]

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Primary impacts are in the area of obtaining Transmission system outages and construction resources. Although Transmission Line Design has the ability to Contract for construction services on the large projects, internal construction resources typically perform the smaller jobs.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Replacing structures and structure components is presently the only alternative considered.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

Smaller projects can take place throughout the year. Most of the large projects take place in the Fall months and Transfer to Plant in the Novemeber time frame.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Aligns with Avista's Culture of Compliance. This Business Case directly impacts our customer, and places them as its focus.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Mitigation design solutions performed within PLS-CADD, which is the industry leader in providing Transmission Line Design computer based programs. Designs are reviewed at multiple stages to ensure prudency and maximum Stakeholder value.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Many and varied throughout Avista.

2.8.2 Identify any related Business Cases

None.

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

Provide and discuss the governance processes and people that will provide oversight

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

3.2 HOW WILL DECISION-MAKING, PRIORITIZATION, AND CHANGE REQUESTS BE DOCUMENTED AND MONITORED

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

The undersigned acknowledge they have reviewed the Transmission Minor Rebuild Business Case Justification Narrative and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ______________________ Date: ____________

Print Name: ______________________

Title: ______________________

Role: Business Case Owner

Signature: ______________________ Date: ____________

Print Name: ______________________

Title: ______________________

Role: Business Case Sponsor

Signature: ______________________ Date: ____________

Print Name: ______________________

Title: ______________________

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

EXECUTIVE SUMMARY

The Transmission Major Rebuild – Asset Condition Business Case covers major rebuilds of transmission lines due to overall asset condition. Factors such as operational issues, ease of access during outages, and potential for communications build-out are also considered in prioritizing this work. The projects within this program are developed through Asset Management's general analysis of Avista's Transmission System facilities that provides a risk based ranking of over 100 Transmission Lines. This ranking is followed up by line specific studies. Projects are chosen to maximize stakeholder value.

Investments made under this program rebuild existing transmission lines based on overall asset condition. "Condition" is measured by useful life or the number of condition-related outages. Factors such as operational issues, ease of access during outages, and need to add automation or communications equipment may be included in the type of spending in this category. Replacing old and worn-out poles and cross-arms and other associated transmission equipment, help guard against increasing risk for more failures and outages. Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations. When facilities reach an age when it is close to or at the end of its useful life, the Company preventively replaces it to maintain reliability and acceptable levels of service.

The implementation of this business case will be considered successful if these projects are completed as planned on time and on budget.

The recommended solution is to rebuild transmission lines as prioritized by the Engineering Roundtable group to ensure that Avista sufficiently addresses its aging Transmission Line infastructure. There are no expected business impacts to continuing this program in place. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North. A spend of $71,900,000 is needed to complete the projects as follows:

- ER 2614, BI ST701 ($1,000,000): MTR-PST/PST-3HT 115kV UndergroundTransmission Line Rebuild
- ER 2611, BI KT901 ($21,650,000): Noxon-Pine Creek 230kV Transmission Line Rebuild
- ER 2594, BI CT908 ($250,000): Benewah-Pine Creek 230kV Transmission Line Rebuild
- ER 2596, BI LT900 ($49,000,000): Lolo-Oxbow 230kV Transmission Line Rebuild

Avista customers benefit from this Business Case through improved service reliability.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Ken Sweigart	Initial draft of original business case	7/10/2020	

GENERAL INFORMATION

Requested Spend Amount	$71,900,000
Requested Spend Time Period	5 years
Requesting Organization/Department	TLD Engineering
Business Case Owner | Sponsor	Josh DiLuciano/Heather Rosentrater
Sponsor Organization/Department	Energy Delivery/Electrical Engineering
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 The Transmission Major Rebuild – Asset Condition Business Case covers nvestments made to rebuild existing transmission lines based on overall asset condition. “Condition” is measured by useful life or the number of condition-related outages. Factors such as operational issues, ease of access during outages, and need to add automation or communications equipment may be included in the type of spending in this category. Replacing old and worn-out poles and cross-arms and other associated transmission equipment, help guard against increasing risk for more failures and outages. Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations. When facilities reach an age when it is close to or at the end of its useful life, the Company preventively replaces it to maintain reliability and acceptable levels of service.

1.2 What is the current or potential problem that is being addressed? . Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations.

1.3 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* **and the benefits to the customer** Asset Condition: Customer benefits by having a reliable Transmission System capable of supporting service needs.

1.4 Identify why this work is needed now and what risks there are if not approved or is deferred Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations.

1.5 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The implementation of this business case will be considered successful if these projects are completed on time and within budget. Typical Project Management tracking tools in regards to schedule and budget will be employed, as well as construction inspection services.

1.6 Supplemental Information

1.6.1 Please reference and summarize any studies that support the problem

Transmission Report 2020 Draft.docx
2016 Lolo-Oxbow 230kV Model Asset Management Plan Rev a.docx
LOL-OXB – model results.pptx
CDA (CDA-Rathdrum & Silver Valley) Transmission Reinforcement.pptx
CDA (Sandpoint) Transmission Reinforcement.pptx
Noxon-Pine Creek Final Report v3.docx
Noxon-Pine Creek Wood to Steel Conversion.pptx

1.6.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Below are a few examples of the metric documents developed for this Business Case.

2015 Transmission Probability, Consequence, and Risk Index Summary

Risk Rank	on Line Name	Voltage (kV)	Tap Name	Area	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
1	Lolo - Oxbow	230		Palouse (Lewiston-Clarkston)	63.41	$45,655,200	85.4	100	100
2	Noxon - Pine Creek	230		CDA (Sandpoint)	43.51	$31,327,200	80.5	87.8	82.8
3	Benewah - Pine Creek	230		CDA (Silver Valley)	42.77	$30,794,400	68.3	87.8	70.3
4	Walla Walla - Wanapum	230		Big Bend (Othello)	77.78	$56,001,600	68.4	83.7	67.1
5	Benewah - Boulder	230		Spokane (Central)	26.15	$18,828,000	67.1	72.9	57.3
6	Hot Springs - Noxon #2	230		CDA (Sandpoint)	70.05	$50,436,000	66	68.8	53.2
7	Dry Creek - Talbot	230		Palouse (Lewiston-Clarkston)	28.27	$20,354,400	51.4	78.3	47.1
8	Latah - Moscow	115		Palouse (Pullman-Moscow)	51.41	$21,592,200	96	41.7	47
9	Devils Gap - Stratford	115		Big Bend (Othello)	86.19	$36,199,800	100	39	45.6
10	Post Street - 3rd & Hatch	115		Spokane (Central)	1.76	$3,696,000	70	100	43
11	Benewah - Moscow	230		Palouse (Pullman-Moscow)	44.28	$31,881,600	61.1	59.3	42.5
12	Cabinet - Rathdrum	230		CDA (Sandpoint)	52.3	$37,656,000	41.7	86.4	42.3
13	Bronx - Cabinet	115		CDA (Sandpoint)	32.38	$13,599,600	59.4	55.2	38.4
14	Metro - Post Street	115		Spokane (Central)	0.5	$1,890,000	60	100	38

Noxon-Pine Creek 230kV

Key Considerations	Recommendations
• Ranked 2 on Risk •43.51 miles in Length •19% Larch , Ave age 42 yrs •20% Cedar, Ave age 34 yrs •Minor Rebuild work 2015 •Last Minor Rebuild work completed in 1997 •Steel poles are in area where trees fall across lines •0.83 sustained outages/yr; 13 ave sustained outage hrs/yr (2008 – 2013 data)	1) Test and Treat minor rebuild 39% wood poles as needed 2) 2020 rebuild wood poles 3) Do nothing 4) Roll-out Steel Pole Inspection Program

Strategy Options

Option	CIRR
Wood Transmission Case	5.11%
Steel Transmission Case	8.27%
Optimized Transmission Line Case	8.32%

Title	IRR	Levelized Gr. Mar. Requirement	NPV of Life-Cycle Costs	NPV of Risk	Benefit/Cost Ratio	Risk Reducti on Ratio
Wood Transmisson Case - weff	5.11%	$29,567	$273,357	$83,090	0.757	-0.163
Optimized Transmission Line Case - weff	7.69%	$24,520	$230,670	$1,557	1.185	0.353

1. Optimized Transmission Line Case

This case assumes that the pre-existing wood poles are replaced to steel at 44 years of age. If a wood pole is already older than 44 years, it will be replaced to steel when replacement is needed.

Option 3: Optimized Transmission Line Case
Strengths:
• Low maintenance and replacement cost over time.
•
Weaknesses:
• Potential for spikes in materials and workforce that are needed to take out the wood pole and then install the new steel pole. • Higher Installation Cost

2. Steel Transmission Case

This case assumes that the existing wood poles are replaced with steel immediately.

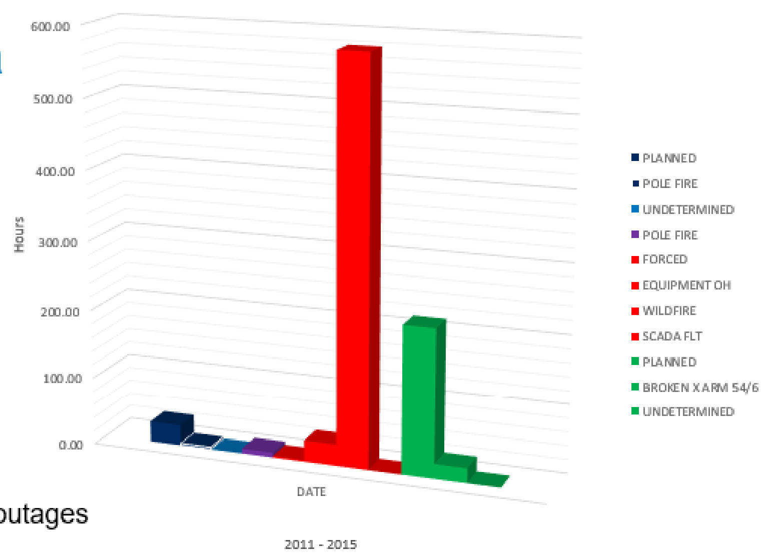
Option 2: Steel Transmission Case
Strengths:
• Low maintenance and replacement cost over time. • Longer Life • Higher survival rate in fire events
Weaknesses:
• High initial cost. This consists of the materials and workforce that are needed to take out the wood pole and then install the new steel pole.

The Noxon-Pine Creek 230kV Line is #2 on the Asset Condition Risk Index; and, when scheduled to be rebuilt, will have most poles at age 44-years or higher. It is therefore recommended to pursue the Steel Transmission Case.

Lolo – Oxbow 230 kV

Key Considerations	Recommendations/Future Planning
• Ranked 1st on Risk mostly due to unplanned outages, condition, miles, terrain, access, system stability, voltage, and power delivery • Originally built in 1958 • 63.41 miles in Length • 578 Cedar Poles; 315 Fir; 46 Larch • 822 wood poles approximately 58 years old • Eta for Cedar = 75 – 95 years • Eta for Larch = 72 years • 2014 pole fire burned 20 poles causing a 24 day outage; 2 unplanned outages totaling 21.33 hours in 2015 (Equipment) • Last inspected 2011 – 2015; 25 poles need stubbing and 12 poles need replacing	• Model results show that we should continue to do aerial inspections and replace structures as they fail • Full rebuild with fiber-ready planned in 5 – 10 years

Outage Data



11	# sustained outages
5	# planned outages
0.5	shortest sustained (hrs)
508	longest sustained (hrs)

Model Results

Alt	Description	NPV Equity	Customer IRR	Earnings per Share
1	Current (Aerial & WPM Inspections)	$5.13 m	9.39%	$0.094
2	RTF (No Reconductor)	$13.0 m	5.08%	$0.234
3	Rebuild Line in 10 Years & No Reconductor	$7.6 m	6.35%	$0.136
4	Rebuild Line in 10 Years & Reconductor	$7.7 m	6.34%	$0.137
5	Rebuild Line in 20 Years & No Reconductor	$5.6 m	7.39%	$0.101
6	**Rebuild Line in 20 Years & Reconductor**	**$5.7 m**	**7.36%**	**$0.102**

The Lolo-Oxbow 230kV Line is #1 on the Asset Condition Risk Index. Given the history of outages due to fire, the time and effort required to mobilize and rebuild in this very remote location, lost revenue during outages, and the desire by Transmission Planning to upgrade this line to match the Idaho Power Company portion of the line, it is recommended to pursue the Rebuild and Reconductor Option.

This is the continuation of an ongoing Program, and requires the replacement of aging infastructure to support service levels. Please see Alternatives Evaluation within documents referenced in Section 1.6.1, and information shown in Section 1.6.2 for details.

Option	Capital Cost	Start	Complete
Rebuild Infastructure	$71.9M	01-2021	12-2025
[Alternative #1]	$M	MM YYYY	MM YYYY
[Alternative #2]	$M	MM YYYY	MM YYYY

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:
- Samples of savings, benefits or risk avoidance estimates
- Description of how benefits to customers are being measured
- Comparison of cost ($) to benefit (value)
- Evidence of spend amount to anticipated return

Reference key points from external documentation, list any addendums, attachments etc.

The benefits of this Business Case are seen in being able to support overall Asset Management strategies.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

- ER 2614, BI ST701 ($1,000,000): The MTR-PST/PST-3HT 115kV UndergroundTransmission Line

Rebuild Project will complete in 2021, having started in 2019. Used and Useful and Transferred to Plant in Spring of 2021.

- ER 2611, BI KT901 ($21,650,000): The Noxon-Pine Creek 230kV Transmission Line Rebuild Project will be in the Design/Procurement stages in 2022-2023, and Procure/Construct in 2024-2025. Used and Useful and Transferred to Plant in Fall/Winter of 2024 and 2025.
- ER 2594, BI CT908 ($250,000): The Benewah-Pine Creek 230kV Transmission Line Rebuild Project is scheduled to begin design in 2025; and, at this time is acting as a placeholder for a future project.
- ER 2596, BI LT900 ($49,000,000): The Lolo-Oxbow 230kV Transmission Line Rebuild Project began construction in 2020, and will complete in 2025. Used and Useful and Transferred to Plant in Fall/Winter of each year between 2021 and 2025.

[Offsets to projects will be more strongly scrutinized in general rate cases going forward (ref. WUTC Docket No. U-190531 Policy Statement), therefore it is critical that these impacts are thought through in order to support rate recovery.]

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Primary impacts are in the area of obtaining Transmission system outages and construction resources. Although Transmission Line Design has the ability to Contract for construction services on the large projects. Design resources can be supplemented by local consulting services.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Please see documents referenced in Section 1.6.1, and information shown in Section 1.6.2.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

Please see Section 2.2.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Aligns with the Focus Areas of Customers and Perform.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Design solutions performed within PLS-CADD, which is the industry leader in providing Transmission Line Design computer based programs. Designs are reviewed at multiple stages to ensure prudency and maximum Stakeholder value.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Many and varied throughout Avista.

2.8.2 Identify any related Business Cases

None.

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

Provide and discuss the governance processes and people that will provide oversight

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

3.2 HOW WILL DECISION-MAKING, PRIORITIZATION, AND CHANGE REQUESTS BE DOCUMENTED AND MONITORED

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain.

The undersigned acknowledge they have reviewed the Transmission Major Rebuild – Asset Condition Business Case Justification Narrative and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	
Print Name:			
Title:			
Role:	Business Case Owner		

Signature:		Date:	
Print Name:			
Title:			
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

New distribution substations added to the system for load growth and reliability are critical to the long term operation of the system. As load demands, increase and customer expectations rise regarding reliability, incremental distribution substation capacity is required. This allows for improved operational flexibility, better system reliability, and easier routine maintenance scheduling as equipment is more easily taken out of service because load can be transferred.

Capacity on the electric system to be able to take components out of service on a planned basis so that maintenance or replacements can be made has reduced as load demands have increased. Having the right amount of backup capacity in each area is critical for the continued appropriate management of the electric system. This business case is important because through it, customers can likely continue to receive electric service at a level that they have grown accustom to receiving.

Service: ED – Electric Direct

Jurisdiction: Various. Each rebuild project has its own Jurisdiction.

Engineering Roundtable Request Number: Various. Each rebuild project has its own ERT Request.

2020 Expected Spend: $7,600,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart	Initial Version	04/14/2017	Initial Version
2.0	Karen Kusel / Glenn Madden	Update to 2020 Template	06/30/2020	

GENERAL INFORMATION

Requested Spend Amount	$6,000,000 per year
Requested Spend Time Period	On Going
Requesting Organization/Department	T&D
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Execution
Category	Program
Driver	Performance & Capacity

1 BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

New distribution substations added to the system for load growth and reliability are critical to the long term operation of the system. As load demands, increase and customer expectations rise regarding reliability, incremental distribution substation capacity is required. This allows for improved operational flexibility, better system reliability, and easier routine maintenance scheduling as equipment is more easily taken out of service because load can be transferred.

1.1 What is the current or potential problem that is being addressed?

As load demands, increase and customer expectations rise regarding reliability, incremental distribution substation capacity is required.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Performance and Capacity – Increasing load on an aging electrical system. And the better the asset condition, the fewer equipment failures and possible customer outages there are.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This is a continuing effort to stay ahead of the curve to avoid reliability issues.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

System Planning Assessments and Studies.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

System Planning Assessments on System Planning Sharepoint site.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Not Applicable.

2 PROPOSAL AND RECOMMENDED SOLUTION

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

This program adds new distribution substations to the system in order to serve new and growing load as well as for increased system reliability and operational flexibility. New substations under this program will require planning and operational studies, justifications, and approved Project Diagrams prior to funding.

Alternatives considered include:

Do Nothing: Maintain (to the best of our ability) all obsolete or end-of-life apparatus. Repair or replace equipment on emergency basis only. Some repairs would not be possible due to obsolescence. Considerably more, and longer, customer outages would result. Although there is zero Capital cost connected with keeping the status quo there are some associated O&M and other system sustainment costs.

Extension of distribution feeders from neighboring substations and increased capacity at those substations would be required at a minimum. The negative impact is most certainly reduced reliability and difficulty in long term maintenance and system operation. Increased liability would result.

Solution: Anticipated load growth requires the addition of two new substations per year over the 2017-2026 horizon

Option	Capital Cost	Start	Complete
Recommended Solution	$6M	Annually	Annually
Alternative #1: Do Nothing	$0		
Extend Existing Distribution Feeders			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:
- Samples of savings, benefits or risk avoidance estimates
- Description of how benefits to customers are being measured
- Comparison of cost ($) to benefit (value)
- Evidence of spend amount to anticipated return

Reference key points from external documentation, list any addendums, attachments etc.

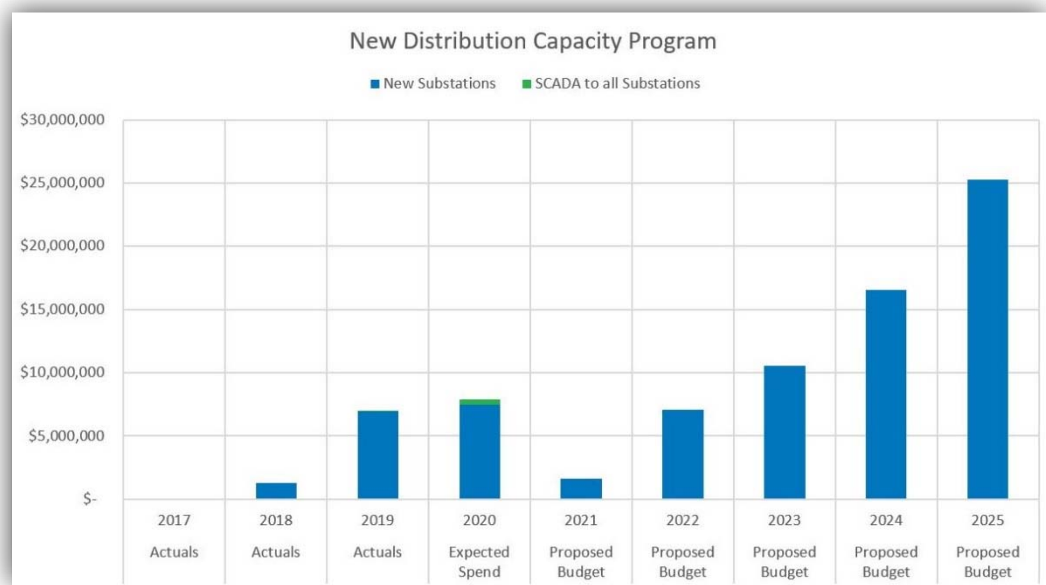
System Planning Assessments.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

Below is a graph showing previous years actual spend on this Business Case, the Expected Spend for 2020 and budget requests for the future.



O&M will increase due to the addition of electric substation and associated transmission and distribution lines. This will include inspections and maintenance of equipment.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Status Quo – Obsolete equipment drives up maintenance costs and outage risks. Extending Distribution Feeders – higher risk of load issues and customer outages.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

See graph above, Section 2.2. Transfers to plant will occur when a substation is in-service or energized. Adhering to project timelines will save capital carrying costs.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

These projects will help Avista stay ahead of the curve of load growth and equipment age to prevent customer outages.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Failure to adjust to load changes and customer needs will lead to equipment failures, customer outages and expensive emergency projects.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Not Applicable.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

- Glenn Madden - Manager, Substation Engineering
- Project Engineer/Project Manager (PE/PM) – Various

The assigned PE/PM holds stakeholder meetings to develop/confirm scope, schedule and costs. Also meets at time of pre-construction. Other meetings held as necessary.

The Engineering Roundtable manages the prioritization of projects within this business case as supported by Asset Management studies and input from company subject matter experts. The Engineering Roundtable is comprised of representatives from the following departments: Asset Management, Compliance, System Planning, System Operations, Telecommunications, Transmission Contracts, Protection Engineering, Substation Engineering, Transmission Engineering, and Substation Support.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Substation – New Distribution Station Capacity Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Glenn J Madden	Date:	12-23-2020
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:		Date:	JDD ~~1/5/2020~~ 1/5/2021
Print Name:	Josh DiLuciano		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:	*Damon Fisher*	Date:	1/5/2021
Print Name:	Damon Fisher		
Title:	Principle Engineer		
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

1 GENERAL INFORMATION

Requested Spend Amount	$715,000
Requesting Organization/Department	B51 - Gas Engineering
Business Case Owner	Jeff Webb / Tim Harding
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Cathodic Protection (CP) group monitors system performance and recommends replacements and upgrades when corrosion control measures become ineffective. Gas Engineering evaluates the recommendations with the CP group and other interested parties. The pros and cons of each option are then reviewed with the Gas Engineering Manager and a preferred alternative is selected to proceed with a funding request. Gas Engineering is responsible for managing this program.

2 BUSINESS PROBLEM

CP system compliance is mandated by Federal Rules within the Department of Transportation code 49 CFR 192, Subpart I. Some of the CP systems have been in service at Avista for extended periods of time and they have exceeded their useful service life. This requires them to be replaced. It is often difficult to predict in advance when specific projects are required, because sudden component failures do occur. Anodes, a key component of the CP systems, are buried and not observable, deteriorate at differing rates, and become ineffective when they are used up. The estimated annual cost for this budget is based on past expenditures. Because of the unpredictable nature of these projects, it is not always know which service territory work will be performed in on any given year.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0	N/A	
Option 2 – Preferred Solution, Replace end of life cathodic protection systems	$800,000	January	December

Option 1 – Do nothing

CP systems have a finite lifespan and must be replaced when they are at the end of their service life. Failing to replace these facilities will result in inadequate external corrosion protection on Avista's steel piping systems. This would result in non-compliance with State and Federal Rules, as well as increased risk to both employee and public safety.

Option 2 – Preferred Solution, Replace end of life cathodic protection systems

Typical types of projects installed under this work type may include (but are not limited to) CP deep and shallow anode wells, Remote Monitoring Units (RMU), installation of CP rectifiers, shorted casing remediation, replacement of gas mains to improve CP system performance.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Cathodic Protection Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Jeff Webb Date: 2-17-20
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: Mike Faulkenberry Date: 2/17/20
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Cmt Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Tim Harding	04/03/2017			Initial version
1.1	Jeff Webb	04/04/2017			
2.0	Tim Harding	2/12/2020	Jeff Webb		Revised for 2020 Oregon GRC filing

Template Version: 03/07/2017

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

EXECUTIVE SUMMARY

In February 2012, Avista's Asset Management Group released findings in the *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"* report. The report documents specific Aldyl-A pipe in Avista's natural gas pipe system, describes the analysis of the types of failures observed, and the evaluation of its expected long-term integrity. The report proposed the undertaking of a twenty-year program to systematically replace select portions of Aldyl-A medium density pipe within its natural gas distribution system in the States of Washington, Oregon, and Idaho.

The Gas Facility Replacement Program (GFRP) was initiated in 2012 and is planned to continue for 20 years (until the end of 2031). It is the sole mission and charter for the GFRP to plan and execute the replacement of 737 miles of Aldyl-A main pipe and to rebuild 17,769 service tee transitions throughout Avista's service territories (Idaho, Oregon, and Washington). The Aldyl-A main pipe replacement work includes Aldyl-A pipe that is 1-1/4" diameter and great and with an install date prior to January 1, 1987, or a manufactured date prior to January 1985.

Avista has a regulatory mandate to complete this program and has a goal of investing in its infrastructure to achieve optimum life-cycle performance. The historical spending trend from 2015 through 2019 has been $20M-$22M annually and is reflective of the program's most recent cost experience updates. The requested budget amounts consider Avista's regulatory mandate to complete this program and has a goal of investing in its infrastructure to achieve optimum life-cycle performance. Inflation of approximately 2.3% has been planned for by escalating the annual costs.

Aldyl-A pipe will eventually reach a level of unreliability that is not acceptable due to the tendency for this material to suffer brittle-like cracking leak failures. There is a potential harm to the public through damage to life and property and there is a high likelihood of increasing regulatory scrutiny from increasing failures. Not approving or deferring this body of work would further exacerbate the risks.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Michael Whitby*	*Initial draft of original business case*	*2011*	
1	*Michael Whitby*	*Budget Change*	*2015*	*Additional $1.8M approved*
2	*Michael Whitby*	*Budget Change*	*2016*	*Additional $3M approved*
3	*Michael Whitby*	*Budget Change*	*2017*	*$2M deferred to 2018*
4	*Michael Whitby*	*Budget Change*	*2018*	*$1M deferred to 2019*
5	*Michael Whitby*	*Budget Change*	*2019*	*$1.5M deferred to 2020*
6	*Karen Cash*	*Budget Change*	*2020*	*$1,035,000 deferred to 2021*

GENERAL INFORMATION

Requested Spend Amount	$22,000,000 - $29,000,000 Annually
Requested Spend Time Period	11 years (2021 through 2031)
Requesting Organization/Department	Natural Gas / Gas Facility Replacement Program
Business Case Owner | Sponsor	Karen Cash / Mike Faulkenberry
Sponsor Organization/Department	Energy Delivery / Natural Gas
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

For Avista, aside from third party excavation damage, the highest risks within our natural gas distribution system is Aldyl-A Main Pipe (Manuf. 1964-1984), and the bending stress that occurs on Aldyl-A service pipe where it is connected to steel main pipe.

GFRP was initiated in 2012 and is planned to continue for 20 years (until the end of 2031). It is the sole mission and charter for the GFRP to plan and execute the replacement of 737 miles of Aldyl-A main pipe and to rebuild 17,769 service tee transitions. The Aldyl-A main pipe replacement work includes Aldyl-A pipe that is 1-1/4" diameter and great and with an install date prior to January 1, 1987, or a manufactured date prior to January 1985.

The GFRP's Service Tee Transition Rebuild (STTR) Program was structured to mitigate the risks associated with the "Bending Stress Services" category within a 5-year time frame. The STTR Program started in 2013 and was deemed substantially complete in December 2017.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Avista has a regulatory mandate to complete this program and has a goal of investing in its infrastructure to achieve optimum life-cycle performance.

As of August 2011, the US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) mandates gas distribution pipeline operators to implement Integrity Management Plans, or in Avista's case, a Distribution Integrity Management Plan (DIMP) in which pipeline operators are required to identify and mitigate the highest risks within their system. For Avista, aside from third party excavation damage, the highest risks within our natural gas distribution system is Aldyl-A Main Pipe (Manuf. 1964-1984), and the bending stress that occurs on Aldyl-A service pipe where it is connected to steel main pipe.

More specifically, and as related to the risks identified above, in February 2012 Avista's Asset Management Group released findings in the "*Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System*" report. The report documents specific Aldyl-A pipe in Avista's natural gas pipe system, describes the analysis of the types of failures observed, and the evaluation of its expected long-term integrity. The report proposed the undertaking of a 20-year program to systematically replace select portions of Aldyl-A medium density pipe within its natural gas distribution system in the states of Idaho, Oregon, and Washington.

Subsequently, the Gas Facility Replacement Program's (GFRP) was formed as the operational entity committed to structuring and implementing a systematic approach to mitigating the Aldyl-A pipe risks as identified in aforementioned report.

On December 31, 2012 the **Washington Utilities and Transportation Commission** (WUTC) issued its policy statement on Accelerated Replacement of Pipeline Facilities with Elevated Risks which requires gas utility companies to file a plan every two year for replacing pipe that represents an elevated risk of failure. The requirement to file a Pipe Replacement Plan (PRP) commenced on June 1, 2013. In response to this order, Avista's first 2-year PRP for 2014-2015 was submitted and approved in 2013 per Docket PG-131837, Order 01. Avista's second two-year PRP for 2016-2017 was submitted in 2015 and approved in 2016 per WUTC Docket PG-160292, Order 01. Avista submitted a PRP in June 2017, and 2019.In Avista's filings, the *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"* report serves as the pipe replacement "Master Plan", and two year pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

On March 6, 2017 the **Oregon Public Utilities Commission** ("Commission") issued Order 17-084 (*Docket UM 1722, Investigation into Recovery of Safety Costs by Natural Gas Utilities)*, which in part required each of the natural gas distribution companies serving customers in Oregon to file with the Commission by September 30th each year an annual "Safety Project Plan" (or Plan).[1] The purpose of the Plan is to increase transparency into the investments made by each utility that are based predominantly on the need to achieve important safety objectives. More specifically, the Plan is intended to achieve the following objectives:

- Explain capital and expenses needed to mitigate safety issues identified by risk analysis or new federal and state rules;
- Demonstrate the utility's safety commitment and priority to its customers;
- Provide a non-technical explanation of primary safety reports each utility is required to file with the Commission's pipeline safety staff; and
- Identify major regulatory changes that impact the utility's safety investments.

The **Idaho Public Utilities Commission** (IPUC) has not required gas utility companies to submit an action plan, Avista has submitted the *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"* report for review, and communicates annual pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

To ensure Avista fulfills the regulatory mandate to complete this program.

The need to conduct this program has been identified in "*Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System*" report. Further, and more specifically, due to the tendency for this material to suffer brittle-like cracking leak failures, Aldyl-A will eventually reach a level of unreliability that is not acceptable. There is a potential harm to the public through damage to life and property and there is a high likelihood of increasing regulatory scrutiny from increasing failures. Not approving or deferring this body of work would further exacerbate the risks as identified above.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The objective of this investment and structured replacement program is to reduce risk by replacing at risk pipe and by rebuilding Service Tee Transitions. Through rigorous Project Management efforts, the GFRP plans and tracks the performance of the projects, and utilizes Earned Value for cost analysis and for upstream reporting. Further, the GFRP tracks and reports Planned vs. Actual quantities by project, by year, by state jurisdiction, and also reports multi-year cumulative statistics.

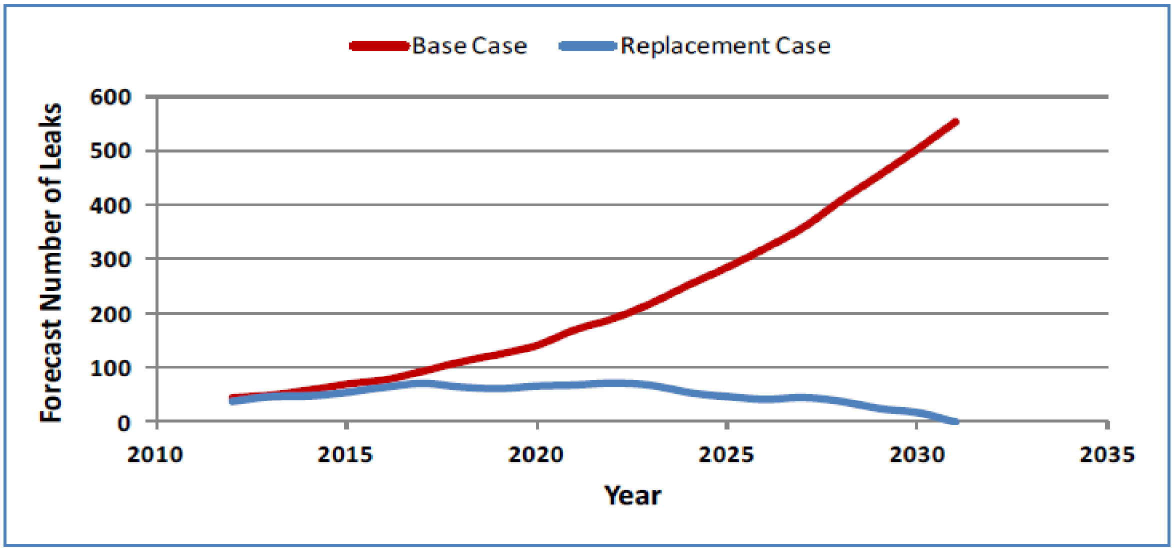
1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

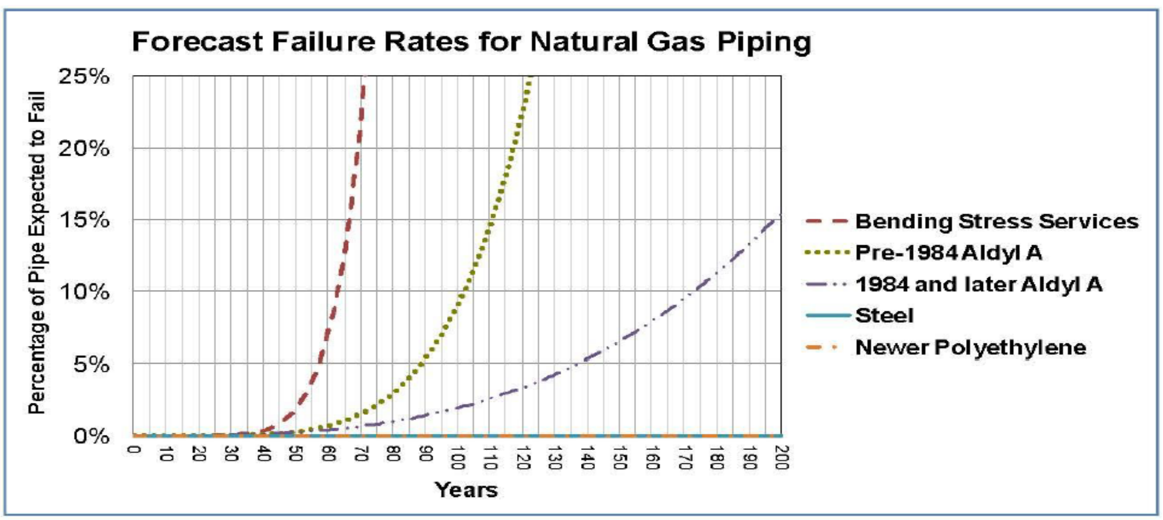
a. On December 31, 2012, the Washington Utilities and Transportation Commission (WUTC) issued its policy statement on Accelerated Replacement of Pipeline Facilities with Elevated Risks which requires gas utility companies to file a plan every two years for replacing pipe that represents an elevated risk of failure. The requirement to file a Pipe Replacement Plan (PRP) commenced on June 1, 2013.
b. February 23, 2012 – Avista Utilities Asset Management "Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utilities' Natural Gas System"
c. April 11, 2013 - Revised Avista Utilities Asset Management "Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utilities' Natural Gas System"
d. July 2013 – ARMS Reliability Report – Avista Study of Aldyl-A Mainline Pipe and Bending Stress Point Leaks
e. Avista's first 2-year PRP to the WUTC for 2014-2015 was submitted and approved in 2013 per Docket PG-131837, Order 01.
f. Avista's second 2-year PRP to the WUTC for 2016-2017 was submitted in 2015 and approved in 2016 per WUTC Docket PG-160292, Order 01.
g. Order of the Public Utility Commission of Oregon in Docket UM 1722, Investigation into Recovery of Safety Costs by Natural Gas Utilities. March 6, 2017.
h. Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System report serves as the pipe replacement "Master Plan", and two year pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.
i. April 2018 – ARMS Reliability Report - Avista Study of Aldyl-A Mainline Pipe Leaks 2018 Update

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The chart below identifies the expected number of material failures in Avista's Priority Aldyl-A piping in two cases: Replacement Case – piping replaced over a 20-year time horizon, and Base Case – assumed that priority piping was not remediated under any program.



As shown in the graph below and outlined in "Forecasting Results" section of "*Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System*" report, Avista's forecast modeling tool "Availability Workbench Modeling" evaluates several classes of pipe which are represented as "curves" showing the percentage of the amount of pipe class that is projected to fail in each year of the forecasted time period.



"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System" report details the various time horizons modeled for the Aldyl-A Pipe Replacement program.

The Aldyl-A Pipe Replacement effort has been proposed and planned as a systematic twenty-year pipe replacement program. The program is expected to have a nominal impact to existing business resources, functions, and processes since the GFRP has been structured to function as a "stand alone" program consisting of dedicated "internal" resources. The primary functions established for these internal resources are to plan, design, oversee, manage, and administer the significant body of projectized work as assigned to "external" contract construction resources.

Periodically, on an as-needed basis, the GFRP will call on other business units for support.

Since pipe replacement work is a capital expenditure, the impact to O&M cost has been minimal. Occasionally GFRP projects will encounter circumstances that necessitate O&M expenditures. When known, these O&M costs are estimated prior to construction. The GFRP tracks and monitors O&M costs monthly.

Option	Capital Cost	Start	Complete
Replace priority high-risk Aldyl-A pipe in a 20-year timeframe	≈ $443M	January 2012	December 2031

The 2013 Avista Study of Aldyl-A Mainline Pipe Leaks was updated in 2018 based on the upon leaks and replacements through the end of 2017. The original study developed failure distributions that described the likelihood of leaks occurring on the Aldyl-A pipe installed by Avista for natural gas distribution and to evaluate multiple replacement scenarios. According to the table below the baseline scenario remains more cost effective when compared to the replacement strategies.

Scenario	Leaks from 2018 through 2088	IRR	Levelized Gr. Mar. Requirement*	Lev ROE*	NPV equity*
Baseline with effects - 2013	26,792	9.21%	$16,417	$0	$0
20 Year Replacement with effects - 2013	255	6.04%	$23,229	$6,513	$93,490
Baseline with effects - 2018	12,335	18.04%	$10,785	$0	$0
20 Year Replacement with effects - 2018	246	3.87%	$36,147	$12,214	$177,848

* In thousands

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The 2013 Avista Study of Aldyl-A Mainline Pipe Leaks was updated in 2018 based on the upon leaks and replacements through the end of 2017. The study incorporated leak reduction and risk avoidance in the analysis.

After updating the model with leaks and replacements from 2013-2018 the expected number or leaks for the remaining period (2018-2088) reduced from 26,792 to 12,335 due to the large amount of the worst pipe already replaced. If the 20-year replacement program where all Aldyl-A pipe is removed continues there is a slight reduction in the expected number of leaks, 255 in the original study and 246 in the updated model.

Safety risks and criticality were also considered as part of the study update. It is understood that each failure event (leak) does not always result in an injury and this is incorporated as a percentage of events that result per Avista standard modeling guidelines. The severities used are shown in table below. The projected number of catastrophic events drop from 258 to 5 events over the next 70 years by replacing the Aldyl-A pipe.

Effect	Severity	% of Failures Where Effect Occurs
Catastrophic event	50 Years	1.82%
Craft injury, WITH Lost Time/Light Duty	1 Year	0.11%
Craft injury, NO Lost Time	3 Months	0.29%

While Avista's 20-year structured replacement program has proven to reduce the highest risk in the early years of the program, the continuation of this structured replacement program is both necessary and prudent to mitigating the remaining risks within the system, and to achieving Avista's goal of operating and maintaining a safe and reliable natural gas distribution system.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

Over the duration of the 20-year program, the GFRP will conduct replacement and rebuild work in virtually every gas district across Idaho, Oregon, and Washington, with large concentrations of Aldyl-A pipe occurring in the metropolitan centers of Spokane, Washington, Medford, Oregon, and Coeur d'Alene, Idaho. Based on the scope of work and schedule, the GFRP will plan and manage more than 100 Major Capital Projects as follows:

Category	Type	Quantity	Duration	Project Count
Major	Main Pipe	737 miles	20 years	~ 105
Major	STTR	17,769 service tees	5 years (Completed)	~20

The 2013 study predicted a total of 26,792 leaks on Aldyl-A mainline pipe from 2018 through 2088 years without any form of a proactive replacement program. Based upon the proactive replacements that have occurred, the number of leaks predicted over the same period has reduced to 12,335 with 246 catastrophic events if the proactive replacement were to not continue. With the current replacement of all Aldyl-A pipe by 2035, the number of predicted leaks from 2018 to program completion reduces slightly, moving from 255 to 246 leaks of which 4 have the potential to be catastrophic events. Assumptions made during the study were as follows:

- Planned replacement of Aldyl-A Mainline pipe costs $357 per three feet in Washington and Idaho and $360 per three feet in Oregon.
- Unplanned replacement of Aldyl-A Mainline pipe costs $5,071 per three-foot section.

- Consequences for a Catastrophic Event, Injury with lost time and injury without lost time are applied per Avista standard practice.

At Avista we forecast Capital Projects/Programs on five-year budget planning cycles which are updated and adjusted annually. In order to provide the most accurate budget forecasts possible it is necessary to draw from the program's most current cost data which is tracked and derived from recently completed projects. The historical spending trend from 2015 through 2019 has been $20M-$22M annually and is reflective of the program's most recent cost experience updates. The requested budget amounts take into account of Avista's regulatory mandate to complete this program with full contractor complement and has a goal of investing in its infrastructure to achieve optimum life-cycle performance. Inflation of approximately 2.3% has been planned for by escalating the annual costs.

Year	System Transfer to Plant (TTP)	Actual vs. Forecasted
2011	$2,683,207	Actual
2012	$187,815	Actual
2013	$17,690,260	Actual
2014	$16,875,629	Actual
2015	$19,709,181	Actual
2016	$19,576,293	Actual
2017	$18,371,496	Actual
2018	$21,914,044	Actual
2019	$22,002,672	Actual
2020	$22,307,086	Forecasted
2021	$22,832,227	Forecasted
2022	$23,357,368	Forecasted
2023	$23,894,587	Forecasted
2024	$24,444,163	Forecasted
2025	$25,006,379	Forecasted
2026	$25,006,379	Forecasted
2027	$26,169,901	Forecasted
2028	$26,771,808	Forecasted
2029	$27,387,560	Forecasted
2030	$28,017,474	Forecasted
2031	$28,661,876	Forecasted
Grand Total	$443,442,553	
Annual Average	$21,116,312	

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Unplanned leak repairs are an O&M cost and are addressed by the local districts. Through this program, O&M expenses are mitigated. The 2013 study predicted a total of 26,792 leaks on Aldyl-A mainline pipe from 2018 through 2088 years without any form of a proactive replacement program. Based upon the proactive replacements that have occurred, the number of leaks predicted over the same period has reduced to 12,335 with 246 catastrophic events if the proactive replacement were to not continue.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

To establish context, Avista's goal is operate a safe & reliable, and cost-effective gas distribution system. Specifically, as related to these goals, § XI of *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"* report details the various time horizons modeled for the Aldyl-A Pipe Replacement program.

To summarize, the primary alternatives modeled are as follows:

- **Do Nothing**

Pipe Replacement Strategies:

Since the "do nothing" option was not an acceptable or prudent approach, the Company evaluated different periods of time for removal of all Priority Aldyl-A pipe, up to a program horizon of 30 years. Avista assessed the prudence of different approaches based on the forecast of likely natural gas leaks due to failed pipe, as well as the rate impact to customers.

- **Less than 20 Year Pipe Replacement Program**
- **Conduct a 20 Year Pipe Replacement Program (Optimal)**
- **Conduct a 25+ Year Pipe Replacement Program**

Based on the time horizon scenarios modeled, it was determined that the optimum timeframe for removing priority Aldyl-A pipe was the 20 years.

RISKS ASSOCIATED WITH ALTERNATIVES CONSIDERED:

To summarize the primary alternatives and associated risks;

- **Do Nothing:**

  It has been determined that this type of pipe is at risk and is approaching unacceptable levels of reliability without prompt attention. The "Do Nothing" option exposes Avista to increased operational risks, and worse, is a potential harm to our customers and the public through damage to life and property, and a high likelihood of legal action against the Company and likely regulatory fines. For this reason it was deemed "not prudent" and is not a serious consideration.

- **Less than 20 Year Pipe Replacement Program:**

  Avista found that a timeline less than 20 years resulted in a greater cost impact to customers in the near term, and that it did little to reduce the forecast number of leaks expected each year. This approach did not effectively optimize the potential risks and rate impacts.

- **Conduct a 20 Year Pipe Replacement Program:**

  The report proposes and suggests that a Systematic Replacement Program conducted over a 20 year timeline is the optimum timeframe to prudently manage this risk, based on the forecast number of leaks and risks, and the rate impact to our customers.

- **Conduct a 25+ Year Pipe Replacement Program:**

  Lengthening the timeframe to 25 years resulted in more than a doubling of the number of leaks expected when compared to a 20-year horizon. Lengthening the timeline beyond 25 years was found to result in a substantial increase in the number of material failures expected.

As outlined above, Asset Management has identified 20 years as the optimum timeframe to prudently manage this risk. Avista's leadership has adopted this recommendation and has funded and staffed the program to achieve this objective. Furthermore, the three state Commissions that regulate Avista's natural gas operations have thoroughly examined this program in several rates proceedings, and in policy proceedings, and have deemed this approach to be prudent, cost effective, and in the interest of our customers.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

Start: January 2012

Expected End: December 2031

The annual list of projects in each of the three states (ID, OR, and WA) are established as unique "blanket projects" that transfer to plant (TTP) each month as they are "used & useful".

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The Gas Facilities replacement Program (GFRP) is responsible for Aldyl-A pipe replacement which aligns with Avista's mission to operate and maintain a "Safe and Reliable Infrastructure". Avista has a goal of investing in its infrastructure to achieve optimum life-cycle performance.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The objective of this investment and structured replacement program is to reduce risk by replacing at risk pipe and by rebuilding Service Tee Transitions. Through rigorous efforts, the GFRP plans and tacks the performance of each project and utilizes Earned Value for cost analysis and for upstream reporting. Furthermore, the GFRP tracks and report Planned vs. Actual quantities by project, year, state jurisdiction, and also reports multi-year cumulative statistics.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Avista's customers and the general public expect Avista's natural gas system to operate safely and reliably without incidents. Avista is dedicated to and focused on maintaining a safe and reliable system that shields the public from imprudent risks. The proposed pipe replacement programs have been initiated with the purpose of mitigating the known risks within the natural gas distribution system. Given this context, the Gas Facility Replacement Program's portfolio of projects could therefore be considered as a customer-related benefit.

The GFRP's Aldyl-A Pipe Replacement projects touch numerous internal and external stakeholders. A comprehensive list of stakeholders is in the "2019 GFRP Operating Plan & Projects" document.

2.8.2 Identify any related Business Cases

Business cases have been submitted annually and updated as necessary since 2012, the inception of the Gas facility Replacement Program.

3.1 Steering Committee or Advisory Group Information

The Gas Facility Replacement Program (GFRP) Advisory Group consists of the GFRP's Program Manager, Cas Operations Contract Construction Manager, Director of Natura Gas, and the Manager of Gas Design & Measurement. This group meets monthly to review program wide Earned Value results, that status of the delivery of the individual projects, budget allocations and variances, internal resource demands, customer care results and issues, contractor performance, and to communicate potential program risks and shortfalls.

In addition, Avista's Distribution Integrity Management Plan and Asset Management groups provide periodic input, and/or validation of the replacement plan and schedule.

3.2 Provide and discuss the governance processes and people that will provide oversight

Each year an annual portfolio of projects is derived from Avista's Distribution Integrity Management Program (DIMP) Aldyl-A prioritization list which currently identifies unique priority project areas (polygons) throughout the natural gas system in ID, OR, and WA. The portfolio of projects is sized to meet jurisdictional commitments. Then individual priority projects are planned, phased, scoped, designed, and detailed estimates are prepared. Once the individual project estimates are finalized, the overall program-wide capital budget is refined to reflect a more precise budget. The requested spend level has historically been determined based upon Avista's experience in the management of the Aldyl-A pipe facilities across Avista's service territories coupled with any changing costs of construction year to year.

There are circumstances where lower priority Aldyl-A projects may be accelerated if it makes sense to coordinate the timing of pipe replacement projects with prior phasing or with other utility and road projects. The individual projects for GFRP are typically managed by the Customer Project Coordinators (CPC's) while the overall program budget is managed by the GFRP Program Manager.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The Gas Facility Replacement Program (GFRP) Advisory Group consists of the GFRP's Program Manager, Cas Operations Contract Construction Manager, Director of Natura Gas, and the Manager of Gas Design & Measurement. This group meets monthly to review program wide Earned Value results, that status of the delivery of the individual projects, budget allocations and variances, internal resource demands, customer care results and issues, contractor performance, and to communicate potential program risks and shortfalls. The monthly documentation tracks the projects and is the primary device for documenting program decision making.

As projects are completed, the Distribution Integrity Management Program (DIMP) Aldyl-A prioritization list is updated annually. As projects are completed, they are removed from the list and new projects are added and evaluated, as necessary.

Annual spend levels and funds change requests to the Capital Planning Group are maintained as documentation of program funding and funding changes throughout the year.

The undersigned acknowledge they have reviewed the **Gas Facility Replacement Program (GFRP)** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Karen Cash	Date:	7/13/20
Print Name:	Karen Cash		
Title:	GFRP Manager		
Role:	Business Case Owner		

Signature:	Mike Faulkenberry	Date:	7/13/2020
Print Name:	Mike Faulkenberry		
Title:	Natural Gas Director		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

1 GENERAL INFORMATION

Requested Spend Amount	$1,400,000 – Annual Request
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb / Jenn Massey
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Isolated Steel Program Manager works closely with the Operations Managers to identify the work. The work is then dispatched to Gas Operations to complete. The overall program budget is managed by the Program Manager and Gas Engineering.

2 BUSINESS PROBLEM

The Program objective is to identify and document isolated steel sections of pipeline in Avista's system, including isolated risers, and to replace each riser or pipeline section within a specified timeframe after its identification.

The methodology for identifying sections of isolated steel is a programmatic survey, taking pipeline to soil potential measurements of the subject system. The overall program area is divided into subareas based on Avista's established cathodic protection zones. A three-man team conducts the survey; first obtaining "native" measurements with the CP system de-polarized, and then "on/off" measurements with the system polarized and current interrupters installed. Data is obtained digitally by each survey technician using a Trimble handheld device. The data is tracked and processed using an ESRI ArcGIS platform. Based on survey results, replacement job orders are dispatched and the replacements executed.

Isolated portions of pipe including risers, service pipe and main will be replaced as required to meet the requirements of 49 CFR 192.455 & .457 and in accordance with WUTC Docket PG-100049. This program will be conducted in ID and OR also to assure cathodically isolated steel is identified and replaced as needed through 2024.

Once the isolated sections of steel pipe are identified, projects are created to replace them with new pipe. This new pipe could be either steel or plastic.

Management of the cathodic protection (CP) zone will drive the decision between steel and plastic pipe. A Generalized Work Flow is provided in Image 1 below.

Per the WUTC agreement, isolated steel risers are being replaced at a rate of at least 10% per year, starting in 2011, and short sections of isolated steel main are replaced within one year of discovery. Work as previously described is also being completed in ID and OR. Work completed under this program results in a safer gas distribution system.

The Program is currently overseen by a Program Manager. Monthly reporting is used to identify budget targets are met and overall completion in each state. Software has been created to identify time constraints based on severity of potential risk. Action codes are listed in below flowchart.

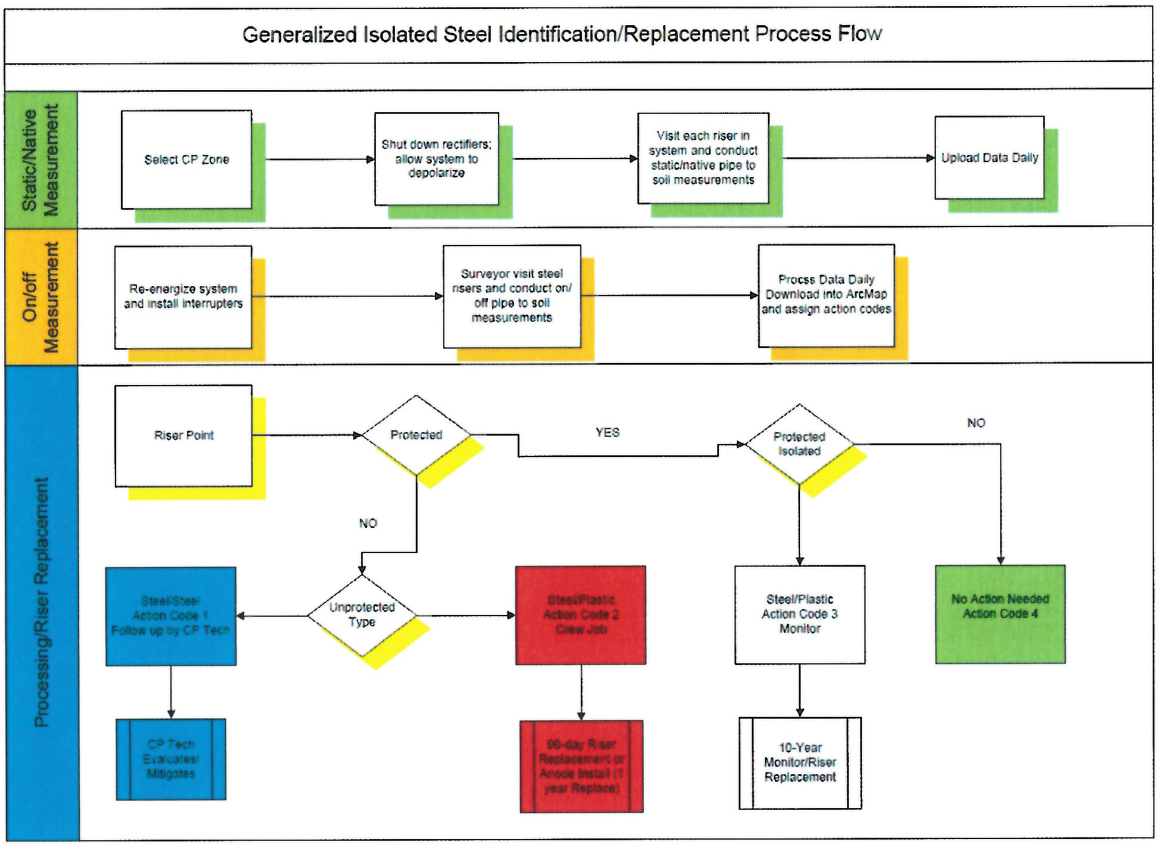


Image 1 – Generalized Work Flow

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$ TBD		
Option 2 – Preferred Solution, Complete the program per the agreement	$2,050,000	2011	11-2021 WA 12-2024 ID and OR

Option 1 – Do nothing

The alternative to completing this program would be to not finish the work within the timeframe mandated by the WUTC. This would be a direct violation of the stipulated agreement between Avista and the WUTC and likely result in financial penalties.

Option 2 – Preferred Solution, Complete the program per agreement as described above

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Isolated Steel Replacement Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeff Webb	Date:	2-17-20
Print Name:	Jeff Webb		
Title:	Manager Gas Engineering		
Role:	Business Case Owner		

Signature:	Mike Faulkenberry	Date:	2/17/20
Print Name:	Mike Faulkenberry		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/16/2017			Initial version
1.1	Jeff Webb	04/07/2017			
2.0	Jennifer Massey	02/05/2020	Jeff Webb	2/17/20	Revised for 2020 Oregon GRC filing

Template Version: 02/24/2017

1 GENERAL INFORMATION

Requested Spend Amount	$400,000
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb / Seth Samsell
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	Gas Operations & Engineering
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

All the known mobile home parks with overbuilt pipe in Avista's Oregon districts were catalogued at one time, analyzed and risk ranked as part of the utility's Distribution Integrity Management Program (DIMP). In addition to these known mobile home parks, with numerous overbuilt facilities, each local District (including those in Idaho and Washington states) periodically finds individual locations with newly overbuilt facilities. These projects and the risk associated with them are mitigated, over time, as part of the Overbuilt Pipe Replacement Program.

DIMP has the capability to analyze risk (probability and consequence) associated with various threats to natural gas facilities, including over-built pipe. The DIMP analysis related to overbuilt segments results in an overall risk score for each of the defined segments. The Overbuilt Pipe Program Manager and each of the Gas Operations District Managers utilize DIMP risk scoring to prioritize projects within an approved level of annual program spend. Ideally, overbuilds would all be addressed as they are encountered, however, there is no compliance requirement behind the timing in which overbuilds must be eliminated. Avista has historically managed overbuilt facilities as part of this program and the associated risks along with other risk priorities in the Company. This is the main reason behind the program's historically approved funding levels instead of addressing all known overbuilds as a large, individually funded project. As the number of known overbuilds in the company has decreased, the level of requested and approved funding has decreased as well. The requested spend level has historically been determined based upon mitigating a manageable level of overbuilt facilities across our service territories coupled with any changing costs of construction year to year.

The goal is to manage and prioritize risk associated with overbuilt pipe and complete projects with the highest risk first. Each Operations District is allotted a manageable portion of the approved budget based upon project need. The projects for each district are typically managed locally while the overall program budget is managed by the Program Manager in Gas Engineering. Image 1 below is a list of the current projects within this program.

ER 3006
Mobile Home Park, Overbuilt Pipe Replacement Program **2/12/2020**

			Requested Budget:	$400,000	$400,000	$400,000	$250,000	$ -	
			Approved Budget:	$400,000	$400,000	$400,000	$250,000	$ -	
			Estimated Costs:	$385,000	$410,000	$420,000	$250,000	$480,000	
District	**Overbuilt Site**	**Completed?**	**Estimated Cost**	**2020**	**2021**	**2022**	**2023**	**2024**	**DIMP Score/ft**
Medford	555 Freeman Rd, Central Point OR	No	$ 450,000			X	X		1930
Medford	301 Freeman Rd, Central Point OR	No	$ 285,000	X					4145
Medford	2252 Table Rock, Medford OR	No	$ 325,000		X				3485
Medford	2335 Table Rock, Medford OR	No	$ 135,000			X			2894
Medford	3555 S Pacific, Medford OR	No	$ 480,000					X	1400
Medford	4425 W Main St, Medford OR	No	$ 15,000	X					717
Klamath Falls	Klamath Falls General Overbuilds	No	$ 35,000	X	X	X	X		
Roseburg	Roseburg General Overbuilds	No	$ 20,000	X	X	X	X		
La Grande	La Grande General Overbuilds	No	$ 30,000	X	X	X	X		

Image 1 – List of current projects within this Program

2 BUSINESS PROBLEM

As a natural gas distribution system operator, Avista is required to operate within the minimum safety standards outlined in Part 192 of the Department of Transportation's Code of Federal Regulations (CFR). The CFR defines the laws that all operators must legally comply with in the operation of natural gas distribution systems. There are sections of existing gas piping within Avista's gas distribution system that have experienced encroachment or have been overbuilt by customer constructed improvements (i.e. living structures, sheds, decks, etc.) and were not designed to be installed under these conditions. In these circumstances, it is difficult to operate and maintain these facilities without increased risk or a reduction in overall safety.

Overbuilt facilities restrict company access to the pipe resulting in accessibility issues. If facilities were not designed for overbuilt conditions it can result in the inability to perform certain maintenance activities required by CFR such as meter inspections or leakage survey. Leakage surveys are typically performed by walking directly above the gas facilities while operating leak detection equipment. This maintenance becomes impossible if access to the ground above the facility becomes hindered. Overbuilds not originally designed to be in an overbuilt condition are also a violation of the CFR for an overbuilt facility as they do not meet code requirements for installation within a sealed conduit that can be vented outside of the overlying structure.

Overbuilds present an increased risk to customers due to the threat that gas can get entrapped inside of a structure, which increases the potential for an unsafe atmosphere to develop as well as result in potential ignition which could be catastrophic to life and property. Multiple factors impact risk and the replacement of these facilities, but of primary concern is the increased risk hazard due to a leak. Overbuilds increase operations and maintenance costs as Avista is often required to return to overbuild locations multiple times to attempt and complete leak survey and other maintenance tasks that cannot be completed at the normal scheduled time due to the overbuild.

Addressing overbuilt pipe in mobile home parks is where the highest risk and greatest quantity of overbuilt facilities exist due to the dynamic nature of these facilities. However, overbuilds are not isolated to mobile home parks and the need potentially exists for this program to be utilized in all of Avista's service territories.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing/defer project	$0	N/A	
Option 2 – Preferred Solution/Complete programmatic replacement of overbuilt sections of pipe	$400,000	January	December
Option 3 – Alternate Solution #1/Reduced Funding Option: Complete programmatic replacement of overbuilt sections of pipe at a reduced rate	$200,000	January	December
Option 4 – Alternate Solution #2/Attempt to enforce Avista's easement rights	Unknown	Unknown	Unknown

Option 1 – Do nothing/Defer project

Under this alternative Avista would continue to operate overbuilt facilities without replacement. There is significant risk associated with not remediating these facilities at all and this would be a violation of the Code of Federal Regulations subjecting Avista to potential State and Federal fines associated with operating facilities that are out of compliance. The financial impact of this alternative is very difficult to estimate as penalties for non-compliance are on a case by case basis. Known risks cannot be mitigated without replacement of these facilities or remediation of the overbuild condition. This option is not recommended.

Option 2 – Preferred Solution/Complete programmatic replacement of overbuilt sections of pipe

It is recommended as part of a programmatic approach to identify and replace sections of existing pipes that can no longer be operated safely as they have experienced encroachment or have been overbuilt by customer constructed improvements. Since there is no required compliance timeline for mitigation of overbuilt facilities, completing this type of work as part of a program will allow for Avista to manage the risk overall and prioritize overbuilt facilities based upon those instances with the highest risk to customers as well as operationally. This methodology is also more proactive and is anticipated to have less overall cost impact than by addressing each specific issue as it is encountered or addressing all know overbuilds at one time as an individually funded project. This program aligns with Avista's organizational focus to operate safe and reliable infrastructure for all of our customers in each of our service territories.

The current funding level balances available manpower with other programs administered at the District Offices and allows crews to also work on other compliance and risk reduction type activities. Annual levels of spending may need to be adjusted in this program as the risks in DIMP are reassessed annually.

Option 3 – Alternative Solution #1/Reduced funding option: Complete programmatic replacement of overbuilt sections of pipe at a reduced rate

Another option is to approach the risk associated with overbuilds with reduced funding. Reduced funding will result in replacement of fewer sections of overbuilt piping. The reduced funding alternative would still allow us a benefit by addressing some of the overbuilt facilities with known risk, but at a pace slower than we feel appropriate to address these safety concerns and maintain compliance. The outcome, should this option be selected, would result in the continued operation of facilities known to be out of compliance and which are currently operating with higher risk to customers and operations personnel. Additionally, Avista is often required to return to an overbuild location multiple times in attempt and complete a leak survey or other maintenance tasks that cannot be completed due to the overbuild. This will continue to result in increased operations & maintenance related costs. This option would be a partial employment of both Options 1 and 2 and is not recommended.

Option 4 – Alternative Solution #2/Enforce Avista's easement rights.

A final option to this program is to attempt to enforce Avista's "rights" and try to force the owners, renters, or mobile home parks owners to be liable for these fixes, however the original piping in these locations typically has weak or no easement protection. The ability to prove that the existing customer was responsible for the overbuild can be difficult and sometimes impossible. Avista has experienced in the past that attempts to force customer to pay for these modifications are difficult and often legal fees approach the cost of the work. Legal actions often take an extensive time and resource commitment. Additionally the negative public relations associated with such a philosophy would be very difficult to overcome. This option is not recommended.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Overbuilt Pipe Replacement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	2-17-20
Print Name:	Jeff Webb		
Title:	Manager Gas Engineering		
Role:	Business Case Owner		

Signature:		Date:	2/17/20
Print Name:	Mike Faulkenberry		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Seth Samsell	04/17/2017	Jeff Webb	04/17/2017	Initial version
2.0	Seth Samsell	02/12/2020	Jeff Webb		Revised for 2020 Oregon GRC Filing

Template Version: 02/24/2017

EXECUTIVE SUMMARY

Avista is required by state commission rules and tariffs in WA, ID, and OR to annually test gas meters for accuracy and ensure proper metering performance. Execution of this program on an annual basis ensures the continuation of reliable gas measurement for our customers and compliance with the applicable state tariffs.

The Planned Meter Change-out (PMC) Program uses a statistical sampling methodology based on ANSI Z1.9 "Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming". Sample sizes and acceptance criteria are defined in the ANSI standard. The annual test results of gas meters that have been removed from the field are analyzed and a determination of the accuracy of each meter family is made. If the analytics determine a meter family (defined as a manufacturer year and model/size) is no longer metering accurately enough to meet the tariff, then that entire meter family will be replaced. Conversely, if the analytics determine a meter family is testing well (close to 100% accurate), the sample size (number of meters in that family required to be tested) can be reduced. These analytics help control costs and remove meters quickly that are not performing well.

This program includes only the labor and minor materials associated with the PMC Program. Major materials (meters, pressure regulators, and Encoder Receiver Transmitter (ERT)) will be charged to the appropriate Gas Growth Programs. The annual cost for the program varies depending on the results of the previous year's statistical analysis. On average approximately 6,000 meters are removed for this program resulting in an average cost of $1,500,000 ($250/meter).

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial Version	03/16/2017	
1.1	Jeff Webb		04/07/2017	
2.0	Dave Smith	Revised for 2020 Oregon GRC filing	2/17/2020	
2.1	Smith-Webb	Updated to the refreshed 2020 Business Case template	7/10/2020	

GENERAL INFORMATION

Requested Spend Amount	$1,500,000
Requested Spend Time Period	Annually
Requesting Organization/Department	Gas Engineering
Business Case Owner | Sponsor	Jeff Webb/Dave Smith | Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Avista is required by state commission rules and tariffs in WA, ID, and OR to test meters for accuracy and ensure proper metering performance. Execution of this program on an annual basis ensures the continuation of reliable gas measurement and compliance with the applicable tariffs.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer.

This program is a mandatory requirement to be in compliance with state commission rules and tariffs in WA, ID, and OR.

The following state rules regulate Avista's PMC Program:

Oregon:

- OAC 860-023-0015 "Testing Gas and Electric Meters"
- Tariff Rule #18

Idaho:

- IDAPA 31.31.01.151 through .157 "Standards for Service"

Washington:

- WAC Chapter 480-90-333 through -348 "Gas companies – Operations"
- Tariff Rule #170

Our customers benefit from this program because it assures that natural gas use is measured accurately in all jurisdictions.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

Avista would not be in compliance with state commission rules and tariffs in WA, ID, and OR if this program is not completed annually.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The PMC Program uses a statistical sampling methodology based on ANSI Z1.9 “Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming”. Sample sizes and acceptance criteria are defined in the ANSI standard. The annual test results of gas meters that have been removed from the field are analyzed and a determination of the accuracy of each meter family is made. If the analytics determine a meter family (defined as a manufacturer year and model/size) is no longer metering accurately enough to meet the tariff, then that entire meter family will be replaced. Conversely, if the analytics determine a meter family is testing well (close to 100% accurate), the sample size (number of meters in that family required to be tested) can be reduced. These analytics help control costs and remove meters quickly that are not performing well.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

- Gas PMC Program Standard Operating Procedure
- ANZI Z1.9 “Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming”
- The following state rules regulate the PMC program:

Oregon:

- OAC 860-023-0015 “Testing Gas and Electric Meters”
- Tariff Rule #18

Idaho:

- IDAPA 31.31.01.151 through .157 “Standards for Service”

Washington:

- WAC Chapter 480-90-333 through -348 “Gas companies – Operations”
- Tariff Rule #170

These documents are saved on the Avista network drive c01d44 and can be made available upon request.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The meter accuracy testing results collected annually from the program are documented in an Excel spreadsheet. This spreadsheet performs calculations based on ANSI Z1.9 to determine the following year’s sampling requirements and identify which meter families do not meet the accuracy standards and must be removed.

The recommended solution is to complete this mandatory programmatic work. Completion of this program will keep Avista in compliance with state rules and tariffs and assure that our customers' natural gas use is measured accurately. Partial completion of this program will result in Avista being out of compliance with state rules and tariffs.

Option	Capital Cost	Start	Complete
Recommended Solution, Fully complete the programmatic work described	$1,500,000	January	December

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Historical program costs are used to determine the average labor costs to remove and test each meter. The number of meters required to be removed varies each year depending on the previous year's testing results. The average cost per meter is then multiplied by the anticipated number of meters to be removed to determine the estimated program cost for the following year.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

The program is completed between January and December of each year.

Gas Engineering, Gas Operations, Gas Meter Shop, and Technical Services work together to administer the PMC program. Gas Operations and the Gas Meter Shop remove the meters from the customer's premise and install new ones. If a large meter family fails Avista may hire a contractor to assist in the removal of the meters. The Gas Meter Shop completes physical calibration tests on the meters and the Technical Services group then analyzes the test results at the end of the year to determine the status of each family of gas meters. The results of this analysis will define the meter removal and testing requirements for the following year. Gas Engineering develops an annual report which is made available to the state commissions upon request.

Completion of this program may result in a reduction to O&M because there may be less high bill complaints from customers as a result of inaccurate meters.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Replacing gas meters is not a new process for Avista. Existing processes and technologies will be utilized for this program.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The only alternatives are to either partially fund this program or to not fund it at all. If this program were not completed fully Avista would be out of compliance with state rules and tariffs and could be exposed to fines from the various state utility commissions. Also, the accuracy of measurement of our customers' natural gas usage could not be assured.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

The program will be completed between January and December of each year. The gas meters are purchased as a pre-capital material item under ER 1050 (Gas Meters). The meter will become used and useful upon installation.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This program aligns with Avista's organizational focus to maintain a safe and reliable infrastructure to achieve optimum life-cycle performance, safely, reliably, and at a fair price for our customers.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project.

This program must be completed to ensure our customer's meters remain accurate throughout their service life. Accuracy data is obtained and analyzed each year to ensure the program is testing the appropriate number of meters and removing ones that no longer meet Avista's accuracy requirements.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case.

All Avista natural gas customers benefit from this program because it ensures their gas meters remain accurate throughout their service life.

Business case stakeholders include Gas Engineering, Gas Operations, Gas Meter Shop, Technical Services, and state commissions.

2.8.2 Identify any related Business Cases

ER 1050 Gas Meters

3.1 Steering Committee or Advisory Group Information

Gas Engineering is ultimately responsible for the PMC plan and annual reports that are developed and made available to each of the state commissions.

3.2 Provide and discuss the governance processes and people that will provide oversight.

Gas Engineering, Gas Operations, Gas Meter Shop, and Technical Services work together to administer the PMC program and ensure compliance with the various state rules and tariffs related to gas meter testing.

3.3 How will decision-making, prioritization, and change requests be documented and monitored.

Meter accuracy testing results are compiled and analyzed in a spreadsheet. An annual report is developed by Gas Engineering and made available to the state commissions upon request. This report defines the program requirements for the following year.

The undersigned acknowledge they have reviewed the Gas PMC Program, ER 3055 and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Jeffrey A Webb Date: 7/10/2020

Print Name: Jeffrey A Webb

Title: Mgr Gas Engineering

Role: Business Case Owner

Signature: Mike Faulkenberry Date: 7/10/2020

Print Name: Michael J Faulkenberry

Title: Director Natural Gas

Role: Business Case Sponsor

Signature: ____________ Date: ________

Print Name: ____________

Title: ____________

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

1 GENERAL INFORMATION

Requested Spend Amount	$3,000,000
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

Gas Operations manages this category of work. The work is generated by the various municipalities that Avista has franchise agreements in. The overall program budget is managed by Gas Engineering.

2 BUSINESS PROBLEM

It is very difficult to forecast year-to-year what the cost in this category will be. Virtually all of Avista's pipelines are located in public utility easements (PUEs) which are controlled by local jurisdictional franchise agreements. Avista is mandated under these agreements to relocate its facilities, when local jurisdictional projects necessitate. Often these come without significant lead time by the local jurisdictions. It is often the case that meetings are called in the Spring to notify franchisees (natural gas, electric, cable, phone etc.) that they will need to relocate their facilities. This does not enable ideal planning and often may cause Avista to spend unbudgeted funds and do so in a manner that is not of the utmost efficiency.

When conflicts are identified that may require relocating gas facilities, meetings with the appropriate entities take place in an attempt to design around the conflict. If relocation of gas facilities are required, then Avista must relocate the gas facility at our cost per the applicable franchise agreement. If the relocation project is of significant complexity, then Gas Engineering will take over the project to design and manage it through completion, otherwise the local districts will manage the project. The business needs and potential solutions identified impact all gas customers in Avista's service territory.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$ TBD		
Option 2 – Preferred Solution, Complete	$3,000,000	January	December

replacements as necessary			

Option 1 – Do nothing

The nature of this work is considered "work in request of others". If the conflicts are not resolved through design changes or relocation of the gas facilities, Avista would be in conflict with franchise agreements and could be charged with delay of a project. This would not only be a financial burden on the company, but it would also greatly damage the working relationship between Avista and the municipality.

Option 2 – Preferred Solution, Complete the replacements as necessary

By completing the projects as requested, then Avista meets the obligations under its franchise agreements, remains in good standing with the municipalities, and avoids financial penalties.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Replacement Street and Highway Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Jeff Webb (signed) Date: 2-17-20
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: (signed) Date: 2/17/20
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Cmt Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/17/2017			Initial version
1.1	Jeff Webb	04/07/2017			
2.0	Jeff Webb	2/17/2020			Revised for 2020 Oregon GRC filing

Template Version: 03/07/2017

1 GENERAL INFORMATION

Requested Spend Amount	$3,000,000
Requesting Organization/Department	Gas Engineering
Business Case Owner	Jeff Webb, David Smith
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Gas Compliance department is responsible for ensuring Avista is compliant with Federal and State Regulations governing the distribution of natural gas. When a new regulation is brought into effect, the Gas Compliance department will determine if Avista is meeting the requirement or not. If the new requirement is not being met, the Gas Compliance department will notify the appropriate work group and work with them to determine the appropriate path forward to ensure compliance. Gas Engineering is responsible for managing this program.

2 BUSINESS PROBLEM

Current industry Pipeline Safety code requires pipeline operators to have pressure test documentation and material specifications for pipelines distributing natural gas. Avista has some deficiencies in these types of records, but industry regulators (state inspectors) historically have not placed much emphasis on this, specifically for facilities that operate at lower stress levels and therefore at a lesser risk to the public. Avista's history, very similar to that of other utilities, involves pipeline construction during times when the pipeline safety code was not in effect or taken to be that important. Also, Avista has acquired properties from other companies and therefore had no control over their testing practices and record keeping prior to the acquisition. The regulatory climate is now changing and more scrutiny is being placed on having these records.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is actively working on a new rule that is expected to be published in December of 2017 called "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines". When implemented, it will require pipeline operators to have "traceable, verifiable, and complete" Maximum Allowable Operating Pressure (MAOP) records for its transmission facilities. Our understanding of the Rule is that Avista will now need to begin aggressively addressing portions of our system in order to be in compliance. Until the Rule is published, it is not clear yet what the timeframe will be to create a plan and mitigate all deficiencies.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 - Do nothing / Defer project	$0		
Option 2 – Preferred Solution, Continue to remediate segments of high pressure pipeline.	$3,000,000	2016	2022
Option 3 – Alternative Solution, Reduced funding option: Replace segments of high pressure pipeline.	$1,500,000	2016	2022

Option 1 – Do nothing / Defer project.

If segments of transmission pipeline without traceable, verifiable, and complete MAOP records are not mitigated, Avista will be non-compliant with Federal Pipeline Safety Codes, especially when the Rule mentioned above becomes final. If the work in this program is not completed, Avista will be going against industry guidance and trends. Once the Federal Rules become final, penalties and fines may be imposed for not completing this work.

Option 2 – Preferred Solution, Continue to remediate segments of high pressure pipeline.

As stated above, the proposed Federal Rule will force action to address lack of sufficient MAOP records. Transmission pipelines without traceable, verifiable, and complete MAOP records will be replaced or mitigated within this program. Reasons for this work will include, but are not limited to; incomplete construction and pressure test documents, pipe quality deficiencies from the manufacturing process, and risk reduction in densely populated areas. As a result of completing this option, public and employee safety will be improved by replacing at risk pipe.

Officials and spokesmen from both PHMSA and the American Gas Association (AGA) have stated it is not prudent for operators to wait for the Federal Rule to become finalized before bettering their systems in this category of work. Avista has been in the process of remediating pipelines under this program since 2015. Incidentally, many of these facilities have been in service for over 30 years.

Depending on the final language of the Rule, the annual levels of spending may need to be adjusted in this program. However, as best as Avista is able to tell at this time, what is proposed is the correct pace to complete this Program. The current rate of work is reasonable with Avista's Engineering and construction workforces.

Avista will address replacement or mitigation of its pipelines in the order of highest operating stress and highest levels of record deficiencies. This program will be prioritized in all three of its natural gas operating states and will analyze risks and priorities regardless of jurisdiction. The projects in 2017 will likely all be in Oregon. Replacement projects in 2018 and beyond have not yet been determined.

Option 3 – Alternative Solution, Reduced funding option: Replace segments of high pressure pipeline.

Reduced funding will result in replacing fewer pipeline segments with insufficient MAOP records. This will be at a pace slower than has been accomplished historically and slower than what we feel is the ideal rate as described above. The outcome, should this option be selected, may be pipeline segments being out of compliance with Federal Regulations and a greater amount of backlog to work through once the Rule is published.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas HP Pipeline Remediation Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeff Webb	Date:	4-17-17
Print Name:	Jeff Webb		
Title:	Manager Gas Engineering		
Role:	Business Case Owner		

Signature:	Mike Faulkenberry	Date:	4/17/17
Print Name:	Mike Faulkenberry		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Dave Smith	03/09/2017	Mike Faulkenberry	04/17/2017	Initial version

Template Version: 02/24/2017

Gas Non-Revenue Program, ER 3005

1 GENERAL INFORMATION

Requested Spend Amount	$9,000,000
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	Program
Driver	Failed Plant & Operations

1.1 Steering Committee or Advisory Group Information

This work is typically unplanned and is initiated by customers or Avista maintenance crews and is managed at the Local District level. Gas Engineering establishes the overall budget based largely on historical spend patterns and reports monthly updates to the Capital Planning Group based on feedback from the Local Districts. Gas Engineering is responsible for projects under this ER that require substantial design efforts such as farm tap retirements, highway or river crossings, and steel pipelines.

2 BUSINESS PROBLEM

The work in this annual program is mostly reactionary, unplanned work and is difficult to predict aside from using historical trends. The following situations are typical triggers for such work: shallow facilities found by excavation (the excavation may or may not be related to gas construction), relocation of facilities as requested by others (except for road and highway relocations), leak repairs on mains or services, meter barricades (only in Washington State and only through the year 2020), and farm tap elimination. Each of these work types are further described below. Customer related benefits include reduced operations and maintenance (O&M) costs and improved safety and reliability from having facilities at the proper depth and from reduced leak rates of new plastic pipe versus older steel. With the exception of the meter barricade work, the business needs and potential solutions identified impact all gas customers in Avista's service territory.

When shallow facilities are discovered, an appropriate response to the situation is determined by Local District Management. If the response to the situation is capital in nature, then the repair is funded from this program. If the scope of the project is large enough to warrant it, the project will be prioritized and risk ranked against other similar type projects. These types of projects allow Avista to remain in compliance and operate the gas facilities in a safe and reliable manner.

If requested by others (typically customers) to relocate facilities, Avista is bound by tariff language to do so at the customer's expense. Under certain circumstances, Avista may choose these opportunities to perform additional work beyond the immediate request to improve or update the gas system. Local District Management and field personnel will evaluate the circumstances and make an appropriate decision based on a holistic view of the situation. Guidance to help evaluate the scenario is established in the Company Gas Standards Manual. An example might be to replace an entire existing steel service with modern plastic material instead of just replacing a small section of the steel service that is in conflict with a customer's home improvement project. This would eliminate the possibility of future deficiencies with the cathodic protection system on the steel pipes and reduce future maintenance related to that steel service. The charges for this additional work are put against this program.

When leaks are found on the gas system, it is sometime advantageous to replace a section of main or service as opposed to just repairing the leak. The Local District looks at the long term fix when possible, not just addressing the immediate concern, and considers what is the right thing to do in these situations. This type of betterment falls under this program.

The need for meter protection can come from a variety of sources: customer, meter reader, atmospheric corrosion inspectors, or from company personnel. Each report is vetted by the Local District to ensure the need is warranted and then the job is scheduled for installation. Installation of meter barricades or break-away fittings on existing meters sets is capital only in Washington State and only through the year 2020.

A single service farm tap (SSFT) installed on a supply main is a common way to provide gas service to a small number of customers. The alternative is to install distribution main from an adjacent distribution system to serve the customer which may be cost prohibitive at the time. Many of these farm taps are reaching the end of their service life or need to be replaced for maintenance reasons. In areas of high concentrations of farm taps that have maintenance concerns, it is sometimes advantageous to rebuild one of them as a traditional regulator station (pressure reduction station), install distribution main to the other services from the adjacent farm taps, and then retire the other farm taps. This reduces O&M by having fewer stations to maintain.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0	N/A	
Option 2 – Preferred Solution, Complete programmatic work as described	$6,000,000	01-2017	12-2017
Option 3 – Alternative Solution, Reduced funding	$3,000,000	01-2017	12-2017

Option 1 – Do nothing

Shallow facilities – Higher likelihood of being damaged and causing a gas leak.

Requested by others & leak repair – To miss the opportunity to better the system while already on-site doing work is shortsighted because we increase the chances of having to be back at the site to remedy other maintenance items at a later date. The decision to simply repair the leak or perform the customer requested work (quickest and easiest thing to do) eliminates the chance to improve the system as a whole, while increasing the chances of having to be back at the site later to fix another leak or maintenance concern. If leaks are not repaired, they must be monitored and re-evaluated on a periodic schedule to ensure they are not becoming a greater hazard to the public.

Meter protection – Not installing meter barricades or break-away fittings is against Federal Rules (CFR 192.353) and presents a significant safety risk to the public, especially if the facilities are damaged.

Farm tap elimination – If Avista is not allowed to optimize the gas distribution system by reducing the number of farm taps that are maintenance intensive, then eventually more staff will be required to perform this federally mandated work. Additionally, farm taps are normally located between the driving lane and the property line, are low profile, and are sometimes difficult for the public to see. This puts them at risk of vehicle damage.

Option 2 – Preferred Solution, Complete programmatic work as described

Shallow facilities – Lowering gas mains and services is not required by Federal Rules, but it is prudent. It reduces the chances of damage caused by excavation over and around the gas facilities. This is critical because damage from excavation is the highest risk to our gas facilities. Excavators are expecting gas pipes to be at the depths they are first installed at. When they are shallow because of grade changes that have been caused by others since installation, there is an increased risk of damage and threat to public safety.

Requested by others & leak repair – Betterment of the gas system when opportunities arise is the prudent way to operate a gas distribution system. Mobilizing crews and equipment to a site often covers the bulk of the costs for small projects, so making the most of the time once there is the sensible way to operate. Betterments as described in Section 2 are driven by Company Standards and best practices.

Meter protection – Avista is mandated by Federal Rules to protect above ground facilities from damage. Gas meters located where vehicles are normally parked or driven create a hazard if the meter is not properly protected.

Farm tap elimination – When there are many farm taps located in close proximity to each other and when those stations have reason to be rebuilt, then it makes sense to rebuild just one of them and install distribution main to the other sites to provide a new source of gas. This allows the adjacent farm taps to be retired, reducing O&M and improving public safety. Triggers for rebuilding a farm tap may include; replacement of inadequate or obsolete equipment that is no longer supported, poor location of station (safety concerns), inability to perform proper maintenance, and capacity constraints.

The customers benefit from these types of projects by having a safer, well maintained distribution system. Also this is a prudent way to spend resources because many deficiencies at stations can be remedied under just one project. Additionally, the new main might be installed in front of structures without gas service, making it easier to serve them with gas in the future should they choose to change their energy source.

Option 3 – Alternative Solution, Reduced funding

Shallow facilities – Likelihood of being damaged and causing a gas leak if fewer facilities were lowered.

Requested by others & leak repair – *This betterment would happen at a reduced rate, causing workload pressure on the maintenance personnel.* To miss the opportunity to better the system while already on-site doing work is shortsighted because we increase the chances of having to be back at the site to remedy other maintenance items at a later date. The decision to simply repair the leak or perform the customer requested work (quickest and easiest thing to do) eliminates the chance to improve the system as a whole, while increasing the chances of having to be back at the site later to fix another leak or maintenance concern. If leaks are not repaired, they must be monitored and re-evaluated on a periodic schedule to ensure they are not becoming a greater hazard to the public.

Meter protection – Not installing meter protection is against Federal Rules and presents a significant safety risk to the public, especially if the facilities are damaged.

Farm tap elimination - *This optimization would happen at a reduced rate, causing workload pressure on the maintenance personnel.* If Avista is not allowed to optimize the gas distribution system by reducing the number of farm taps that are maintenance intensive, then eventually more staff may be required to perform this federally mandated work. Additionally, farm taps are normally located between the driving lane and the property line, are low profile, and are sometimes difficult for the public to see. This puts them at risk of vehicle damage.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Non-Revenue Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	2-17-20
Print Name:	Jeff Webb		
Title:	Manager of Gas Engineering		
Role:	Business Case Owner		

Signature:		Date:	2/17/20
Print Name:	Mike Faulkenberry		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Cmt Review		

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/16/2017			Initial version
1.1	Jeff Webb	04/05/2017			
2.0	Jeff Webb	2/17/2020			Revised for Oregon 2020 GRC filing

Template Version: 02/24/2017

EXECUTIVE SUMMARY

This annual program will replace or upgrade existing at-risk Gate Stations, Regulator Stations and Industrial Meter Sets ("stations") located throughout Avista's gas territory in WA, ID, and OR that are at the end of their service life and/or not up to current Avista standards. Additionally, it will address enhancements that will improve system operating performance, enhance safety, replace inadequate or antiquated equipment that is no longer supported, and ensure the reliable operation of metering and regulating equipment.

These stations require annual maintenance per 49 CFR 192.739 and if the equipment at the station is obsolete and replacement/maintenance parts are no longer available, then proper maintenance cannot be completed. Incomplete maintenance could cause Avista to be out of compliance and be exposed to fines from the various state utility commissions.

Avista's gas customers from all jurisdictions benefit from these types of projects by having a safer, more reliable, well maintained distribution system. Also, this is a prudent way to spend resources because many deficiencies at a station can be remedied under just one project.

Annual cost to fund this program is $1,000,000.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial version	3/17/2017	
1.1	Jeff Webb		4/07/2017	
2.0	Jeff Webb	Revised for 2020 Oregon GRC filing	2/17/2020	
2.1	Smith-Webb	Updated to the refreshed 2020 Business Case template	7/10/2020	

GENERAL INFORMATION

Requested Spend Amount	$1,000,000
Requested Spend Time Period	Annually
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Jeff Webb/Dave Smith | Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Existing stations located throughout Avista's gas territory in WA, ID, and OR have a finite service life and will eventually no longer meet Avista's current design standards, may feature obsolete equipment, or may develop operational or safety issues that need addressed in order to delivery safe and reliable gas service to customers.

Another category of work in this program is moving regulator stations located underground in a vault to a more traditional above ground configuration. Stations located in vaults are difficult to maintain because of the limited working room for tools and workers. Additionally, water in the vault can make maintenance more difficult. Regulator Stations in a vault are also a safety concern as they are confined spaces and can trap harmful levels of natural gas should a leak be present.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer.

This program's primary driver is asset condition. By replacing obsolete stations, we will continue to deliver safe and reliable gas service to customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

This work is needed now because there is already a backlog of stations needing replacement. The list of stations needing replacement continues to grow as stations meet the end of their service life. Postponing the work will cause the list of stations needing replacement to outpace the number of stations remediated.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The success of the program can be measured by the completion of station replacement projects. These stations are a vital link to providing gas service and replacing obsolete stations will help Avista continue to deliver safe and reliable gas service to customers.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

A master list of stations with reported deficiencies is maintained by Gas Engineering and is shown below.

Project List/Capital Plannin					Next Projec	20	1							
3002	2007-95	Rebuild	Rebuild - Reg Station #562 Gold Creek, Colville WA	Colville, WA	Ken Sampson	9/7/2007				High	D Smith		In Const.	Replace outlet valve on bypass and station. Existing Kerotest valves are difficult to throttle. Consider a regulated bypass. Need to also look at the system capacity. An asphalt plant is down stream. According the Ken S it is necessary to operated the regs @ 55 psig to ensure adequate pressure to the asphalt plant. Valves need replaced, they are older kerotest valves and mixed ANSI class. Need regulated bypass due to fast acting load downstream. Possible Summer Student project. (11/21/08 - Add a regulated Bypass). Targeting First week of June 2018 if possible.
3002	2007-129	Rebuild	Rebuild - Reg Station #1-2, Mead Gate Kaiser Run, Spokane WA	Spokane, WA	Rich I	12/14/2007	TBD			High	D Smith	1/9/2015	In Design	Replace Axial flows w/ Mooney's to improve maintenance. Project goes hand in hand with Mead Gate Rebuild. On Hold until we determine an overall plan to increase capacity of the 174 psig system.
3002	2008-6	Rebuild	Rebuild - Reg Station #316, Colton WA	Colton, WA	Trevor S	1/17/2008	TBD			High	T Harding	9/21/2012	In Const.	Current reg station has 2" Fisher 630 w/ 1/2" Orifice and 2" Axial Flow. Trevor would like a Reg/Monitor w/ 2x1" Mooney's.
3002	2008-60	Rebuild	Rebuild - Reg Station #27, Liberty Lake WA (Golf Course)	Liberty Lake, WA	David H	7/14/2008	TBD			High	D Smith		In Design	Full relief station installed directly under power lines. Need to convert to a Reg /Monitor station. In addition, HP inlet line should be replaced as it has a MAOP of 250 and is a limiting factor on the Liberty Lake HP Feeder which has a MAOP of 440 PSIG.
3002	2008-86	Rebuild	Rebuild - CDA East Reg Station #221, CDA ID	CDA, ID	Steve F	9/10/2008	TBD			High	R Anderson	10/8/2012	In Design	Turbine Meter Redundant, Pulse for YZ Odorizer from Meter, Hard to turn plug valves. Build in 2013, install in 2014. Delayed until HP reinforcement complete 2017.
3002	2008-87	Rebuild	Rebuild - Reg Station 206, Sandpoint ID	Sandpoint, ID	Steve F	9/10/2008	TBD			High	R Anderson	1/9/2015	In Design	Top run of side of Regs is 2" (May be to small), Station has settled, No outlet vavle for station. (Reviewed 9/18 w/ Steve F, needsoutlet isolation valve, Raise station approx. 12", replace fence. Need to bypass station during construction. - DRH)
3002	2008-88	Rebuild	Rebuild - Reg Station 213, Odorizer, **Post Falls, ID**	Post Falls, ID	Steve F	9/10/2008	TBD			High	R Anderson	10/8/2012	In Design	Odorizer Float Sticks (Pearless Bypass Odorizer), Clean up header, some threaded valves. Build in 2013, install in 2014. Total Rebuild
3002	2009-146	Upgrade	Upgrade - Odorizer #315, replace four valves, Colton, WA	Colton, WA	Jenny B	9/4/2009	TBD			High	T Harding		In Design	Here are four valves (differential valves) at Odorizer Station #315 on Rimrock Rd, Colton, WA being used as Emergency Valves in case of a problem and being turned yearly as maintenance. #PUM711, #PUM721, #PUM722, #PUM852.
3002	2009-160	Rebuild	Rebuild - Reg Stn #31, Nine Mile Rd & Royal, **Spokane WA**	Spokane, WA	Rich I	11/12/2009				High	D Smith		In Const.	Clean up Rockwell Strainer, Axial Flow Relief, only 2' off ground, bypass valves stuck, cobbled up sense lines.

Image 1 – Master List of Stations with Deficiencies

This list saved on the Avista network drive c01d44 and can be made available upon request.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The master list of stations with reported deficiencies referenced in section 1.5.1 summarizes the issues at each station.

The requested level of spending for this program allows the high priority projects to be completed every year. The list of new requests continues to grow as stations meet the end of their service life. At this pace, the number of stations remediated will slowly outpace the number added each year. The workforce available to do this type of work is responsible for both maintenance of these stations and the rebuild efforts. This level of spend complements their available time well without requiring additional headcount.

Since these stations are a vital link to providing customers with reliable gas, planned work is better than unplanned work. Unplanned work during times of high gas use (normally the winter) can be more difficult to perform and have negative impacts to customers if it fails to operate properly.

Option	Capital Cost	Start	Complete
Recommended Solution, Replace at risk stations at requested funding level	$1,000,000	January	December
Alternative Solution, Replace at risk stations at a reduced funding level	$500,000	January	December

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

A master list of stations with reported deficiencies is maintained by Gas Engineering. Each year this list is evaluated by subject matter experts in Gas Engineering and Gas Operations and the stations are prioritized by risk level. Stations with the highest risk level are selected for completion while others are deferred to future years. The workforce available to do this type of work is responsible for both maintenance of these stations and the rebuild efforts. The requested level of spend in the Recommended Solution complements their available time well without requiring additional headcount.

Stn #	Priority	2020 Cost	Comments	State	Budgeted for 2020	Deferred to 2021
722	1	$ 6,000	Eastern St Hosp MSA	WA	$ 6,000	
4406	1	$ 10,000	Interstate Conrete MSA, Rathdrum	ID	$ 10,000	
316	1	$ 25,000	Colton DR, materials already ordered	WA	$ 25,000	
201	1	$ 30,000	Bonners Ferry DR, materials ordered already	ID	$ 30,000	
0801	1	$ 50,000	Cove Ave, La Grande	OR	$ 50,000	
0812	1	$ 25,000	Hilgard, La Grande w/ Heater Maintenance	OR	$ 25,000	
2713	1	$ 280,000	Keno Gate Rebuild	OR	$ 280,000	
562	1	$ 50,000	Gold Creek Loop Rd	WA	$ 50,000	
7701	1	$ 25,000	Lakeland Village MSA	WA	$ 25,000	
2404	2	$ 57,000	Ave G, White City	OR	$ -	$ 57,000
213	2	$ 80,000	McGuire GS	ID	$ 80,000	
307	2	$ 15,000	Moscow DR, reg change only	ID	$ -	$ 15,000
375	2	$ 20,000	Spangle Odorizer	WA	$ 20,000	
24c18	3	$ 100,000	Eastman Kodak - Kirtland Road	OR	$ -	$ 100,000
206	3	$ 60,000	Sandpoint DR	ID	$ -	$ 60,000
303	3	$ 10,000	High pressure DR, change to FT station	WA	$ -	$ 10,000
36	3	$ 95,000	Airport Road	WA	$ -	$ 95,000
221	4	$ 50,000	CDA East GS & RS 2210	ID	$ -	$ 50,000
Various	4	$ 10,000	Misc FT replacement, one is likely to happen	ID	$ -	$ 10,000
24P23	4	$ 55,000	Payne Road Rebuild	OR	$ -	$ 55,000
31	4	$ 30,000	Nine Mile & Royal	WA	$ -	$ 30,000
23	5	$ 30,000	Trent & Woodlawn	WA	$ -	$ 30,000
260	5	$ 30,000	Silverton Reg Station	ID	$ -	$ 30,000
315	5	$ 30,000	Colton Gate Station	WA	$ -	$ 30,000
420	5	$ 60,000	Lewiston DR	ID	$ -	$ 60,000
2412	5	$ 125,000	Siskiyou & Willamette Rebuild/Relocate	OR	$ -	$ 125,000
4577	6	$ 40,000	Trent & Harvard	WA	$ -	$ 40,000
115	7	$ 35,000	Odorizer Station Rebuild	WA	$ -	$ 35,000

Image 2 – Partial list of of stations ranked by priority

(only 2020-2021 are shown)

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

Gas Engineering, Gas Operations, and the Gas Meter Shop work together to prioritize and administer the work for the year. The work is generally prioritized early in the year and then implemented throughout the spring, summer, and fall. The work is typically comprised of several individual station replacement projects.

Completion of this work may reduce unplanned O&M costs because obsolete stations are being removed from the system resulting in an increase in the overall reliability of the gas distribution system.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Gas Operations rely on station replacement projects as a vital part of their work. The current level of spend complements their available time to do this work without requiring additional headcount.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

There are two outcomes if this program is funded at a reduced rate. One is to replace fewer regulator stations and industrial meter sets. There is already a backlog of high-risk stations to be replaced, so this approach would take an even longer time to get through that backlog while new stations are continually added to the list every year. Secondly, an alternative to rebuilding the entire station would be to replace only the individual components that are antiquated or outdated. If this short-sided course were chosen, the work would be less productive and the opportunity to bring the entire station up to current standards would be lost. This option is not recommended.

If the program were to not be funded, Avista would be forced to operate at-risk stations in an unsafe, unreliable, and sometimes non-code compliant manner. O&M costs would escalate as the number of unplanned visits to these stations would likely increase due to operating them at or beyond their useful lives. This option is not recommended.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

The program will be completed between January and December of each year. The investments become used and useful to the customer at the completion of each station rebuild project.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This program aligns with Avista's organizational focus to maintain a safe and reliable infrastructure to achieve optimum life-cycle performance, safely, reliably, and at a fair price for our customers.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project.

The requested funding level is prudent to continue to serve safe and reliable gas service to customers. A master list of stations with reported deficiencies is maintained by Gas Engineering. Each year this list is evaluated by subject matter experts in Gas Engineering and Gas Operations and the stations are prioritized by risk level. Stations with the highest risk level are selected for completion while others are deferred to future years. The workforce available to do this type of work is responsible for both maintenance of these stations and the rebuild efforts. This level of spend complements their available time well without requiring additional headcount.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case.

Avista gas customers in WA, ID, and OR benefit from this program as these stations are utilized in all territories to deliver safe and reliable gas service.

Stakeholders including Gas Engineering, Gas Operations, and the Gas Meter Shop work together to ensure a successful program execution.

2.8.2 Identify any related Business Cases.

N/A.

Steering Committee or Advisory Group Information

Gas Engineering is ultimately responsible for prioritizing the projects and reporting out financial updates to the Capital Project Group.

2.10 Provide and discuss the governance processes and people that will provide oversight.

Gas Engineering, Gas Operations, and the Gas Meter Shop work together to administer this program. Year to date spend and budget updates are reviewed monthly. Annually, the Gas Engineering Prioritization Investment Committee (EPIC) reviews the 5-year plan and ensures the budget level is appropriate given other categories of work and risk on the gas system.

2.11 How will decision-making, prioritization, and change requests be documented and monitored.

A master list of Regulator Stations and Industrial Meter Sets with reported deficiencies is maintained by Gas Engineering. Gas Operations and the Gas Meter Shop report concerns while performing regular maintenance and these deficiencies are collected on the master list. Annually, subject matter experts from Gas Operations and Gas Engineering review the master list and risk rank the work for the following year. Stations with the highest risk (typically due to multiple different concerns) are prioritized over stations with only minor issues. Prioritizing this work annually with the subject matter experts provides a consistent approach. Through this process, the highest risk projects are selected to be funded. The spend for each individual project that falls under this ER is monitored on a monthly basis by the Project Engineers. Changes to the total annual spend for this ER is monitored by the business case owner.

The undersigned acknowledge they have reviewed the Gas Regulator Station Replacement Program, ER 3002 and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 7/10/2020

Print Name: Jeffrey A Webb

Title:	Mgr Gas Engineering		
Role:	Business Case Owner		
Signature:	Mike Faulkenberry	Date:	7/10/2020
Print Name:	Michael J Faulkenberry		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

1 GENERAL INFORMATION

Requested Spend Amount	$10,000,000
Requesting Organization/Department	Gas Engineering
Business Case Owner	Jeff Webb, David Smith
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Gas Planning department routinely runs an analysis (load study) on Avista's gas distribution system to identify areas of the system with insufficient capacity to serve existing Firm customer loads on a design day (Avista defines design day as the projected system demand for a "coldest day on record" weather event). These deficient areas are given a priority level based on the severity of the risk associated with insufficient system capacity. The areas with the highest priority are selected for remediation and the project is assigned to Gas Engineering to evaluate options to provide sufficient capacity to meet Firm gas demands on a design day. Options are reviewed with Gas Planning, Gas Operations, and other interested parties. The pros and cons of each option are then reviewed with the Gas Engineering Manager and a preferred alternative is selected to proceed with a funding request.

2 BUSINESS PROBLEM

Based on load studies performed by the Gas Planning department, load growth on the Williams Northwest Pipeline (NWP) Coeur d'Alene Lateral pipeline has exceeded both Avista's contractual delivery amounts as well as the physical capacity of the NWP Coeur d'Alene Lateral pipeline. In addition, the distribution system in the Hayden Lake, Idaho area will experience insufficient pressure during periods of peak demand on a design day. Sufficient capacity is defined as pressures at or above 15 pounds per square inch (psig) in the distribution system on a design day analysis. Without a reinforcement project, Avista will not have sufficient capacity to serve Firm customer load in the Coeur d'Alene, ID to Kellogg, ID corridor on a design day scenario.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 - Do nothing	$0		
Option 2 – Preferred Solution, Avista to construct approximately six miles of high pressure distribution pipeline in two phases to reinforce the distribution system in the greater Post Falls and Coeur d'Alene area.	$10,000,000	11/2015	12/2018
Option 3 – Alternative Solution, Compensate Williams Northwest Pipeline (NWP) for a mainline expansion of their Coeur d'Alene Lateral pipeline.	$10,000,000	11/2015	12/2019

Option 1 – Do nothing

Without a reinforcement project Avista does not have sufficient capacity to serve existing Firm customer load in the Coeur d'Alene, ID to Kellogg, ID corridor on a design day scenario, and cannot support any future customer growth. See Image 1 below for a load study analysis showing the Hayden Lake area distribution system with insufficient capacity. Approximately 3900 customers are at risk of losing their gas service during a cold weather event.

It is important to note that if service is lost during severe cold weather, gas service may not become available again until weather warms and customer demand decreases. Depending on the length of the outage, this can cause severe injury up to and including death to some customers.

Option 2 – Preferred Solution, Avista to construct approximately six miles of high pressure distribution pipeline in two phases to reinforce the distribution system in the greater Post Falls and Coeur d'Alene area.

This option capitalizes on the capacity available from the recently constructed Chase Road Gate Station (supply point into Avista's system) located on the GTN-TransCanada (GTN) pipeline. This option consists of a multi-year project comprised of a two phase high pressure distribution pipeline reinforcement that will shift gas usage from NWP to GTN, and will also allow Avista to choose a portion of gas nominations from either NWP or GTN to take advantage of price differentials. This additional capacity will be used to support customer growth in the Post Falls, ID and Coeur d'Alene, ID area currently served from NWP. This option also inherently increases system reliability by having two independent interstate pipeline gas sources, which will reduce the risk of customer outages in the event of an abnormal operating condition. Another benefit of this option is that it will be completed approximately one year before Option 3, which will accommodate the existing needs and support additional customer growth sooner. Phase one and phase two both consist of installing approximately three miles of 6" high pressure distribution pipeline and two Regulator Stations (pressure reductions stations) within Avista's system, with phase one scheduled to be constructed in 2017 and phase two constructed in 2018. See Image 2 below for a load study analysis showing how the proposed reinforcement provides sufficient capacity to the Hayden Lake, ID area distribution system.

Option 3 – Alternative Solution, Compensate Williams Northwest Pipeline (NWP) for a mainline expansion of their Coeur d'Alene Lateral pipeline.

The NWP expansion would include the installation of up to 6 miles of 10" pipe beginning at or near the WA/ID border (west of Post Falls, ID), which involves investing significant money into the Williams NWP system instead of Avista's infrastructure. Additionally, Avista would be required to refurbish and expand at least four Gate Stations (NWP supply point into Avista's system) along the NWP Coeur d'Alene Lateral to accommodate the projected load growth. This option is estimated to take 4 years to complete, which does not provide a timely reinforcement to the deficient Hayden Lake area, nor does it offer timely support of continued customer growth. Another disadvantage of this option is that Avista would not gain the ability to have two independent interstate pipeline gas sources into one of the largest load centers in our system, which would reduce system reliability in the event of an abnormal operating condition.

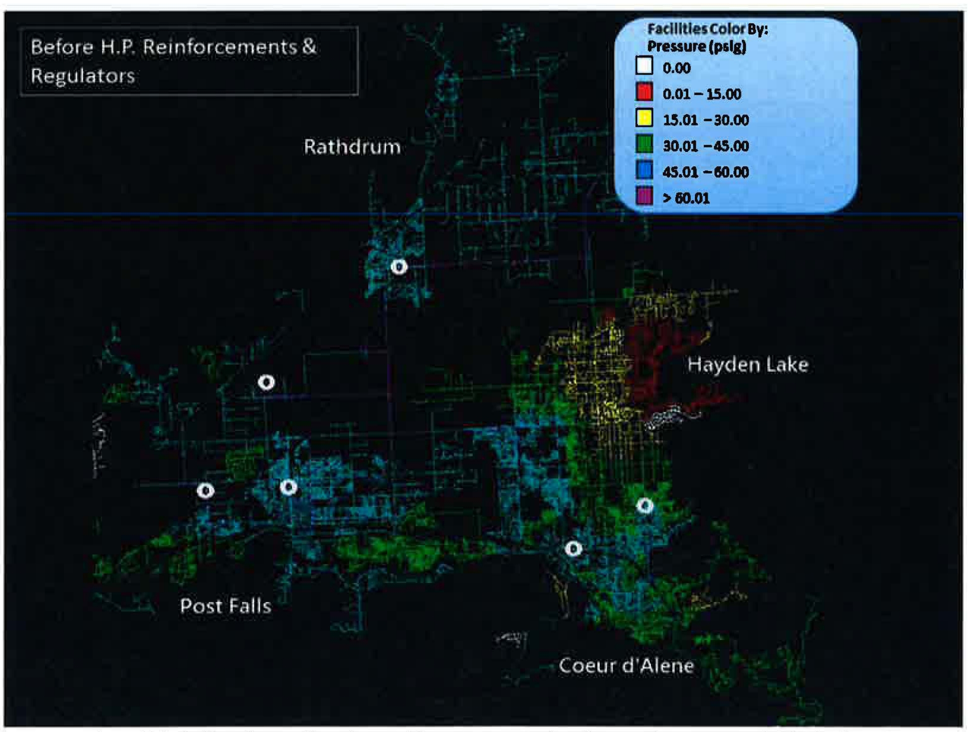


Image 1 – Distribution System Pressures before Proposed Reinforcement

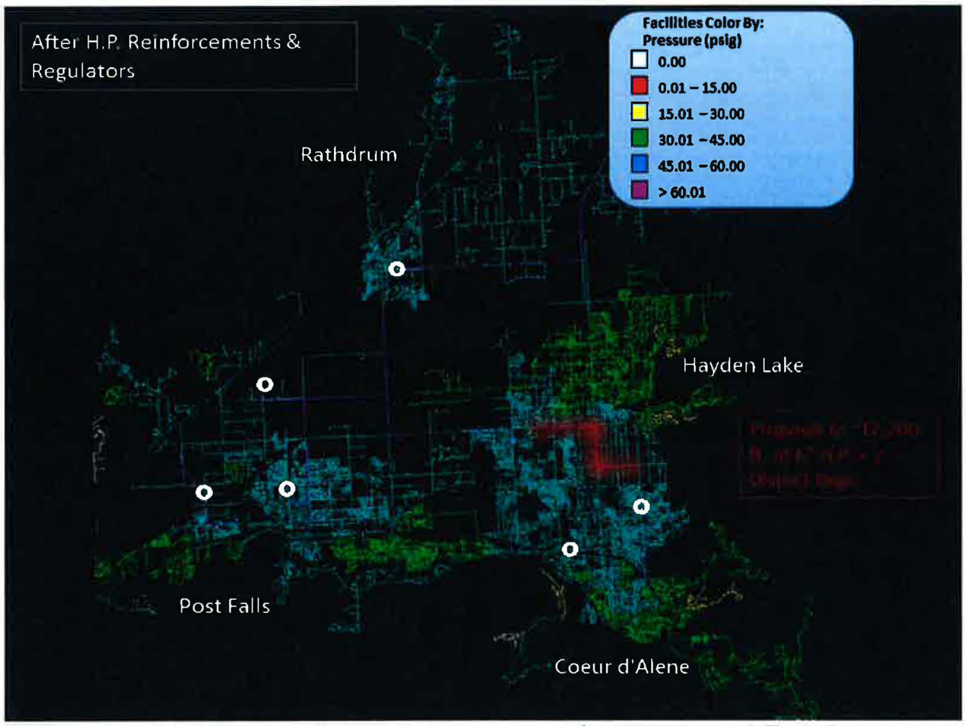


Image 2 – Distribution System Pressures after Proposed Reinforcement

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Rathdrum Prairie HP Reinforcement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeff Webb	Date:	4-17-17
Print Name:	Jeff Webb		
Title:	Manager Gas Engineering		
Role:	Business Case Owner		

Signature:	Mike Faulkenberry	Date:	4/17/17
Print Name:	Mike Faulkenberry		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Dave Smith	4/17/2017			Initial version

Template Version: 02/24/2017

EXECUTIVE SUMMARY

This annual program will identify and provide for necessary capacity reinforcements to the existing natural gas distribution systems in WA, ID, and OR. Avista has an obligation to serve existing firm gas customers by providing adequate capacity on design day conditions. Sufficient capacity is defined as pressures at or above 15 pounds per square inch (psig) in the distribution system on a design day analysis. Periodic reinforcement of the system is required to reliably serve firm customers due to increased demand at existing service locations and new customers being added to the system. Execution of this program on an annual basis will ensure the continuation of reliable gas service that is of adequate pressure and capacity.

Typical projects completed under this Business Case may include (but are not limited to) upsizing existing gas mains, looping existing gas mains (bringing in a second source to an area), and installing new regulator stations (pressure reduction stations). When a reinforcement is done by looping a system, there is a secondary benefit of higher reliability to the area. Most of these projects will have a unique project number assigned to them, but the lower cost (smaller scope) projects may be completed under the blanket project numbers set up for each district.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial draft version	03/17/2017	
1.1	Jeff Webb	Business Case Refresh PH 1	04/06/2017	
1.2	Jeff Webb	Revised for 2020 Oregon GRC filing	2/17/2020	
2.0	Harding-Webb	Revised V2 Business Case Refresh PH 2	7/10/2020	

GENERAL INFORMATION

Requested Spend Amount	$1,300,000
Requested Spend Time Period	1 Year / Perpetual Annual Request
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Tim Harding - Jeff Webb | Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Program
Driver	Performance & Capacity

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Avista's gas distribution systems are constantly changing as new customers are added to the system and other construction activities occur. It is expected that these systems are able to supply gas to all firm customers during high demand, including cold 'Design Day' conditions. There are certain systems that currently do not have adequate capacity to meet these needs. Reasons for this can include increased customer loads, new gas customers being added to the system, undersized piping, long piping lengths, and undersized valves and regulators.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer.

This program is Performance & Capacity related. These reinforcements improve system capacity and allow un-interrupted service to firm customers. Additionally, these reinforcements reduce the likelihood of low-pressure outages for all customers in effected areas.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

One of Gas Planning's responsibilities include the identification of low pressure areas on our distribution system, low pressure is synonamous with insufficient capacity. Insufficient capacity can result in a gas outage during a cold weather event. The impacts of a gas outage is very different than an electric outage. Even after temperatures warm and pressures have recovered in a gas system, it can take several days to restore service to customers, because each meter must be first shut off and then individually turned back on by a serviceman performing a safety check. To make matters worse, an outage will occur during extremely low temperature conditions – a very serious safety concern when customers may not have heat for days. This is a customer safety issue.

Additionally, according to tariff language, firm customers are paying for a reliable fuel source at all times short of a “Force Majure”. Therefore it would be unfair to have customers paying for firm service while Avista is intentionally operating a system that cannot meet the intent of the tariff.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Seasonal pressure recorders are placed at key locations in our distribution systems each winter. These devices record and regularly transmit pressure data that is reviewed remotely. This monitoring allows the Gas Planning department to cross-check and calibrate the computer model data with actual system pressures. By doing this, they are better able to suggest new reinforcements, while also verifying improved performance from previously installed reinforcements.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

Load studies, using computer models are run annually. Their findings are best reviewed graphically and are too numerous to display in this document. Gas Planning stores copies of load study results.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Sample Reinforcement Priority List:

OBJECTID	SIZE	MATERIAL CODE	NOTES	SHAPE.LEN	STATUS	LOCATION	CITY
23417	6"	Plastic	High	2561.08	Proposed	Reinforcement for Medford	Medford
21178	4"	Plastic	High	2476.81	New	Install new 4" and replace section of 2" with 4", Load study resu	Medford
21179	2"	Plastic	High	28.98	New	2" Tie-In	Medford
17977	6"	Plastic	High	4028.42	Replacemen	Load Study Result (currently ADL)	Medford
16377	4"	Plastic	High	1882.30	New	IP Connection to feed end of 55 psig system	Medford
20858	2"	Plastic	High	257.28	<Null>	2" Tie-In, E 6 psig system	Medford
20860	2"	Plastic	High	350.30	<Null>	2" Tie-In, W Medford	Medford
18301	4"	Plastic	High	3516.67	Replacemen	3500' of 2" to 4" Replacement	Spokane Valley
18300	8"	Steel	High	27535.87	New	*HP 27,700' 8" parallel to existing 4"*	Cheney
17981	6"	Plastic	High	4218.98	Replacemen	ADL Replacement Bellinger Rd	Jacksonville
20866	6"	Plastic	High	4808.68	New	Additional Jacksonville feed	Jacksonville
16068	4"	Plastic	High	3072.72	Replacemen	Palouse 2" Main Replacement	Palouse
16057	6"	Plastic	High	9418.36	Replacemen	South Hill	Spokane
17337	4"	Plastic	High	271.27	Replacemen	Along E St, 280'	Riddle
11577	6"	Steel	High	19572.92	Proposed	*HP Warden*	Warden
19901	6"	Plastic	High	5265.93	<Null>	6" main upsize for new development	Spokane
6777	2"	Plastic	High	407.66	Proposed	Loomis and Railroad	St John
21177	4"	Plastic	Medium	2796.64	Replacemen	Replace 2" with 4", low pressure area reinforcement	Spokane Valley
20861	6"	Plastic	Medium	2426.55	<Null>	Replace 4" with 6"	Colfax
20862	4"	Plastic	Medium	150.82	<Null>	Replace 2" with 4"	Roseburg
20863	4"	Plastic	Medium	3356.39	<Null>	Replace and install 4"	Roseburg
20864	4"	Plastic	Medium	523.10	<Null>	Replace 2" with 4"	Roseburg
20865	2"	Plastic	Medium	207.30	<Null>	2" Tie-in	Spokane
20857	2"	Plastic	Medium	157.07	<Null>	2" Tie-In, W 6 psig system	Medford
20859	4"	Plastic	Medium	724.85	<Null>	Replace 2" with 4", W 6 psig system	Medford
20537	2"	Plastic	Medium	167.22	New	Tie-in to eliminate AOI	Spokane
20218	6"	Steel	Medium	1395.06	Replacemen	ADL replacement	Spokane
18620	4"	Plastic	Medium	459.75	Replacemen	ADL Replacement, 500' of 2" to 4"	Medford
18618	4"	Plastic	Medium	5756.67	Replacemen	ADL Replacement	Spokane
18617	4"	Plastic	Medium	1768.88	Replacemen	ADL Replacement, 1800' of 2" to 4"	Medford
18297	4"	Plastic	Medium	6655.04	Replacemen	6700' of 2" to 4" Replacement	Rogue River
18298	4"	Plastic	Medium	1414.99	Replacemen	1500' of 2" to 4" Replacement	Spokane
17984	2"	Plastic	Medium	222.96	New	2" Tie-In Ashland 8 psig System 250'	Ashland
17985	4"	Plastic	Medium	529.18	Replacemen	Ashland 8 psig system 530' along Meade St	Ashland
17986	4"	Plastic	Medium	492.56	Replacemen	Ashland 8 psig system 500' along Harrison St	Ashland
17982	4"	Plastic	Medium	1268.93	Replacemen	1300' 2" to 4" along Keasey St	Roseburg
17983	4"	Plastic	Medium	2470.64	Replacemen	ADL Replacement 2400' Kline St 2400'	Roseburg
16065	2"	Plastic	Medium	143.52	Proposed	14th and Eastern	Spokane
15737	2"	Plastic	Medium	610.08	Proposed	Intersection of Lenter and Lathen	Moscow
15738	6"	Steel	Medium	4152.18	Replacemen	6" Main Replacement	Moscow
15106	6"	Steel	Medium	20412.47	Replacemen	Klamath Main Replacement	Klamath Falls
14779	2"	Plastic	Medium	414.46	Proposed	Plum and Winchester Tie-In	Medford
14780	2"	Plastic	Medium	410.38	Proposed	Plum and Winchester Tie-Ins	Medford
4542	2"	Plastic	Medium	136.73	New	Alderwood Tie-in	Spokane

Option	Capital Cost	Start	Complete
Proposal / Recommended Solution – Strategically install assets	$1,300,000	01 2020	12 2020
Alternative Solution – Reduced funding option: Strategically install assets with reduced funding level	$800,000	01 2020	12 2020

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The current budget request is based on past historical spending. This is a reasonable amount of construction work to divide between Engineering and Operations resources. There continues to be about a 6 year backlog of high and mediuom priority projects within this program. A reduced budget will increase the backlog and increase the risk of low-pressure outages.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

The money spent for this budget goes directly to the design and installation of new assets. Installations typically happen in Q2, Q3 and Q4 across all three states.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

N/A

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Alternatives include halting reinforcement efforts, or reducing program funding. Failing to meet firm customer demand, resulting in customer outages due to low pressure conditions are circumstances that Avista needs to avoid. These situations can have financial implications for the Company, reduced levels of Customer Experience, and legitimate safety concerns for vulnerable customers.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

These projects typically take place in Q2, Q3, and Q4. The assets become used and useful upon installation and are transferred to plant soon after completion.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Reinforcement projects allow the natural gas system to operate safely and reliably, meeting customer demands during all reasonable conditions.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project.

As the gas systems expand and customer growth continues, there continues to be a need for capacity reinforcements. Projects will be reviewed and prioritized on an annual basis by Gas Planning.

When reinforcements are successfully installed, the risk for customer outages due to low pressure conditions are greatly reduced. This positively impacts the Pressure Controlmen and Servicemen groups because of the reduced number of incidents they must respond to.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case.

This program touches on all service territories that Avista serves. Construction of these projects is done by both contractors, as well as in-house crews. Design duties are split between Gas Engineering and local CPCs. All Avista gas customer are stakeholders in these projects.

2.8.2 Identify any related Business Cases.

N/A

3.1 Steering Committee or Advisory Group Information.

The Steering Committee/Advisory Group for this program consists of Gas Planning and Gas Engineering.

3.2 Provide and discuss the governance processes and people that will provide oversight.

The Gas Planning department annually runs an analysis (load study) on Avista's gas distribution system to identify areas of the system with insufficient capacity to serve existing firm customer loads on a design day (Avista is consistent with other utilities in the industry and defines design day as the projected system demand for a "coldest day on record" weather event). These deficient areas are given a priority level based on the severity of the risk associated with insufficient system capacity. The areas with the highest priority are selected for remediation and the project is assigned to Gas Engineering to evaluate options to provide sufficient capacity to meet firm gas demands on a design day.

Year to date spend and budget updates are reviewed monthly. Annually, the Gas Engineering Prioritization Investment Committee (EPIC) reviews the 5-year plan and ensures the budget level is appropriate given other categories of work and risk on the gas system.

3.3 How will decision-making, prioritization, and change requests be documented and monitored.

The Gas Planning department formally sends a list of proposed reinforcements to the Gas Engineering group each year. As described above, the highest priority projects are assigned to Gas Engineering to be completed that year. Any proposals for re-prioritization is reviewed by Gas Planning. In a typical year there is a backlog of several years' worth of work (from a budget perspective). Top priority projects, that fit within the annual budget, are assigned to specific engineers to manage.

The undersigned acknowledge they have reviewed the Gas Reinforcement Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeffrey A Webb	Date:	7/10/2020
Print Name:	Jeffrey A Webb		
Title:	Manager Gas Engineering		
Role:	Business Case Owner		

Signature:	Mike Faulkenberry	Date:	7/10/2020
Print Name:	Michael J Faulkenberry		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

1 GENERAL INFORMATION

Requested Spend Amount	$200,000
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb / Dave Moeller
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 Gas Engineering
Category	Program
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Gas Measurement Engineer works with the Gas Telemetry Technicians, Gas Planning, Gas Engineering, Metering Automation, Gas Operations, Gas Control Room, Supervisory Control and Data Acquisition (SCADA), and Gas Supply groups to determine possible projects or locations for new telemetry sites or upgrades of existing equipment. The Gas Engineering Manager reviews the recommendations from the Gas Measurement Engineer and approves the specific projects within this program. A five year plan is also created by the Gas Measurement Engineer and approved by the Gas Engineering Manager.

2 BUSINESS PROBLEM

Avista's commitment to safety and reliability dictates that we monitor our gas system to ensure safe and reliable operation and accurate metering and accounting for gas purchased and sold. This includes compliance with Federal and State Gas Control Room Management Rules.

Gas Telemetry provides data that is used pro-actively for early detection of abnormal operating conditions before they become major problems which may affect safety or gas delivery. Additionally, telemetry is used to remotely monitor system pressures, volumes, and flows from areas of special interest such as gate stations which supply gas to Avista's system, gas transportation customers, regulator stations which reduce and regulate pressure, selected large industrial customers, end of line pressures, and per CFR192.741 requirements, pipeline systems with more than one source of gas.

Alarm set points in the field instruments such as flow computers, electronic volume correctors, and electronic pressure monitors to alert the Gas Control Room of abnormal operating conditions such as low or high pressure, high flow, high or low gas temperatures indicating problems with gas heaters at gate stations, and transducer failures. Communication with the instruments is via cellular modems or telephone lines.

An important example is the detection of degraded pressure regulator performance resulting in high or low pressures caused by dithiazine deposits in our regulators. In 2019 this occurred over 100 times at sites with telemetry. This is a mix of early detection by pro-active human analysis by evaluating pressure trends recorded in PI and pressure alarms received in SCADA. More pressure monitoring with telemetry is planned at additional stations relating to this issue. By proactively monitoring these sights, Avista can dispatch field personnel during normal business hours instead of waiting to respond to an alarm that may happen at any time of the day.

Additionally, data from these telemetry sites is used to validate the system modeling tool that Gas Planning creates every year. Since the data collected is electronic, it can be represented graphically to quickly analyze any anomalies. In addition to permanent equipment, around 50 temporary, portable pressure recorders with cellular modems are connected to piping in areas of interest where permanent equipment has not yet been installed, will not be needed, or is not practical.

The Gas Supply department benefits from these projects by having metering data from Gate Stations that is calculated and transmitted independently of the interstate pipeline's metering and billing info based on our instrument's measuring pressure and temperature and calculating gas volume based on pulses from the Pipelines meter. This aids in finding calculation or metering errors at the Gate Stations. Billing errors left unfound can create problems that lead to extra work and manual corrections between Avista and the interstate pipelines. This also provides data for cases when the Pipelines' do not have data on their side.

The customers and general public benefit from Avista having good "visibility" to the gas transmission and distribution system. This allows for a quicker response and better decision making from the Gas Control Room and Gas Operations when an abnormal or emergency situation occurs.

For example, we are quickly notified electronically of low pressure situations that if not addressed in a timely manner could result in significant loss of gas service to our customers. We are also notified of high pressures which could be hazardous or result in blowing gas such as when a pressure relief valve opens to limit the pressure in our piping.

If there were no telemetry, Avista would have to wait for customers to call in after they've lost gas service which at that point would have a significant impact to our customers and require substantial time and manpower to restore service. Costs could range from a few thousand dollars to a million dollars. In the case of high pressure and relief valve venting at one of our stations, we could be releasing gas to atmosphere for extended periods until a passerby notified us of the noise or a gas odor.

Avista strives to replace equipment that has reached the end of its reasonable service life with new equipment that makes use of current technology before reliability is significantly degraded or maintenance costs are excessive. We also review existing installations for opportunities to improve reliability, acquire more data, or more efficient ways of collecting the data.

Enhancing the gas telemetry system increases situational awareness and visibility of the gas system to help analyze operational concerns and monitor cold weather performance by the Gas Control Room Operators, Gas Operations, and Gas Engineering and Planning.

This program will continue the installations and upgrades of gas telemetry throughout Avista's gas service territory in Oregon, Washington, and Idaho. Over the last several years, costs have averaged approximately 45% spent in OR, 35% in WA, and 20% in ID.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0	N/A	
Option 2 – Preferred Solution, Replace/install telemetry at the current funding level	$200,000	January	December

Option 1 – Do nothing

To make no further additions or upgrades to Avista's gas telemetry system would result in less capability to see "real time" performance of the gas system, inability to see operational abnormalities in a timely fashion, subject our customers to increased chances of low or high pressure situations and their related safety risks, and the reliability of the existing system would decline due to equipment failures. More equipment would reach end of life and maintenance costs would increase.

***Option 2 – Preferred Solution, Replace/install telemetry at the current funding** level*

At the current funding level, Avista adds approximately 10 new sites and upgrades approximately 15 sites per year. Costs per site typically range from $5,000 for a simple upgrade to $50,000 for adding telemetry to a gate station.

The cost of this option represents a minimal amount and may need to be increased in future years depending on equipment failures. Some years more work is required and costs may be shared with other departments such as in 2019 when Verizon Wireless announced it was turning off 3G cellular service starting at the beginning of 2020 so we replaced approximately 170 3G cellular modems with 4G modems.

Based on current failure rates and funding, on the average this funding level has allowed upgrades as instrumentation fails and allows for modest enhancements to the system. This allows the high priority sites to be addressed as the need arises or equipment fails.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Telemetry Program (ER3117) and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Jeff Webb Date: 2-17-20
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: MF Date: 2/17/20
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Cmt Review

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/14/2017			Initial version
1.1	Jeff Webb	04/07/2017			
2.0	Dave Moeller	2/17/2020	Jeff Webb	2/17/2020	Revised for 2020 Oregon GRC filing

Template Version: 02/24/2017

1 GENERAL INFORMATION

Requested Spend Amount	$ 1,626,667
Requesting Organization/Department	Gas Supply
Business Case Owner	Jody Morehouse
Business Case Sponsor	Jason Thackston
Sponsor Organization/Department	Gas Supply
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Risk Management Committee (RMC) oversees decisions to enter into a joint projects such as Jackson Prairie Storage Project (JP). The RMC is comprised of the following:

- Scott Morris, Chairman, President & Chief Executive Officer, Chair of Risk Management Committee
- Dennis Vermillion, Senior Vice President Avista Corporation – President Avista Utilities
- Mark Thies, Senior Vice President & Chief Financial Officer
- Marian Durkin, Senior Vice President, General Counsel, Corporate Secretary & Chief Compliance Officer
- Jason Thackston, Senior Vice President Avista Corporation – Vice President of Energy Resources Avista Utilities
- David Meyer, Vice President & Chief Counsel for Regulatory & Governmental Affairs
- Ryan Krasselt, Vice President, Controller & Principal Accounting Officer
- Patrice Gorton, Director of Finance, Assistant Treasurer
- Tracy Van Orden (non-voting), Director of Internal Audit

Additionally, the JP Management Committee meets quarterly to review and approve the capital budget status for the current year as well as for vetting of any ongoing or future expenses. A business owner representative from each of the 3 partners has final authority on the Committee. Currently, these representatives are

- Lynn Dahlberg of Williams NWP
- Ron Roberts of Puget Sound Energy
- Jody Morehouse of Avista.

2 BUSINESS PROBLEM

Avista must provide solutions for the following gas supply needs:

- A flexible, diverse portfolio with components that enable Avista to serve customers during peak load demand.
- Risk mitigation methods for shielding customers from extreme daily gas price volatility during cold weather or other events affecting the natural gas commodity market.
- A mechanism or methodology for purchasing gas at lower prices during off-peak periods for use during high cost periods.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing – this is not an option			
Package together various solutions to fulfill Gas Supply obligations	*None – See below for expenses that would flow through the PGA*		
Continue with ownership in JP and fund necessary annual capital expenditures	*$ 1,626,667*	*01/01/2017*	*12/31/2017*
Build LNG Storage	*Cost prohibitive*		

No viable singular capital project options exist for replacing JP Storage at this time. Because JP Storage provides benefits/solutions for an array of business problems, it's likely that in its absence, a combination of solutions would be packaged together.

- For meeting peak load requirements, an option is purchasing additional leased pipeline transport on GTN at an estimated cost of $9,900,000 per year for 90,000 dth/day at $0.30/dth. This expense would flow through the PGA.
- Another solution that has been assessed in past Gas IRPs to meet peaking needs and/or transport needs is to build an LNG storage facility. The capital cost estimates have been in the multi-million dollar range and have proven to be cost prohibitive. The timeline to design and build an LNG facility would be 4 or more years.
- Replacing the optimization benefit JP provides to customers with other options would be difficult if not impossible. Over the 2016 – 2017 gas procurement year, the storage optimization saved gas customers an estimated $20,000,000. This benefit currently flows through the PGA.
- Without storage, the flexibility is lost to purchase gas during seasonal periods of lower gas prices (typically summer), to use or sell back into the market when markets are higher (typically winter). The estimated savings for this seasonal buying approach varies, but has been as high as $10,000,000 over a gas procurement year.
- To replace JP storage capacity with leased capacity would be estimated at more than $34,000,000/year plus additional pipeline transport. This is based on storage capacity lease estimates of approximately $4/dth for equivalent

working gas capacity.

The recommended solution is to continue to fund 1/3 of the capital budget for Jackson Prairie (JP) Underground Storage Facility. Avista owns this facility as a 1/3 partner with Puget Sound Energy and Williams' Northwest Pipeline. Puget Sound Energy is the managing partner for the facility which is located in Chehalis, WA. The requested capital represents Avista's 1/3 share of the capital needed to maintain the existing facility and maintain equal ownership status.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Jackson Prairie Storage Project and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 4-13-2017
Print Name: Jody Morehouse
Title: Director Gas Supply
Role: Business Case Owner

Signature: Date: 4/17/17
Print Name: Jason Thackston
Title: SVP & VP Energy Resources
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jody Morehouse	04/13/2017	Jason Thackston	04/14/2017	Initial version

Template Version: 03/07/2017

EXECUTIVE SUMMARY

Avista manages 11 Federally regulated apprenticeships that require instructional aides and equipment deemed necessary to provide quality instruction. [Regulated by 29 CFR 29 & 30] The Joint Apprenticeship Training Committee (JATC) administers these apprenticeships. These funds are used to purchase tools, materials and equipment for training apprentices and journey workers in all crafts. These tools and materials provide for related instruction that is closely correlated with the practical experience and training received on the job. The trained and competent workforce produced through the various apprenticeship's benefits customers in all Avista service territories. These apprenticeship programs further benefit Avista's customers by providing a safe, proficient and skilled workforce.

Support of apprenticeship at Avista through this capital program aligns strategically to Avista's Mission and Focus Areas. In order to deliver innovative energy solutions safely, responsibly, and affordably, Avista must have a field workforce of highly proficient professionals. This professionalism is achieved through apprenticeship. Without this funding, Avista will not have the ability to train in-house. This leaves Avista's customers without critical craft positions needed for energy delivery. Further, there is a potential that regulating bodies may de-certify Avista's Apprentice program, leaving Avista without the ability to train in-house and require significant expense to meet labor demands and maintain required skillsets. This project will train apprentices in all Avista states and service territories, the rate jurisdiction is Common Direct – Allocated All. The total capital expense to support this ongoing project is $375,000 over 5 years or $75,000/year.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Joe Brown*	*Executive Summary Only*	*7/1/2020*	*Business Case 2020 Refresh*
1.0	*Joe Brown*	*Updated for Approval*	*7/28/2020*	*Full amount approved*

GENERAL INFORMATION

Requested Spend Amount	$375,000
Requested Spend Time Period	*5 years*
Requesting Organization/Department	Craft Training [I02]
Business Case Owner | Sponsor	Joe Brown | Jeremy Gall
Sponsor Organization/Department	Human Resources
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

This capital program provides for tools, materials and equipment for training apprentices and journey workers across eleven skilled crafts or trades. This training consists of hands-on skills development that builds competency in a safe learning environment that may not always be available or controllable in the field. A well trained and competent workforce ensures reliable delivery of energy to Avista's customers and maintains a safe environment for employees, customers and the general public in all Avista Utilities service territories. Being unable to provide these needed tools, materials and equipment leaves apprentices and journeyman without the resources needed for their related instruction.

As stated previously, support of apprenticeship at Avista through this capital program aligns strategically to Avista's Mission and Focus Areas. In order to deliver innovative energy solutions safely, responsibly, and affordably, Avista must have a field workforce of highly proficient professional. In addition to creating a safe and skilled workforce, this training helps Avista to deliver timely training on new and emerging technologies as well as meet several federal and state mandated regulations including:

- Department of Labor, Standards of Apprenticeship – Title 29 CFR 29.5 (b)(4) and (b)(9) – Apprentice on the job training and related instruction
- Department of Labor, Occupational Safety and Health Standards – Title 29 CFR 1910.269 (a)(2) – Electric Power Generation, Transmission, and Distribution training
- Department of Transportation, Transportation of Natural Gas and Gas by Pipeline: Minimum Federal Safety Standards - Title 49 CFR 192.805 (h) – Qualification of Pipeline Personnel, Qualification Program training
- State of Washington – WAC 480-93-013 (4) – Covered Tasks: Equipment and facilities used by pipeline company for training and qualification of employees

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The primary driver of this business case is Mandatory & Compliance with the secondary drivers being Customer Service Quality & Reliability and Performance & Capacity. Avista must meet comply with the laws, rules and regulations associated with apprenticeship. Further, customer service and asset performance will benefit from a highly skilled workforce.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Avista will not have the ability to train in-house if this program is not funded. This leaves Avista's customers without critical craft positions needed for energy delivery. Further, there is a potential that regulating bodies may de-certify Avista's Apprentice program, leaving Avista without the ability to train in-house and require significant expense to meet labor demands and maintain required skillsets.

1.4 Supplemental Information

1.4.1 Please reference and summarize any studies that support the problem

The cost to outsource hands-on-training and field simulations would be approximately $473,000 a year for facility rental alone. This is based on current training programs that have averaged over 530 hours per year at the training center. The overall annual costs including travel, lodging, meals and registration are estimated to more than triple this rental cost and be classified as operations and maintenance costs. It is estimated this total cost would be approximately $2.4M in O&M expense over 5-years. Again, this would result in a negative impact to Avista's customers

1.4.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

NA

The recommended solution (Option 1) is to provide the resources needed for related instruction of craft personnel.

Option	Capital Cost	Start	Complete
1. On-Going Capital Improvement Program	*$375,000*	*01 2021*	*12 2025*
2. Outsource Training [No Facility]	*$2.4M (O&M)*	*01 2021*	*12 2025*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The cost to outsource hands-on-training and field simulations would be approximately $473,000 a year for facility rental alone. This is based on current training programs that have averaged over 530 hours per year at the training center. The overall annual costs including travel, lodging, meals and registration are estimated to more than triple this rental cost and be classified as O&M costs.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

Under this program, projects could include items such as building new facilities or expanding existing facilities, purchase of equipment needed, or build out of realistic utility field infrastructure used to train employees. Examples include new or expanded shops, truck canopy, classrooms, backhoes and other equipment, build out of “SmartCity”- commercial and residential building replicas, and distribution, transmission, smart grid, metering, gas and substation infrastructure.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

The greatest impact will be seen by Avista’s Operations and Avista’s Customers. Operations will have employees with the knowledge and skills to do their jobs professionally, and customers will be served by these competent professionals.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The primarily alternative for this program is to outsource training. If this is done, at great expense, there will be significant impact on operating budgets, company culture, and possibly labor relations.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

The projects associated with this business case will be planned on an annual basis and be used and useful during the calendar year in which they are implemented.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Support of apprenticeship at Avista through this capital program aligns strategically to Avista's Mission and Focus Areas. In order to deliver innovative energy solutions safely, responsibly, and affordably, Avista must have a field workforce of highly proficient professionals. This professionalism is achieved through apprenticeship. This is an investment in Our People. Providing Avista's employees with the tools, equipment and materials they need to train in a safe, simulated environment is essential: This is an investment in the people of Avista and allows these apprentices to deliver value to customers and the communities they serve.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Apprentices are the future workforce of Avista. Ensuring that they have the facilities, equipment, tools and materials they need to become successful journeyman is an investment in the future. Taking care now to invest in the future workforce will benefit Avista's customers and operations.

This project will be evaluated annually in the Craft Training Department and ensure projects of the highest need area addressed.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The key stakeholders associated with this business case are primarily internal Avista employees and departments.

2.8.2 Identify any related Business Cases

NA

3.1 Steering Committee or Advisory Group Information

As part of the Craft Training annual planning process, the list of projects for apprenticeships will be established, vetted and managed within the department. The manager of Craft Training & OQ will be accountable for the business case and annual funding.

3.2 Provide and discuss the governance processes and people that will provide oversight

Oversight will be provided by the Manager of Craft Training & OQ, and through periodic meetings with the Sr. Manager of Safety & Craft Training.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The manager of Craft Training & OQ will be accountable for making decisions on the business case in coordination with the Sr. Manager of Safety & Craft Training.

The undersigned acknowledge they have reviewed the *Apprentice Craft Training Business Case* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Joe Brown	Date:	7/29/2020
Print Name:	Joe Brown		
Title:	Mgr Craft Training & OQ		
Role:	Business Case Owner		

Signature:	Jeremy Gall	Date:	7/30/2020
Print Name:	Jeremy Gall		
Title:	Sr. Mgr Safety & Craft Training		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Capital Equipment Program (ER7005/7006)

EXECUTIVE SUMMARY

The Capital Equipment Program (ER7005/7006) funds the essential tools required for Avista employees to perform work efficiently and safely. This equipment is necessary to construct, monitor, ensure system integrity, and properly repair and maintain the Avista systems (electric, gas, communications, fleet, facilities, and generation). This equipment needs to be fully functional and available for planned work as well as emergency outage repairs on our facilities and equipment. Capital tools are utilized in all service territories, and by all Crafts. Capital tools are required to execute and support work across all business units and it is recommended to continue to fund these tools at an annual level of $2.4M for 2021 and then escalated for inflation and increase technology ($100k) each year for the five year plan.

Capital tools benefit customers by reducing labor cost due to improved efficiency and improving quality of the work by advanced performance of the tools. Customer will also benefit from improved system reliability and reduced outage duration enabled by diagnostic tools. It is critical that capital tools are consistently and adequately funded year over year to maintain performance and ensure tool availability. The risk of not funding capital tools is reduced work performance, increased safety risk, reduced work quality, and increased outage time for customers.

VERSION HISTORY

Version	Author	Description	Date	Notes
2.0	*Cody Krogh*	*Updated plan to new outline*	*7/13/2020*	

GENERAL INFORMATION

Requested Spend Amount	$ 2,400,000
Requested Spend Time Period	5 years
Requesting Organization/Department	Supply Chain
Business Case Owner | Sponsor	Cody Krogh | Dan Johnson
Sponsor Organization/Department	H51 / Supply Chain
Phase	Monitor/Control
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

1.1 What is the current or potential problem that is being addressed?

Each year, the Capital Equipment Program has more requests for tools and equipment than can be funded. The funding deficit prevents the purchase of all submitted requests. In addition, there is a trend of decreased funding for the capital tools. Over this same time period, the tool complement has been expanding by replacing manual tools with battery assist devices to increase safety and productivity. These additional tools will require more funding, over time, to support replacement costs, as well as ensure all areas of the company can take advantage of this technology.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The Capital Equipment Program (ER7005/7006) funds the essential tools required for Avista employees to perform work efficiently and safely. This equipment is necessary to construct, monitor, ensure system integrity, and properly repair and maintain the Avista systems (electric, gas, communications, fleet, facilities, and generation). Much of the capital equipment used in the utility industry is very specialized and may not be readily available due to long lead times. This equipment needs to be fully functional and available for planned work as well as emergency outage repairs on our facilities and equipment. Equipment failures contribute to injuries, slowdowns in work performance, and increased customer restoration time.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This work is needed to ensure that our workers have safe and reliable tools to complete their tasks, and also to ensure that if there are any tools that are broken, they can be replaced in a timely matter to keep projects/tasks on schedule. If this work is not approved/deferred the risks include breakage of equipment that is critical to daily operations/projects leading to longer lead times for repairs or project completion. Also, our employees need safe tools to ensure there are no injuries on the job. By having these updated through this program, we can increase our productivity by having tools that will allow us to complete our work efficiently on time and increase the safety of our employees.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The Capital Equipment Committee (CEC) ensures that the investment successfully addresses all capital equipment requests to ensure each is warranted. The CEC also ensures that each request is prioritized based upon importance of need and equal allocation of funds for capital equipment requests.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

Attachment 1: Email from Tony Klutz describing the benefits of the Capital Equipment Program
Attachment 2: Scoring Criteria & Weighting
Attachment 3: Capital Equipment Committee Board Charter
Attachment 4: Capital Committee Notes

NOTE: All files are stored in the "N-Drive" under "Capital Budget", then "Business Case Folder" and then "2020 Business Case"

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Safety project for ergonomic related battery assist tools was widely implemented in 2016 with the addition of 44 battery assist tools. This was followed by 2017 with 75 tools, 2019 with 58 tools. This equipment has a 5 year warranty, so future failures for 5 year old equipment will not be covered by warranty. Replacements for these out of warranty tools will need to be budgeted for within the ER7006 budget each year, as per all additional "new" capital equipment.

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

Option	Capital Cost	Start	Complete
[Recommended Solution] Option 1 (Recommended)	*$2.4 M*	*01/2018*	*NA*
Partially Fund (based on priority)	*Varies*	*01/2018*	*NA*
Rent 4% of total equipment and purchase the rest	*$2.3 M*	*01/2018*	*12/2020*

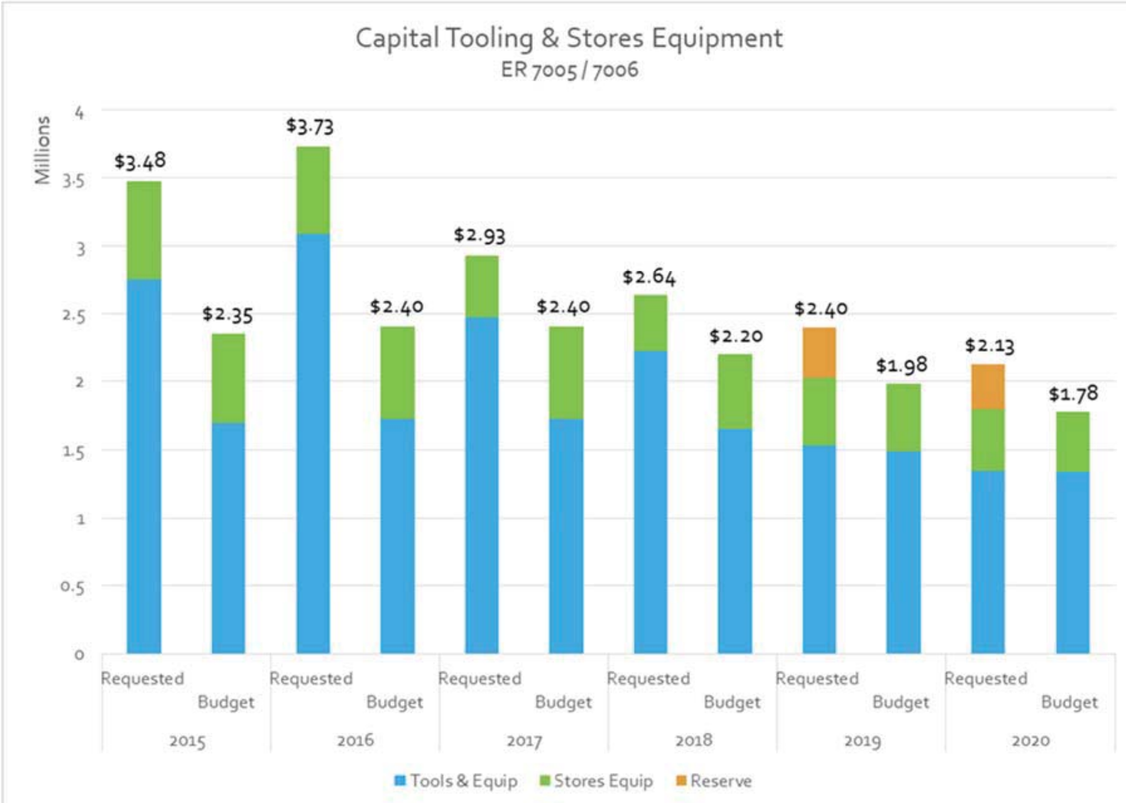
2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:
- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

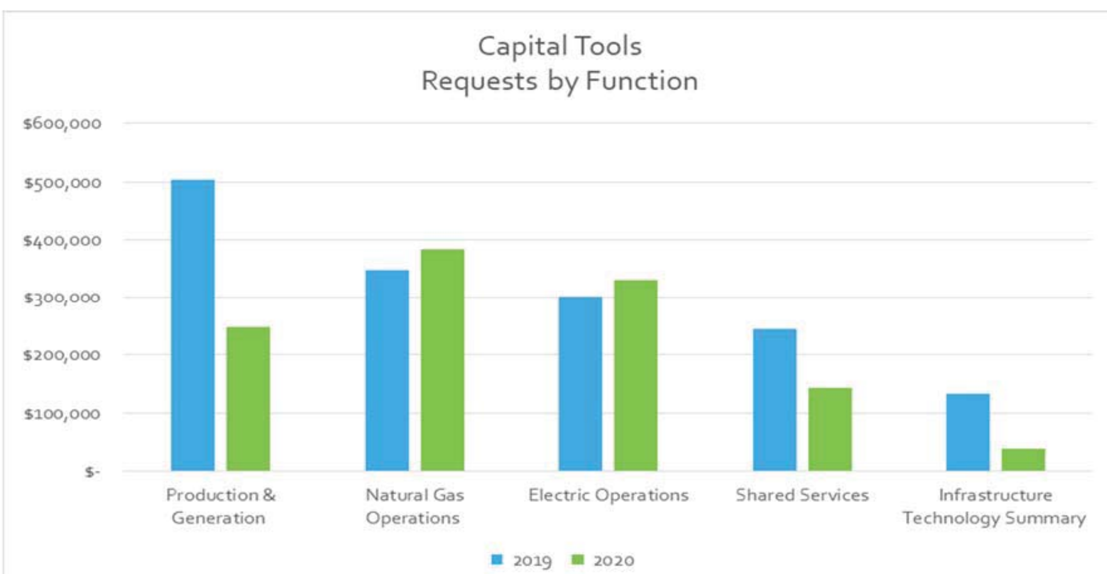
Reference key points from external documentation, list any addendums, attachments etc.

Each year, the Capital Tool Program has more requests for tools and equipment than can be funded as shown below in Figure 1. The requests are prioritized and tool selection is completed as described in Section 2.2. The funding deficit prevents the purchase of all submitted requests. In addition, there is a trend of decreased funding for the capital tools. Over this same time period, the tool complement has been expanding by replacing manual tools with battery assist devices to increase safety and productivity. These additional tools will require more funding, over time, to support replacement costs.

Capital Equipment Program (ER7005/7006)

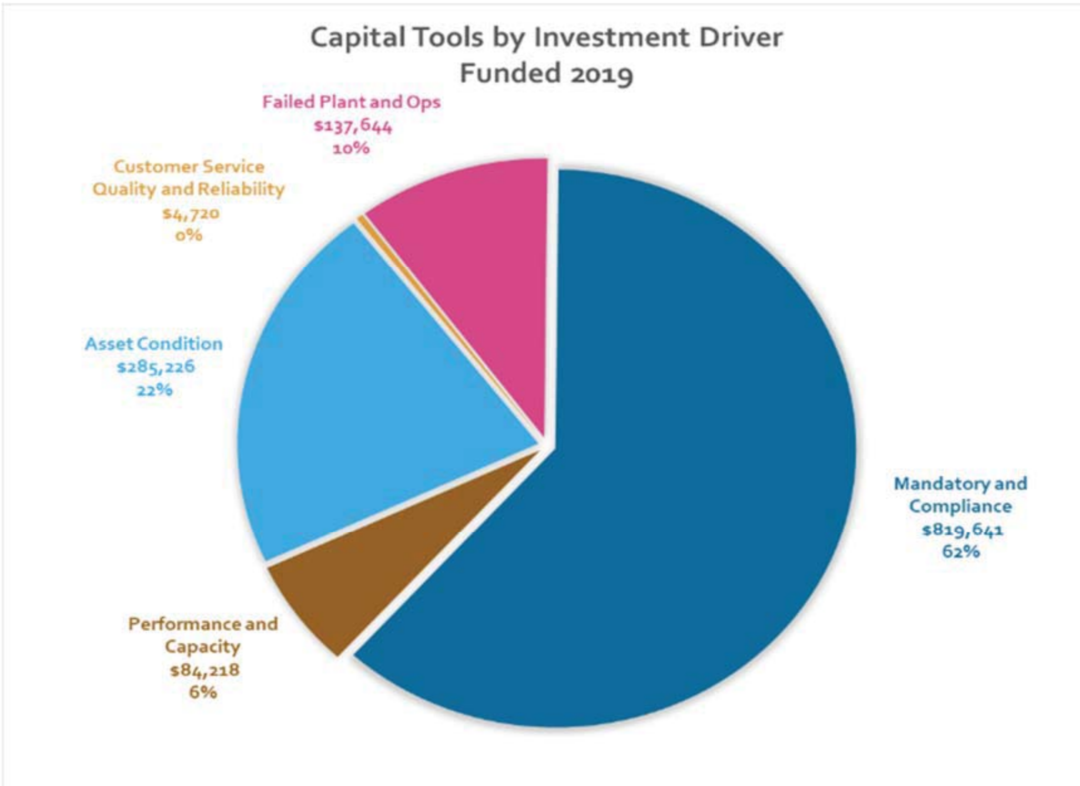


The distribution of Capital Equipment funds by the Business Unit is shown below in Figure 2 (see below). The allocation is based on overall tool ranking and priority rather than a set allotment by department. As a result, there is variation year over year (as noted in the graph) ensuring that the most critical tools are funded.



Capital Equipment Program (ER7005/7006)

The 2019 capital tool breakdown by investment driver is represented below in Figure 3. The highest percent of spend (62%) was for tools related to Safety and Compliance. This category is also the highest ranking investment driver. Spend in this area is related to changing industry complinace standards and tools identified to improve safety or ergonomics (improved body posture, reduced exertion of force, and reduction in frequency).



2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

An updated process was created in 2019 and is being fully implemented in 2020. The process begins by requesting Business Unit Managers to upload their tool needs into a SharePoint site. As part of the tool submittal the Manager must complete several ranking criteria used to support the business need for the tool. These criteria are Priority, Current State, Investment Driver, Strategic Alignment, Stakeholder, and Demand Type. The Managers' requests are then routed to the respective Business Unit Directors for approval. For a detailed breakdown of the criteria see reference document "Scoring Criteria & Weighting" in section 1.5.1.

The final list from each Business Unit is then reviewed by the CEC to ensure funding is distributed fairly and impartially across the company. The equipment request list is ranked per the scoring criteria ensuring all equipment is funded in order of ranking. This is required to prioritize spending as the total equipment requests exceed the allocated budget. Decision records and meeting notes are maintained on the SharePoint site once the CEC finalizes the list and purchasing is ready for execution.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

One of the business functions that will be impacted are those areas using outdated equipment/tools. We need to replace existing tools that have failed or reached the end of their life, or have been deemed unsafe do to current safety or regulatory issues. Avista employees must be able to rely on this equipment while performing hazardous duties, and must be confident that the equipment will perform safely and efficiently. Failed equipment not in compliance with current safety standards can lead to hazardous conditions for the operators, potentially causing injury or death.

Another important priority for tool and equipment purchases is enhanced productivity. Capital equipment is used to perform new construction work or repair work for unplanned failures. Often this work can take less time or be completed quickly with better results by using improved tools.

These processes need to be implemented to not only improve the safety, but also the productivity of employees. These benefits do impact other parts of the business as work will be completed efficiently and safely, reducing delays and injuries. There are also benefits to our external customers in regard to restoration time and reliability.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

<u>Option 1 – Fund Program at Current Level (Recommended)</u>

It is recommended that this Program be funded, annually, at its current level with a 5% annual increase to ensure Avista has the proper capital equipment necessary to safely and efficiently perform all required work. This 5% increase is to cover inflation of current pricing, support replacement equipment as complement has increase in time, and support increases in technology leading to higher equipment costs. Due to the specialized nature of utility equipment, it is most efficient for Avista to equip employees with the necessary tools and equipment to safely perform timely emergency repairs, while using the same tools and equipment to perform ongoing scheduled work and maintenance. Furthermore, this specialized equipment is often only available directly from the manufacturer, and is not typically available as a rental.

By funding this Program, Avista ensures that employees have the proper equipment to safely and efficiently perform their work, while providing safe, reliable service to customers.

<u>Option 2 – Partially Fund Program based on priority</u>

This option is not the preferred approach over the long-term; however, it is exercised when necessary. Each year, when the requests for tools and equipment are submitted, cuts to the Capital Equipment Program are made by the business units to bring the projected cost of the list of equipment and tools into line with the budgeted amount. Further modification of the funding level for the Program is performed in concert with other business budget needs.

When the program budget needs to be reduced, reductions are first made to requests in the category of enhanced productivity, then replacement. Replacement is intended to replace aging units to achieve more predictable capital requirements and avoid replacement peaks caused by large-scale failures. Cutting into these requests over an extended period leads to reduced efficiency and have safety impacts. This has caused excessive rollovers each year, which build up extensively when they are not able to be purchased within the current budget cycle. This leads to a buildup in capital equipment requests that cannot be adequately funded.

Having the ability to test and incorporate equipment that falls within the enhanced productivity category can help support improved processes and lead to enhanced safety and longer equipment lifecycles.

Option 3 – Rent Equipment

Renting a percentage of the capital equipment was considered as a possible alternative. Of the 430 items purchased from 2012 to 2014, 233 can be rented, although 216 out of the 233 items are needed, on hand, at all times for emergency locates and repairs. This leaves 17 possible items, or 4% of the total equipment, which qualifies as potential rental equipment (see Figure 3).

If equipment is rented, there is no guarantee of availability. Rental companies rent equipment on a first-come, first-served basis, making equipment scheduling for specific time sensitive jobs very difficult. Safety and compliance regulations are also affected when correct equipment is not available for rent.

Equipment failure is often a concern with rental equipment, as it is uncertain what condition rental equipment is in, or how it has previously been maintained. This can lead to safety issues for equipment operators when failures occur, as well as lost production time.

Depending on the timeline of the rental equipment, it would not be cost effective to rent long-term as the rental costs would exceed the base price of new equipment. An average rental price for a basic cable locator is $450/month, which equates to $5,400/year. The 2017 purchase price of this item is $3,700.

Training on rental equipment would also be required, if different than standardized Avista equipment. For example, Avista gas employees are only trained/qualified on specific equipment that has been standardized by Avista, which may or may not be what can be rented for specific jobs. This can contribute to added time necessary to qualify employees on the operation of the equipment, and safe operating procedures.

Due to the Department of Transportation (DOT) compliance, Avista is also required to maintain maintenance and calibration records for all gas equipment, along with operations guides for all on-site equipment. Avista would be out of compliance using various rental equipment as rental companies are not required to provide this documentation for their equipment to their customers.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

An updated process was created in 2019 and is being fully implemented in 2020. The program is projected for five (5) years to account for equipment/tool life cycle and replacements. The planning and execution of the program is managed by the Supply Chain Department. Tools are received and delivered to internal customers and immediately become used and useful, this program has been ongoing for decades. The average tool lead-time is 12-14 weeks.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.

Capital equipment benefits customers by reducing labor cost due to improved efficiency and improving quality of the work by advanced performance of the tools. Customer will also benefit from improved system reliability and reduced outage duration enabled by diagnostic tools. It is critical that capital equipment is consistently funded year over year to maintain performance and ensure equipment/tool availability. The risk of not funding capital equipment is reduced work performance, increased safety risk, and reduced work quality.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The funding is managed through a well-defined process with oversight from the CEC the final list from each Business Unit is then reviewed by the CEC to ensure funding is distributed fairly and impartially across the company. This is required to prioritize spending because the total tool requests exceed the allocated budget. Decision records and meeting notes are maintained on the SharePoint site. The Capital Equipment Steering Committee submits the revised list to the CPG for final approval and execution.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Internal customers would be employees such as line workers and other employees who will be using the capital tools to perform their jobs. They are also the stakeholders as some equipment will need to be replaced in order for the employees to effectively and safely complete their jobs. Our external customers also benefit from this program as they will reap the benefits of our workers increased reliability and decreased down time. With more reliability and less down time we are able to fix/repair any issues the customers may have much faster and keep our external customers satisfied with our quick service and reduced down time.

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

All business cases need the proper tools in order to best utilize the labor for the completion of work benefiting our employees and customers. Examples of Business cases that utilize these tools are: Wood Pole Management, Grid Modernization and Wild Fire Resiliency.

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

The final requested tool list from each Business Unit is then reviewed by the Capital Equipment Committee (CEC) to ensure funding is distributed fairly and impartially across the company. The tool list is ranked from the scoring criteria to make certain the tools are funded in order of ranking. Ranking is required because the total tool requests exceed the allocated budget.

3.2 Provide and discuss the governance processes and people that will provide oversight

The governance process is documented in the Capital Equipment Committee Board Charter (See attachments in section 15.1). In summary it is guided by the following scoring criteria: Priority, Current State, Investment Driver, Strategic Alignment, Stakeholder, Demand Type and Age of request. Each of these scoring criteria are weighted to help place the requests in order of high to low importance.

Those who provide oversight will be those who make up the Capital Equipment Committee Board (these members are nominated annually by Directors). These members will help to ensure that the funding for capital equipment is distributed fairly and impartially based of the needs of Avista.

The following are those members that make up the board composition:

Tool Keeper (Gas):	Voting Member
Tool Keeper (Elec):	Voting Member
Safety & Health Coordinator:	Voting Member
Electric Operations Manager:	Voting Member
Gas Operations Manager:	Voting Member
Generation & Production Manager:	Voting Member
Capital Planning Group Member:	Voting Member
Supply Chain Manager:	(Non) Voting Member
Capital Equipment Sourcing Professional:	(Non) Voting Member

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The Capital Equipment Committee works to ensure that the funding for capital equipment is fairly distributed, all decision-making, prioritization and change request records along with meeting notes will and are maintained on the SharePoint site as “Capital Committee Notes”. All participants in the process (Directors, managers, requesters) have access to the approvals and addition for their area via the SharePoint site. The members of the CPG are also the Directors approving the requests for their areas prior to the Cap Equipment Committee’s approval session.

Capital Equipment Program (ER7005/7006)

The undersigned acknowledge they have reviewed the Capital Equipment Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: DocuSigned by: Cody Krogh 72D171D0C3F0478 Date: Jul-29-2020 | 11:19 AM PDT
Print Name: Cody Krogh
Title: Supply Chain Manager
Role: Business Case Owner

Signature: DocuSigned by: Dan Johnson 8547C8F8C05E4C4... Date: Jul-29-2020 | 12:56 PM PDT
Print Name: Dan Johnson
Title: Director, Shared Services
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

1 GENERAL INFORMATION

Requested Spend Amount	$7,700,000
Requesting Organization/Department	Fleet
Business Case Owner	Greg Loew, Manager, Fleet Services
Business Case Sponsor	Dan Johnson, Manager, Shared Services
Sponsor Organization/Department	Shared Services
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Fleet capital replacement program is based on the Vehicle Replacement Model that is a product of our Utilimarc benchmarking subscription. The model uses benchmark data, purchase and auction data, combined with nationwide vehicle information that Utilimarc uses to build an accurate and robust model. The Fleet Specialist for Capital then takes the results of the model to validate, verify usage and work with operations managers to ensure that the identified unit meets their business needs. Capital projects requests are created for each discrete project (vehicle/equipment) that is approved by the Fleet Manager with notifications to the Manager of Shared Services and the Vice President of Operations.

2 BUSINESS PROBLEM

Fleet equipment as it ages experiences a growth in cost related to its operation. Those costs are driven by the requirement of more parts and more labor required to keep that unit up and running. As your fleet's average age increases you will see a steady but accelerating trajectory of costs servicing hours required. It can be described as more complex repairs requiring more hours and parts to fix. Those increasing costs are not just the burden of Fleet; the users will see the impact in lost productivity/downtime. In a 2011 analysis of Avista's class 46 vehicles and a subsequent analysis done in 2016 saw a 52% reduction in the labor hours required per truck by bringing the classes average age from 9.5 years to the industry average of 5.5 years.

	2010	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*
AVA Avg Age	*8.03*	*7.81*	*7.59*	*6.81*	*6.55*	*6.23*	*5.94*	*6.13*	*6.32*
Industry Avg Age	*6.11*	*6.27*	*6.27*	*6.56*	*6.37*	*6.49*	*6.10*	*6.46*	*6.35*
Avg Op Cost / Unit	*$10,924*	*$11,558*	*$11,534*	*$10,845*	*$9,739*	*$9,285*	*$8,665*	*$9,571*	*$10,065*

							2016	2017	2018
OR Avg Age	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5.5	5.3	5.8
OR Avg Cost/Mile	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1.01	$1.16	$1.18

2020 and 2021 Oregon Capital Replacements

2020 Capital Expenditures in Oregon Jurisdiction	*2021 Capital Expenditures in Oregon Jurisdiction*
$326,431	*$289,549*

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 (Recommended): Fully fund replacement program	*$7,700,000*		
Option 2: Partially fund program	*$3,700,000*		
Option 3: No funding	*0*		

Option 1 (Recommended) – Fully Fund Replacement Program

The Fleet asset model is optimized for the lowest total cost of ownership. Our life cycle model seeks the goal of balancing risk and limited investment dollars. The model allows Fleet to provide users with a reliable and safe tool that is ready for work at any given moment. The fully funded option allows our capital purchasing model of equipment to continue replacing aging equipment in a predictive manner that keeps technician staffing levels constant to the predictive number of repair work orders generated. The program does not include additions to the existing fleet. The analysis of the data by Utilimarc shows that this fully funded model over time will yield the lowest cost per vehicle.

The recent large outages from the summer of 2014 and November 2015 show the strength of our fleet. During those thousands of hours of combined operation we only had two minor breakdowns that we were able to quickly repair and return to service before the start of the operator's next shift.

The customer benefits from this in two distinct ways. One, that crews are quicker to respond to issues because they operate reliable equipment that can be ready for duty. Two, that costs for customers remain steady from a fleet cost perspective because we have a constant investment in the equipment along with a progressive maintenance that has a monthly average over 95% of vehicles ready for duty. By pursing the recommended investment path we avoid rising maintenance costs, outside of economic inflationary trends, and increasing down time due to mounting demand repair work orders. Additionally, this investments allows us to purchase equipment that has modern emissions controls or alternative energy sources allowing us reduce carbon emissions from our fleet vehicles.

Option 2 – Partially Fund Replacement Program

The partially funded, option 2 continues to replace vehicles but at reduced amount when compared to the recommended option. The combined ownership and maintenance costs to appear to be nominally less in costs over the time of the model. However what you see is a rapidly aging fleet in the last two thirds of the model which have increasing work order counts for repairs and significant impacts to reliability/uptime not shown in the total fleet costs.

Option 3 – Do Not Fund Replacement Program

Option 3 is a plan designed to replace a unit only at failure. This model has rapidly increasing costs due to significant repairs required. This model will require increasing numbers of repair work orders to be assigned to outside vendors since company technicians will be able to handle only incrementally more work than today. This outside work has a higher price per hour and higher parts costs due to vendor markups. This model will lead to increasing down time of equipment as it ages. The repairs will become more costly and consume more technician time. Increasingly, even with the best preventative maintenance plan, there will be unplanned failures in the field downing a crew while the issue is addressed. This model was practiced at Avista for over 20 years and led to clusters of vehicles failing at approximately the same time and creating capital constraint issues.

Vehicle Replacement Analysis

The following information demonstrates the effect of three different replacement strategies on Avista's Fleet performance. Three projections were built using Utilimarc Vehicle Replacement Model (VRM) to show the effect of different levels of capital commitment on fleet maintenance cost, ownership cost, average age, and demand repairs. In the Full Budget (Option 1) scenario, vehicles are replaced in line with each vehicle's calculated, optimal, lifecycles with an annual capital cost starting at approximately $8,000,000. The Half Budget (Option 2) scenario cuts the annual replacement budget in half to start at approximately $3,700,000. The No Budget (Option 3) scenario restricts the annual capital cost to $0.

Summary

The table below shows the effects of each budget on annual vehicle ownership and maintenance cost for Avista's fleet. The full projections are provided on the pages to follow.

Annual Vehicle Ownership and Maintenance Cost	2016	2020	2025	2030
Full Budget	$9,588,817	$9,735,956	$10,604,849	$11,700,794

Half Budget	$9,439,904	$9,274,112	$10,197,151	$11,658,431
No Budget	$9,350,935	$9,145,384	$10,854,088	$13,913,603

Avista's fleet is currently ahead of its ideal lifecycle. This is shown by the increase in average age we see under even the Full Budget scenario. Because of this, the No Budget scenario is marginally cheaper in the first few years of the projection (<2%). However, by the 15th year, the No Budget scenario is 19% higher than the two alternative scenarios. Avista would also see average age increase from 9.0 years to over 20 years under this worst-case scenario.

The Full Budget scenario is marginally more expensive then the Half Budget scenario in these projections, but will begin to outperform the Half Budget scenario beyond the 15th year. While their total costs are comparable, the Full and Half Budget scenarios differ in how money is being spent. Under the Full Budget scenario, capital investment is larger each year, but maintenance costs are significantly lower. The Full Budget scenario also offers younger units for the crews to operate (average age of 9.22 in the 15th year) vs 14.74 in 15th year) and fewer demand repairs (7,082 work order in the 15th year). Conversely, The Half Budget scenario sees a smaller capital investment each year, but the unit for the crews to operate will be older (average age of 14.74 in year 15) and will see more demand repair (9,671 work orders in the 15th year).

Vehicle condition, availability and downtime should also be considered in these scenarios. In order to maximize safety, reliability and responsiveness for customer needs, including emergency outage restoration, vehicles should be equitable in terms of standards and in optimal working condition.

Assumptions

- Inflation: All capital, ownership and maintenance costs are increase annually be 2% to account for inflation.
- Consistent Replacement: The replacement model is programed to replace a consistent number of unit each year to achieve more predictable capital requirements and avoid replacement bubbles. When many vehicles are concentrated in relatively few vintages, these "bubbles" can cause sudden increases in parts and labor cost, vehicle downtime, and technician requirements. Replacing a constant number of unit each year avoids this problem, but consequently the model will occasionally replace a unit before it reaches in lifecycle or let a unit run beyond its lifecycle.
- Maintenance: Maintenance cost includes the cost of all parts and labor needed to maintain the asset over the course of its lifetime. Note that maintenance cost does not include the cost of fuel or any administrative or corporate overheads. While there will be some fuel efficiencies associated with running younger vehicles, the unpredictable nature of the price fuel make it difficult to quantify the savings associated with these efficiencies.
- Maintenance Savings: The replacement model maintains a constant cost per wrench-turning hour of technician labor. This means that when maintenance cost increase or decrease, the model adjusts staffing levels to meet the increased or

decreased demand for labor. This should be considered alongside historic overtime and contract labor practices when interpreting these results.

Cost Tables

Full Budget	2016	2017	2018	2019	2020
Annual Maintenance (Parts, Labor, Vendor) Cost	$4,742,786	$4,856,108	$4,976,085	$5,129,998	$5,303,926
Annual Ownership Cost	$6,559,724	$6,390,102	$6,363,332	$6,262,211	$6,210,697
Annual Capital Budget	$8,010,456	$7,625,997	$8,550,766	$7,983,602	$8,457,832
Units Replaced Annually	112	106	106	103	104
Average Age	8.47	8.38	8.36	8.42	8.51
Units Out of Lifecycle	134	110	74	57	41
Annual Demand Repair Work Orders	6,609	6,637	6,660	6,711	6,768

3.7M Budget	2016	2017	2018	2019	2020
Annual Maintenance (Parts, Labor, Vendor) Cost	$4,945,378	$5,262,213	$5,553,296	$5,876,138	$6,194,199
Annual Ownership Cost	$6,130,531	$5,589,192	$5,260,460	$4,914,123	$4,665,065
Annual Capital Budget	$3,719,912	$2,905,936	$4,096,366	$3,574,700	$3,664,350
Units Replaced Annually	50	44	50	46	47
Average Age	9.11	9.59	10.01	10.47	10.92
Units Out of Lifecycle	186	203	202	238	247
Annual Demand Repair Work Orders	6,899	7,191	7,434	7,694	7,942

No Replacement	2016	2017	2018	2019	2020
Annual Maintenance (Parts, Labor, Vendor) Cost	$5,236,220	$5,756,008	$6,296,020	$6,859,429	$7,436,489
Annual Ownership Cost	$5,735,049	$4,936,895	$4,259,317	$3,682,958	$3,191,696
Annual Capital Budget	$-	$-	$-	$-	$-
Units Replaced Annually	-	-	-	-	-
Average Age	9.77	10.76	11.74	12.71	13.69
Units Out of Lifecycle	281	322	403	457	572
Annual Demand Repair Work Orders	7,276	7,828	8,380	8,932	9,485

Full Budget	2021	2022	2023	2024	2025
Annual Maintenance (Parts, Labor, Vendor) Cost	$5,469,634	$5,626,095	$5,806,710	$5,936,489	$6,088,050
Annual Ownership Cost	$6,231,649	$6,252,235	$6,244,883	$6,383,525	$6,422,122
Annual Capital Budget	$8,744,956	$8,763,990	$8,633,034	$9,629,551	$8,990,833
Units Replaced Annually	103	111	101	106	103
Average Age	8.62	8.65	8.77	8.83	8.93
Units Out of Lifecycle	34	40	41	38	32
Annual Demand Repair Work Orders	6,834	6,880	6,945	6,956	6,990

3.7M Budget	2021	2022	2023	2024	2025
Annual Maintenance (Parts, Labor, Vendor) Cost	$6,505,655	$6,847,961	$7,168,380	$7,465,391	$7,801,053
Annual Ownership Cost	$4,509,902	$4,243,790	$4,133,092	$4,111,033	$4,009,498
Annual Capital Budget	$4,301,788	$3,281,927	$3,841,499	$4,613,173	$4,025,692
Units Replaced Annually	49	45	46	50	46
Average Age	11.35	11.80	12.23	12.60	13.01
Units Out of Lifecycle	307	330	366	400	418
Annual Demand Repair Work Orders	8,169	8,404	8,618	8,790	8,985

No Replacement	2021	2022	2023	2024	2025
Annual Maintenance (Parts, Labor, Vendor) Cost	$8,036,849	$8,660,759	$9,299,771	$9,958,388	$10,638,865
Annual Ownership Cost	$2,772,141	$2,413,132	$2,105,273	$1,840,887	$1,613,357
Annual Capital Budget	$-	$-	$-	$-	$-
Units Replaced Annually	-	-	-	-	-
Average Age	14.66	15.63	16.59	17.55	18.50
Units Out of Lifecycle	620	681	734	769	793
Annual Demand Repair Work Orders	10,037	10,588	11,140	11,691	12,242

Full Budget	2026	2027	2028	2029	2030
Annual Maintenance (Parts, Labor, Vendor) Cost	$6,226,667	$6,411,144	$6,535,809	$6,698,371	$6,853,080
Annual Ownership Cost	$6,549,886	$6,593,568	$6,783,330	$6,851,754	$6,967,321
Annual Capital Budget	$9,764,701	$9,296,048	$10,423,336	$9,731,966	$10,310,050
Units Replaced Annually	112	106	106	103	104
Average Age	8.93	8.95	9.02	9.13	9.22
Units Out of Lifecycle	23	20	16	17	19
Annual Demand Repair Work Orders	6,995	7,048	7,045	7,074	7,082

3.7M Budget	2026	2027	2028	2029	2030
Annual Maintenance (Parts, Labor, Vendor) Cost	$8,099,925	$8,432,876	$8,704,428	$9,019,315	$9,318,223
Annual Ownership Cost	$3,998,122	$3,899,631	$3,982,001	$3,957,415	$3,994,430
Annual Capital Budget	$4,534,552	$3,542,320	$4,993,447	$4,357,539	$4,466,822
Units Replaced Annually	50	44	50	46	47
Average Age	13.34	13.75	14.06	14.41	14.74
Units Out of Lifecycle	422	443	459	477	497
Annual Demand Repair Work Orders	9,136	9,314	9,419	9,555	9,671

No Replacement	2026	2027	2028	2029	2030
Annual Maintenance (Parts, Labor, Vendor) Cost	$11,342,717	$12,068,385	$12,823,413	$13,603,405	$14,412,019
Annual Ownership Cost	$1,417,138	$1,247,603	$1,100,859	$973,611	$863,098
Annual Capital Budget	$-	$-	$-	$-	$-
Units Replaced Annually	-	-	-	-	-
Average Age	19.46	20.41	21.36	22.31	23.25
Units Out of Lifecycle	828	860	889	921	940
Annual Demand Repair Work Orders	12,793	13,343	13,894	14,444	14,994

Methodology

Annualized Total Cost

For each class, Utilimarc's Vehicle Replacement Module (VRM) determines what lifecycle achieves the lowest cost to own and maintain an average asset over its lifetime. This done by calculating the *annualized total cost* for each potential lifecycle. Annualized cost total is the sum of all ownership and maintenance cost a unit obtains over the course of its life, divided by the number of years the unit is in service. Minimizing annualized total cost guarantees the lowest total cost over the life of the asset. As an example, the table below shows the annualized cost for the possible lifecycles of a light duty pickup truck.

Replacement Age	Annualized Total Cost	Deviation
1	$5,964	12.3%
2	$5,759	8.4%
3	$5,598	5.4%
4	$5,476	3.1%
5	$5,390	1.5%
6	$5,337	0.5%
7	$5,313	0.0%
8	$5,316	0.1%
9	$5,345	0.6%
10	$5,397	1.6%
11	$5,472	3.0%
12	$5,567	4.8%
13	$5,682	7.0%
14	$5,816	9.5%

Consider the following three replacement scenarios over a 14-year financial period:

Scenario 1: A fleet manager plans to replace this vehicle every year. The annualized cost of this replacement strategy is $5,946. Over the 14-year period, this replacement strategy will cost fleet 14 x $5,946 = $83,244.

Scenario 2: A fleet manager plans to replace this vehicle every seven years. The annualized cost of this replacement strategy is $5,313. Over the 14-year period, this replacement strategy will cost fleet 14 x $5,313 = $74,382.

Scenario 3: A fleet manager plans to replace this vehicle every fourteen years. The annualized cost of this replacement strategy is $5,816. Over the 14-year period, this strategy will cost fleet 14 x $5,816 = $81,424

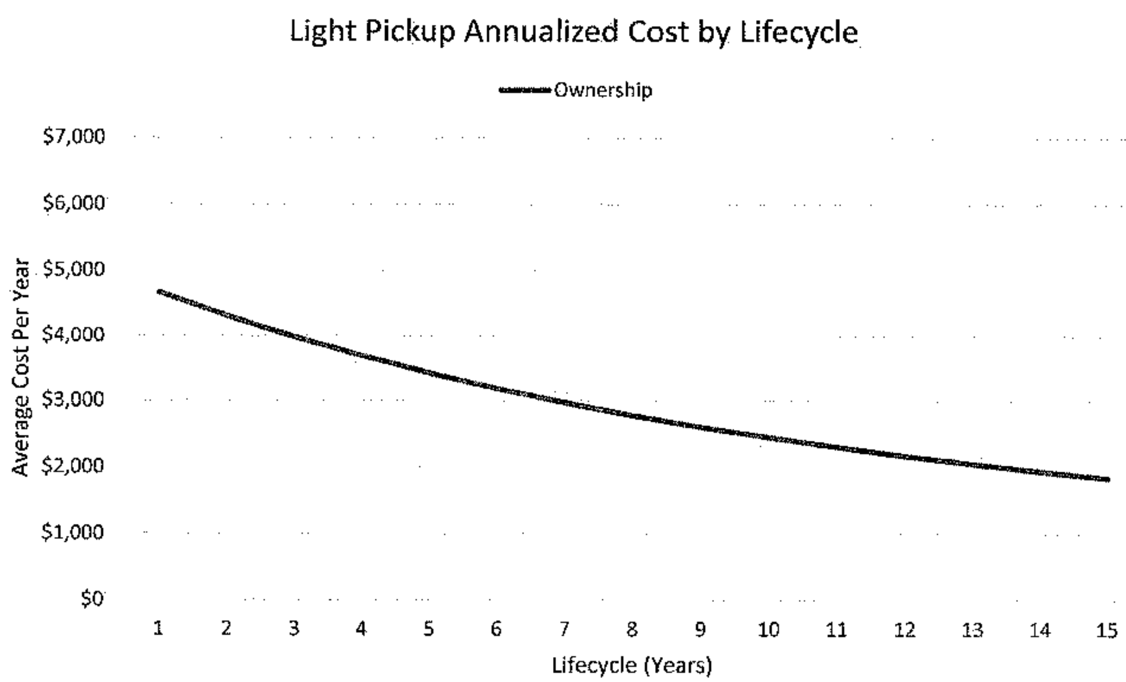
The table below summarizes the calculations in the previous example.

	Chosen Replacement Age	Financial Period (Years)	Annualized Cost	Total Cost for Financial Period
Scenario 1	1	14	$5,946	$83,244
Scenario 2	7	14	$5,382	$74,382
Scenario 3	14	14	$5,816	$81,424

This example illustrates that by minimizing annualized total cost achieves the lowest total cost of ownership over the life of the vehicle. Utilimarc recommends replacing units within 1.0% of the true lowest cost of ownership. This generally provides a three-year range for replacement, which allows for flexibility when planning replacement without dramatically affecting overall cost.

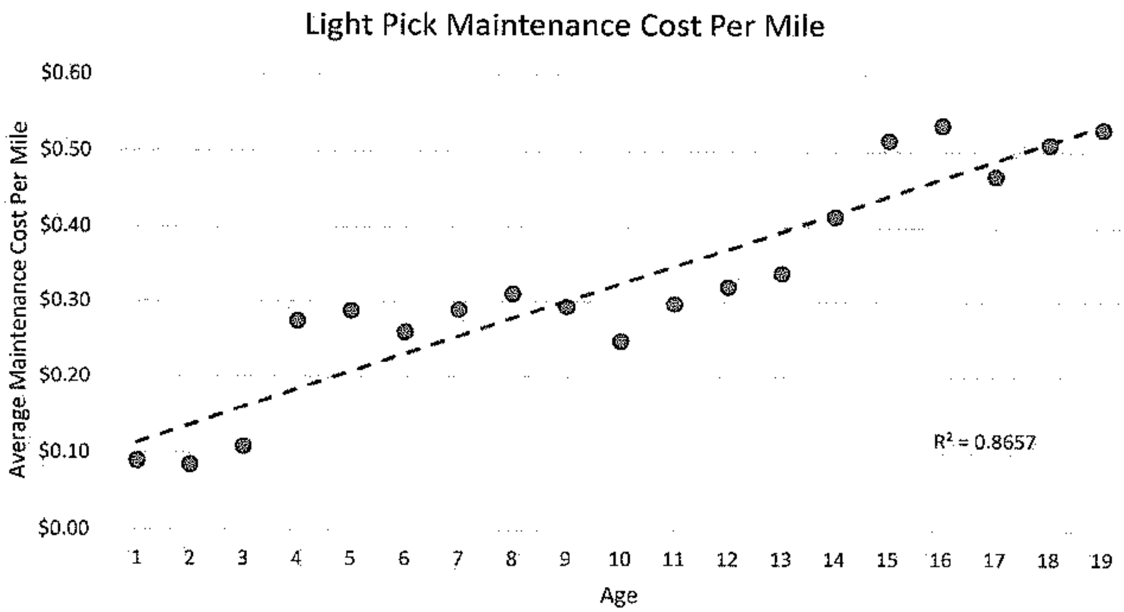
Modeling Ownership Cost

The Vehicle Replacement Model uses an exponential decay model to project the ownership cost of an asset over its lifetime. Each asset is assumed to lose 18% of its current book value every year as a cost of depreciation. This decay rate of 18% is established based on historical auction information from companies across the industry. *Annualized Ownership Cost* is calculated by taking the cumulative sum of each year of depreciation for the asset and dividing by the number of years the asset is in service. Continuing the example from the previous section, the graph below shows the annualized ownership cost for a light pickup truck for each potential lifecycle.

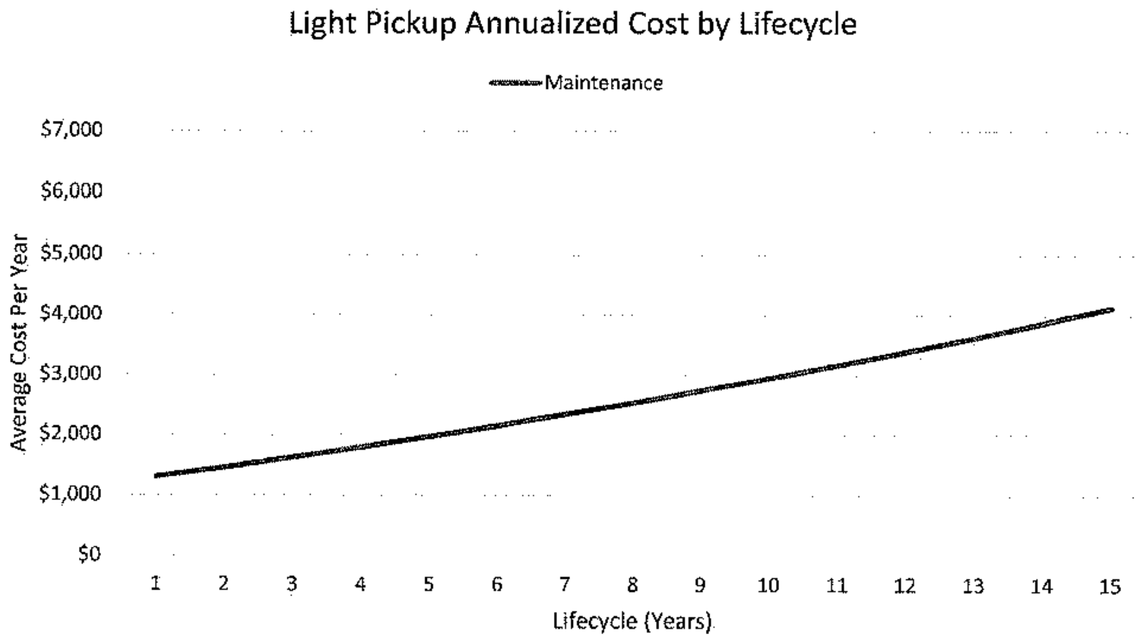


Modeling Maintenance Cost

The Vehicle Replacement Model uses a linear regression model to project the maintenance cost of an asset over its lifetime. These class specific models are built using historical, maintenance cost per mile data taken from the Utilimarc data. In the graph below, the red dots represent the average historical maintenance cost per mile for a light pickup truck of each age. The red, dashed line represents the linear regression model used to estimate the maintenance cost of an average pickup. The linear regression model helps predict the increase cost of maintenance associated with running older vehicles.

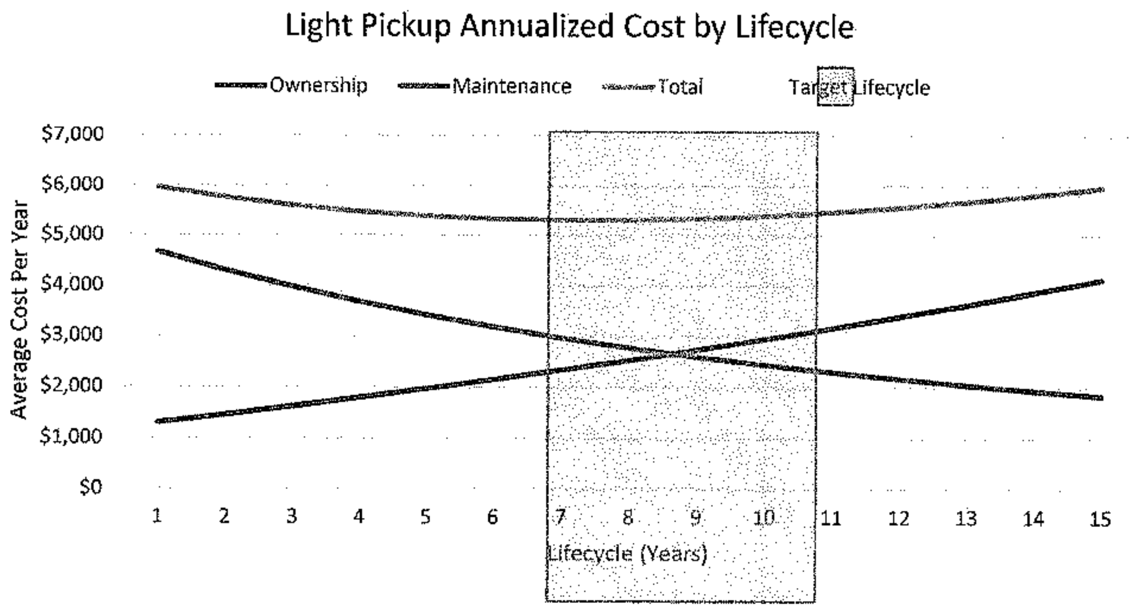


Annualized Maintenance Cost is calculated by taking the cumulative sum of each year of maintenance cost for the asset and dividing by the number of years the asset is in service. The graph below shows the annualized maintenance cost for light pickup trucks, based on the linear regression model and a calculated average annual mileage.



Modeling Annualized Total Cost

Annualized total cost is calculated by taking the sum of annualized maintenance and ownership cost. The graph below shows the annualized total cost for a light duty pickup truck. The target lifecycle is indicated by a green shaded zone. This is a visual representation of the table from pg. 7 and demonstrates how the model identifies each lifecycle.



4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Fleet Services plan and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ____________ Date: 2/20/20

Print Name: Greg Loew

Title: Manager, Fleet Services

Role: Business Case Owner

Signature: ____________ Date: 2/20/2020

Print Name: Dan Johnson

Title: Manager, Shared Services

Role: Business Case Sponsor

Signature: ____________ Date: 2-21-2020

Print Name: Heather Rosentrater

Title: Vice President, Energy Delivery

Role: Steering/Advisory Committee Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1	*Greg Loew*	*04/25/17*	*Heather Rosentrater*	*04/25/17*	*New template*
2	Greg Loew	2/19/20			Oregon 2020 update

Template Version: 03/07/2017

EXECUTIVE SUMMARY

This program is be responsible for the capital maintenance, site improvement, and furniture budgets at over 40 Avista offices, storage buildings, and service centers (over 900,000 total square feet) Companywide. This program is intended to systematically address: lifecycle asset replacements (examples: roofing, asphalt, electrical, plumbing), lifecycle furniture replacements and new furniture additions (to support growth) and business additions or site improvements.

Facilities apportions approximately 50% to Asset Condition work that is identified using Paragon Asset Condition software (Terracon), 30% is set aside for Manager Requested projects, and 20% is kept aside for unexpected capital needs and furniture replacements. There is currently a $7M Asset Condition backlog identified using Paragon Asset Condition software. A funding of $3.5M will allow us to maintain a flat backlog over the next 5 years.

This program supports Avista's entire Service Territory and all service codes and jurisdictions. Performing adequate Asset Management allows the Company to preserve and fully utilize their properties while reducing expensive repairs in the long term. It also ensures a safe environment for people and equipment. Damaged or poorly maintained facilities can create very real safety risks and associated liability for employees, customers, and contractors.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Lindsay Miller	Initial Version	07/10/2018	Initial Version
2.0	Lindsay Miller	Executive Summary Only	07/07/2020	Revised Template

GENERAL INFORMATION

Requested Spend Amount	$3,500,000
Requested Spend Time Period	Yearly
Requesting Organization/Department	Facilities
Business Case Owner | Sponsor	Eric Bowles | Dan Johnson
Sponsor Organization/Department	Shared Services
Phase	Planning
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

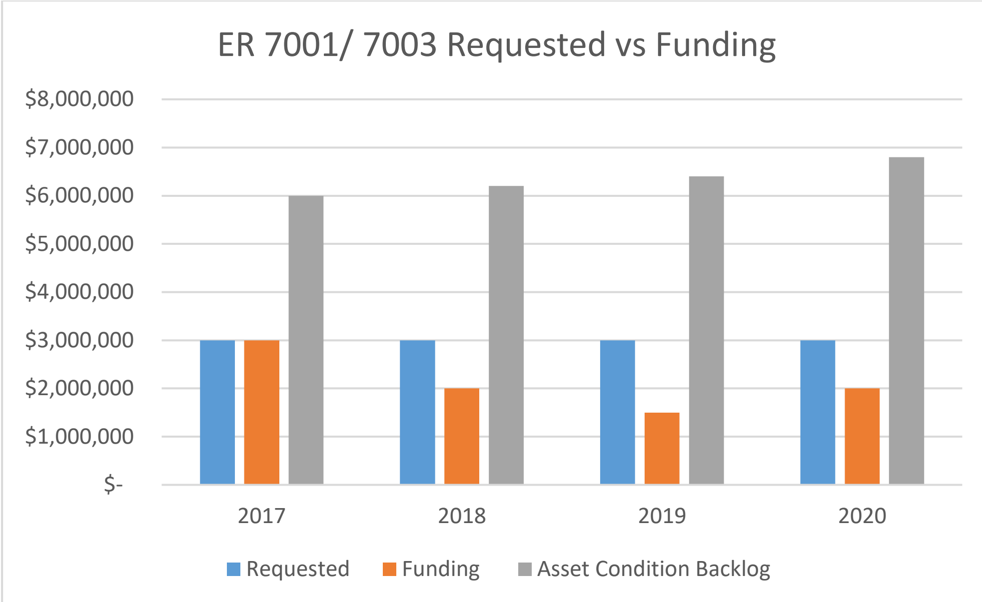
1.1 What is the current or potential problem that is being addressed?

Many of the service centers in Avista's territory were built in the 1950s and 60s and are starting to show signs of severe aging. Almost half of Avista's Assets were built before 1980. Most of our building systems are also past their recommended life based on recognized industry standards defined by Building Owners and Managers Association (BOMA), and International Facility Management Association (IFMA) and are requiring renovation or replacement. Many of the original campus layouts and buildings at our Service centers are no longer optimal today due to changes in our vehicle sizes, materials storage, and operations flow. These changes have required the need for project funding to address changing business and site requirements as well.

Location	Date Built	Address	City	State
Airport Hangar	2019	7500 W. Park Dr., Bldg 1060	Spokane	WA
Beacon (battery building and canopy)	2015	2180 N Havana St	Spokane Valley	WA
Clark Fork Bunkhouse	1959	806 Main St.	Clark Fork	ID
Clarkston Service Center	1975	1300 Fair Street	Clarkston	WA
Coeur d'Alene Service Center	1994	1735 N. 15th Street	Coeur d'Alene	ID
Colfax Facility	1990	704 North Clay	Colfax	WA
Colville Service Center	2010	176 Degrief Road	Colville	WA
Davenport Pole Yard and Vehicle Storage	1996		Davenport	WA
Davenport Service Center	1966	327 Morgan Street	Davenport	WA
Deer Park Service Center	2018	Airport Drive	Deer Park	WA

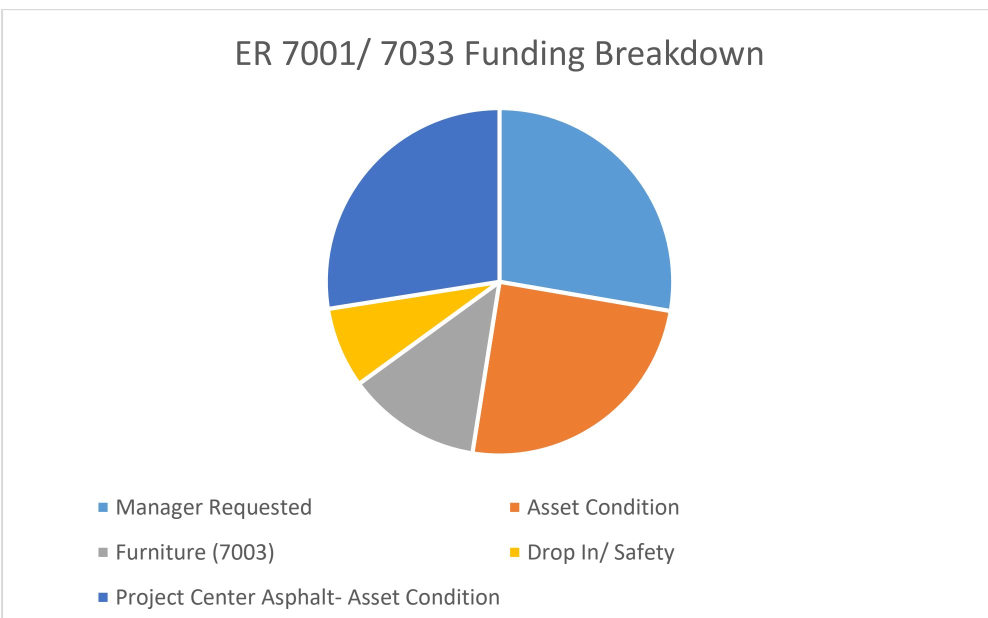
Dollar Road Fleet Shop	2015	2,406 N. Dollar Road	Spokane	WA
Dollar Road Service Center	2019	2406 N. Dollar Road	Spokane	WA
Dollar Road Truck Storage	2014	2406 N. Dollar Road	Spokane	Wa
Dollar Road Wash Bay	2018	2406 N. Dollar Road	Spokane	Wa
Downtown Network Center	2016	1717 W. 4th Ave	Spokane	WA
Downtown Project Center	2016	1717 W. 4th Ave	Spokane	WA
Elk City Facility	2017	Hwy 14	Elk City	ID
Goldendale	2015	912 E. Broadway	Goldendale	WA
Grangeville Facility	1933	201 E. Main Street	Grangeville	ID
Grangeville Pole Yard	2016		Grangeville	ID
Grants Pass Service Center	1960	618 SE J Street	Grants Pass	OR
Jack Stewart North Line Trailer	1985	8308 N. Regal	Spokane	WA
Jack Stewart Office Modular	2012	8307 N. Regal	Spokane	WA
Jack Stewart South Line Trailer	1993	8309 N. Regal	Spokane	WA
Jack Stewart Training Center	1999	8307 N. Regal	Spokane	WA
Kamiah Facility	1992	No Kidd Rd.	Kamiah	ID
Kellogg Covered Vehicle Storage	2012	121 Hill Street	Kellogg	ID
Kellogg Materials Storage	1980	122 Hill Street	Kellogg	ID
Kellogg Service Center	1960	120 Hill Street	Kellogg	ID
Kettle Falls Generating Plant Offices	1976	1151 Hwy 395 N	Kettle Falls	WA
Klamath Falls Service Center	2008	2825 Dakota Ct.	Klamath Falls	OR
Klamath Falls Storage Building	2012	2826 Dakota Ct.	Klamath Falls	OR
LaGrande Service Center	1994	10201 F Street	LaGrande	OR
Lewiston Call Center	1976	803 Main Street	Lewiston	ID
Main Campus Café/Auditorium	1959	1412 E. Mission Ave.	Spokane	WA
Main Campus Canopy 5	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Central Operating Facility	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Investment Recovery	2011	1411 E. Mission Ave.	Spokane	WA
Main Campus Mini Line Dock	1970	1411 E. Mission Ave.	Spokane	WA
Main Campus New Fleet Building	2017	1411 E. Mission Ave.	Spokane	WA
Main Campus Oil Storage Vault	1996	1412 E. Mission Ave.	Spokane	WA

Main Campus Parking Garage	2019	1411 E. Mission Ave.	Spokane	WA
Main Campus Ross Park Building	1903	1411 E. Mission Ave.	Spokane	WA
Main Campus Service Building	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Warehouse Building	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Waste and Asset Recovery	2014	1411 E. Mission Ave.	Spokane	WA
Medford Outdoor Storage Canopy	1994	581 Business Park Drive	Medford	OR
Medford Service Center	1994	580 Business Park Drive	Medford	OR
Noxon Bunkhouse	1959	33 Avista Power Road	Noxon	MT
Orofino Service Center	1970	1051 Michigan Ave	Orofino	ID
Othello Service Center	1974	36 South 4th Avenue	Othello	WA
Pierce Facility	1985	104 Moscrip Dr.	Pierce	ID
Post Street Mobius / Annex Parking	1903	337 N. Post Street	Spokane	WA
Pullman Mechanic Shop	2012	5704 SR 270	Pullman	WA
Pullman Service Center	1959	5702 SR 270	Pullman	WA
Pullman Shed	1959	5704 SR 270	Pullman	WA
Pullman Storage Canopies	1959	5703 SR 270	Pullman	WA
Ritzville Facility	1955	401 E First	Ritzville	WA
Roseburg Service Center	2004	1404 Green Siding Road	Roseburg	OR
Sandpoint Covered Storage	1985	103 N. Lincoln	Sandpoint	ID
Sandpoint Service Center	1957	100 N. Lincoln	Sandpoint	ID
Sandpoint Storage Bays	1957	101 N. Lincoln	Sandpoint	ID
Sandpoint Truck Canopy	1985	102 N. Lincoln	Sandpoint	ID
Spokane Valley Call Center	1979	14523 E. Trent Ave.	Spokane Valley	WA
St Maries Offsite Garage and Pole Yard	2011		St. Maries	ID
St. Maries Service Center	1974	528 College Avenue	St. Maries	ID
Tekoa Facility	1971	West 101 Main Street	Tekoa	WA



Funding backlog

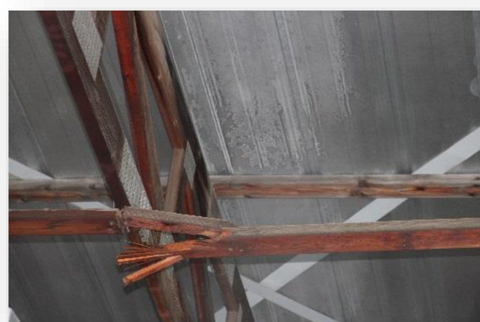
There is currently an identified backlog of $6.8M in Asset Condition work needed across the system of assets Facilities manages. In 2017 Terricon identified $6M in work on their initial assessment. This list is growing every year as our buildings age and new items are identified that need replacement. At the current funding level this backlog of capital work will continue to grow. The backlog is growing faster than our current funding model can accommodate.



Capital Lifecycle Asset Replacements ER 7001

This portion of the Structures and Improvements Program is based on the results of the Facilities Condition Assessment Survey. This survey will take into account the condition and lifecycle of each Facilities asset. Assets will be graded and those requiring replacement within the next 10 years will be estimated and scheduled for replacement at an appropriate year during the 10 year time frame of the survey. Buildings as a whole will be assigned a Facilities Condition Index (FCI) as part of the survey to help compare future capital needs and drive the decision of continued capital expenditures vs. possible replacement.

Examples (asphalt and structural issues):



Furniture Replacement or Additions ER 7003

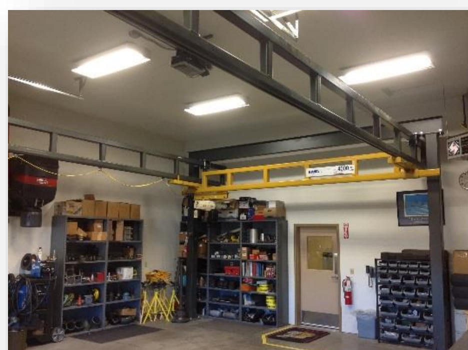
This portion of the program is for furniture replacements based on industry standard lifecycles, condition, and availability of parts. The program is also meant to support new furniture additions required on approved building projects.

Examples:

Business Additions or Site Improvements ER 7001

This portion of the program is intended to support site improvement requests and productivity or business-related needs. Project requests are made by Operations site managers in June the year before. The list is then vetted for validity and business need by director-level management. Approved projects are then prioritized vs. capital asset replacement priorities, and assigned per available capital funding. Projects that are tied to compliance, safety, or productivity will be given funding preference.

Example (security fencing and gate, weld shop crane):



A robust operations and maintenance program will be required to help further extend the lifecycle of our Facilities assets and help to lessen capital replacement needs. Conversely, limited O&M maintenance programs will result in shorter than standard asset lifecycles, and ultimately increased Capital spending.

As the condition of our Facilities improve, capital asset replacements should lessen in future years of the program. This is again dependent on sufficient O&M maintenance budgets and workforce.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* **and the benefits to the customer**

The major driver of this business case is Asset Condition. Facilities apportions approximately 50% to Asset Condition work that is identified using Paragon Asset Condition software (Terracon), 30% is set aside for Manager Requested projects, and 20% is kept aside for unexpected capital needs and furniture replacements.

Customers benefit from this project by Facilities providing a safe, usable buildings through which our Operations teams provide electricity and gas to our customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

As previously stated there is an identified backlog of Asset Condition work of $6.8M. This list is growing every year as our buildings age and new items are identified that need replacement. Deferring this work will cause a large bowel wave of Capital investment in future years. Providing a level investment over the next 10 years will allow us to prevent equipment failures and the need for a large one time capital investment.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

At this time, the only measure that can be used is to design solutions that provides room for growth, expands technology requirements, and adheres to safety and security best practices. Some of these solutions would include items such as:

1) Materials/ Storage: Provide spaces that meet the needs of the Stores team and Operations
2) Environmental/ Compliance: Ensure that the building and site meets with Avistas environmental standards
3) Employee/ Customer Impacts: Room for employee or operations growth
4) Operational Efficiency: Ensure that operational needs of employees are being met
5) Asset Condition: Provide systems and materials that meet with Avista standards

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The Asset Condition Study and Asset Condition Report for all of Avista's Assets is used to help determine the best options to resolve the various Asset Condition needs.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The Asset Condition Study and Asset Condition Report for all of Avista's Assets is used to help determine the best projects to fund in any given year. Projects are prioritized by the Paragon Asset Condition program using metrics such as risk, impact and ROI. This prioritized list is then used to create the Asset Condition project list for the coming year.

Recommended Solution – Fund Program at full amount

This will allow us to address capital asset replacements and business needs. Safety, compliance, and productivity requests are rated highest and given priority first. Many of these replacements can create safety risk if not addressed (sidewalks, structural repairs). Not systematically addressing maintenance needs could ultimately result in complete replacement of the buildings at some point.

Option	Capital Cost	Start	Complete
Fund Program at Full Amount	$3.5M	01 2021	12 2021
Alternative #1- Partially Fund Program	Less than $3.5M	01 2021	12 2021
Alternative #2- Do Nothing	$0	-	-

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

There is currently an identified backlog of $6.8M in Asset Condition work needed across the system of assets Facilities manages. In 2017 Terricon identified $6M in work on their initial assessment. This list is growing every year as our buildings age and new items are identified that need replacement. At the current funding level this backlog of capital work will continue to grow. The backlog is growing faster than our current funding model can accommodate. It is the goal of this program to maintain a level backlog that projects are selected from using Terracon's risk assessment and the impact the item has on the Company's ability to perform its work, making the highest priority projects readily apparent.

Even funding this program at the $3M level we will never be able to completely reduce the backlog. Providing more than the $3M requested would require additional Project Management personnel and possibly FTE's. Facilities can accommodate this request within their current staffing model. It is the goal of this program to maintain a level backlog that projects are selected from using Terracon's risk and the impact the item has on the Company's ability to perform its work, making the highest priority projects readily apparent.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

Average funding splits based on project priorities

This program is be responsible for the capital maintenance, site improvement, and furniture budgets at over 40 Avista offices, storage buildings, and service centers (over 900,000 total square feet) Companywide. This program is intended to systematically address the following needs:

- Lifecycle asset replacements (examples: roofing, asphalt, electrical, plumbing)
- Lifecycle furniture replacements and new furniture additions (to support growth)
- Business additions or site improvements (examples: adding a welding bay, vehicle storage canopy, expanding an asphalt yard. Can sometimes include property purchases to support site expansions.)

This program would encompass capital projects in all construction disciplines (roofing, asphalt, electrical, plumbing, HVAC, landscaping, expansions, remodels, energy efficiency projects). Facilities apportions approximately 50% to Asset Condition work that is identified using Paragon Asset Condition software (Terracon), 30% is set aside for Manager Requested projects, and 20% is kept aside for unexpected capital needs and furniture replacements.

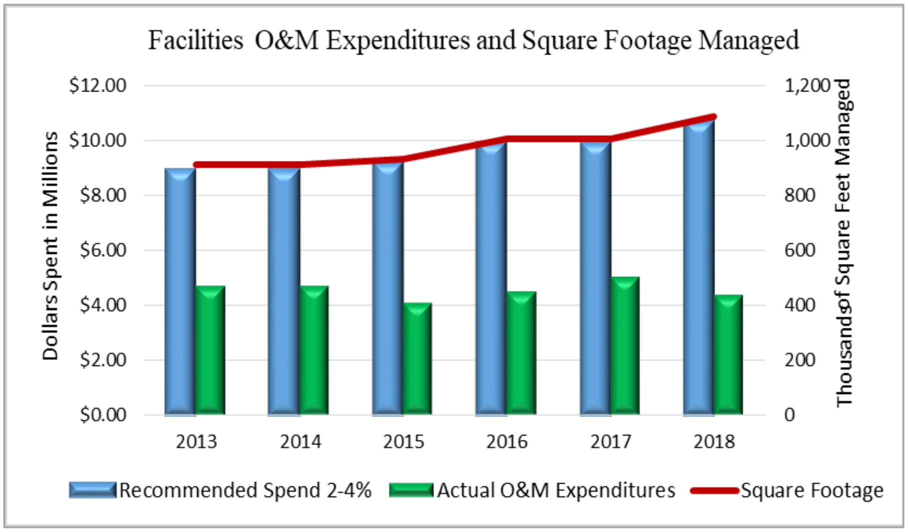
2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

This Business Case will impact the employees that work out of the offices and locations where projects are completed. Other teams that may be impacted are: ET, ET Security, Radio Relay, Environmental and Stores/ Warehouse.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

<u>Alternative #1 – Partially Fund Program based on priority</u>

This option would decrease the capital program and increase existing O&M budgets to prolong structures' lifecycles beyond rated life, and reduce capital needs. This option is not the preferred approach over the long-term. Capital investments can be limited with a corresponding increase in O&M dollars. As building systems continue to decline O&M burden will increase.



The estimated replacement value of Avista's assets when the Terricon survey was taken in 2017 was approximately $242 million, with estimated maintenance and replacement requirements based on the Terracon report of $8,800,640 *per year*, which equals 3.64% of the current replacement value of the assets. The graph above clearly demonstrates that the amount spent by Avista (the green bars) typically does not reach the minimum level of O&M expenditures (the blue bars) standard in the building industry for basic sustenance of facilities. This level of underfunding would need to be addressed if the choice is made to underfund this program.
Business site improvement requests are intended to address changing business needs. These projects are usually linked to an enhanced productivity outcome. Having the ability to incorporate structures and equipment that fall within the improvement and business needs category can help support improved processes and lead to enhanced safety and longer lifecycles. When the budget needs to be reduced, reductions are first made to requests in this category.
Replacement is intended to replace aging units to achieve more predictable capital requirements and avoid replacement peaks caused by large-scale failures. Cutting into these requests over an extended period could lead to reduced efficiency and have safety impacts.

Alternative #2 – Do nothing

This option is not recommended. Building improvements are capital events that materially extend the useful life of a building and/or increase the value of a building. Building improvements are capitalized and recorded as an addition of value to the existing building. Sites will continue to decline due to normal wear and tear. The failure of certain systems, such as roofing or HVAC, can cause major damage to other areas of the building. Walkways and structural issues not being addressed could have safety impacts to employees, visitors and customers.

When failures occur the capital investment must be made, regardless of funding. This program provides an avenue to PLAN these capital investments.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

The majority of projects in the Facilities Structures and Improvements program begin work in the 2nd or 3rd quarter of each year, and will usually transfer to plant before the end of the year. Some of the larger projects, or projects with extensive design, can carry over to the following year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The major reason to perform this project is to align with Avista's strategic vision of customer performance and reliability. Being able to provide service to our customers safely and efficiently is a cornerstone of Avista and the current Pullman Operations office does not allow employees to meet those goals.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Hopefully the business problems described earlier makes a strong case that this investment makes sense, as to avoid significant operational, reliability, and performance risks. As the project progresses, the scope and budget will be re-baselined as required. And hopefully the project can come in possibly under budget and ahead of schedule. Full oversight of the scope and budget will be provided to the Facilities Steering Committee (see Section 3.1 (A)) for their review and evaluation as described in Section 3.2 and 3.3.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The project within this business case will impact the Pullman Service Center Team. The team will be able to work out of the current service center during construction but we will be reaching out to the team during the design and construction phases.

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

ER7001 Facilities Structures and Improvements is a 5-year program created to address the capital lifecycle asset replacements and business/site improvements at all of Avista's regional sites and offices. Asset lifecycle replacements are compiled by Facilities and are based on an asset condition report and industry recognized lifecycles. Site improvement projects are approved based on productivity and/or business need.

Asset Lifecycle Replacement Projects

In 2017 Avista hired Terracon Consultants to perform a condition assessment on 76 Avista-owned facilities and 35 real estate sites at 34 different locations, comprising approximately 981,000 square feet. These facilities were constructed between 1903 and 2016. Terracon estimated the value of this infrastructure at approximately $242 million.

The Terracon study was highly detailed and in depth. They examined every characteristic of each facility from a variety of perspectives. External structures from asphalt in the parking lot to roof condition, fences, curbs, work, and storage areas were examined to ascertain and score condition and to identify issues and note concerns. Internal aspects such as walls, carpets, and furniture condition were evaluated.

They surveyed building systems including plumbing, heating and cooling, electrical, lighting, air quality, drainage, and security. They also looked at safety aspects from both the customer and employee perspective. Then each item in the facility was rated based upon its condition and assigned a budget category of O&M Preventative Maintenance, O&M Deficiency Repairs, Capital Replacement, and Capital Renewal/In-Kind Replacement. Terracon's list is sorted by relative risk and the impact the item has on the Company's ability to perform its work, making the highest priority projects readily apparent. Of the 363 "at risk" items Terracon identified, nearly 60% had a risk rating higher than 5 (on a 1 to 10 scale) and 20% were identified as having an actual impact on operations. This rating is what is used to identify the highest risk replacements needed and the project list is created using this information.

Site Improvement Projects

These types of requested facilities projects undergo a multi-level internal review process. It begins with the related manager who either identifies the capital need themselves or is notified of an issue that needs to be resolved by an employee. If the manager believes the project is in the best interests of his group and the Company, the proposal is submitted to that manager's director. If the director also sees the value of the request, it is submitted to a group known as the Facilities Capital Request Board.

This Board meets every fall to review the requested projects for the upcoming year. Managers from each major business area send a representative (the employee chosen usually changes every year). In addition, there is a requirement of at least one person from Operations, Environmental Affairs, Materials Management, and Facilities. This broad mixture of perspectives is designed to provide a neutral and "outside" perspective while having access to the expertise and experience of the directly related and impacted business entities.

By the time the Board receives the list of requests, it has already been vetted twice within its related department. The requests are prioritized based on the Capital Request form that was filled out and approved. At the Board level, each request is reviewed for required criteria such as risk, safety, environmental impact, and compliance. Thus this process is designed to ensure that multiple stakeholder participation provides a thorough and robust analysis of all facility needs and alternatives across the Company.

3.2 Provide and discuss the governance processes and people that will provide oversight

Facilities Capital Steering Committee

Once the project list is assembled, the finalized list of projects is approved by the Capital Facilities Steering Committee. This Committee of Directors is responsible for approving the submission of Business Cases to the Capital Planning Group and approval of projects and any changes within this program.

In the past this has most often been:

- Director of Shared Services
- Director of Environmental Affairs
- Director of Financial Planning and Analysis
- Director of Generation, Production, Substation Support
- Director of IT and Security
- Director of Natural Gas

The project shall use certain Project Management Professional (PMP) guidelines and procedures during the course of this project.

A Project Execution Plan, consisting of the documents below, will be drafted and approved by the SteerCo described in Section 3.1 (A).

- Project Charter, Change Management Plan, Communication Management Plan, Cost Management Plan, Procurement Management Plan, Project Team Management Plan, Risk Management Plan and Risk Register, Schedule Management Plan, Scope Management Plan, and Project Execution Approval Form.

Each month, the project manager will provide the following information either at the scheduled SteerCo meeting, or via email.

- Approved Yearly Budget, Accrued Yearly to Date, Year Estimate at Complete, Year Variance at Complete, Approved Lifetime Budget, Accrued Life to Date, Lifetime Project Estimate at Complete, and Lifetime Project Variance at Complete.

Each month, the SteerCo will make decisions on cost, scope, or budget items as required by the Project Execution Plan. The project manager reserves the right to present items not outlined in the Project Execution Plan if he/she determines its importance is relevant to SteerCo input.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The final decisions regarding these items, especially certain change requests as required by the Project Execution Plan, will be presented to, and voted upon by the SteerCo. The decisions will be documented in a monthly meeting minutes of the SteerCo for documentation and oversight.

It will be the Project Manager's role to monitor the scope, budget, and schedule and present the results to the SteerCo, regardless of they are within tolerances, or not.

The undersigned acknowledge they have reviewed the ER 7001/ 7003 Structures and Improvements and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Eric Bowles Date: 8/3/2020

Print Name: Eric Bowles

Title:	Corporate Facilities Manager
Role:	Business Case Owner

Signature:	Dan Johnson	Date:	8/3/2020
Print Name:	Dan Johnson		
Title:	Director Shared Services		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

EXECUTIVE SUMMARY

Fleet operations across the US and within the utility industry are implementing telematics solutions to solve complex business problems. The Advisory Group has identified five ways that vehicles on the road impact Avista. The first represents the first generation of telematics and is focused on utility owned trucks. The next four have the potential to positively or negatively impact our business but they are vehicles not owned by the Avista. It could be the contractor working for Avista in a contractor owned truck, a contractor in their personal vehicle, Avista's employee's doing business on behalf of the utility in their personal vehicle and crews responding to mutual aid in our service territory. Telematics has been implemented on the Avista's fleet since 2012. The first generation of telematics was implemented to streamline and track the inspections of trucks and mounted equipment. The digitization of inspections has been very successful and has improved the tracking of federally required inspections and the administration of those records as required by the same authorities.

In February 2022 our current provider has notified us that the 3G network that nearly 500 devices connect to will sunset. This network shut down forces us to invest capital in an upgrade. Additionally, customer requirements and our strategy to put the customer at the center of every decision necessitate the need for us to leverage vehicle location data on a modern and timely platform. Finally, best in class utilities are using telematics to provide both coaching to drivers and collecting leading indicators on decisions a fleet of drivers are making. The Advisory Group's recommendation is to replace Zonar telematics with a modern cloud platform system from Verizon Connect or Utilimarc-Geotab. Both platforms address latency issues and integrate more info sources than ever before. The final estimated cost for this is upgrade $2,387,500 spread over three years. An upgraded system will integrate location data with the CX platform to give our customers accurate response info, safer roads for all and lower overall costs by streamlining our operations with data. We must begin this investment in 2021 with the February 2022 shutdown of the AT&T 3G network coming. In doing nothing we will lose our ability to complete a critical compliance function by being unable to complete our daily vehicle inspections. Additionally, we fail to meet our customers where they expect us to be in today's digitally connected economy.

VERSION HISTORY

Version	Author	Description	Date	Notes
ExeSum	Greg Loew	Exe summary only	7/7/20	
Rev1	Greg Loew	Completed case	7/24/20	

GENERAL INFORMATION

Requested Spend Amount	$2,387,500
Requested Spend Time Period	*3 years*
Requesting Organization/Department	Fleet Services
Business Case Owner | Sponsor	Greg Loew | Dan Johnson
Sponsor Organization/Department	Energy Delivery
Phase	Planning
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Advances in technology, customer requirements and safety are driving the need to invest capital in our connected vehicle systems. Implementing the next generation of telematics in vehicles on the road operating on behalf of Avista have the opportunity to delight our customers, reduce our liability exposure and improve operational safety.

Technological Changes: Telematics works by connecting the vehicle to the cellular data network. Currently, most telematics connectivity use third generation networks (3G) provided by the major carriers. In February 2022 this network will no longer be supported and many carriers are already preventing new 3G devices on their networks. To ensure current functionality we will need to equip our vehicles to connect to the fourth and fifth generation networks (LTE and 5G respectively). We also know that connected worker solutions are proliferating across our workforce. This has driven numerous data connections inside and outside of the vehicle. Telematics technology has advanced to allow the consolidation of connections. Leading telematics providers have embraced a platform perspective. They have acknowledged that original equipment manufacturers are controlling some of the data flow from the vehicle or like Caterpillar it is just build in to the equipment computer. This migration to a platform is beneficial for Avista as we advance solutions for the fully digitized worker of the coming decade.

Customer Requirements: Our customers are being influenced by Amazon and Google and other leading customer experience companies. They expect timely and relevant communications from everyone they do business with. The utility is not exempt from these expectations. Next generation telematics is an enabling technology for a fully integrated and digital field work process. The connected vehicle and worker, integrated with the mobile work management system and customer experience platform will provide greater visibility about where our field personnel are and when they will arrive. The information will be available to employees and to customers, improving our ability to provide firm estimates of when we will be there to complete the work. The platform will also improve emergency response times through improved routing and real time location services. Finally, providing more crew location information to our dispatchers will allowing us to dispatch the crew closet to the work saving valuable time and resources.

Safety: The impact of telematics on the overall safety to a fleet of vehicles is under estimated. Telematics allows the capture of data around all facets of the drive cycle. More importantly, telematics is to several leading indicator safety metrics. Next generation telematics integrations will allow us to see items as specific as seat belt usage, the engagement of reverse or how close we backed up to an object. Telematics also has the ability to coach drivers in real time and or provide them a summary of their performance on a pre-determined interval. Finally the next generation systems will provide metrics on the co-location of supervisors to the crews which has been proven to be a major predictor in crew safety performance

Additionally, as the Advisory Group has engaged internal stakeholders we have created a required functionality list. Based on current published Zonar capabilities the following issues with Zonar were identified:

Issue	Impact on Capability
Dynamic Reporting	Provides inconsistent data points
Server based system	5-8 minute lag in actual unit status
Only support Android operating system	Avista has standardized on iOS
No vehicle as a hotspot capability	Multiple connections and expense
Driver coaching	Requires dedicated tablet
Workflow management	No integrations or partnerships
Behavior metrics	No metrics outside of speed to posted
Auxiliary system data capture	No 3rd party device integration
Point designed solution	No platform capabilities at this time
No manufacture API integration	Requires us to always us an ancillary device

Telematics 2025 will initially provide a platform for compliance. We can and will continue to measure inspections completions and other safety related functions. We will use this platform to capture, track and communicate this information to users and leaders. A feedback loop to the driver on their driving performance will be a key feature of this initiative. Over time the advanced telemetry data from this system will help us shrink the gap between actual behaviors and expected behaviors.

The Driver Safety team that was stood up in 2017 identified a dozen key actions to improve our vehicle incident rate. These recommendations where based on the analysis of multiple best in class companies and the programs/practices they had in place to achieve such results. Every program we looked at had some sort of driver performance feedback mechanism.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Asset Condition

Telematics 2025 is also an enabling platform for Customer Experience advancements and Business Intelligence. We could measure improvements in customer satisfaction, reduced maintenance costs, and lower overall cost per customer being driven by fleet related activities.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The 3G network that Zonar currently operates on will cease operations in February of 2022. Our DOT/FMCSA compliance with CFR49 and the inspections required before and after operation are digitally managed. Not doing anything will force our commercial vehicle operators to complete inspections by pen and paper and creates a document management challenge because we must keep them for 12 months before disposing of them. Failure to do so opens the company to additional liability.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Cost Savings: Estimated savings to the organization will be driven both directly and indirectly through multiple factors. Savings are ranked from initial platform deployment to additive next generation work management solutions to be deployed by future

- ✓ Compliance and regulatory costs—Avoided cost from effort and resources to once again track vehicle inspections with paper and the increased risk due to the inspection records not being correctly maintained per US Department of Transportation regulations 49CFR
- ✓ Automated recording of miles—Current work flow requires over 50% of Avista vehicles to submit mileage in paper form. Up to 25% of mileage is not turned in and as such vehicle use cost are not being fairly distributed to all users.
- ✓ Assuming data plan aggregation can occur while still supporting the critical business functions of the workers in the field, anticipated savings from reduced network connections in the vehicles are estimated as follows:

Vehicle Quantity	Data Plan Cost
80	$40.52/month
Total Cost Savings Per Year	$38,900

- ✓ Improved utilization—Currently, we average 11% less in miles and hours than the industry. 30% of fleet vehicle get less than 50% of the class average miles per year. By improving utilization we can spread our fixed cost across more miles and work to lower the fleets total fixed costs by reducing complement.
- ✓ Improved maintenance using advanced business intelligence tools and data—Revised maintenance programs could save up to $170,000 per year in total maintenance costs. This would be achieved by moving vehicles to a usage based maintenance model in which the collection of mileage data by the system alerts us to do a PM only when it approaches a use threshold.
- ✓ Less vehicles because of improved capabilities to share assets among some groups of workers—Reduced total fleet acquisition costs, higher utilization, reduced fixed and variable expenses.
- ✓ Improved routing and fuel savings—New operations driven tools could reduce total fuel consumption by expediting vehicles from job to job.
- ✓ Customer Service savings driven by reduced calls to the call center—The three year average for complaint calls related to vehicles and the potential whereabouts of people doing work on behalf of Avista totals 55 call hours per year using customer complaint records and an average call duration of 6.5 minutes.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

See the Driver Safety Team report out February 2018 by Greg Loew and Tony Klutz

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The current network for Zonar will cease operation in 2022. As noted in section 1.1 several functions were noted as missing for future anticipated business processes.

Option	Capital Cost	Start	Complete
Implement Telematics 2025	$2,385,500M	01 2021	06 2023
Partial implementation of Telematics 2025	$1,850,000M	01 2021	12 2021
Upgrade Zonar to 4G devices	$157,500	03 2021	10 2021

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Telematics Capabilities				
Problem Statement	Identify a telematics solution that provides safety and compliance data on vehicles doing work on behalf of Avista and enables or supports solutions connected to the digital worker of the future.			
Required Functionality	**Details**	**Alternatives**	**Priority**	**Focus Area**
Electronic Inspections	The completion and documentation of DOT required inspections plus pre-flight inspections	Paper		Compliance
Regulatory Mileage Reporting	Multiple federal and state agencies require exact mileage to be reported per state	N/A		Compliance
Diagnostic Alerting and Reporting	The ability for the truck to push diagnostic trouble codes to Fleet	N/A		Fleet
AssetWorks Integration	Pushing mileage to database to act as system of record eliminating the need for the vehicle ledge	N/A		Fleet
iOS Compatible	Must work on iOS devices	N/A		IT
Driver Behavior Scoring and Coaching	Feed back mechanism to help drivers know how they are driving	In cab or daily summary		Safety
4G and 5G capable	3G network is at end of life	N/A		IT
Customer facing info	Customer know who the worker is that will be serving them and visibility into when they will be t	N/A		Customer Service
Utilization	Reporting and mechanisms for understanding under utilized equipment	N/A		Fleet
Idle Reduction	Knowing what it productive idle and non-productive idle	N/A		Fleet
ECM data/Vehicle Performance	Real-time performance data to build dynamic maintenance response	Maintain current system of time base		Fleet
Integration for Distribution Dispatch	Showing vehicle assets to distribution dispatchers to improve dispatch capabilities	N/A		IT
Work Flow Management	Match personnel and resources to work requiring completion (work management) (maybe a tie to	N/A		Operations
Driver Identification	Knowing who is driving every single truck every time it moves	Assumptions based on inspection		Safety
Behavior Metrics	Data analysis info to understand trends and habits	N/A		Safety
Accident Reconstruction	Capability to record some amount of data that can be analyzed after minor crashes	Uses air bag computer after major crashes		Safety
Integration of mulitple telemetry data systems	Trailers and other AVA assets can use different location systems.	Put everything one syste		Fleet
Auxiliary System Data Capture	Capability to capture data from other systems installed on the truck (back up sensors, seatbelt usa	N/A		Safety
GPS location for non motorized units	Find the lost trailer	N/A		Fleet
Vehicle Hotspot	Vehicle based data connection point	Current system with rugged laptops		IT
Smart Phone App	App that could be installed on contractors phone to know where they are at in our system (think gas survey)	N/A		IT
Productivity	Expedited routing	N/A		Operations
Co-Location	Where are supervisors (GFs, managers) in relations to crews	N/A		Safety
Mobile Device Use Reporting	Utilizing mobile device app integrated with telematics to know if the phone is used while vehicle is in motion	App deployed with MDM solution		Safety
Satellite Connectivity	For use in remote wilderness areas	N/A		Safety
Vehicle Pooling	Dynamic assignment of available vehicle to worker requiring vehicle	One vehicle for each worker		Fleet
Driver Cameras	Forward and rear facing in cab cameras	Forward facing camera only		Safety

Reference key points from external documentation, list any addendums, attachments etc.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

Telematics 2025 will be implemented over a three year period beginning in 2021 in order to meet 3G obsolescence. In year one our commercial fleet will be functional and on the new systems. In years two and three we will bring our light duty vehicles fully on to the platform plus trailers and complete integrations to systems like Assetworks, Intelex and Oracle.

On an ongoing basis the operational costs for telematics flow to the Fleet Clearing Account. From there a portion of the costs go to capital and some to O&M depending on the class of vehicle. Vehicle rates for light duty trucks and trailers will see a small impact from this technology.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Telematics 2025 will continue to be used by Fleet and Distribution Ops. The CX project will use the data stream from this system as described in section 1.1. Vehicle electrification efforts have the potential to tap into the platform.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Upgrade existing system. Preserve current functionality with technology that does not meet current or future business needs across the enterprise.

Partial install on only the on-road portion of our fleet (excludes trailers)

Partial install of new system on commercial motor vehicles only. Preserves current functionality does not integrate or capture almost a third of all Avista owned vehicles. Many safety and operational benefits would not be met.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

$1.1M	Q1-2021 Project planning	Q2-2021 Product ordering	Q3-2021 Vehicle installs TTPs as districts or orgs completed	Q4-2021 Project planning and remaining TTP
$675K	Q1-2022 Planning and SOW	Q2-2022 Integrations, installs and TTP	Q3-2022 Remaining 2nd year project TTP	Q4-2022
$612.5K	Q1-2023 Planning and SOW	Q2-2023 Integrations, installs and final TTP	Q3-2023	Q4-2022

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Enhancing the telematics in the fleet vehicles directly aligns with the four focus areas; customers, people, perform and invent.

Customers are better served by providing a platform that enables notifications and awareness of crew arrival times. Avista **Employees** are better served through interactive coaching and feedback on their driving behavior. **Performance** is better served through the enhanced integrations that are enabled and the information that can be shared across multiple systems. **Invention** is served by recognizing that the expectations of customer service has changed, and that technology is required, not only in our back office but in the front-line vehicles that serve as the initial touchpoint for many customer interactions

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The majority of Telematics 2025 scope is the replacement of a system that will no longer operate after February 2025. As outlined in section 1.1 our next generation telematics will enable additional functions and help streamline analog processes. Project management and business case owner will continue to review the scope of the project for material changes.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholder Name	Department
Andrea Pike	Customer Service
Reuben Arts	Distribution Dispatch
Amy Parsons	Finance
Mike Faulkenberry	Gas Ops
Alexis Alexander	GPSS
Mike Littrel	Enterprise Technology
Jon Thompson	Enterprise Technology

2.8.2 Identify any related Business Cases

None at this time

3.1 Steering Committee or Advisory Group Information

Mike Littrel	Erica Ellis	Kim Boynton
Matt Redding	Eric Rosentrater	Jason Johnson
Steve Aubuchon	Russ Feist	Jim Corder

3.2 Provide and discuss the governance processes and people that will provide oversight

This project reports in with the executive advisory committee comprised of:

Heather Rosentrater	Jason Thackston	Jim Kensok
Bryan Cox		

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The project manager and the business case owner will be responsible for monitoring and recording priority changes and material change requests. Full values and scope to be determined at a later date.

The undersigned acknowledge they have reviewed the Telematics 2025 and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Gregorymloew Date: 7/24/20
Print Name: Gregory Loew
Title: Fleet Manager
Role: Business Case Owner

Signature: Dan Johnson Date: 7/28/2020
Print Name: Dan Johnson
Title: Director, Shared Services
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title: Shared with committee on 7/24/20 via email
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

EXECUTIVE SUMMARY

In the 1990s, an underground vault was built at the Mission Campus to house several tanks intended to hold new oil, used but viable oil, and scrap oil, all related to substation maintenance and electrical distribution operations. This system connected the electric shop and the scrap oil recovery areas through a series of manifolds and pumps to segerate the new and used oils. Several incidents, including one holiday weekend overfill incident in 2010, brought to light the disadvantage of using an underground system, as problems could go undetected. This risk was further highlighted during a 2019 pipeline spill and subsequent investigation/excavation and cleanup.

In 2014, two new above-ground scrap oil storage tanks were built as part of the Waste & Asset Recovery (WAR) Building. This allowed for the two scrap tanks in the underground vault to be decommissioned, but the remaining four underground tanks, and associated underground piping, remain in use. This system still poses risks of undetected leaks. In addition, access to the underground system becomes more problematic as we redevelop the campus. The vault space itself limits use of the area. Finally, the vault has been subject to intrusion by water, and maintenance costs to ensure the vault provides proper containment are increasing.

The recommended solution will build two additional new oil tanks by the WAR Building, with several smaller "day" containers for the Electric Shop, allowing the underground vault to be permanently removed, eliminating environmental risk.

The recommended solution is estimated to cost $1.5 million (as of June 2020). Since the project is at the Mission Campus, the rate jurisdiction is Common Direct – Allocated All. The major customer benefit would be the reduction in future O&M maintenance, and costs of clean up of environmental events. Customers will also benefit with an enhanced oil storage process that will provide Avista employees with reduced overall environmental risk, time efficiencies and generally faster response times within substation maintenance. It is recommended to proceed with this business case as soon as possible to avoid any additional environmental risk and inefficiencies utilizing the existing system.

VERSION HISTORY

Version	Author	Description	Date	Notes
0.0	*Vance Ruppert*	*Initial draft to be approved by Sponsors*	*7/6/2020*	
1.0	*Vance Ruppert*	*Final Draft, Sponsor edits incorporated*	*7/10/2020*	

GENERAL INFORMATION

Requested Spend Amount	$1,500,000
Requested Spend Time Period	2 years
Requesting Organization/Department	Shared Services (Facilities)
Business Case Owner | Sponsor	BC Owner: Eric Bowles Sponsors: Bruce Howard, Andy Vickers, and Dan Johnson
Sponsor Organization/Department	Environmental / GPSS / Shared Services
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

In the 1990s, an underground vault was built at the Mission Campus which housed several tanks that were intended to hold new oil, used but viable oil, and scrap transformer oil, all related to substation maintenance and electrical distribution operations. Over time, there have been several incidents of an environmental regulatory nature that began to question the ongoing practicality of retaining this asset.

A. The prime event occurred in September 2019, when an Electric Shop Electrician discovered a pipe rupture into the containment vault after operating the system for approximately 30 minutes. The pipe connects the vault and the Electric Shop (a substation maintence shop) within the Service Building (one of several standalone buildings on the Mission Campus). The leak released an estimated two hundred gallons of oil, and required excavation to a depth of 15 feet deep and approximately 31 cubic yards of soil. The system is currently curtailed to direct pumping operations from the containment building, which is cumbersome to Avista personnel. We are awaiting confirmation from Washington State Department of Ecology for a “no further action” letter regarding site cleanup..

B. Another incident occurred in 2010, when an oil transfer occurred on a Friday with electric shop personnel and a contractor. The wrong tank was selected to fill, the oil overflowed out of the tank and oil was allowed to float on the floor for over three days as it was a holiday weekend. It is unknown if the oil significantly penetrated the concrete floor but some concrete may have been contaminated. Designation and disposal will occur under this business case.

C. O&M dewatering - The roof to the underground vault is an asphalted lid that doubles as a drive path for Avista vehicles. However, water seeps down into the vault through cracks and porous surfaces. This problem has accelerated through the years and requires a hazardous waste technician to pump out the water, and screen it for oil/PCB contamination before disposing of it. This occurs 5-10 times per year.

D. The oil storage vault is a “stranded asset” as multiple stakeholders claim use of the resource, without a single stakeholder that “owns” the asset for O&M checks or maintenance. O&M checks are currently performed by Hazardous Waste Technicians and Security contractors to ensure that oil isn’t present in the containment on a weekly basis.

1.2 Discuss the major drivers of the business case and the benefits to the customer

The major driver for this Business Case is “Asset Condition,” due to its containment failures and environmental risks as outlined in Section 1.1. The major customer benefit would be the offset of any future O&M maintenance or clean up of environmental events. Customers will also benefit with an enhanced oil storage process that will provide Avista employees with time efficiencies and generally faster response times within substation maintenance.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

With the past failures as outlined above, it is Avista’s belief that a major environmental event with the underground vault is a matter of when, not if. Avista cannot predict when that event would occur, be it months or years. However, in general, the longer this Business Case is not implemented, the greater the chance the risk could occur without the problem being fixed.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

At this time, the only measure that can be used is to design a oil storage system that takes lessons learned from the underground vault and uses them to mitigate risks. Some measures include a system that will:

1) be easily viewable by multiple employees on a daily basis to check for leaks

2) not use any underground tanks or piping

3) use oil containment best practices such as: active electronic monitoring, modern pumping equipment, reinforced single or double-walled tanks, weathertight roofing, purpose-built concrete containment with impermeable coating.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

2010 CH2M Hill Assessment of Undergorund Storage Tanks for Avista. Available on request (Facilities / Vance Ruppert).

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Pictures of the underground pipe oil leak as described in Section 1.1 (A) above are available on request (Facilities / Vance Ruppert).

Pictures of the oil tank overflow as described in Section 1.1 (B) above are available on request (Facilities / Vance Ruppert).

Pictures of the annual water roof leaks as described in Section 1.1 (C) above are available on request (Facilities / Vance Ruppert).

Option	Capital Cost	Start	Complete
Build new above ground tanks, demolish underground vault and tanks	*$1.5M*	*08/2020*	*10/2021*
Build a new GPSS Maintenance Shop at Mission or off-site, with a new tank(s) arrangement.	*$15M - $25M (?)*	*2021 (?)*	*2023 (?)*
Do nothing.	*$0M*	*N/A*	*N/A*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The main intent of this project is to avoid significant environmental risks as described in Section 1.1 Any risks that actually occur carry with it significant O&M costs as well. For instance, the underground pipe oil leak as described in Section 1.1(A) had a remediation cost of approximately $100,000.

If (and when) a major environmental risk were to occur with the underground vault, such as a burst oil tank and vault containment failure, a remediation cost of the soil below the vault would probably start at $200,000, and would potentially reach multiples of that amount if the contamination reached groundwater. Avista would be subject to environmental enforcement, penalties, and significant reputational harm.

Avista Facilities employee time to contend with the other issues in Section 1.1 can range from a few hours to several days. A conservative estimation of an average Avista Facilities maintenance employee labor rates, which includes hour rates, overhead, and benefits, is at least $60 an hour. If an average estimate of each event requires 2 employees for 4 hours, 1 time a month, then yearly O&M savings could be assumed to be $5,760.

In addition, the Avista senior hazardous waste technician ($75 per hour) spends at least two and a half hours per event (with 5-10 events every year) to dewater the vault as described in Section 1.1 (C). The 10 event estimate would calculate to a yearly O&M savings of approximately $1,875, plus disposal costs of approximately $1000. Should cross contamination of water occur, costs would increase by orders of magnitude.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). Include any known or estimated reductions to O&M as a result of this investment.

The requested capital cost amount of $1.5M will be broken out between two years. In 2020, $300K will be requested to design, permit, and competitively bid the project to a general contractor. In addition, some monies will be used to conduct environmental investigations to determine if there are any additional unknown contaminations or failures. The remaining $1.2M will be primarily for construction in 2021.

<u>The project will provide the following new equipment and processes:</u>

Two new 10,000 gallon tanks, one for new oil, and one for used but viable oil. They shall be installed near the existing tanks at the Waste & Asset Recovery Building (WAR Bldg). The tanks shall be above ground, surrounded by a concrete spill containment. They will also require a covered roof/canopy, and may also require metal siding to prevent snow/rain accumulation in the containment.

A smaller racked oil storage containers will be purchased for the Electric Shop for day use.

The new oil tank will be filled as needed by our oil supply vendor. The used but viable oil tank will be filled by our Electric Shop (ES), a department within Avista's Generation Production Substation Support (GPSS) business unit.

A 500 gallon portable storage tote to be filled with new oil from the tank mentioned above. It will be filled as required by the ES, but it is expected to be no more than 2-3 times a year.

A 300 gallon portable storage tote to be filled with used but viable oil, or to transport scrap oil to, the tank mentioned above. It will be used as required by the ES, but it is expected to be no more than 2-3 times a year.

A storage area (concrete slab or asphalted) will be provided for 20 empty 55 gallon drum barrels for new or used oil as required by the ES.

A storage area (concrete slab or asphalted), with a covered roof/canopy, will be provided for 12 full 55 gallon drum barrels for new oil as required by the ES. It may also require metal siding to prevent snow/rain accumulation in the storage area.

The ES will forklift the totes to and from the WAR Building. Due to the storm water containment systems and oil water separators that have been installed on the Mission

Campus over the past decades, the risk of any major oil spill events from forklift traffic is extremely low.

The new oil tank will also provide oil to an approx. 3000 gallon Isuzu tanker truck or an 8000 gallon tanker trailer Avista owns and stores at our Beacon Substation. Both pieces of equipment will be used as needed for large substation equipment work at both at the Mission Campus ES, and in the field / at any particular substation.

Demolish the exising underground vault. Technique of demolition T.B.D. Option 1: remove the entire vault including the floor slab and footings, or Option 2: remove only 6 feet or so top-down, with existing slab and footings to remain. The removed underground vault will be replaced with a new asphalt parking lot, approximately the same footprint, for GPSS use.

Possility of adding siding and slider doors to the (2) existing tanks at the WAR Bldg., due to snow/rain/ice accumulation inside its concrete containment the past few years.

In addition to the O&M savings for Avista employees as described in Section 2.1, it can be conservatively estimated that this new process will save at least 30 minutes for two ES employees at least once a week. The yearly O&M savings, using a $75 ES employee rate, can be assumed to be $3,900.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Current processes, metrics, & data:

1) Currently, the underground vault has four tanks that can be used by the Electric Shop (ES). There are (2) 10,000 gallon tanks to hold oil, and (2) 5000 gallon tanks subdivided into (4) 2500 gallon compartments that hold new or used but viable oil. The (2) 5000 gallon tanks can be used as queuing tanks from either of the 10,000 gallon tanks.
2) The 5000 gallon tanks were previously accessed by the ES through direct underground plumbing coming from the vault directly into the ES. The controls for switching between all the tanks, and also the (4) 2500 gallon subdivided tanks, are in the vault.
3) Inside of the ES, 55 gallon drums/totes (usually around four total) were being filled using the direct plumbed line. This practice recently ended however, due to the discovery of the leak in the underground piping as described in Section 1.1 (A). Now that the underground plumbing is no longer usable, if the totes need refilling, they will be forklifted over to the external, above-ground, hose hook up located at the vault.
4) Once the full totes are placed back in the ES, the oil is manually pumped into “smaller” pieces of equipment, as needed. Since the smaller equipment doesn’t usually require much oil, the totes only need to be refilled maybe twice, or three times a year.
5) However, the ES will sometimes require thousands of gallons at one time to work on larger equipment such as power transformers or oil circuit breakers, on a scheduled or emergency basis. Instead of using the totes, the ES has a separate process.
    a. Use the large tanker trailer or the smaller Isuzu tanker truck stored at Beacon Substation.
    b. More often than not, the ES will work on large equipment in the field / at the substation. They will fill the Isuzu or our tanker trailer at our vault at Mission Campus. After filling, they will then drive to the substation to dispense.
6) Lastly, whenever the ES needs a refill of either 10,000 gallon tank in the underground vault, they will usually have to “shuffle” some oil between the 10,000 gallon tanks and the 5000 gallon tanks in order to receive the full approx. 8000 gallons of oil for any tanker truck delivery from our vendor.

All of the above current processes will be replaced by the new processes as described above in Section 2.2.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

There was some discussion to build a new GPSS Shops Maintenance Building either at the Mission Campus, or at another off-site location. There is significant risk that the scope of such a building could fluctuate and produce a project requiring anywhere from $15M - $25M. At this time, this is not a reasonable solution to the main problem – the environmental issues with the underground vault and tanks.

Doing nothing was also considered, but given the difficulties numerous departments such as Facilities, Environmental, and GPSS have endured the past few decades, as well as the risk of a major future environmental event, the do nothing option is also not reasonable.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

This business case is considered a project, as it is not intended to be an ongoing project beyond 2021. The major milestones and timeline of the project is estimated to be the following:

Complete Design Drawings: 5 months

Bidding / permits complete, General Contractor (GC) selection: 2 months

GC procure tanks and long lead items: 2-3 months

GC complete new tanks: 4 months

GC complete demolition of underground vault: 2 months

The project is expected to complete and become used and useful in early-to-mid Q4 of 2021, with all of its $1.5M transferring to plant in 2021, around the same timeframe.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The major reason to perform this project is to align with Avista's stragetic vision of environmental stewardship. It is hopeful this Business Case clearly identifies the environmental regulatory issues that could, and probably will, occur at some point if no action is taken.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Hopefully the environmental regulatory issues and O&M maintenance described in the business case earlier makes a strong case that this investment makes sense, as to avoid significant operational and environmental risks. As the project progresses, the scope and budget will be re-baselined as required, and hopefully the project can come in possibly under budget and ahead of schedule.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Major customers/stakeholders:

Environmental Department (Bruce Howard, Darrell Soyars, Bryce Robbert, Heath Peterson, Casey Cardenas, Luke Pate)

Generation Production / Substation Support Department (Andy Vickers, Alexis Alexander, Brad McNamara, Loren Davidson)

Facilities (Dan Johnson, Eric Bowles, Robert Johnson, Vance Ruppert)

Minor customers/stakeholders:

Electric Operations, Fleet Maintenance, Warehouse/Stores

2.8.2 Identify any related Business Cases

Not applicable.

3.1 Steering Committee or Advisory Group Information

A. The Steering Committee (SteerCo) (as of July 2020) shall consist of the following: Dan Johnson, Mike Faulkenberry, Andy Vickers, David Howell, Jim Corder, Lauren Pendergraft, and Bruce Howard.

B. The Advisory Group that assisted in shaping this Business Case consisted of the following stakeholders:

Environmental Department (Bruce Howard, Darrell Soyars, Bryce Robbert)

Generation Production / Substation Support Department (Andy Vickers, Brad McNamara)

Facilities (Dan Johnson, Eric Bowles, Robert Johnson, Dave Schlicht, Nick Lasko, Vance Ruppert)

3.2 Provide and discuss the governance processes and people that will provide oversight

The project shall use certain Project Management Professional (PMP) guidelines and procedures during the course of this project.

A Project Execution Plan, consisting of the documents below, will be drafted and approved by the SteerCo described in Section 3.1 (A).

- Project Charter, Change Management Plan, Communication Management Plan, Cost Management Plan, Procurement Management Plan, Project Team Management Plan, Risk Management Plan and Risk Register, Schedule Management Plan, Scope Management Plan, and Project Execution Approval Form.

Each month, the project manager will provide the following information either at the scheduled SteerCo meeting, or via email.

- Approved Yearly Budget, Accrued Yearly to Date, Year Estimate at Complete, Year Variance at Complete, Approved Lifetime Budget, Accrued Life to Date, Lifetime Project Estimate at Complete, and Lifetime Project Variance at Complete.

Each month, the SteerCo will make decisions on cost, scope, or budget items as required by the Project Execution Plan. The project manager reserves the right to present items not outlined in the Project Execution Plan if he/she determines its importance is relevant to SteerCo input.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The final decisions regarding these items, especially certain change requests as required by the Project Exectuion Plan, will be presented to, and voted upon by the SteerCo. The decisions will be documented in a monthly meeting minutes of the SteerCo for documentation and oversight.

It will be the Project Manager's role to monitor the scope, budget, and schedule and present the results to the SteerCo, regardless of they are within tolerances, or not.

The undersigned acknowledge they have reviewed the *Oil Storage Improvements Business Case* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Eric Bowles	Date:	7/8/2020
Print Name:	Eric Bowles		
Title:	Corp Facilities Manager		
Role:	Business Case Owner		

Signature:	Dan Johnson	Date:	7/10/2020
Print Name:	Dan Johnson		
Title:	Director of Shared Services		
Role:	Business Case Sponsor		

Signature:	Bruce F Howard	Date:	July 8, 2020
Print Name:	Bruce Howard		
Title:	Sr Director of Environmental Affairs		
Role:	Business Case Sponsor		

Signature:	ANdrew Vickers	Date:	7/9/2020
Print Name:	Andy Vickers		
Title:	Director GPSS		
Role:	Business Case Sponsor		

Template Version: 05/28/2020

1 GENERAL INFORMATION

Requested Spend Amount	$28,000,000
Requesting Organization/Department	Facilities
Business Case Owner	Vance Ruppert / Eric Bowles, Facilities
Business Case Sponsor	Anna Scarlett, Manager, Shared Services
Sponsor Organization/Department	Shared Services
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Campus Repurposing Phase 2 Steering Committee is made up of a cross section of directors that represent groups impacted by the projects, as well as a couple members not directly affected to add an outside view. The current group is as follows:

- Director of Environmental Affairs
- Director of Shared Services
- Director of IT and Security
- Director of Natural Gas
- Director of Financial Planning and Analysis
- Director of Operations

Advisors may contribute input, approvals, or information as needed, and include:

- Vice President of Energy Delivery
- Executive Officers
- End Users

Each project within this business case is reviewed and approved by the Steering Committee group, and regular updates are provided during project execution.

2 BUSINESS PROBLEM

The Campus Re-Purposing Plan is a multiyear plan (Phase 1 and Phase 2) that address the following issues:

- Employee space needs
- Improving safety and efficiency of campus traffic flow
- Outdated fleet maintenance space and processes
- Lack of materials storage yards, no short-term flexibility

- Alignment of campus parking and number of employees based at main campus

The Avista corporate campus comprises 28 acres located next to the Spokane River in heart of the Logan Neighborhood. The campus in just north of the downtown Spokane corridor. Avista also owns eight additional acres of property directly adjacent to the campus at the north end. This parcel is separated from the main campus by North Center Street (a main city arterial).

Avista's corporate campus footprint is currently bound to the east by the Spokane River, and to the west and south by the Mission Park and Burlington Northern Railroad, leaving minimal flexibility to manage company parking, employee and materials space needs.

The Avista corporate campus was built in 1958 to consolidate and house all utility operations that were at that time spread throughout the community. As business needs changed over time, one-off expansion projects were to reactively address changes in business need. Employee growth and materials storage increases through the years have created the need to locate employees and materials at offsite locations, requiring space leases and other non-optimal solutions to meet growing company space needs.

Strategic property purchases to the North of the campus have been ongoing since 1988 as they become available to help address the issue and grow the campus to give us future flexibility. The final properties between Avista and the neighboring Riverview Retirement Community were purchased in 2014, now allowing us to develop them for company use.

The decision was made in 2011 to take a holistic approach to these issues and create a single proposed solution for the Corporate Campus that would address current issues, and future needs. The campus repurposing planning group began working in 2011 to find a way to address the growing employee space needs, parking issues, campus materials storage issues, safety and traffic flow issues (Operations traffic and employee traffic mixing), as well as look into addressing the changing business needs of our vehicle fleet and operational processes.

The result of this approach is a total campus plan that repurposes the existing campus for the next 50 years, minimizing our reactive approach and ensuring the best long term results for the Company and Ratepayers.

3. PROPOSAL AND RECOMMENDED SOLUTION

Campus Repurposing Phase 2 includes three major projects:

1. **North Center Re-Route**
2. **Construct New Fleet Building**
3. **Construct Parking Garage**

These three projects are connected and largely dependent on each other because of location, timing and the overall campus design. The projects will ultimately allow us to:

- Expand and consolidate the campus footprint while establishing a formal boundary between the Avista campus and the Riverview campus.
- Modernize the aged Fleet Building and address Fleet queuing needs.
- Expand and locate campus parking to align the available number of parking spaces with the number of employees working onsite, improving employee and public safety by reducing parking sprawl.
- Separate operations traffic from pedestrian traffic to improve safety and increase workflow efficiencies.

Project 1: North Center Street Re-Route

Avista-owned properties separated from campus by North Center Street

North Center Street currently divides us from the eight acres of property owned to the north on Ross Court. Re-routing North Center Street will allow us to consolidate our campus to include these properties. As North Center Street is a major city arterial that connects Indiana Street to Upriver Drive, a considerable amount of traffic uses the street daily. This traffic creates an ongoing safety risk to employees moving back and forth between the properties. It also creates challenges with securing the lots during business hours (gates, entrances, etc.).

Beginning in 2013, Avista began discussion with Riverview to plan the future development of each of our campuses. Riverview management expressed concern with future development on our adjacent properties due to the proximity of these properties to their resident housing. With no formal separation between our campuses, they were concerned with the height of proposed buildings as well as idling diesel trucks next to their resident properties.

Several options were considered (see options listed below). After many discussions, there was interest on both sides to explore rerouting North Center Street to the north in order to: 1) consolidate our properties into our secured campus; and 2) give Riverview a formal separation between our campuses.

Ross Court Property Options (re-route of North Center Street)	Capital Cost	Start	Complete	Risk Mitigation
Option 1 (Recommended): North Center rerouted around our Ross Court properties, adding eight acres to the Campus	$6M	2016	2017	Riverview prefers this option due to formal separation.
Option 2: no reroute (minimum development required to make Ross Court property usable). North Center Street remains in place creating a separated campus to the North, accessed by crossing North Center. Fencing, gates, and lot development still required.	$3,000,000	2016	2017	Risk involved in transporting materials across a major City Arterial. Strong opposition from Riverview on any development other than basic storage.
Option 3: no reroute, with tunnel or bridge connection to Ross Court North Center Street would remain and a tunnel or bridge would be created to safely access Ross Court and create a single secured Campus.	$8,000,000	2016	2017	Higher maintenance costs for bridge or tunnel. Strong opposition from Riverview on any development other than basic storage
Option 4: Do nothing	$0	Basic storage use only with no development. Property does require basic Civil and site work to be usable though.		

Option 1 (recommended): Reroute North Center Street to consolidate Ross Court properties with the main campus.

The re-route of North Center Street would allow us to create a new operations entrance to our campus, separating operations traffic from pedestrian traffic and resulting in operations workflow efficiencies and improved safety of the company and employees.

Campus Repurposing Phase 2

Recommended Option	
Positive Benefits	**Negatives**
Allows the creation of a new Operations entrance	Issues with City permitting?
Riverview's preferred option due to formal separation. No opposition to future developments options	Closure of North Crescent Street to access apartments behind Riverview
Single connected/secured Campus	
Better Operations traffic flow from entry, drop off, and parking	
Create a formal separation between Avista and Riverview	
Better separation of employee and Operations traffic would dramatically lessen safety risk to the company	

Options 2 and 3: No reroute, leave North Center Street in place and secure as separate campus.

A minimum of Option 2 or 3 would be required to make the Ross Court properties usable; however, these options would not allow separate operations entrance to be added.

Options1 and 2	
Positive Benefits	**Negatives**
Lower cost options (Option 1 lower cost, Option 2 similar cost)	Development options we are considering would be strongly opposed by Riverview due to direct adjacency of our operations to their resident properties
Slightly larger usable area vs Option 1	Two separate campuses requiring constant traffic across North Center Street creates safety risk (Alternative 2 only).
Alternative 2 would create a single Campus access	Alternative 2 would require higher O&M cost for tunnel or bridge
Quicker project execution	These 2 alternatives will not allow for a new Operations entrance

Project 2: Construct New Fleet Operations Facility

Avista's existing fleet operations building is located in the heart of the main campus and was originally built in 1958 to centralize all Avista fleet maintenance operations.

Vehicle and Building Size

The original fleet building was built to house smaller half-ton pick-ups and has been expanded twice through the years to accommodate the increased size of the new service trucks, once in 1978 and again in 1999. The size of vehicles in today's fleet have continue to increase since 1999 and some of the current fleet is difficult to service in the existing building. The current building is much smaller than City of Spokane and Waste Management facilities, which utilize similar-sized vehicles. Many of our larger trucks cannot be worked on in the existing space without leaving the doors open.

Existing Fleet Building Location

CNG

Avista has added vehicles fueled by compressed natural gas (CNG) to our fleet over the past four years. The existing fleet building is not CNG rated and all CNG-fueled vehicles must be taken offsite for repairs. To make the building CNG compliant would require the addition of a new emergency exhaust system. The estimated cost to make the building CNG compliant is around $1.3 Million

Environmental

The hydraulic lift system installed in the existing building did not include secondary containment when originally installed, and testing has indicated possible leakage of hydraulic oil in the soil under the building. Relocation of the building will allow us to completely encase all new hydraulic systems and mitigate any current or potential leakage.

Safety

The existing fleet staging and queuing area is also in the heart of the campus and is directly adjacent to multiple parking canopies and surface parking areas. This staging area is small and requires multiple trips in and out of the area for day-to-day operations. A main employee walkway also goes through this major traffic area and brings considerable safety risk to the company as some of the pedestrian traffic can be hidden by the parking canopies. Moving the fleet building to the north will allow for increased queuing area and lessen the employee and operations traffic risk considerably.

Building Conditions

In addition to compliance, environmental and safety issues, the existing building has a number of conditions that affect operations and employee safety and health, including the issues below (see attachment *Corp Fleet Building Issues* for complete list).

- Current facilities have bays less than 14' wide. Current trucks are 103" wide at the mirrors, leaving limited space for maneuvering and working on vehicles.
- We cannot lift rear tandem axle trucks with in ground lifts. We utilize wheel lifts which add 38" to the width of the vehicle. This leaves less than 2' for the technician to move himself and his tools into position. Tandem axle trucks make up 35% of the Avista Fleet. This effects productivity.
- Roof leaks at multiple points.

Options and Alternatives

Fleet Operations Options	Capital Cost	Start	Complete	Risk Mitigation
Option 1 (Recommended): Build a new CNG-compliant Fleet Operations building at the north end of the property and address the existing issues. • This options would allow us to use the existing fleet footprint for the Parking Garage and move all	$10,000,000	2017	2018	Major safety risk mitigated with employee and Ops traffic mixing.

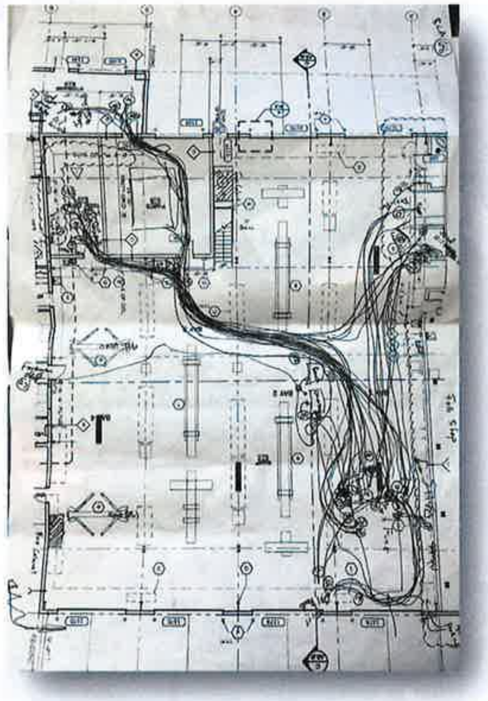
Operations traffic to the North end of the Campus.				
Option 2: Address the major issues in the existing building separately. • Replace Hydraulic systems, replace the constantly leaking roof, and install a CNG compliant exhausting system. • Increase the building in the future if needed.	$4,000,000	2017	2018	• Location not optimal in regards to safety and risk • Environmental and compliance issues • Continued rising of maintenance costs due to age of the building and systems
Option 3: Do nothing	$0	Still need to address the future impact of larger fleet vehicle sizes, aging hydraulic systems, non-compliant CNG space, and most importantly the safety risk due to the constant traffic and employee mixing.		

Option 1 (recommended): Construct a new fleet operations facility at the north end of the campus.

Constructing a new fleet operations center operations building strategically located at the north end of the campus would achieve a number of objectives:

- Enable us to increase the size of bays to accommodate larger fleet vehicles
- Address CNG compliance requirements and environmental issues related to the aging current facility
- Increase efficiency and safety of pedestrians and operations traffic on campus
- Increase efficiency of fleet operations

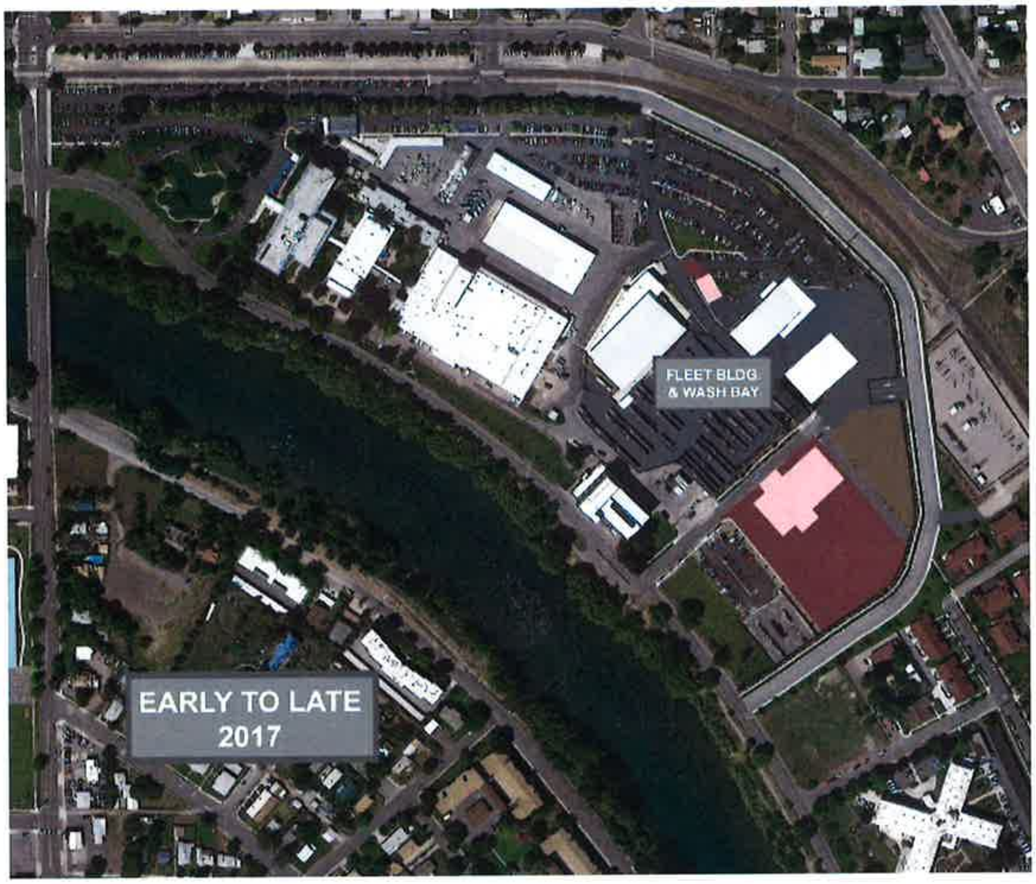
A pre-design BPI process was undertaken in early 2016 to look at efficiencies that would be created by a new building and new processes. It was discovered that the poor layout of the existing building resulted in numerous extra steps taken each day resulting in wasted time and resources. The new building was designed using industry best practices, and observed employee workflow.



BPI Spaghetti workflow diagram

See attached bullet points for a comprehensive list of issues that a new building would address.

Recommended Option: New Fleet Building on Ross Court



Option 2: Address individual issues with existing building

Remodeling the existing building to accommodate fleet vehicles that no longer fit the current facility is not possible within the current footprint's size. In addition, this option does not address environmental, compliance or safety concerns described above. To make the building CNG compliant would require the addition of a new emergency exhaust system. The estimated cost to make the building CNG compliant is around $1.3 Million

Option 3: Do Nothing:

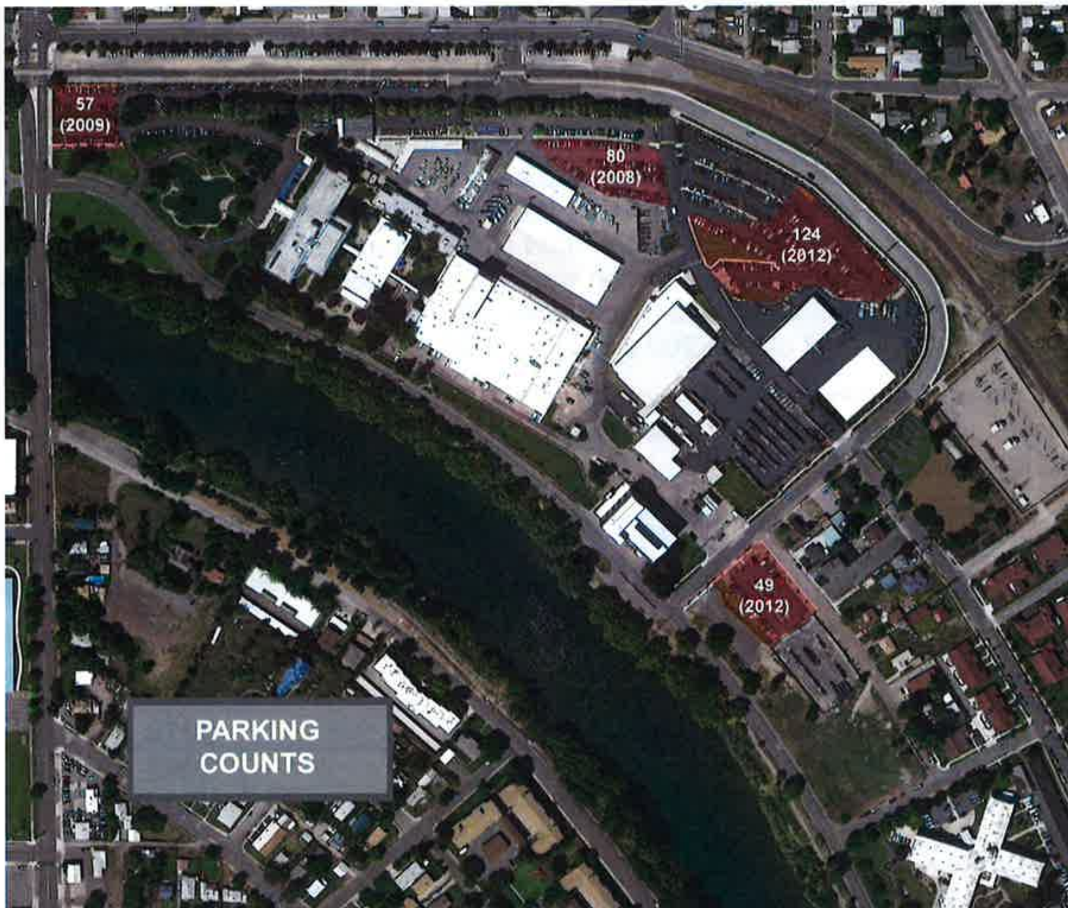
Doing nothing is not a viable option. New hydraulic lifts would be required soon, and basic space, environmental and compliance issues would still need to be addressed. We would need to reevaluate how to continue servicing CNG vehicles.

Project 3: Parking Garage

As of June 2016, Avista has a headcount of approximately 1,280, including company and contracted employees, reporting to the main campus facility. The number of parking spaces available for employees is approximately 728 (not including visitor and disabled parking). Assuming not all employees are on the property at any one time, a minimum of 400 additional parking spaces are required each day to address the current existing need as well as additional spaces for future flexibility. Avista leases parking space along Perry Street from Burlington Northern Railroad (BNR), in an open-ended lease that can be cancelled by BNR with 30 days written notice. Employees walk across railroad tracks to get to and from the buildings and these parking areas. Additionally, loss of this lease would result in the loss of almost 200 parking spaces.

Aligning campus parking with employee count has been addressed through the years by relocating materials storage yards from the campus footprint and adding surface parking lots (see below).

Action Taken	Year	Parking Spaces
Mission Campus Parking Space Count	2008	538
Added Spaces South Mission Lot	2009	+ 57
Added Spaces Transformer Storage Lot	2009	+ 55
Expanded North Pole Yard	2012	+124
Added North Ross Court	2012	+ 49
Total Current Parking Spaces **(including Disability and Visitor Parking)**		**823**
Total Parking Spaces Available **(excluding Disability and Visitor Parking)**		**728**
Estimated Employees/Contractors Assigned to Mission Campus as of June 2016*		1282
Estimated Employee/Contractors e not at Mission Campus on any one day (15%)		-129
Shortage of Parking Spaces to Meet Current Need for Employees/ Contractors Assigned to Mission Campus**		**425****



Using valuable campus real estate for parking lots has required us to take our operations vehicles and materials storage offsite to our Beacon substation property more than a mile away, increasing crew time and resources to access materials and vehicles each day.

This daily deficit in parking is currently absorbed in gravel lots on Ross Court and along the railroad tracks on Burlington Northern Railroad land. This parking is not in compliance with City of Spokane parking code, and we could be required to cease at any time. Additional parking overflow beyond these locations usually takes place in the immediate neighborhoods around Avista, and has resulted in frustrated calls, threats, and visits from our residential neighbors.

The proposed parking garage is intended as a long-term solution to the employee and visitor parking deficiency and related safety concerns.

Safety

With our current parking conditions, employees and visitors face a number of ongoing safety risks:

- The main building and service center, where the majority of regular and contract employees are located, is separated from parking areas by railroad tracks, busy arterials (Mission and Perry Streets), and operations areas, forcing pedestrians to cross these areas throughout the day.
- Operations traffic peaks in the mornings and afternoons, when employees are often walking to or from their vehicles.
- Parking areas are open and must be maintained throughout year to keep lots safe and clear of seasonal conditions. Even with ongoing maintenance, lost work days due to slipping and falls on the main campus (both inside and outside) is estimated at 11,000 days since 1997. In the first quarter of 2017, Avista experienced a record number of slips, trips and falls related to icy conditions.
- While we have full-time security on campus with cameras and patrol staff, there is no security off campus to protect employees, visitors and their vehicles.

Options and Alternatives

We analyzed three primary options for adding up to 500 parking spaces to fully solve the parking issue and give protection against the loss of the BNR leased space:

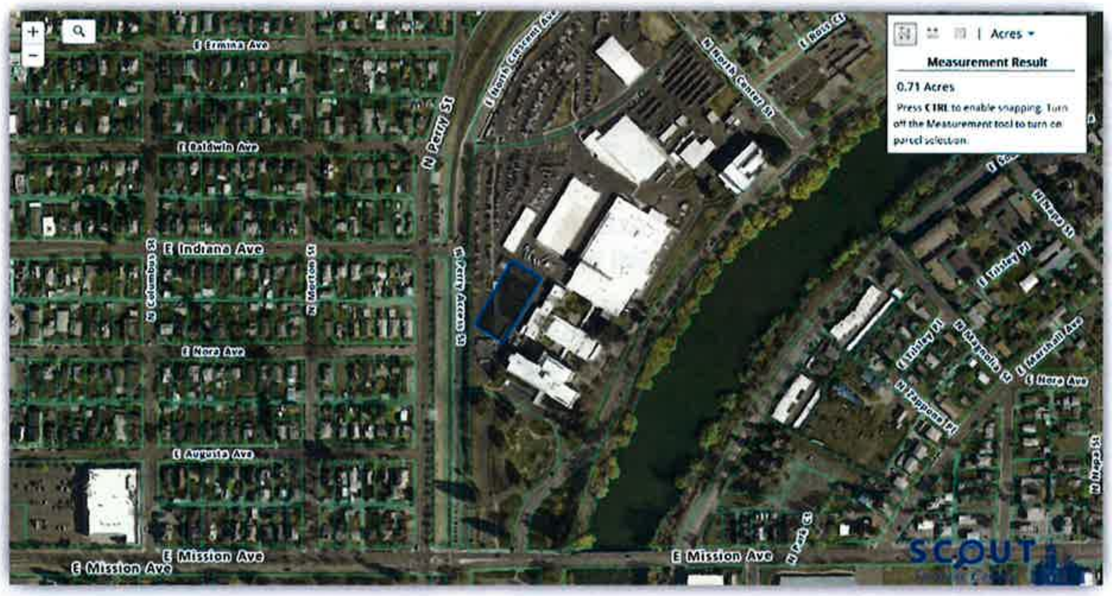
- **Option 1 (recommended)** – Construct a parking garage in the location of the original fleet building. The garage would be a four-story structure with five levels of parking.

- **Option 2** – Convert property at the north end of campus (Ross Court) into parking lots.
- **Option 3** – Purchase properties to the east of campus, across Perry Street, and develop parking lots.

Ross Court Property Options (re-route of North Center Street)	Capital Cost	Start	Complete	Risk Mitigation
Option 1 (Recommended): Build Parking Garage Build a 4-story 500-space parking garage in the location of the existing Fleet Building.	$12,000,000	2018	2018	• Coverage in the event of the loss of BNR leased space. • Employees would not need to park in the neighborhood.
Option 2: Convert Ross Court property into parking to address current deficit Pave the remaining four acres of undeveloped Ross Court property and make a parking lot. Would need to include drainage swales, parking island vegetation, and sidewalks to be comply with city code.	$3,000,000	2017	2018	• Not highest and best use of existing property. Will only net ~175. spaces. • Would impact Fleet construction project as this space is earmarked for the new building. • Risk of impact from losing BNR lease still possible.
Option 3: Purchase properties to the east of Avista to build 500 parking spaces (10 acres required) Purchase 10 acres of property along Perry to the east and develop to create 500 parking spaces.	$16.2M	2016	2017	• Risk of not getting all properties. • Highest maintenance costs (snow removal, crack seal, seal coat, 15-year average asphalt replacement).
Option 4: Do nothing	$0	• Risk of City of Spokane compliance issues with using Ross Park in its current form. This can be called out at any time. • Negative perception from local neighbors due to parking overflow in front of their houses. • Loss of BNR lease would be catastrophic to employee parking with no immediate resolution.		

Option 1 (recommended): Build a 4 story Parking Garage

This option will minimize the physical footprint required (only 0.71 acres). Constructing it in the location of the original Fleet Building will locate parking density next to employee workspace density, maximizing safety and operations efficiency.



Parking Garage Footprint

Option 1 (Recommended): Building a four-story parking garage with five levels of parking	
Positive Benefits	**Negatives**
Locates parking density near employee density.	Customer perception of structure
Will drastically reduce slips, trips and falls experienced by employees walking through 20 acres of existing parking lots each day, reducing risk and L&I claims to the Company.	Possible environmental issues under existing fleet footprint
Majority of parking would now be secured within the Campus.	
Will dramatically reduce the risk to the company from employee and Operations traffic mixing in the north lot areas.	
Lowest O&M maintenance costs, and longest life vs. asphalt lot.	
Lowest snow removal cost vs.10 acres of traditional blacktop.	
Could allow us to repurpose campus real estate back to materials storage.	

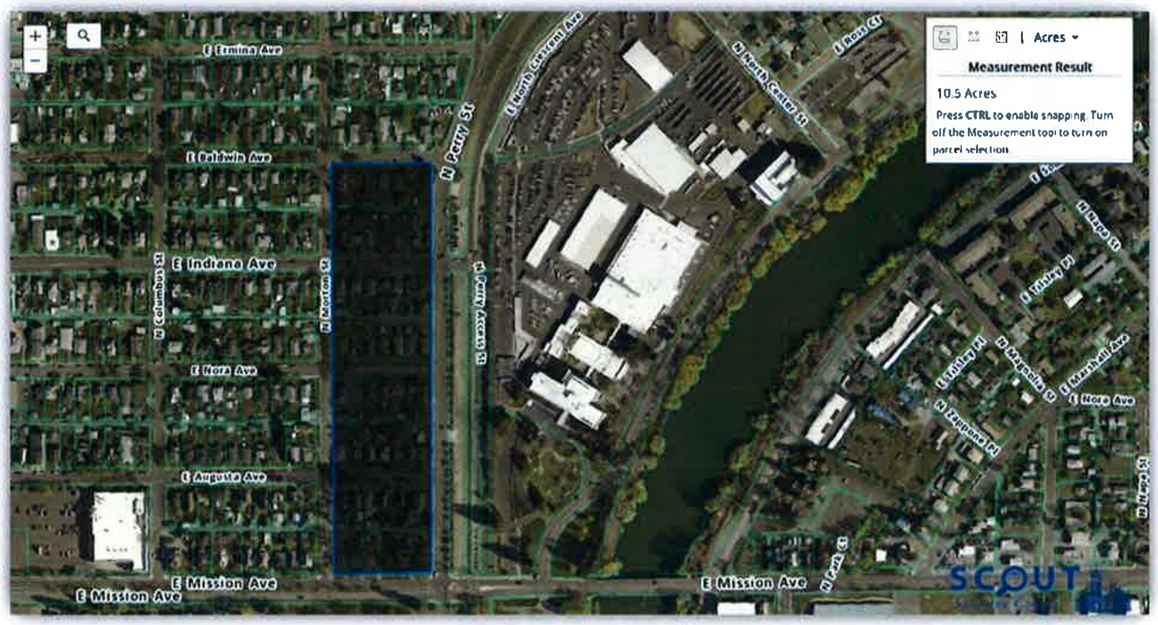
Option 2: Convert Ross Court property into parking to address current deficit

Converting property on the north side of Campus (Ross Court), would only address part of the current parking deficit, with a net of approx. 175 spaces. This solution doesn't address a potential BNR lease loss and would impact plans for the new fleet facility.

Option 2: Pave existing Ross Court properties to be used for parking	
Positive Benefits	**Negatives**
Lower cost vs. recommended	Not highest and best use of purchased properties on Ross Court. High cost vs strategic value (when including property purchases). No option for a new Fleet Building.
Quickest Solution	Solution would only address the current parking deficit, (only net approx. 175 spaces) Doesn't address BNR lease loss.

Option 3: Purchase properties to the east of Avista to build 500 parking spaces

Traditional parking lot construction for 500 spaces would require 10 acres of land to accommodate 208 drainage swales, vegetation for heat island mitigation, and other items required by the City of Spokane. The only available option for adding additional land to the campus would be the properties to the east, on the other side of Perry Street. These would be difficult and costly to acquire, and add additional challenges of expanding the campus into a residential area separated by a major arterial.



500 spots using surface parking construction

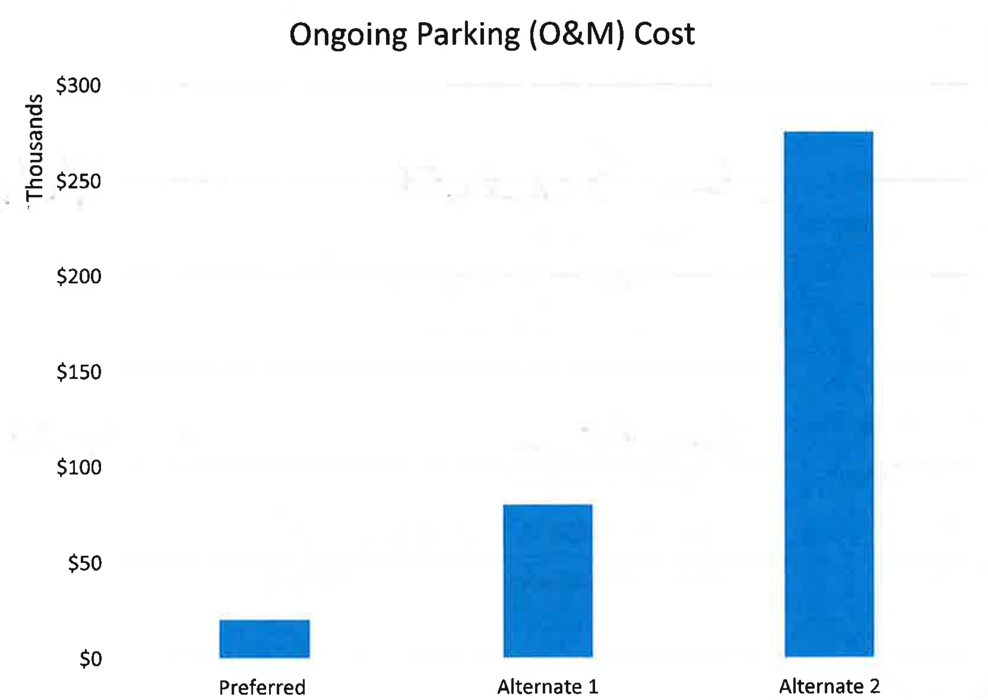
Option 3: Purchase 10 acres to the east and build 500 spaces	
Positive Benefits	**Negatives**
Would net the full 500 spaces	Highest cost option
	High risk of not getting all properties required to build. Risk of street vacations not being approved.
	Increased risk of injury with 500 employees crossing Perry Street daily.
	Highest cost maintenance option, (snow removal, crack seal, sealcoat, complete asphalt replacement every 15-20 years).

Option 4: Do Nothing

This option would not solve the parking deficiency or the problems it has created:

- Operations vehicles and materials storage offsite at Beacon substation property
- Non-compliant parking
- Neighborhood impacts

Do Nothing	
Positive Benefits	**Negatives**
Lowest Cost	Does not address the current parking deficit
	Still out of compliance with current City of Spokane parking code
	Frustration from neighbors due to employees parking in front of their houses.
	At risk if BNR lease is ever lost.



Ongoing O&M costs include snow removal, crack seal, seal coat, and asphalt renewal at 15 years. Parking Garage useful life based on 45 years.

See attached PowerPoint Presentations for high level explanations.

APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Campus Repurposing Phase 2 plan and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ______________ Date: 5/1/17

Print Name: Eric Bowles

Title: Manager, Facilities

Role: Business Case Owner

Signature: ______________ Date: 5/1/17

Print Name: Anna Scarlett

Title: Manager, Shared Services

Role: Business Case Sponsor

Signature: ______________ Date: 4-28-17

Print Name: Heather Rosentrater

Title: Vice President, Energy Delivery

Role: Steering/Advisory Committee Review

VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1	Eric Bowles	04/24/17	Heather Rosentrater	04/25/17	New template

Template Version: 02/24/2017

EXECUTIVE SUMMARY

As an operator of gas infrastructure, Avista Utilities is required by regulation to minimize the impact of safety and integrity of the pipeline facilities due to human error that may result from an individual's lack of knowledge, skills, or abilities during the performance of certain activities, or covered tasks. Craft Training and Gas Operations are responsible for ensuring a qualified and competent workforce. This is partially accomplished by evaluating and qualifying internal and contract employees on Operator Qualification tasks specific to Avista's natural gas infrastructure.

This business case will provide the tooling, vehicles, and equipment necessary to enable internal Avista Evaluators to evaluate Avista "non-peer" employees and contract personnel under the PHMSA regulations for Operator Qualification. Further, the tooling, vehicles and equipment may be used by Avista's Evaluators to maintain proficiency in the tasks required by the program and to design, construct and implement new testing tools, techniques and technologies. Not providing these resources would result in the Evaluators being unable to perform their duties, possibly resulting in regulatory penalties and incidents that impact Avista's customers and the public. This project will support Avista's gas operations in Idaho, Washington and Oregon. The total cost of the recommended solution to support these activities is $185,000 over a 5-year period or $37,000 annually.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Joe Brown*	*Executive Summary Only*	*7/6/2020*	*Business Case 2020 Refresher*
1.0	*Joe Brown*	*Final version for 2020 capital update*	*7/29/2020*	*Full amount approved*

GENERAL INFORMATION

Requested Spend Amount	$185,000
Requested Spend Time Period	*5 years*
Requesting Organization/Department	Craft Training and Operator Qualification [I02]
Business Case Owner | Sponsor	Joe Brown | Jeremy Gall
Sponsor Organization/Department	Human Resources
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Growth and high attrition rates in the Natural Gas industry has led to a workforce shortage of trained and competent personnel. Employing this workforce has resulted in several safety and quality control issues on Avista's natural gas infrastructure.

Currently, Avista Utilities evaluates internal personnel by utilizing loaned employees from Gas Operations to evaluate other peer employees. The utilization of peer craft employees to conduct evaluations is not recognized as a best practice in the natural gas industry.

Further, Avista's Gas Contractors train and evaluate themselves on Avista's covered tasks. These activities are conducted independent of Avista's oversight. Evaluation of contract employees by contract employees, with no utility oversight, is not recognized as a best practice in the natural gas industry.

Recent safety and quality incidents in the field and questionable evaluation practices has demonstrated the need for direct evaluation by internal, "non-peer", Avista evaluators for Operator Qualification. This unbiased evaluation practice will determine the knowledge, skill and ability of personnel and ensure the integrity of qualifications.

The following regulations outline the requirements of Operator Qualification that must be met by Avista as an Operator of a natural gas utility. These requirements apply to both internal and contract employees.

1. Background. 49 C.F.R. §§ 192.803 through 192.809 prescribe the requirements associated with qualifications for gas pipeline company personnel to perform "covered tasks." 49 C.F.R. § 192.801 contains a definition of "covered task." In WAC 480-93-999, the commission adopts 49 C.F.R. §§ 192.801 through 192.809. However, in this section, the commission includes "new construction" in the definition of "covered task."
2. Accordingly, for the purpose of this chapter, the commission defines a covered task that will be subject to the requirements of 49 C.F.R. §§ 192.803 through 192.809 as an activity, identified by the gas pipeline company, that:
    a. Is performed on a gas pipeline;
    b. Is an operations, maintenance, or new construction task;
    c. Is performed as a requirement of Part 192 C.F.R.; and
    d. Affects the operation or integrity of the gas pipeline.
3. In all other respects, the requirements of 49 C.F.R. §§ 192.801 through 192.809 apply to this chapter.
4. The equipment and facilities used by a gas pipeline company for training and qualification of employees must be similar to the equipment and facilities on which the employee will perform the covered task.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The primary business driver for this business case is *Mandatory & Compliance* and the secondary drive is *Customer Service Quality*. Avista must have and execute an OQ Program in order to maintain compliance with laws, rules and regulations. Secondarily, the safety and quality of Avista's gas delivery business is greatly impacted by the testing program carried out through the implementation of the OQ program.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Avista's OQ Program is in its implementation stage and must be funded. Deferring or canceling this funding altogether exposes the company to regulatory risk and possible fines.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The implementation of this new evaluation process for the OQ Program began on June 1, 2020. Monitoring, metrics and reporting will be developed based on this implementation stage. Currently, Avista has more than 350 active contractors that go through testing and evaluation. Lagging safety and quality metrics may be used in the future to assess the success of this change in program execution.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

No studies have been conducted to date. This business case supports an industry "best practice" where non-peer employees with evaluate personnel on OQ tasks.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

NOT APPLICABLE

The proposed solution is to obtain the resources needed for OQ Program evaluation

This is the least cost alternative from a capital perspective when considering the risks associated with outsourcing the OQ evaluations to a third party, or fully funding all tools and equipment.

Option	Capital Cost	Start	Complete
1. OQ Evaluator Tools and Material – Partial	*$185,000*	*01 2021*	*12 2025*
2. OQ Evaluator Tools and Material – Full	*$460,000*	*01 2021*	*12 2025*
3. Outsource OQ Evaluator Program	*$0*	*01 2021*	*NA*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

For the recommended solution (Option 1) [OQ Evaluator Tools and Material – Partial], this amount is based on the estimate of tools and equipment that will need to be purchased and utilized annually in order to support the program. The tools and equipment in this solution will be shared among the Spokane and Oregon locations and there will not be significant duplicate. This will slightly increase O&M expense due to travel and sharing of equipment among evaluators.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

This is a compliance program and there are no O&M offsets associated with the project.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

The greatest impact of this business case is on Gas Operations and Avista's Gas Customer. Gas Operations contracted resources will be tested through this program which may result in safer, higher quality work products. Avista's Gas Customer may receive safer, better service in the areas where Avista utilizes contract personnel for gas work.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

For the recommended solution (Option 1) [OQ Evaluator Tools and Material – Partial], this amount is based on the estimate of tools and equipment that will need to be purchased and utilized annually in order to support the program. The tools and equipment in this solution will be shared among the Spokane and Oregon locations and there will not be significant duplicate. This will slightly increase O&M expense due to travel and sharing of equipment among evaluators.

For Option 2, it is estimated that Avista may need to spend $92,000 annually in order to purchase each evaluator their own tools and equipment utilized for skill evaluations. This would include upgrading existing equipment and replacing all outdated equipment. This includes many of the tools and materials utilized by contractors, such as leak survey and locating, that are extremely capital intensive. We believe the prudent decision is to share this equipment among the evaluation areas and reduce the overall capital spend.

Finally, for Option 3, OQ skill evaluations could be outsourced to a 3rd Party contract resource. This outsourced testing model has been adopted by some peer companies. This option is estimated to cost more than $600,000 in O&M alone, not to mention the risk this option would pose from an employee morale and labor relations perspective. Further, this option does not drive a culture of safety, compliance and quality that we hope to achieve by executing on Option 1.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

Equipment and tools will be purchased on an annual basis and will become 'used-and-useful' during the year as the evaluators implement the resources in the field.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This investment aligns with two of Avista's key Focus Areas of 'Our Customers.' and 'Perform.'.

When it comes to Avista's customers, this program promotes transparency in the safety, quality and integrity of Avista's work product delivered to each customer. The safety and integrity of the gas system depends on a highly skilled workforce, and this program helps ensure these skills meet or exceed Avista's standards. Regarding performance, this program helps ensure customers are served with safe and reliable infrastructure.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Avista must comply with laws, rules and regulations as well as provide customers with safe, reliable gas resources. This program helps ensure the safety and quality of Avista's gas system. As stated previously, this program was implemented on June 1, 2020 and monitoring, metrics and reporting will be developed as part of the ongoing program as it is executed.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Key internal stakeholders include Craft Training, Gas Operations, and Compliance. Key external stakeholders include Avista's Customers and 3rd Party Contractors.

2.8.2 Identify any related Business Cases

NA

3.1 Steering Committee or Advisory Group Information

See the governance process below

3.2 Provide and discuss the governance processes and people that will provide oversight

As a practical matter, the OQ Evaluators [3] will plan their needs for tools, materials and equipment with the Manager or Craft Training &OQ. The team will prioritize their needs and manage the funds accordingly.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The Manager or Craft Training & OQ will be responsible for prioritization, change requests, documentation and monitoring of this project.

The undersigned acknowledge they have reviewed the *Gas Operator Qualification Compliance Business Case* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Joe Brown	Date:	7/29/2020
Print Name:	Joe Brown		
Title:	Mgr Craft Training & OQ		
Role:	Business Case Owner		

Signature:	Jeremy Gall	Date:	7/30/2020
Print Name:	Jeremy Gall		
Title:	Sr. Mgr Safety & Craft Training		
Role:	Business Case Sponsor		

Signature:	NA	Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

1 GENERAL INFORMATION

Requested Spend Amount	$ 4,500,000 (Avista Contribution)
Requesting Organization/Department	Research and Development/ Distribution Operations
Business Case Owner	Kenneth Dillon (Project Manager)
Business Case Sponsor	Heather Rosentrater
Sponsor Organization/Department	Distribution Operations
Category	Strategic
Driver	Customer Service Quality & Reliability

1.1 Steering Committee or Advisory Group Information

- Heather Rosentrater (Executive Sponsor)
- John Gibson (Project Sponsor)
- Curt Kirkeby (Concept Engineer/Project Sponsor)
- Kenneth Dillon (Project Manager, CEF1 and CEF2)
- Mike Diedesch (Project Engineer)
- Washington State, Department of Commerce advisory group

2 BUSINESS PROBLEM

Distributed Energy Resources (DERs) interconnected to the grid and operated by the utility can be optimized to meet the needs of the customer as well as the grid – economies of scope or "vertical values". Sharing the investment in DERs across multiple building owners and coordinated across the grid reduces the investment cost to each building owner as well as provides opportunity to optimize utilization – economies of scale or "horizontal values". Leveraging both economies of scope and scale to derive value out of DERs requires the development of a platform to supervise, control, synchronize and optimize these assets – Avista Distribution System Platform (ADSP).

Micro-Transactive Grid (MTG) is an extension of the ADSP platform to support the optimal utilization of DERs. Rather than optimizing a single building's utilization of DERs, the MTG will leverage building fleets, load diversity, and building management systems to optimize the DERs across the distribution loop network. In addition, the MTG will be designed to sectionalize the load into distinct districts which share common DER assets to improve system resiliency and reduce DER investment requirements.

The opportunity to address these issues is a Strategic opportunity which has a great deal of support from the Washington State Department of Commerce, the Governor of the State of Washington, and Avista's Clean Energy Fund 2 Partners (McKinstry, Itron, SEL, SPIRAE). By enabling the seamless integration of renewable and distributed energy resources, and by leveraging and extending the electric distribution grid infrastructure to support intrastate micro-transactive energy markets, Avista can enhance the role and relevancy of utilities in ways that directly align with the state's objectives for reducing emissions and increasing the strength and competiveness of its economy. New types of energy and energy service models can create opportunities for utilities to act as trusted brokers between providers and consumers – to manage and optimized use, performance, safety, and reliability towards a more responsible, resilient, and sustainable energy future.

A delay in implementing this project could result in a lost opportunity to address these issues and the loss of matching funding from the Department of Commerce.

Avista's analytical partner, the Pacific Northwest National Lab (PNNL), will extend the analysis leading to a valuation of the Shared Energy Economy by simulating a transactive market. In these simulations, a "trading hub" enabling energy transactions between participants will be designed across multiple MTG platforms. Due to the limitation of regulatory requirements, the energy transactions will be simulated rather than executed across the MTG platforms. However, once established, the MTG platforms will operationally be utilized to facilitate the exchange in energy and balance the grid logistics from system capacity, available resources, trading routes, and system stability. The valuation and operation of the MTG Platforms will determine technical, operational, and economic opportunities to deploy DERs across an investment community participating in a Shared Energy Economy.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Implementation of CEF2 Proposal	$8,000,000[1]	05/2018	6/2020

Project Proposal/Solution Overview

Avista and its Partners will control and optimize the utilization of shared DERs across a MTG. The MTG will consist of building management systems, solar panels, and energy storage assets integrated on a loop feed to support a shared model of renewable energy resources for commercial, university campus, and industrial parks.

The MTG project will be deployed in Spokane's University District in order to maximize the impact and visibility of the project. The University District, designated by the Department of Commerce as an Innovation Partnership Zone, is adjacent to Spokane's downtown core. It consists of 770 acres, including the campuses of Gonzaga University, Washington State University Health Sciences Spokane, and programs from Eastern Washington University, Whitworth, University of Washington and Spokane Community Colleges. In addition to higher education, the University District is home to Urbanova, a collaborative effort to create a living laboratory for smart cities of the future.

Avista and its Partners will extend the valuation of DERs into a Shared Energy Economy model. In this model, Avista will be evaluating how a conventional micro-grid and the inherent combination of distributed assets could provide value while connected to the grid or during an islanded condition away from the distribution system. In a Shared Energy Economy, building owners and tenants can share in the investment and benefits obtained by a MTG. The valuation analysis for a Shared Energy Economy is fundamentally trying to show that a non-utility portion of the community can participate in the deployment of local DERs and derive both financial and operational benefits which cannot be realized within the conventional regulatory and utility model. In addition, the Shared Energy Economy can help support the valuation of DERs when compared to traditional centralized generational assets.

[1] Of the $8 million total capital cost, $3.5 million has been appropriated and approved by the Washington State Department of Commerce and will be provided to Avista upon meeting defined Milestones

To provide analysis to demonstrate the above statements, Avista and its partners will develop a set of operational modes for the MTG including both grid connected and grid islanded states.

Two MTG "platforms", or "nodes", will be deployed. The MTG platforms consist of DER assets, control devices, and distribution equipment necessary to integrate, control, and operate the MTG Platform. The projected list of major equipment for the project is listed below:

- 100 kW/350 kWh Energy Storage Asset
- 500 kW/1.5 kWh Energy Storage Asset
- Solar Arrays with total peak capacity between 50 and 125 kW
    - Avista intends to utilize 4-quadrant smart inverters compliant with UL1741A and similar to those compliant to CPUC Rule 21, allowing for extended voltage ride through as well as voltage and frequency grid support
- 2 750 kVA Power Transformers
- Automated Transfer Switches
- MGCS – Micro Grid Control System
- Building Management Systems
- Load Shedding Devices (isolation of critical loads during Critical Resiliency Mode)

Proposed Project Schedule

- Completion of Phase 0 – September 2017 – fully funded by State DOC
- Engineering Design/Interconnect – December 2017
- Procurement of large items – June 2018
- Construction and Installation (solar, battery, distribution system transfer to plant) – October 2018
- Systems Commissioning (control system transfer to plant) – April 2019
- Analytics and Testing – September 2019
- Final Report – December 2019

Strategic Innovation

The innovation of the project's business case lies in the development of a shared economy to reduce the initial cost of the DER assets and to increase the value from the DER assets and their operation. The MTG distributes the cost of distributed generation assets like solar and storage across multiple building or tenant members to reduce the cost of renewable assets per member. This economic model is similar to the Combined Heat and Power (CHP) model which shares the waste heat across multiple buildings by the use of steam pipes. The MTG will supervise and control the renewable assets to coordinate and optimize their utilization across Avista's distribution loop feed between building and assets.

The functionality above is not being met by other vendors or utilities in the industry, thus allowing a significant opportunity for innovation in an open part of the market.

Impacts to Future O&M/Stakeholder Involvement

- Protection

  Initial project design, implementation and construction; no ongoing O&M in addition to the programs in place (relay testing, replacement, etc)

- Spokane Area Engineering/Distribution Engineering

  Initial project design, implementation and construction; no ongoing O&M in addition to the programs in place (project and electrical design)

- Distribution Dispatch

  Project implementation, commissioning and ongoing operation; no ongoing O&M in addition to the staff in place (operation will be assigned to existing staff)

- Asset Maintenance

  Ongoing battery and solar panel maintenance will be addressed through an O&M Agreement with each supplier, and is expected to be less than $100,000 per year

Budget Development

The proposed budget for the project was created and vetted thought the State of Washington Clean Energy Fund oversight committee, with significant input from the CEF1 (Turner Energy Storage Project) budget and actual costs. This allowed the Grant Application to include a budget and request developed with a fair amount of confidence, and provided a stepping stone for the Phase 0 process.

Phase 0, facilitated by Avista and supported by the Partners, was an opportunity to refine the proposed scope and budget of the Project. During a multi month period, Avista and the Partners met numerous times to better understand the scope of each Partner's role and to produce a 30% design document with a more accurate cost estimates. Given the unknown issues that can arise during the deployment of new technology and the experience of Avista and others during the CEF1 implementation, the Department of Commerce was highly supportive of this effort and provided funding during the development process to fund this effort.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Clean Energy Fund 2 – Shared Energy Economy and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 4/24/2018

Print Name: Kenneth Dillon

Title: Project Manager

Role: Business Case Owner

Signature: Date: 4/30/18

Print Name: Heather Rosentrater

Title: Vice President, Energy Delivery

Role: Business Case Sponsor

5/18/18 CPG

Signature: Date: 5/23/18

Print Name: Mark Thies

Title: CFO

Role: Steering/Advisory Committee Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Kenneth Dillon	4/24/2018	John Gibson	4/25/2018	Initial version

Template Version: 03/07/2017

1 GENERAL INFORMATION

Requested Spend Amount	$ 4,500,000 (Avista Contribution)
Requesting Organization/Department	Research and Development/ Distribution Operations
Business Case Owner	John Gibson (Project Sponsor)
Business Case Sponsor	Heather Rosentrater (Executive Sponsor)
Sponsor Organization/Department	Distribution Operations
Category	Strategic
Driver	Customer Service Quality & Reliability

1.1 Steering Committee or Advisory Group Information

- Heather Rosentrater (Executive Sponsor)
- John Gibson (Project Sponsor)
- Curt Kirkeby (Concept Engineer/Project Sponsor)
- To-be-determined (Project Manager)
- To-be-determined (Project Engineer)
- Washington State, Department of Commerce advisory group

2 BUSINESS PROBLEM

This Eco-District Grid Modernization project proposal ("EGM Proposal") will seek to leverage Avista's participation in the Eco-District by utilizing the net-zero, carbon free Catalyst building being constructed in the Eco-District to evaluate how these types of net-zero, carbon free developments impact the energy production and delivery system. Avista will deploy advanced thermal and electric storage assets integrated with load control and inverter technology with an overall objective to develop a control strategy within the Eco-District which balances the competing certification requirements of net-zero, carbon free developments against grid utilization strategies to reduce unnecessary investment in grid infrastructure. This project is branded the Grid To Green ("G2G") Project. The G2G Project assets and analytics will be designed to measure and value how net-zero, and carbon free developments impact the regional and local electrical system production and delivery system. The G2G Project objectives are: (1) to deploy electric and thermal storage assets in the Eco-District to modulate the voltage swings resulting from local intermittent generation; (2) to deploy electric, thermal storage assets with load management control strategies to reduce production, transmission and feeder peak demands; (3) to evaluate the transmission and distribution deferral that may be created through the deployment of the Eco-District combined with control and storage assets; and (4) to develop a social and economic outreach program to incentivize local small business adjacent to the Eco-District to deploy demand response programs.

Business Model Challenge

Avista's core business is centered on providing safe, reliable, efficient and low cost energy to our customers. However, consumers are increasingly asking for value-add energy products and services like self-generation, clean energy and socially responsible buildings.

Electric and Thermal Storage Integration Challenger

Within the last ten years, significant technology advancements have occurred in building mechanical systems to heat and chill building environments. Many of these advancements have evolved around various thermal dynamic processes to store, extract and recycle hot and chilled water. However, these mechanical system advances have been driven to support just the building conditioned environment.

Electrical Transactive Bus

Consumers want to participate in their local economy, which is evident just from the simple concept of local farmers markets. In the energy environment, energy prosumers are wanting to participate in local energy exchanges with renewable. So, what is the local exchange? And how would transactions occur and be valued?

Operational Challenge: Open Source Energy Operating System

Today, the interconnection requirements to deploy controllable Distributed Energy Resources ("DERs") on the grid requires significant engineering resources in order to perform interconnection studies, establish design specifications and deploy control and protection settings. How could we develop a grid platform which would support a "plug and play" type capability to allow for a seamless interconnection of DERs?

DC Bus

The delivery of electrical energy across long distances is more efficiently accomplished with Alternating Current ("AC") power. Current estimates show approximate energy loss in the twenty to thirty percent due to the conversion between AC to Direct Current ("DC"). Would it be practical to centralize DC generation resources like solar and storage in order to reduce these losses? Could a DC system or bus be leveraged by a buildings' participation in the Eco-District in order to address building code requirements for backup generation or lighting?

Extending Benefits to Local Community

The Eco-District development is being built in the East Sprague area of Spokane that has traditionally been economically disadvantaged, and small businesses currently struggle with their bottom line.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Implementation of CEF3 Proposal	$4,500,000[1]	6/2019	12/2022

Project Opportunities for Solution Development

This EGM Proposal contains key components of innovation around the utility business model, grid and control assets, technology platforms and outreach learning programs. For each innovative component, the challenge, opportunities and solution is summarized.

Changes to the Business Model
Net-zero and carbon free developments are expensive and difficult to finance using the traditional capital funding model. The HUB building will centralize electrical, thermal and mechanical assets in order to improve the economic viability of these net-zero, carbon free developments

Integration of Electric and Thermal Storage
Centralizing the electrical, thermal and mechanical components in the HUB provides adequate scale to evaluate the relative impact of these systems on the grid.

Creation of an Electrical Transactive Bus
The HUB and its 480 V bus offers potential to facilitate a local market hub (balancing area) for local exchanges. This 480 V bus in the HUB is common point of coupling of the Eco-District's load and renewable and storage resources.

Operation Through an Open Source Energy Operating System
Avista and a coalition of like-minded utilities are investing in an effort to develop an open source platform that can enable an interoperable framework to interconnect resources to the electric distribution system (branded as "openDSP")The first release of openDSP is currently scheduled for the 3rd quarter of 2019. This platform will enable a variety of grid services similar to that envisioned by the Eco-District G2G Project.

Centering Around a DC Bus
The HUB is being designed with a DC system to tie the Catalyst and HUB solar assets to a common inverter in the HUB which ties to the 480 V AC bus.

Extending Benefits to Local Community
The East Sprague business area receives energy and capacity from the same distribution station and feeders which serve the Eco-District. Could small businesses and the community benefit from the optimization of these feeders? Would the community be able to participate in the renewable energy ecosystem somehow by offsetting demand or through other efficiencies?

[1] With a total capital project cost of $7 million, $2.5 million has been appropriated and approved by the Washington State Department of Commerce and will be provided to Avista upon meeting defined Milestones and $4.5 million is being requested of Avista

Strategic Innovation

Innovative Component #1: Business Model

The HUB will deploy a 480 V bus and switchgear which will pass through electric service to the building owners participating in the Eco-District. For the first time, private investment will be made in utility infrastructure, which would have historically been made by the utility. Also, the Eco-District distributed generation resources ("DERs") will be inter-tied to a 480 V bus which serves the Eco-District load. Ultimately, the HUB's 480 V bus will enable the Eco-District to serve its own load with its generation, creating a unique and new type of business model.

Innovative Component #2: Electric and Thermal Storage

The HUB's centralized thermal storage, boiler and chillers will be combined with electric storage and controller technology to co-optimize value between building efficiency and grid utilization.

Innovative Component #3: Electrical Transactive Bus

Under the G2G Project, PNNL and WSU will develop a combination of market and control strategies to simulate transactions that could occur across the HUB 480 V bus for building tenants. The research goals are to establish the technical and economical capability to deploy a transactive market in the HUB.

Innovative Component #4: Open Source Energy Operating System

The G2G Project control technology will be designed and deployed to adhere to the openDSP platform interoperability specification. This specification requirement will allow the G2G Project deployments to be scalable across the country.

Innovative Component #5: DC Bus

The G2G Project will tie the electric storage assets to the DC bus as a part of its deployment. The control technology will manage assets on the DC bus to optimize values between building and grid services. Metrics will be put in place to determine if the energy savings occur by centralizing the conversion between AC and DC.

Innovative Component #6: Extending Benefits to Local Community

As a part of the G2G Project, PECI will create outreach programs to the local business to gage interest in programs that could reduce capacity requirements on the local feeders. PECI will leverage Urbanova's software platform to advertise options for system reduction programs which would direct specific savings to a neighborhood urban renewal district.

Proposed Project Schedule

Scope Development and Partner Coordination	6/2019 through 6/2020
Asset Procurement	9/2019 through 6/2020
Detailed Engineering Design	6/2020 through 3/2021
Equipment Delivery, Installation and Construction	3/2021 through 6/2021
Systems Integration and Commissioning	6/2021 through 8/2021
Analytics and Reporting	8/2021 through 6/2022

Impacts to Future O&M/Stakeholder Involvement

- Spokane Area Engineering/Distribution Engineering

  Initial project design, implementation and construction; no ongoing O&M in addition to the programs in place (project and electrical design)
- Distribution Dispatch

  Project implementation, commissioning and ongoing operation; no ongoing O&M in addition to the staff in place (operation will be assigned to existing staff)
- Asset Maintenance

  Ongoing battery maintenance will be addressed through an O&M Agreement with each supplier, and is expected to be less than $100,000 per year

Budget Development

The proposed budget for the project was created and vetted thought the State of Washington Clean Energy Fund oversight committee, with significant input from the CEF1 (Turner Energy Storage Project) and CEF2 (Micro-Transactive Grid) budget and actual costs. This allowed the Grant Application to include a budget and request developed with a fair amount of confidence.

Expected Spend Schedule

Calendar Year 2019	$ 500,000
Calendar Year 2020	$ 3,000,000
Calendar Year 2021	$ 1,000,000

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Clean Energy Fund 3 – Eco-District G2G and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ____________________ Date: 6/26/2019
Print Name: John Gibson
Title: Chief Engineer, R & D
Role: Business Case Owner

Signature: ____________________ Date: 6/27/19
Print Name: Heather Rosentrater
Title: VP, Energy Delivery
Role: Business Case Sponsor

Signature: ____________________ Date: 7/30/19
Print Name: Mark Thies
Title: SVP + CFO
Role: CPG

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Kenneth Dillon	5/29/2019	John Gibson	6/05/2019	Initial version
2.0	Kenneth Dillon	6/26/2019	John Gibson	6/26/2019	Included JW revisions

Template Version: 03/07/2017

Scott Morris Center for Energy Innovation Tenant Improvements

1 GENERAL INFORMATION

Requested Spend Amount	$ 4,250,000
Requesting Organization/Department	Distribution Services
Business Case Owner	John Gibson
Business Case Sponsor	Heather Rosentrater (Executive Sponsor)
Sponsor Organization/Department	Energy Delivery
Category	Strategic
Driver	Customer Service Quality & Reliability

1.1 Steering Committee or Advisory Group Information

- *Heather Rosentrater (Executive Sponsor)*
- *Ed Schlect (Executive Stakeholder)*
- *Kevin Christie (Executive Stakeholder)*
- *Jim Kensok (Executive Stakeholder)*
- *John Gibson (Project Sponsor)*
- *Matt Reding (Project Manager)*
- *Mike Diedesch (Project Engineer)*

2 BUSINESS PROBLEM

The Investor Owned Utility regulatory compact was established in the early part of the twentieth century to prevent private light companies from installing redundant infrastructure to serve neighboring customers. In addition, the regulatory compact enabled regulated monopolies to leverage economies of scale both in production and delivery.

With the societal concern regarding climate change, state legislatures are passing laws to regulate the amount of renewable energy contained in the electrical energy mix. In addition, Avista's customer expectations are being shaped by evolving customer experience platforms across retail and other market sectors which set new expectations for how they desire to interface with their energy provider. As a result, the utility industry is experiencing rapid changes in technology relating to customer experience, energy efficiency, and grid interconnection technology.

To be responsive to the evolving customer, regulatory and market drivers, Avista will have to develop capabilities and processes to enable new technologies for customers while continuing to provide safe, reliable, and efficient delivery of energy.

2.1 Avista Utilities Leased Space Occupancy Plan

Avista Utilities is proposing to lease space in the Scott Morris Center for Energy Innovation. The building will reside within an eco-district which will operate as a renewable central plant to deliver a net zero energy and carbon neutral footprint for buildings on the University District South Landing campus, such as the Catalyst building. The eco-district is a private development combining universities, and private industry to address the challenges of delivering clean, efficient and secure energy.

The space leased by the Utility will initially be setup for 3 different functions:

1. **Integrated Test Facility** – To date, a significant barrier to deploying new devices on the grid centers on the development of operational confidence and procedures necessary to integrate into internal utility processes. Avista wants to contribute to the successful integration of these evolving grid edge technologies, which drives our interest in the development of an integrated test facility which can help evaluate and test technologies at all stages of the development life cycle. By collaborating with internal and third party solution providers, the utility can develop operational confidence and knowledge to deploy new devices and resources on the grid, as well as new ways for customers to interact with Avista.

   The space within the integrated test facility will consist of collaborative office, meeting, testing and demonstration areas. The facility will enable the utility to accelerate new grid technology deployment in a safe and cost effective manner. Examples of activities to be performed in the facility include (but are not limited to):
   - Develop and test standard settings for new intelligent grid devices
   - Develop and test new communications architectures and protocols
   - Validate the controls operations of new grid edge technologies
   - Validate device interoperability and software system interoperability
   - Test conformance with cyber security requirements
   - Perform interconnection analysis and develop interconnection requirements
   - Support pilot projects with offline testing and concept validation
   - Enable simulation-based operator training for new types of grid devices
   - Demonstrate new technologies

2. **Energy Efficiency Demonstration** – this space will be designed and used for energy efficiency training, demonstration, and support to enable customers, vendors, and building owners to deploy and measure a variety of new and existing efficiency appliances.

   Examples of activities to be performed in the Energy Efficiency space include (but are not limited to):

   - Showcase new technology that can help Avista customers achieve their efficiency goals.
   - Teaching classes about the different technologies Avista brings in. In addition, the team may host seminars from outside sources.
   - Tool lending library. This tool library will be stocked with data collection tools, IR cameras, and other tools used to assess and measure energy usage and efficiency. The classroom space will be used to train customers on how to use the tools before they check them out.
   - Demonstrations and education sessions on insulation, high efficiency water heaters and heating systems to the commercial customer who wants to improve the buildings environment and reduce their energy load, as well as for designers that are looking to design a building that is sustainable and efficient.

3. **Customer Solutions Usability Testing** – this space will be used to interact with Avista customers (and prospective customers) through usability testing and analytics to better understand why/how they interact with digital channels and how Avista can be a better partner for the choices they make pertaining to their energy usage.

Examples of activities to be performed in the Customer Solutions space include (but are not limited to):

- Test sessions to measure participant's ability to complete tasks on various digital channels (e.g. web, mobile app, screen-less, SMS/Text) or products
- Test sessions that are task-oriented with specified goals on effectiveness, efficiency, and satisfaction. Participants are informed there is no "right or wrong" answer, and encouraged to speak out loud about their thoughts, feelings, intentions, and frustrations
- Test sessions where participants interactions are recorded (audio and video) and displayed live in the observation room for analysis and reporting purposes. Tests are conducted on live applications, beta-versions, digital or paper prototypes, or products
- Storyboarding exercises that map use cases around customer behavior and preferences pertaining to energy usage and digital channels

2.2 Scott Morris Center for Energy Innovation – Avista Utilities Tenant Improvements

This business case includes the cost to design, bid and build the facilities and technology improvements of Avista Utilities leased space in the building. The estimate does not include the lease rate or maintenance agreement of the facility which is included under a lease contract between Avista Utilities and the building owner. This ongoing operational costs for lease, parking, and maintenance will be planned into the appropriate budgets within the company.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Tenant improvement and technology build out of the leased space	*$4,250,000*	*10/2019*	*07/2020*

Proposed Project Schedule

Design Operate Approval	*6/2019 through 9/2019*
ET Fiber Extension to HUB	*6/2019 through 4/2020*
RFP Construction Improvements	*9/2019 through 9/2019*
Construction of Tenant Improvements	*10/2019 through 4/2020*
Furniture Furnishing Equipment	*3/2020 through 4/2020*

Anticipated Impacts to Future O&M

A full O&M impact summary will be provided as part of project deliverables. Below is a summary of anticipated impacts at this time:

- Avista Facilities Department
  - Ongoing O&M pertaining to maintenance and lease costs as defined in the lease agreement
- Avista Enterprise Technology
  - Ongoing O&M costs pertaining to servers, desktop and communication network (operation will be assigned to existing staff)
- Avista Energy Efficiency (Demand Side Management group)
  - Ongoing lease costs for Energy Efficiency space will be funded by the DSM group via the tariff rider process. Tenant improvement capital costs to outfit Energy Efficiency space will be funded by this business case

Budget Development

The proposed budget for the Scott Morris Center for Energy Innovation tenant improvement project was created with Facilities, Enterprise Technology, Energy Efficiency, Customer Solutions, and McKinstry participation.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the ***Scott Morris Center for Energy Innovation Tenant Improvements*** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ________________ Date: Nov 4 2019

Print Name: John Gibson

Title: Chief Engineer, R & D

Role: Business Case Owner

Signature: ________________ Date: 11-5-19

Print Name: Heather Rosentrater

Title: Sr. VP, Energy Delivery

Role: Business Case Sponsor

CPG 11-6-19

Signature: ________________ Date: 11-6-19

Print Name: Mark Thies

Title: EVP, CFO

Role:

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*John Gibson*	*6/17/2019*			*Initial version*
2.0	John Gibson	11/01/2019			Revision to scope. schedule and cost

Template Version: 03/07/2017

Real Time Power System Simulator (RTS)

1 GENERAL INFORMATION

Requested Spend Amount	$ 925,000
Requesting Organization/Department	Distribution Services
Business Case Owner	John Gibson
Business Case Sponsor	Heather Rosentrater (Executive Sponsor)
Sponsor Organization/Department	Energy Delivery
Category	Strategic
Driver	Customer Service Quality & Reliability

1.1 Steering Committee or Advisory Group Information

- *Heather Rosentrater (Executive Sponsor)*
- *John Gibson (Project Sponsor)*
- *Matt Reding (Project Manager)*
- *Mike Diedesch (Project Engineer)*

2 BUSINESS PROBLEM

The proposed integrated test facility, which will reside within the Scott Morris Center for Energy Innovation, has the goal to contribute to the successful integration of evolving grid edge technologies. To date, a significant barrier to deploying new devices on the grid centers on the development of operational confidence, standards, and procedures necessary to integrate new technologies safely, reliably and cost effectively. Simulated grid environments accelerate the ability to develop, validate and operationalize new grid solutions. The Integrated Test Facility requires simulation equipment to meet its goals.

2.1 SOLUTION AND JUSTIFICATION

Enabling a flexible and realistic utility test environment requires specialized equipment, called a real time power system simulator (RTS). The RTS consists of specialized computing hardware connected to dedicated simulation software, plus the ability to interface to equipment being tested. This is known as hardware-in-the-loop simulation (HIL). The proposed solution to the needs of the Integrated Test Facility is procuring an RTS solution. There are 3 providers in the space: RTDS, Opal-RT, and Typhoon HIL.

Figure 1 - Typical RTS setup testing Utility Automation Equipment

"RTS is like a flight simulator for power systems"

The justification for the RTS is based on the needs of the test facility. Traditional power system simulation software serves the purpose of simulating system conditions within pre-planned scenarios, which you can think of like snapshots in time. Real time simulations take that concept a step farther, performing continuous calculations and allowing for system changes to be reflected in real time within the simulation. In this sense, an RTS is like a flight simulator for power systems, where a digital twin of an airplane interacts with a test pilot by responding to their inputs. Avista will have the ability to create a simulation which looks and behaves like a live power system, for the purposes of testing new device and operator interactions with that system, without needing to connect the new devices to the production power system. Safety and productivity are both greatly increased using this method, and the ability to implement innovative solutions for (and with) our customers is accelerated.

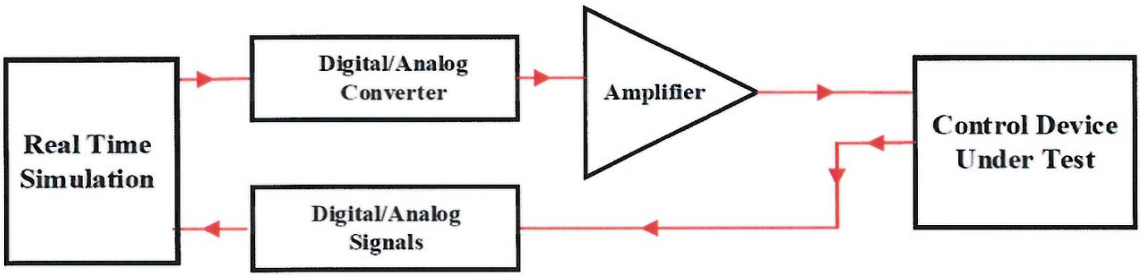


Figure 2 - Functional Diagram for Hardware in the Loop (HIL) testing. Power system conditions are continually updated in real time

2.2 PLATFORM USES

The RTS platform is a powerful tool which can be used by many stakeholders within the utility for a variety of purposes from development, testing, validation and certification. Ideally, any new automated and/or remotely controllable devices connected to the Avista system will undergo a certification process prior to deployment. The following are some examples of activities enabled by the proposed testing platform:

2.2.1 Inverter Controls Design and Testing

Solar and Electric Storage both rely on inverters to create AC power from their DC sources. Testing inverter technology, and the various modes inverters can be placed in, is critical to maintaining a reliable distribution system of the future. Potential inverters could be connected to the Avista test feeder network, where their ability to be dispatched into various modes could be tested, their proper settings could be developed and/or verified.

2.2.2 Communications Architecture Design and Testing

Smart devices on the grid are often communications enabled, allowing for remote controls and data acquisition. The communications architectures traditionally used by the utility are evolving, and new entrants are becoming more prevalent. RTS can aid in communications testing by providing realistic device inputs and allowing users to study the performance implications of different communications designs. Examples include IEC-61850 automation, OpenFMB, Volttron, IEEE 2030.5, OpenADR, etc.

2.2.3 Protection Scheme Design and Testing

One of the original purposes for RTS systems was protection scheme testing. Protective relays continue to evolve, and new protection methods are becoming more popular, such as time domain relays which rely on communications between substations. In addition, communications methods are changing as new technology emerges and older technologies become unsupported by vendors. RTS can help by allowing new types of schemes and systems can be tested against a series of realistic fault scenarios with relay hardware in the loop. In addition to protective relay schemes, the testing can simultaneously validate the security and access methods for relay systems to aid in complying with standards (e.g. NERC CIP).

2.2.4 Validate the controls operations of new grid edge technologies

New equipment proposed to be deployed on the Avista distribution system often has digital controls with a complex set of configurable settings. The RTS system can be used by any team deploying a new type of device to ensure the settings perform as expected. This includes devices proposed by 3rd parties interested in connecting, or internal teams introducing a device which hasn't been previously deployed. Examples include controllable DERs such as EV chargers and building automation systems.

2.2.5 Validate device interoperability and software system interoperability

As part of the RTS platform, we will have a test bed with typical equipment. Connecting potential new devices to this equipment can validate the interoperability between the devices. In addition, if a new software system is proposed which interacts with grid devices, that software system can be deployed to interact with the test environment first, allowing users to verify the interaction is as designed. Examples include DMS, DERMS, DER aggregators, OMS, OpenDSP, etc.

2.2.6 Test conformance with cyber security requirements

Robust cyber security is built in to existing grid automation, but the complexity of keeping systems safe increases with ever increasing amounts of digital devices from an increasing number of manufacturers. The RTS system can be used to help develop/verify cyber security requirements, then ensure that the cyber secure systems still function as designed and performance and usability are maintained.

2.2.7 Perform interconnection and analysis and develop interconnection requirements

Transmission and Distribution interconnections are increasing with renewable energy goals, and with the increasing demands on the power system come new dynamics which need to be accounted for. RTS can help develop requirements and test concepts using its transient analysis capabilities, allowing for proper interconnection requirements tailored for the Avista system to be developed. The end result will reduce the cost of interconnection studies and allow for more renewable energy to be deployed without impacting reliability.

2.2.8 Support pilot projects with offline testing and concept validation

Pilot projects often seek to push the boundaries of how the power grid is designed and/or operated. Thus, they are often seen as a risk by the operational parts of the utility due to fear of the unknown consequences of new operating schemes or devices. The RTS can be used to simulate scenarios, test designs, and validate controls schemes. This will lead to faster innovation without sacrificing operational safety or reliability. Examples include automatic islanding schemes for microgrids and using storage to provide ancillary services.

2.2.9 Enable simulation-based operator training for new types of grid devices

The RTS platform will be connected end-to-end to the DMS system (model office) in order to provide the operators a realistic view of the digital twin feeders. Thus, as new equipment is deployed, we can get input from operators on the interface requirements. Training can use the platform as well, so the first time an operator interacts with a device it is simulated rather than live on the feeder.

2.2.10 Demonstrate new technologies

When a new technology is introduced to the utility, especially if it is grid connected, often there are many stakeholders who never get to interact with it. The RTS platform can be used as a demonstration, education, and training tool for those stakeholders. New ideas can be generated faster as employees from different skillsets learn about the new grid technologies. External stakeholders, such as project partners and utility regulators, can also visit the site to learn about grid devices in a safe environment. This becomes increasingly important as physical security of substations is more stringent than ever and it is not always safe to tour live facilities.

2.3 INITIAL DEPLOYMENT SCOPE

RTS systems are scalable in design, and the cost of the system is dependent on the complexity of the power system being modeled. For the use cases in this business case, a system which can accommodate the modeling of two of Avista's typical automated feeders, back-to-back, will provide a platform for distribution scenarios. The requirement to model 3HT 12F1 and 12F7, with all automated devices, is a 100 node RTS system. A 100 node system will also be sufficient for modeling localized scenarios on Avista's transmission system, with the broader transmission grid being represented by Thevenin equivalents. For both transmission and distribution, the 100 node capable system has enough capability to add simulated future projects like energy storage, inverter-based renewable resources and microgrids.

2.3.1 Hardware in the loop Requirements to Enable Platform Uses

- Real-Time Simulation system with enough processing power to model all control nodes on 2 back to back typical Avista distribution feeders, plus model the addition of any devices being certified and/or tested. To meet this requirement, the system needs the capacity to run approximately 100 nodes.
- Proper analog and digital I/O cards, communication cards, and amplifiers to interface the simulation system with power system hardware IEDs
- Hardware IEDs to represent Avista's standard control devices on the distribution system (feeder breaker relays, voltage regulator controllers, cap bank controllers, recloser relays, switch controllers, ATS relays).
- Network connection to Avista DMS and other Avista operational systems which are to be tested (e.g. DERMS, ADMS, OMS, etc.)
- LAN connections from Test racks to simulation user workstations
- Ability to connect multiple hardware setups (e.g. outside users, multiple internal projects) to a single RTDS then coordinate testing time with the simulator. This involves each project having its own rack space which is not in the same rack at the simulation platform.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Real-Time Power System Simulator	*$925,000*	*10/2019*	*3/2020*

Proposed Project Schedule

Design Operate Approval	*11/2019 through 3/2020*
Equipment and Software Procurement	*3/2020 through 6/2020*
Assemble and Construction	*6/2020 through 9/2020*
Test and Simulate Use Cases	*9/2020 through 12/2020*

Impacts to Future O&M/Stakeholder Involvement

- Facilities

The RTS will be deployed in the Integrated Test Facility located in the Scott Morris Center for Energy Innovation. There are no anticipated impacts to Facilities O&M as part of this installation.

- Enterprise Technology/Distribution Services

The RTS will be procured under this business case and be designed and configured under the Clean Energy Fund 3 (CEF3) business case. Ongoing licensing costs are anticipated as part of the system deployment. Department cost allocation will be determined at a later date as part of this project.

Budget Development

The proposed budget estimate for the RTS project was created and vetted with Facilities, Enterprise Technology, and Energy Delivery departments.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the ***Real Time Power System Simulator (RTS)*** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: Nov 4 / 2019
Print Name: John Gibson
Title: Chief Engineer, R & D
Role: Business Case Owner

Signature: Date: 11-5-19
Print Name: Heather Rosentrater
Title: Sr. VP, Energy Delivery
Role: Business Case Sponsor

CPG 11/6/19

Signature: Date: 11-6-19
Print Name: Mark Thies
Title: EVP, CFO
Role:

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	John Gibson	11/01/2019			Initial version

Template Version: 03/07/2017

1 GENERAL INFORMATION

Requested Spend Amount	$2,000,000
Requesting Organization/Department	Spokane River License Implementation / C04
Business Case Owner	Speed Fitzhugh
Business Case Sponsor	Scott Morris / Dennis Vermillion
Sponsor Organization/Department	President / E01
Category	Strategic
Driver	Choose an item.

1.1 Steering Committee or Advisory Group Information

- Steering Committee:
  - Bruce Howard, Senior Director, Environmental Affairs and Real Estate
  - Latisha Hill, Senior Vice President, Avista Development
  - Anna Scarlett, Director, Shared Services

2 BUSINESS PROBLEM

Avista's Upper Falls Reservoir has been experiencing an increase in non-motorized boating use over the last few years, especially since the standup paddle board became popular, and as other entities (City of Spokane, McKinstry and NoLi) developed formal and informal non-motorized boat launches on the lower and middle reservoir. Additionally, the shoreline next to Upriver Drive and Avista's Mission Avenue Campus has seen a significant increase in transient/homeless camps and other inappropriate uses. The uses associated with the transient/homeless situation have and continue to damage the shoreline and property, as large quantities of litter and garbage are left behind and there are no sanitary facilities. Public safety is also threatened when encounters occur between recreational users and transients or homeless people who camp along the river. Access to the shoreline and river by Centennial Trail users or people who live in the neighborhood is difficult and unsafe, particularly given the speed of traffic along Upriver Drive and the lack of separation between the road and Trail in this area.

In an effort to address the above concerns, Avista plans to develop Upriver Park (Park), which will be situated between Mission Avenue and North Center, and between Avista's campus and the Spokane River. By developing the Park, Avista will address the increase in demand for non-motorized boating use that Upper Falls Reservoir has been experiencing, enhance public and employee safety by eliminating and/or significantly reducing automobile traffic on Upriver Drive, and by thinning and managing the vegetation between Upriver Drive and the river, thereby eliminating camping opportunities for transients and/or homeless in the immediate area. The development should greatly reduce littering, dumping human waste in the area, and should enhance ecological functions along the shoreline, as non-native and invasive species will be replaced with native plants.

Avista will include the portion of the Park that it owns and that provides water-based recreational opportunities in the Spokane River Project Boundary. This is consistent with the Spokane River Project License and FERC approved Recreation Plan, in which Avista periodically reviews the resource and public use within the Project Boundary to determine the need for additional or enhanced recreation facilities and/or opportunities.

If the work is not approved, the area will remain unmanaged with the transient and homeless population remaining a challenge, pedestrian/bicycle conflicts with vehicles continuing along Upriver Drive, and the demand for non-motorized boat access to Upper Falls Reservoir will continue to grow but will not be addressed.

Success will be determined by the lack of homeless camps along the shoreline where the non-native trees have been thinned and the area opened up to the public. Additionally, pedestrian and bicyclists will no longer be in danger from motor vehicles as they move along the Centennial Trail, and boaters will be able to use the new non-motorized boat launch to access the reservoir. Finally, this project will provide access to the River environment for an underserved community, the Logan and Chief Garry neighborhoods. Community meetings have revealed a strong desire to see this project completed and to set an example for the broader revitalization of the entire reach of the River from the Iron Bridge to Upriver Dam. The City of Spokane is among these enthusiasts, including both staff and elected officials.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Develop Upriver Drive Park	$2,000,000	01 2019	12 2020

The Facilities Department will manage the Park as part of the Avista Campus once it is developed. Operation and Maintenance (O&M) costs will increase, however at this time it is not possible to provide an accurate cost estimate, as the Park has not been fully designed. Preliminary costs are expected to range between $30,000 and $50,000 depending on the level of management, i.e. seasonal management, snow removal, final land ownership arrangement, etc. It is important to note that all efforts are being made to develop the Park in a manner that minimizes both short- and long-term O&M costs.

Two options were considered for the Park. One option considered Upriver Drive narrowed down to one-way traffic going north but separated from the Centennial Trail. The other option removed Upriver Drive completely, with just the Centennial Trail bisecting the property. The preferred option is the one that eliminated Upriver Drive, with just the Centennial Trail bisecting the property. It was selected because it is the only one that met all of the Park's objectives. This is the least costly option. This is because demolition costs are equal to the option that retained part of Upriver Drive. The option that retained the north-bound portion of Upriver Drive would cost more because the road would likely have to be reconstructed. Both options would include similar amenities throughout the rest of the Park.

Planning and permitting are expected to occur in 2019, with construction slated to begin and end in 2020. It is possible that certain aspects of the Park project would occur later in 2019.

External stakeholders that will be involved in the Park Project include:

- City of Spokane
  - Park and Recreation Department
  - Park Board
  - Integrated Planning Department
  - Water Department
  - Sewer Department
  - Traffic Department
- Logan Neighborhood
- Riverview Retirement Community
- Friends of the Centennial Trail
- Spokane River Forum
- Spokane RiverKeeper
- Washington State Parks and Recreation Commission (State Parks)
- Federal Energy Regulatory Commission
- City of Spokane
- Washington Department of Fish and Wildlife

The requested amount is related to the cost for demolition of Upriver Drive and for constructing public recreation facilities, i.e. boat launch, trails, plaza, overlook, etc., within the Shoreline Jurisdiction.

IF APPROVED

The project should eliminate or reduce traffic flow and/or speed along Upriver Drive and create a semi-natural riverside park for the neighborhood and for the public in general. Sight visibility to the river will be greatly enhanced, improving public safety and a healthier river ecosystem with the reduction of the dense non-native tree and shrub cover. Boaters will have a formal access site to the Upper Falls Reservoir, which will help disperse use through its entire length, and bank anglers will be able to fish in the river without conflicting with the transient and homeless population that currently takes the area over during the summer and fall months. Use of the Centennial Trail will be easier and safer in the area.

IF NOT APPROVED

The area will remain unmanaged, with the transient and homeless population remaining a challenge, and pedestrian/bicycle conflicts with vehicles will continue along Upriver Drive into the future. The current situation creates costs for Avista and hazards for the public using the Centennial Trail, citizens in nearby neighborhoods, and company employees.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Upriver Park and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Speed Fitzhugh Date: 6/12/19
Print Name: Speed Fitzhugh
Title: Spokane River Project Mgr.
Role: Business Case Owner

Signature: D. Vermillion Date: 6/13/19
Print Name: Dennis Vermillion
Title: President
Role: Business Case Sponsor

Signature: Scott Morris Date: 6-13-19
Print Name: Scott Morris
Title: CEO
Role: Business Case Sponsor

Signature: Bruce F Howard Date: 6.14.19
Print Name: BRUCE F HOWARD
Title: SR. DIRECTOR
Role: Steering/Advisory Committee Review

Laura Vickers Laura -CPG 7/17
Mark Thies 7/31

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*Heide Evans*		*Speed Fitzhugh*		*Initial version*

Template Version: 03/07/2017