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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-23-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-23-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 9
AND NATURAL GAS CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	JOSHUA D. DILUCIANO

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

Avista Utilities Asset Management

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

May 2013

www.avistautilities.com

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

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.

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[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

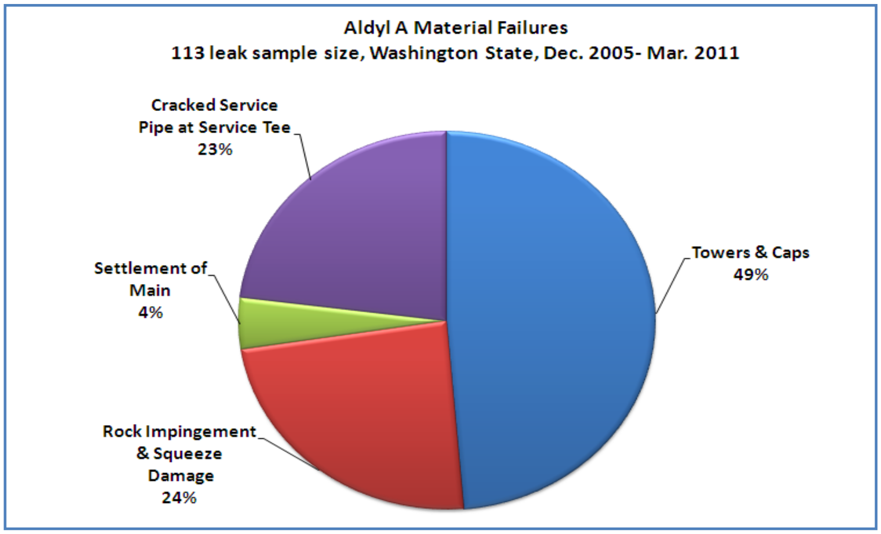
As described briefly above, the Integrity Management approach, now required by law, begins with the aggregation of historical leak-survey data and other facility information relevant to Avista's natural gas piping system. Then, in conjunction with the input of subject matter experts, individual threats 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.

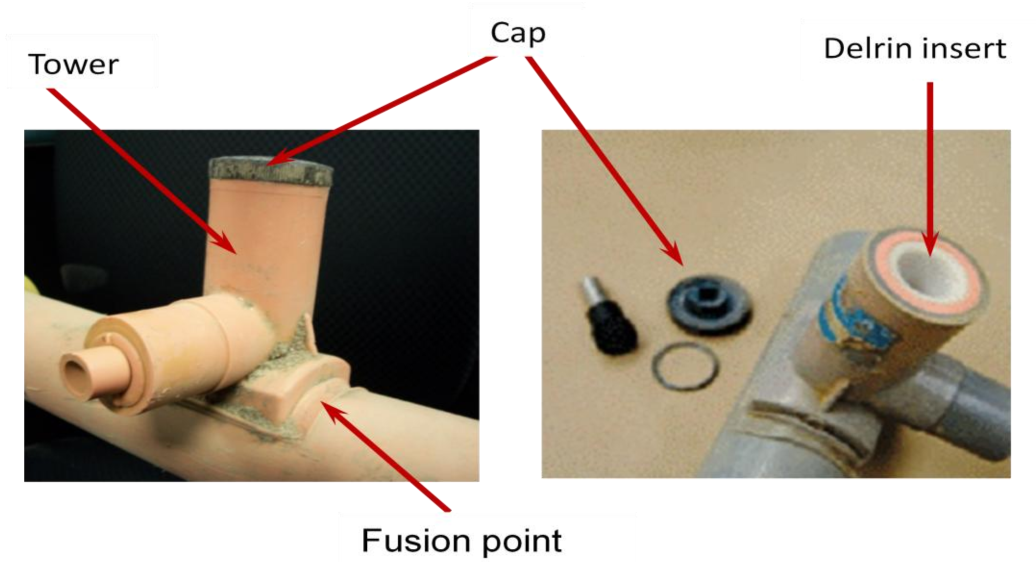
Figure 1. Modes or types of material failures documented in a sample of 113 leaks in Avista's Aldyl A piping in Washington State, December 2005 through March 2011.



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.

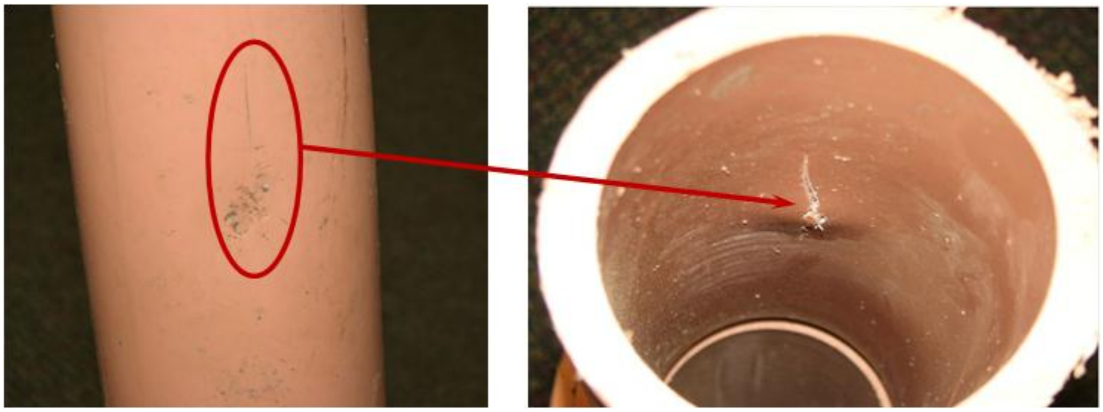
Figure 2. External features and internal components of a typical Aldyl A service tee, as fused to Aldyl A main pipe.



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.

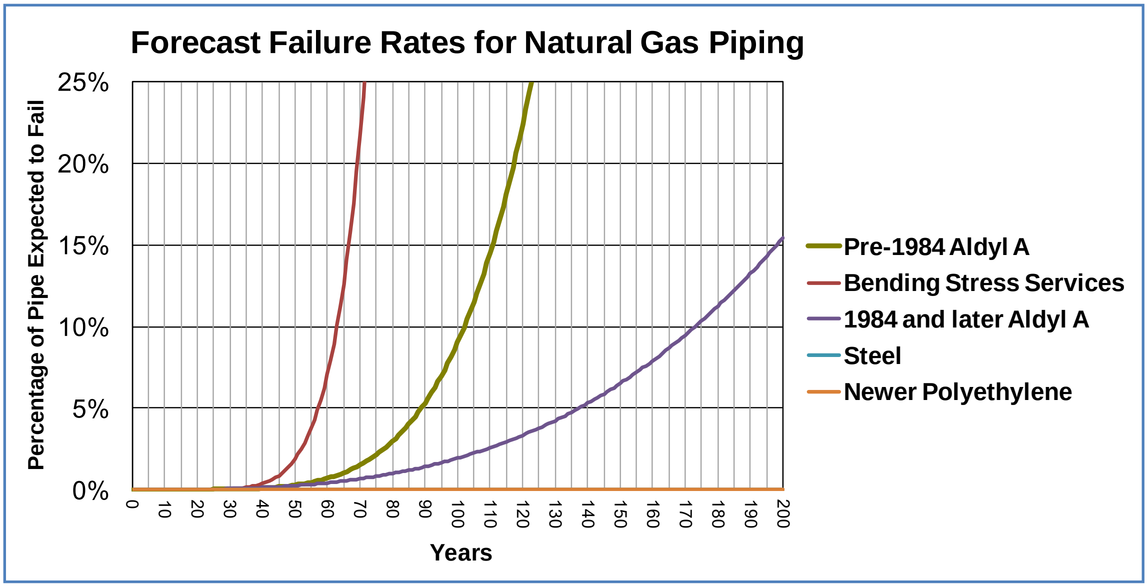
Services Tapped from Steel Mains - Avista identified 16,000 such services in its system, also referred to as 'bending stress tees.' For the reliability modeling, the individual service is the discrete element.

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 80^{th} 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

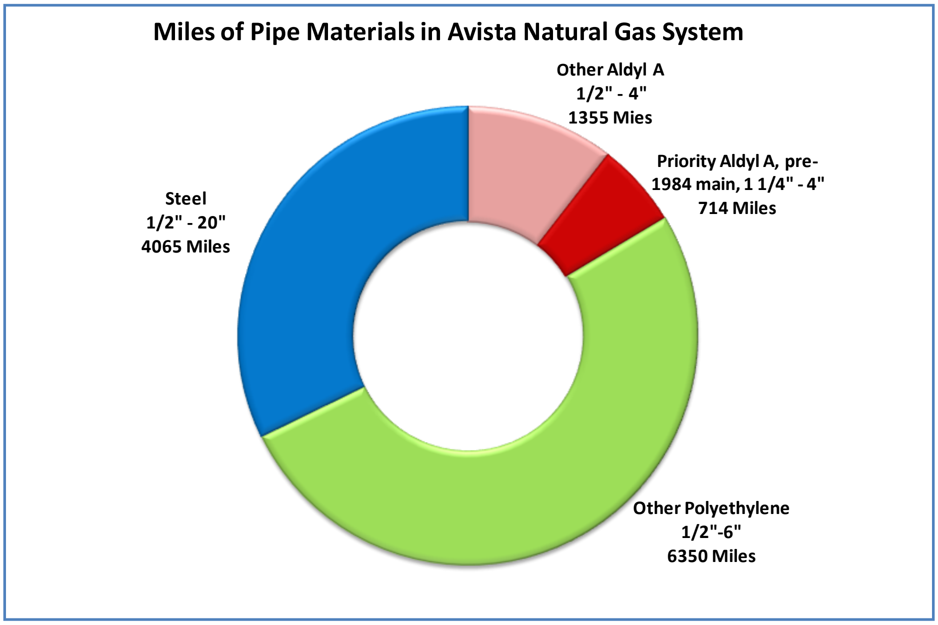
Avista has determined these classes of pipe are at risk of approaching unacceptable levels of reliability without prompt attention. Accordingly, Avista believes the decision to formulate a management program for its priority Aldyl A pipe is both timely and prudent, and is consistent with results of our 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

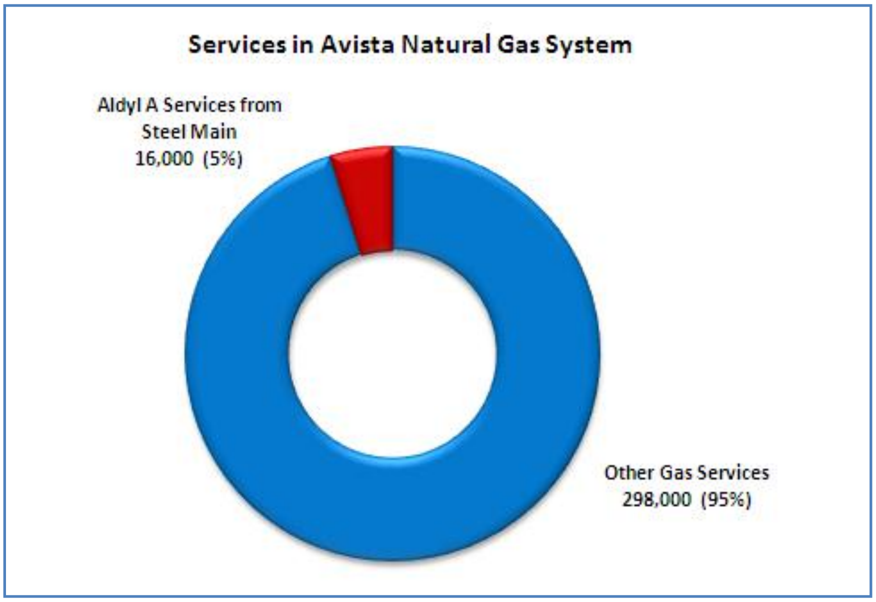
Main Pipe - Avista has approximately 12,500 miles of natural gas main pipe in its service territories in the States of Washington, Oregon and Idaho. Approximately seventeen percent of this total, or 2,000 miles, is Aldyl A pipe of all classes and sizes. Proportions of various classes of piping in Avista's 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.

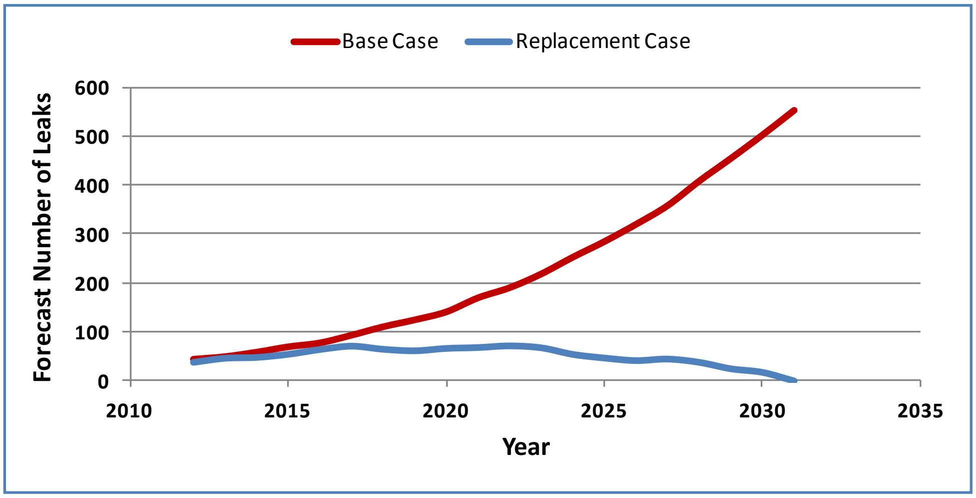
Avista's Integrity Management approach provides the analytical tools that integrate key knowledge and information needed to effectively prioritize replacement activities based on the potential hazard. In the prioritization process, each segment of Aldyl A pipe in Avista's system is assigned a relative 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 Utilities

Study of Aldyl-A Pipe Leaks 2022 Update

Asset Management

9/15/2022

Executive Summary

Avista began a program to replace all its Aldyl-A pipe in 2011 in Washington, Oregon, and Idaho. A regulatory mandate to replace the pipe in 20 years is in place for Washington State (2031 deadline). While not mandated to do so, Avista enabled similar replacement timelines for Idaho and Oregon. The purpose of this report is to provide a regulatory update on progress made. Avista provided similar updates in 2013 and 2018. While not limited to the following, the update's primary intent is to show the amount of pipe removed (to date), the pipe removal costs, and the impact to safety from the remaining Aldyl-A pipe in the ground.

Washington and Idaho, despite rising costs, are on track to have all Aldyl-A pipe replaced by 2031. It is likely the Oregon replacement will not be complete until 2037. Several slowdowns have occurred in Oregon due to COVID-19 impacts, contractor strikes, 3rd party contractor staffing issues, wildfires, and municipal permitting turnaround times. Part of this study/update will target specifically the risk impact of extending the Oregon program out additional years. While all risk cannot be eliminated, the question to be answered is whether the Oregon extension adds substantial risk to Avista's customers living within these service territories.[1]

Scope

The scope is limited to Asset Management providing a review and update on Avista's Aldyl-A pipe replacement program. A key factor in this update is testing whether the remaining ("in use") pipe carries an unacceptable level of catastrophic failure risk that justifies amending the program's existing timeline[2]. Based on risk levels, can the program be extended, in Oregon, to 2037, given the delays noted above? The update will also provide detail on the amount of pipe that has been replaced, the amount of pipe still in active use, and the costs associated with pipe replacement. Benefit/Cost for the program will be discussed and it is noted the primary driver for removing the pipe is the catastrophic risk associated with the Aldyl-A pipe and not whether the program cost justifies itself. Consideration is being given to two failure type modes: service tees and slow crack growth. It is recognized that other failure modes exist, but these two failure modes are unique to the Aldyl-A pipe.[3]

[1] Similar safety criticality test and results will be discussed for WA, ID and OR. However, OR will be looked at separate due to the likely extended timeline (completion by 2037).
[2] Refer to Key Assumptions/Constraints. Availability Work Bench ('AWB') software was utilized to run Safety Criticality tests for the remaining pipe still in use.
[3] Remaining failure modes, considered for the Aldyl-A pipe, would not be all that dissimilar to the replacement pipe being installed.

Regulatory Requirements

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 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. 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 **Public Utility Commission of Oregon** ("OPUC") 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 OPUC by September 30th each year an annual "Safety Project Plan" (or Plan). 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 OPUC'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.

Key Objectives/Assumptions/Constraints

Key Objective:

Utilizing a Safety Criticality test, demonstrate whether an unacceptable risk of catastrophic failure exists on the remaining Aldyl-A pipe. Assuming a test failure, alternative approaches would be considered, including moving up, rather than extending timelines. Through this same test, confirm whether a timeline extension in Oregon is appropriate given the risk parameters set around this program. In addition, provide an update on progress made (to date) and discuss the costs involved with this program.

Key Assumptions/Constraints:

Weibull Curve

- Utilizing data from prior updates, existing leak data, and input from Subject Matter Experts, the Weibull curve parameters were established. Existing pipe data was incomplete for building out the model due to the fact it has yet to complete a full life cycle. Therefore, the existing data set required certain assumptions to be made to build out the model.
    - ETA, 80 years.[4]
    - Beta, 4.[5]
- Unit quantity based on size of Phase replacement. Oregon = 1,025 feet (Phase). Washington/Idaho = 2,000 feet (Phase).[6]

[4] Assumes 63.2% of all pipe sections will have experienced a failure within 80 years of installation.
[5] Beta < 1, Infant Mortality, Beta = 1, Random Failure, Beta > 1, Long Term Failure. In line with 2018 study that used a 3.95 Beta for Rocky Soil and 4.02 for Sand.
[6] A 10,000-foot stretch of pipe would equate to 5 units for WA/ID and 10 units (rounded) for OR.

Failure Mode(s)/Consequences

- Failure modes utilized in this update:
  - Slow crack growth
  - Service Tees.
- Leak data is from 2011 (program start date) to 2021 and was provided by Avista's Manager, Natural Gas Pipeline Integrity.
- Effects (consequence of failure), for modeling purposes, were limited to catastrophic failure. Failures, both catastrophic and non-catastrophic, would require immediate replacement. However, the costs to repair a non-catastrophic failure are immaterial to the overall results, do not impact the Safety Criticality test, and do not provide cost justification for the overall program.
  - Catastrophic Failure cost, $20,000,000.
  - Catastrophic Event occurrence, 1 every 40 years.
    - Redundancy Factor, 0.00125, based on an assumed 20 leaks/year.[7]
- Inspections are successful in detecting leaks but not necessarily preventing future leaks. Therefore, the Potential Failure/Functional Failure (P-F) Interval on leak detection = 0.[8]

Safety Criticality Test

- Safety Criticality Test models the likelihood of a catastrophic failure over a certain time period.
- Test parameter, 1 failure in 40 years.[9]
- Lifetime model simulation, 10 years. Assumes all or most of the remaining pipe will be replaced in the next 10 years; Oregon is likely to be complete in 15 years.
- Test simulation run for each year of the 10-year period. When the next year is modeled, the pipe is aged 8,760 hours (1 year) and the amount of expected pipe to be removed (prior year) is subtracted from the total.
- Oregon replacement assumed to be 15 years. Therefore, residual safety risk exists, for Oregon, after the 10-year run period. Approximately 56 miles of pipe, to be replaced, will remain in Oregon after 10 years.
- Safety Criticality results ≥ 1 = failure.
- Safety Criticality test run separately for Idaho & Washington and Oregon, given the expected different timeline to completion for Oregon.

[7] 28 leaks were detected in 2020 (WA/ID/OR) while 18 were detected in 2021. 20 leak assumption is conservative based on pipe replacement program which reduces mileage annually. Less pipe in the ground assumes fewer leaks.
[8] Assumes a pipe section passes a leak test but could fail as soon as the next day. Inspection does not create safe period for risk avoidance. Test is limited to determining whether an existing leak exists.
[9] For clarification, 1 or greater failures over a 40-year period would indicate a test failure.

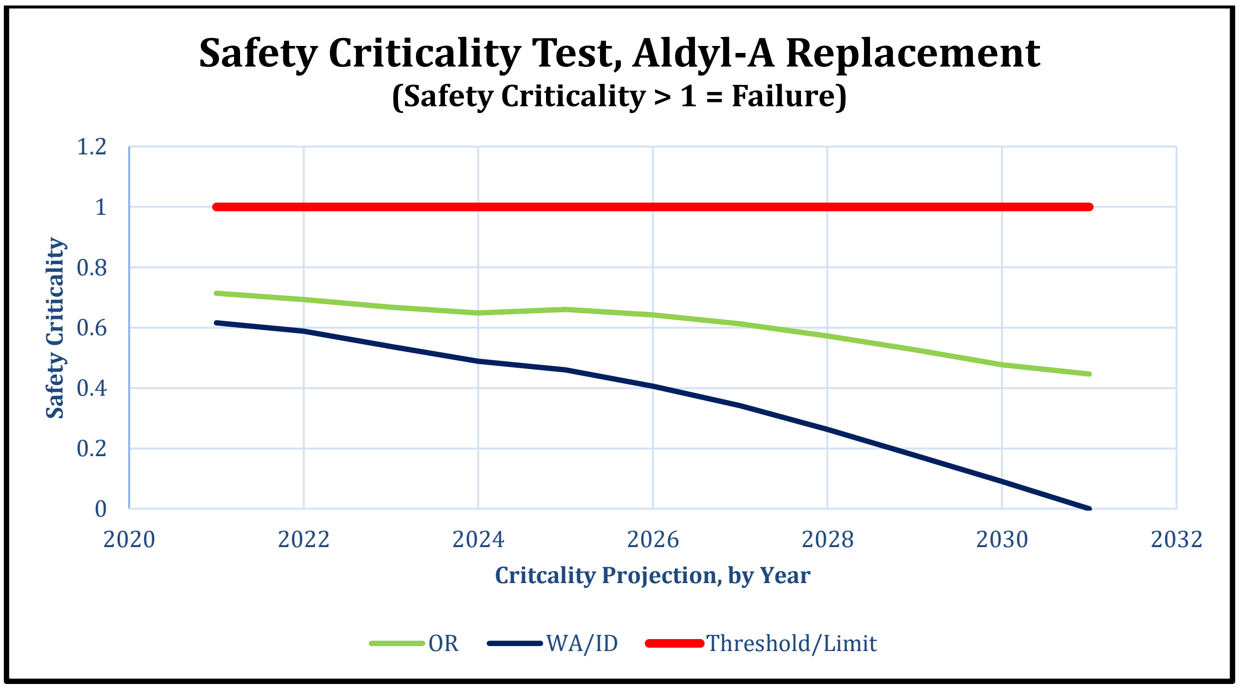
Linear Regression Assumptions

- Linear Regression analysis based on the leak data from 2011-2021.
- All slow crack growth and service tee leaks are included. Additional leaks, not specific to Aldyl-A, are removed from consideration as those leak types would occur with non Aldyl-A pipe.[10]
- Leaks per mile are determined by comparing total leaks to in use pipe remaining (end of year).

Results/Findings

Safety Criticality threshold not exceeded: (<u>Test Passed</u>)

Safety Criticality Test was built in Availability Workbench (refer to Key Assumptions, above). As already noted, the Safety Criticality Test was built around the probability of a catastrophic event occurring in the next 10 years. Based on the replacement schedule, the test is passed in all instances for Idaho/Washington and Oregon. Therefore, a critical failure is highly unlikely throughout the remainder of this program (refer to chart below).



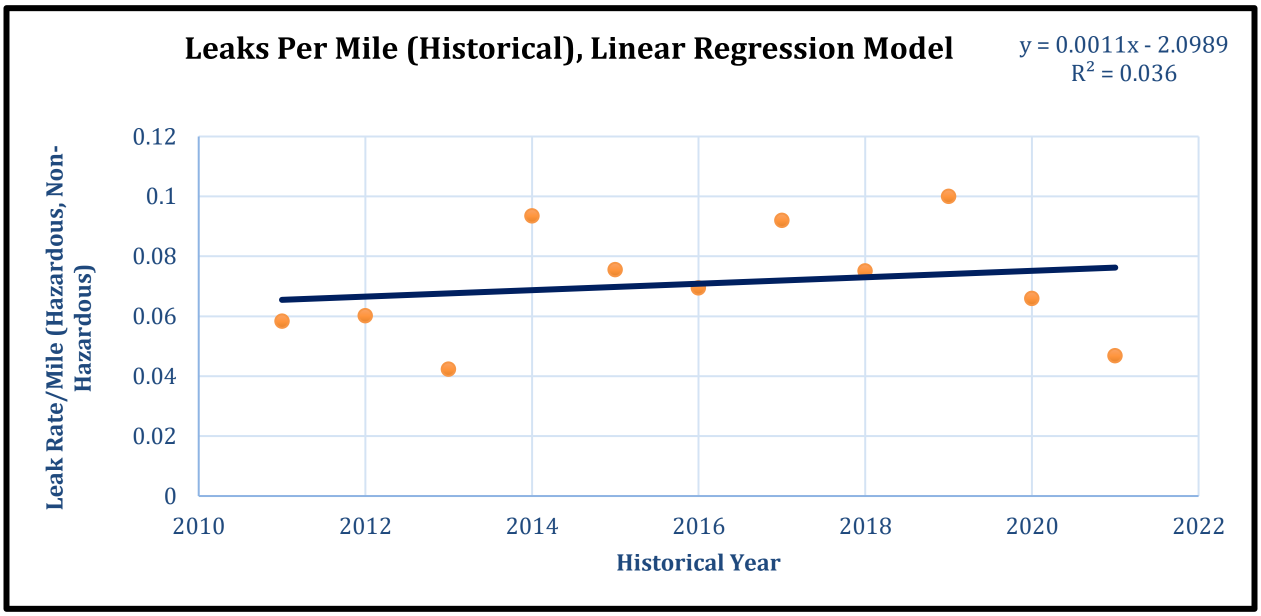
- Safety criticality test success does not eliminate all risk. Rather, the likelihood of a catastrophic failure is unlikely.[11]

[10] Purpose of the study is to isolate those leaks (failures) specific to Aldyl-A.
[11] Safety Criticality Test factors in number of prior leaks, age of pipe and the planned replacement schedule.

- Declining trend supported by pipe replacement. The pipe that is replaced is removed from future test consideration. Example: 300 miles of in use pipe remains. 40 miles is removed in year 1. Year 2 calculation would be based on 260 miles of in use pipe (300-40=260 miles).
- Residual risk remains for OR after 2031 because the OR portion is not expected to be completed until 2037. WA/ID assumes all pipe is removed by 2031.

Linear Regression Analysis shows stable trend and overall risk reduction:

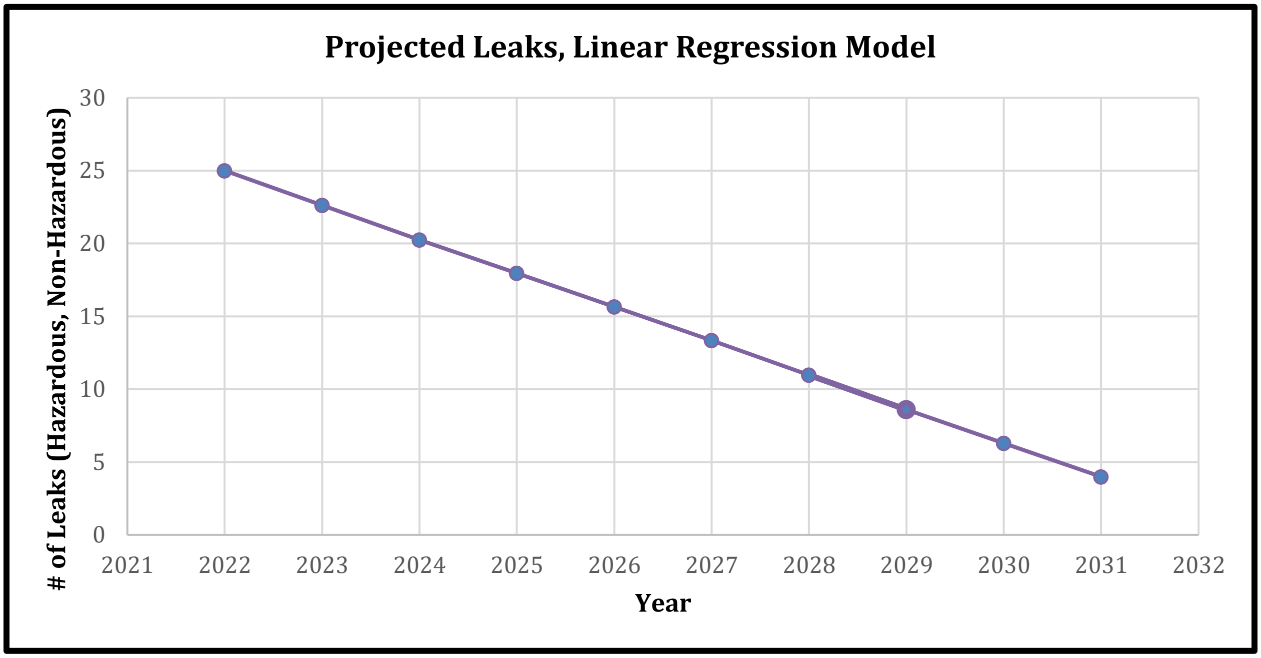
The Linear Regression Model (below) measures the number of hazardous and non-hazardous leaks since 2011.[12] The leak rate per mile can be determined through linear regression. As shown, there has been a slight uptick in the number of leaks per mile but the overall the trend is relatively flat and stable.



- Low R^2 suggests randomness in the data set but is consistent with the age of the pipe (yet to experience long-term wear out, therefore subject primarily to random failures and infant mortality).
- Trend line is relatively flat and while ticking up, it does not suggest a near-term material concern that supports changing the project's timeline.

[12] Linear Regression includes slow crack growth leaks and service tee problems experienced since 2011 for OR, ID and WA (combined). Hazardous and Non-hazardous leaks relate to the immediacy for a response. A hazardous leak does not mean a catastrophic failure has occurred.

Utilizing the linear regression equation (chart, above, top-right), the expected number of leaks can be plotted against anticipated remaining pipeline in the ground at end of year.



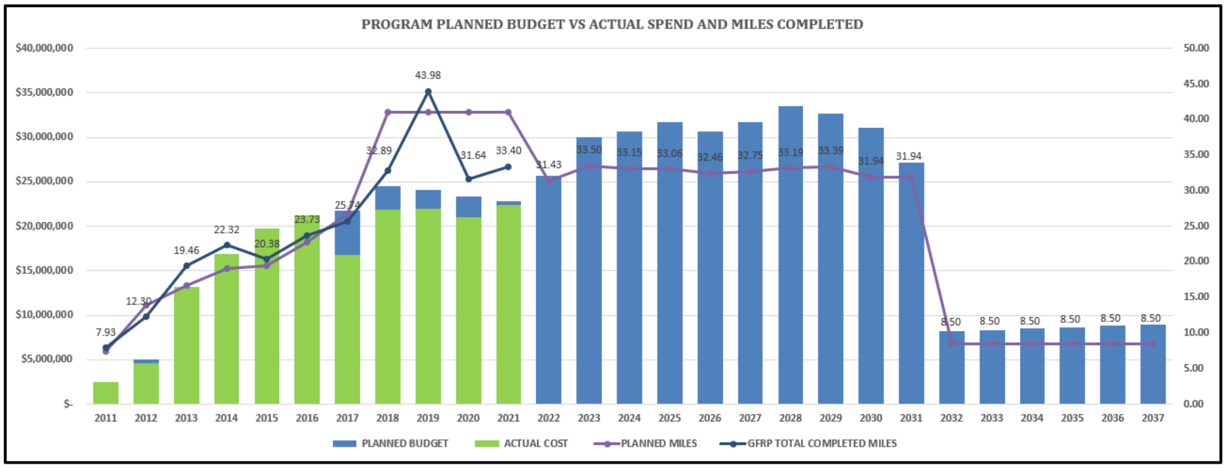
The Projected Leaks, Linear Regression Model (above) demonstrates continued risk reduction through pipe replacement and covers the combined service territory (WA, ID, and OR). The modeling does not indicate a need for any material adverse changes in the program's timeline and supports extending Oregon an additional five years (due to already mentioned delays in Oregon). Risk for a catastrophic failure remains but the chances of such an event occurring are remote. In addition, the leak survey program serves as an additional mitigant as many of the past leaks have been detected, through the program, and remedied.

Program is on schedule to be completed in time in WA and ID. Additional time is needed in OR (2037):

Completion in WA and ID is expected by 2031; the project remains on schedule for both states. Oregon is expected to be completed by 2037. As noted in the Executive Summary, delays have occurred in Oregon due to COVID-19 impacts, municipal permitting delays, wildfire, and 3rd party contractor strikes, to name a few.

The chart below measures mileage completed (to date) and mileage planned against budget costs. [13]

[13] Source: GFRP Historic Program Analysis Asset Management V.2



The table below shows progress in aggregate terms by listing out the amount of pipe in the ground at the end of 2011 versus 2021. It highlights the slower progress being made in Oregon but overall demonstrates the program is on track for completion. It should be noted, however, budgets are tentative and subject to revision, based on[14]:

- Schedules and miles completed (prior year)
- Distribution Integrity Management Plan (DIMP) Analysis
- Budget Constraints

Any material changes in dollar amounts made available to the program could limit its progress going forward.

State	**Pipe Remaining (EOY 2011, Miles)**	**Pipe Remaining (EOY 2021, Miles)**	**Percent Complete[15]**
Washington	353	208	41%
Oregon	253	178	30%
Idaho	131	77	41%
Total	737	463	37%
Opportunity Work		*385*	*48%*

- *Note. As of January 2022, an additional 78 miles of pipe replacement has been completed, outside of the program, through opportunity work done by local*

[14] Budget and actual costs incorporate all planned work within the program: major main work, minor opportunity work, STTR work, priority services, and Aldyl-A replacement (cross bore).
[15] Includes 'Good' miles. 'Good' pipe is pipe that was manufactured and installed in 1985 and 1986 and does not need to be replaced. It is found during the year through potholing and map editing. This amount is combined with the construction completed amount to arrive at the annual total.

districts, pipe verification and map editing. Therefore, the overall project is closer to being 50% complete.

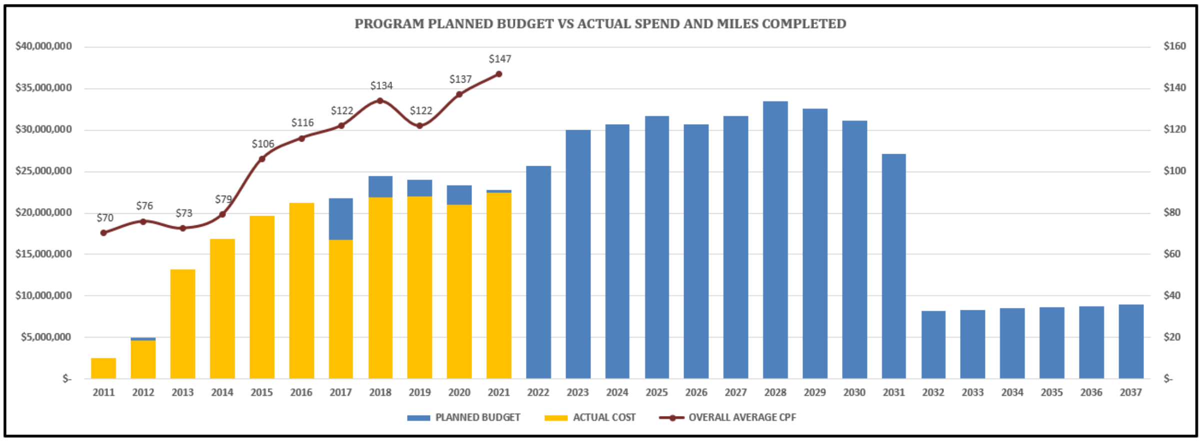
The program is getting more expensive as the cost per foot (CPF) has increased:

Replacing natural gas facilities decades after the initial installation, and after the subsequent development of the service areas is challenging. Replacement pipe must be installed in fully developed and occupied areas that consist of numerous below ground facilities, paved streets, sidewalks, arterials, landscaped residential neighborhoods, and hard-surfaced commercial developments teeming with daily traffic and other activity. New main pipe is most often installed by either "horizontal drilling" or open trenching. While horizontal drilling is far less invasive, both methods require cutting into existing pavement or other hard surfaces. Care must be taken to plan and locate the existing underground facilities to avoid damaging them, new service lines must be ditched into landscaped yards, etc., and all these features must be restored to unblemished service once the installation is complete.

During the first two years of the program Avista reported average per foot replacement costs ranging from $69 to $83 per foot. These costs included pipe replacement in hard-surfaced areas as well as areas of exposed soil, such as the shoulder of semi-rural roadways with limited adjacent facilities and road restoration. More recently, Aldyl-A pipe replacement project locations have been primarily located in suburban developments in which the right-of-way is fully built-out with paved roads and sidewalks and has required increased permitting stipulations. As a result of these conditions, pipe replacement costs have increased. In 2021, the average cost of main pipe replacement was $122/LF (per linear foot), with a low of $ $90/LF in Klamath Falls and a high of $155/LF in the City of Medford.

Avista continued to report its experience with replacement construction costs, in particular, as we experienced a trend on the part of municipalities toward more restrictive and expensive roadway restoration and traffic control requirements. Over the past several years these traffic control, pavement cutting, and remediation policies of local jurisdictions have had a significant impact on the scheduling, logistics, operational methods, extent of the area to be repaved, and the ultimate cost of pipe replacement. In Avista's experience, this continuing trend to enforce more restrictive moratoria on cutting in newer arterials and streets, to require more stringent requirements for backfill and compaction, for patching or repaving of streets cut for pipe replacement, and traffic control requirements have had a substantial impact on installation costs.

The chart below shows the average cost per foot from 2011-2021 for all three states. The actual pipe replacement costs are higher in Oregon. The major element of the total cost disparity is related to road restoration requirements in Oregon jurisdictions. These higher construction costs are a direct result of municipally driven traffic control permit requirements (e.g. plate locks), material handling requirements that include 100% export and import of trench backfill materials (e.g. slurry backfill), significant soil compaction the width of pavement restoration, which averages 4 feet and can range from 2 feet up to 8 feet for segments of a project all which are beyond Avista's direct control.



- CPF has increased steadily since the program's inception.
- The program does not cost justify itself in that the actual and planned spends far exceed the dollar costs associated with a catastrophic failure.[16]

Summary of program changes for Oregon

While taking into consideration the extension of Oregon's Aldyl-A pipe replacement to 2037, there has been extensive analysis and research completed to ensure risk does not increase. As previously stated, various slowdowns have occurred which have impacted program timelines relating to work in Oregon. Impacts such as COVID-19, contractor strikes, contractor staffing issues, wildfires, municipal restrictions and municipal permitting delays have all created significant effects on operations and made replacement efforts much more challenging. Extending Avista's Aldyl-A replacement work in Oregon to 2037 will allow us the opportunity to balance affordability and overall impact to our customers. The data in this report supports that risk is continuing to be mitigated and that extending work in Oregon will not increase the risk of catastrophic failure.

[16] Cost associated with a catastrophic failure is $20,000,000 and is based on the following risk formula to determine its annual value: ***Pf * Pc * c, where Pf = Annual probability of failure, Pc = Annual probability of consequence, and c = consequence cost ($20 million).*** This annual amount can then be measured against the annual spend.

Exhibit No. 9, Schedule 3
Capital Investment Business Case Justification Narratives Index

EXECUTIVE SUMMARY

Avista defines these investments as "customer requests for new service connections, line extensions, transmission interconnections, or system reinforcements to serve a single large customer." We have often in the past referred to new service connects as "growth," as in growth in the number of customers, however, these investments are beyond the control of the Company, and as such they do not reflect a plan or strategy on the part of Avista. Responding quickly to these customer requests is a requirement of providing utility service. Typical projects include installing electric facilities in a new housing or commercial development, installing or replacing electric meters, or adding street or area lights per a request from an individual customer, a city, or county agency. As would be expected, fluctuation in the number of new customer connections is largely dependent on local economic conditions both in the housing and business sectors. New customers are served for electric in WA and ID and gas in WA, ID, and OR.

Both connects forecast and 12-month rolling Cost Per Service information are used to calculate costs directly related to providing service to customers. Electric and Gas devices are also included in this business case - Meters, Transformers, Gas Regulators, and ERTs (Encoder Receiver Transmitter). Many of these Meters, Transformers, and ERTs are used as replacements for Wood Pole Management, and Periodic Meter Changes, for example. The costs are allocated based on an estimate of how many devices of each type will be used for replacement, rather than new connects.

Growth Business Case Funds request:

ELEC & GAS	2023	2024	2025	2026	2027
Connects Forecast: Res & Comm	13,028	12,146	10,900	10,644	10,603
Extensions, Services	75,887,090	69,425,018	64,773,214	63,200,151	62,738,711
Lighting	2,677,439	2,757,762	2,840,495	2,925,710	3,013,482
Meters & Devices	6,516,323	7,875,812	4,667,114	4,767,561	4,938,395
Transformers & Network Protectors	13,316,290	12,407,503	8,758,676	8,531,675	8,392,753
Business Case Total	**98,397,142**	**92,466,095**	**81,039,499**	**79,425,097**	**79,083,340**

The 5 yr average annual spend for this business case has been around $83M. Requests for service are variable in number and in cost, sometimes requiring significant investment for system reinforcements such as gas reg stations and electric distribution infrastructure. This funds request is based on ordinary expectation as supported by forecast and input from electric and gas operations engineers.

For 2023, there are updated impacts to Growth costs, see 2.1 for more detail.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Julie Lee*	*Initial draft of business case*	*6/26/20*	
Final	*Julie Lee*	*Final version of business case*	*7/31/2020*	

Draft	*Julie Lee*	*Draft version of business case*	*7/9/2021*	*Exec summary, Sec 2.1,2.2 updated*
Final	*Steve Carrozzo*	*Business Case for 2023 to 2027 funding*	*10/2022*	

GENERAL INFORMATION

Requested Spend Amount	$430M
Requested Spend Time Period	5 years
Requesting Organization/Department	Energy Delivery
Business Case Owner | Sponsor	David Howell | Josh DiLuciano
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Mandatory
Driver	Customer Requested

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The New Revenue – Growth Business Case is driven by tariff requirements that mandate obligation to serve new customer load when requested within our franchised area. Growth is also seen as a method to spread costs over a wider customer base, keeping rate pressure lower than would otherwise be experienced.

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

Customer Requested: The New Revenue – Growth Business Case serves as support of several focus areas in Avista. We seek to serve the interests of our customers, in a safe and responsible manner, while strengthening the financial performance of the utility. Our growth contributes to strong communities, ongoing value to our customers, and the device portion of the business case keeps our system safe and reliable.

All new customers on Avista's system are benefitted by this business case. In addition, all customers who have their metering or regulation changed, or who have transformers replaced, benefit from this business case.

Transmission Interconnects:

- Periodically, Avista receives requests from 3rd party generation customers seeking interconnection on our Transmission facilities. Two types of customers seek service on our system:
  - First, those who want to wheel on our Transmission system. For this type of customer, Avista receives Transmission revenue for wheeling service. These customers are classified as New Revenue, as the construction costs are offset by ongoing revenues much like new retail customers.
  - The second category of generators are those that sell their output directly to Avista under PURPA contracts. Their output is contained in Avista's gross margin calculation as power supply costs.
- For the first class of customer, a financial analysis shall be performed, as justification for the construction costs to be included as New Revenue – Growth, and the capital so constructed shall be treated as growth for ratemaking purposes.
- PURPA customers' facilities shall be constructed under our existing non-revenue programs.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Avista is required to serve appropriate new load, complying with our Certificate of Convenience and Necessity, and as part of our Obligation to Serve.

The New Revenue – Growth Business Case will provide funds for connecting new Electric and Gas customers in accordance with our filed tariffs in each state.

Our obligation to serve, mandates that we must extend service to new customers in our franchised service areas. We do not currently have an alternative to serving new customers. All projects are subject to our Line Extension Tariffs, filed with each State Utility Commission.

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.

We periodically review and update the line extension tariffs to ensure we are not creating excessive rate pressure in connecting new customers.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

N/A

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
Serve new customer load, and purchase appropriate devices	$79M-$98M per year	01 2023	12 9999
No other alternatives allowed under current tariff	$M	MM YYYY	MM YYYY

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Avista uses a rolling 12-month Cost Per New Service spreadsheet to measure ER1000, Electric New Revenue, and ER1001, Gas New Revenue spending. Device blankets are subject to demand for both new revenue and non-revenue installation and replacement.

Enclosed is a spreadsheet showing projected spend through 2027 with a breakout by Expenditure Request for the New Revenue – Growth Business Case. Connects forecast and 12 -month rolling Cost Per Service information are used. Electric and Gas devices are also included, such as Meters, Transformers, Gas Regulators, and ERTs (Encoder Receiver Transmitter). Many of the Meters, Transformers, and ERTs are used as replacements for Transformer Change Out Program, Wood Pole Management, and Periodic Meter Changes. These costs are allocated based on an estimate of how many devices of each type will be used for replacement, rather than new connects. Those splits are shown on the spending summary.

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.**

As requests for services and lighting are received, design and the subsequent execution processes begin immediately. Similarly, as the gas and electric meters, devices, and transformers needs are identified by program managers and engineers, the purchasing department will place orders.

ELEC & GAS	2023	2024	2025	2026	2027
Connects Forecast: Res & Comm	13,028	12,146	10,900	10,644	10,603
Extensions, Services	75,887,090	69,425,018	64,773,214	63,200,151	62,738,711
Lighting	2,677,439	2,757,762	2,840,495	2,925,710	3,013,482
Meters & Devices	6,516,323	7,875,812	4,667,114	4,767,561	4,938,395
Transformers & Network Protectors	13,316,290	12,407,503	8,758,676	8,531,675	8,392,753
Business Case Total	**98,397,142**	**92,466,095**	**81,039,499**	**79,425,097**	**79,083,340**

There are no offsets to O&M.

[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.

In some instances, providing a service may require build-up of distribution infrastructure to support customer load. These are the Distribution System Enhancements and Distribution Minor Rebuild.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

In some instances, there may be alternative ways to serve a customer. Customer project coordinators and engineers determine the solution that best serves the customer while considering subsequent customers and Avista's infrastructure.

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 timeline is primarily driven by the request of the customer. The transfer to plant occurs monthly.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This business case is about connecting customers to Avista's facilities. The work directly reflects our focus area for customers as well as our mission statement."We must hold our customer's interests at the forefront of all our decisions" and "We improve our customer's lives through innovative energy solutions."

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.

Providing service to customers upon request is mandated. As needed CPC's and engineers review requests to determine solutions that best meet the needs of the customer and Avista. These extraordinary requests lend themselves to more visibility and oversight.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

New customers. For meters, devices and transformers - program managers.

2.8.2 Identify any related Business Cases

3.1 Steering Committee or Advisory Group Information

The Energy Delivery Director Team assumes the role of advisory group for the New Revenue – Growth Business Case, with quarterly reporting to the Board of Directors through the Financial Planning & Analysis department. The appropriate extension and service tariffs are designed and updated by the Avista Rates Department, in cooperation with Construction Services, and the Financial Planning & Analysis department. All Customer Project Coordinators are trained regularly, by Rates and Finance, on tariff application.

3.2 Provide and discuss the governance processes and people that will provide oversight

For the Electric and Gas New Revenue ERs: Operations managers and directors receive monthly Cost of Service reports providing 12-month rolling average costs for the construction areas. This allows for review of trending of costs for decision-making regarding processes and resources.

For the Metering and Devices ERs: Monthly Capital ER and project results reports are distributed. These provide updated variance information facilitating oversight by the Electric Meter Shop and Gas Engineering department.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

This business case consists of many separate requests, primarily independent of each other. Requests for services and extensions are supported by work order documentation. Extensions over $100k are assigned a specific project number to allow for more visible management awareness. Should the forecast for new connects or devices or the average cost of service significantly change from budget, the Capital Planning Group will be notified as to the new spending forecast.

The undersigned acknowledge they have reviewed the Growth 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: 11/14/2022
Print Name: David Howell
Title: Electric Operations Director
Role: Business Case Owner

Signature: Josh DiLuciano Date: 11/14/2022
Print Name: Josh DiLuciano
Title: Vice President - Energy Delivery
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

EXECUTIVE SUMMARY

The Electric Replacement and Relocations (Road Moves) program is driven by compliance that is 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 cost of electric relocations varies slightly year to year. Current funding needs have increased due to additional road projects driven by both additional government funding sources, 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 $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 due to an increase in transportation project spending. So far in 2022 our spend is nearly $3.3m.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.1	*Katie Snyder*	*5 Year Planning Draft - 2023*	*06/10/2022*	
1.2	*Katie Snyder*	*In Year Change Request*	*07/19/2022*	
2.0	*Katie Snyder*	*Business Narrative 2023*	*07/25/2022*	

GENERAL INFORMATION

Requested Spend Amount	$6,950,000
Requested Spend Time Period	1 year
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Katie Snyder | 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 cost of electric relocations varies slightly year to year. Current funding needs have increased due to additional road projects driven by both additional government funding sources, 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

Then major driver of this business case is Mandatory & Compliance. Franchise agreements, typical state highway and Railroad permits, and WA Department of Transportation 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

N/A

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

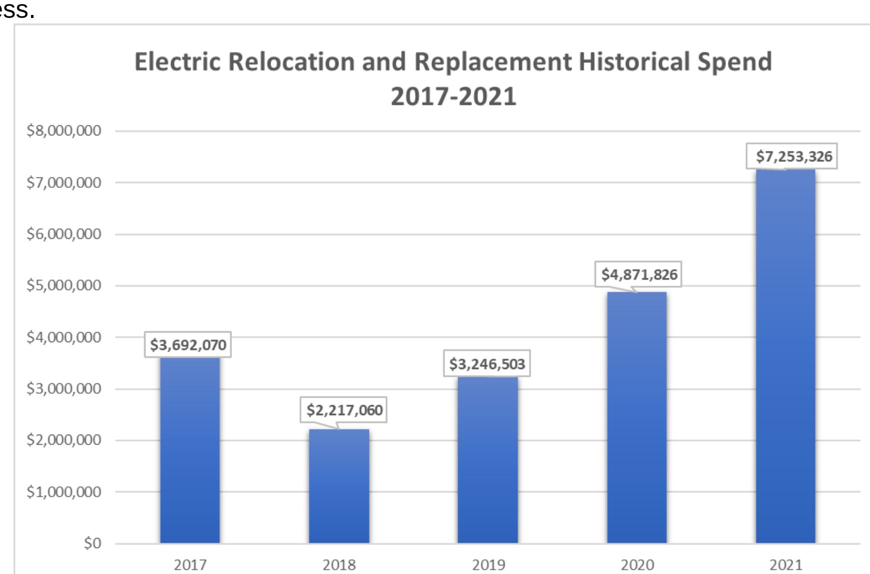
2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Relocate/replace facilities in conflict with street and highway projects where established franchise agreements and/or permits exist.	*$6,950,000 annually*	*Continuous Program*	
UNFUNDED: Avista would be out of compliance with established franchise agreements and/or permits if work is not completed.	$0	N/A	

2.1 Describe what metrics, data, analysis, or information was considered when preparing this capital request.

The Electric Relocations 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 Electric Relocation (2016 – 2020). The average spend over the five years is $3.4 million. Because electric relocations are directly correlated with the number of highway and street projects, the reason for the upward trend in spend is due to an increase in transportation project spending. Significant projects currently planned for the 2022-2026 timeframe total $6M+ per year. This amount is in addition to the costs of the normal course of business.



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 Electric Relocations 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.

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

Control Zone Mitigation

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Electric Distribution and Transmission Relocation and Replacement Program 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 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.

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

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 though the Operations Roundtable (ORT).

For the work: Each office will work with their Area Engineer and impacted jurisdiction/Railroad in determining priority.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Electric Replacement and Relocation 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: Katie Snyder Date: 07/28/2022
Print Name: Katie Snyder
Title: Asset Maintenance Business Analyst
Role: Business Case Owner

Signature: David Howell Date: 7/28/2022
Print Name: David Howell
Title: Director of Operations
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

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 72 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	*Jesse Butler*	*Initial draft of original business case*	*9/13/2022*	

GENERAL INFORMATION

Requested Spend Amount	$6.0M
Requested Spend Time Period	*Year to year*
Requesting Organization/Department	Operations/Joint Use
Business Case Owner | Sponsor	Jesse Butler | 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.

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	*$6.0M*	*Ongoing*	*Ongoing*
[Alternative #1]	*$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 (Jeremiah Webster), Operations Analyst (Joe Wright), Facilitor of the Operations Round Table (Katie Schneider), Manager of Distribution Engineering (Caesar Godinez), Operations Engineers (Brian Chain and Tim Figart), Operations Director (David Howell), and the Joint Use Manager (Jesse Butler). 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 (Jeremiah Webster) and Operations Analyst (Joe Wright) 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 Jesse Butler 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:	Jesse Butler	Date:	9/13/22
Print Name:	Jesse Butler		
Title:	Joint Use Manager		
Role:	Business Case Owner		

Signature:	David Howell	Date:	9/16/2022
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

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 including restoration activity related to MED's of relativity minor restoration impact. Request excludes costs related to very large 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*	
Draft	*Julie Lee*	*Revise Funds Request for 2022 5 yr plan*	*7/1/2021*	*Updated Exec Summ,Sec 2.1*
Final	*Steve Carrozzo*	*Updated Business Case for 2023 to 2027 funding*	*10/14/2022*	

GENERAL INFORMATION

Requested Spend Amount	$6,000,000 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**.

Benefits to Customers
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.

N/A

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
Unadjusted Average - Includes all MED costs; subject to more volatiility in funding needs in the year	*$8,500,000 annually*	*Continuous Program*	
Adjusted Average - Excludes very large MED costs; less volatility in funding needs in the year	*$6,000,000 annually*	*Continuous Program*	
Minimum Funding - Excludes all MED costs; additional funding needed in the year as MEDs occur	*$5,000,000 annually*	*Continuous Program*	

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 (2016-2021) for the distribution/transmission storm business case and YTD 2022 expenses through September. From 2016-2021, the average annual cost for capital storm response was $8.4 million dollars, with a range of $3.6MM (2018) to $14.6MM (2021). There were 7 MEDs in 2020 and again in 2021. The majority of the MED costs in 2021, however, occurred in January, one $7.2MM storm. Consequently, 2020 results were excluded and 2021 results were adjusted downward to exclude the particularly large January storm for determining the proposed funding level. The average spend for 2016-2019/2021 was $5.9MM. This includes some MED activity of comparatively minor restoration impact during these years. Our proposed funding for 2023-2027 is $6M per year. Further funding for significant MED's will be requested as needed.

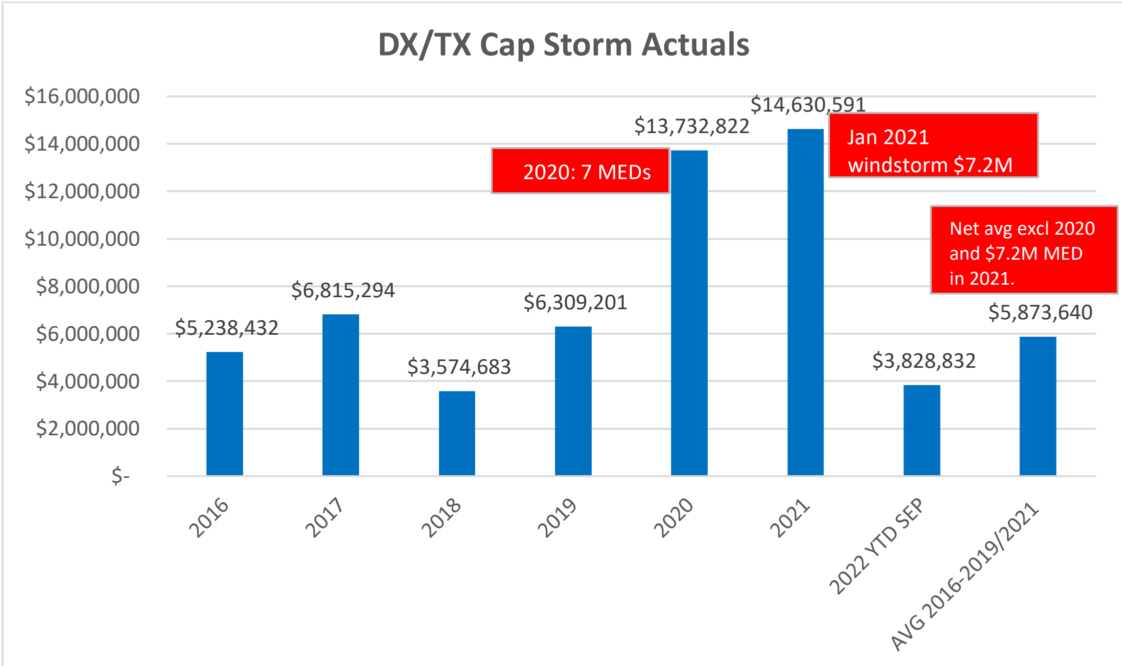


Figure 1: Storm Historical Costs

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. There are no estimated impacts to O&M with this 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.

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 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:	David Howell	Date:	10/17/2022
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Owner		

Signature:	David Howell	Date:	10/17/2022
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 meter minor blanket is used to charge the labor associated with new electric meter installations in Washington and Idaho due to the replacement of failed plant (meters) that can no longer gather or communicate accurate consumption data.

The Meter Minor Blanket Business Case is driven by tariff requirements that mandate Avista's obligation to serve existing customer load within our franchised area. Annual spending is approximately $250k per year.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Geena Duczek*	*Initial draft of original business case*	*09/21/2022*	

GENERAL INFORMATION

Requested Spend Amount	$250
Requested Spend Time Period	1 Year- Reoccurring annually
Requesting Organization/Department	Z08 Electric Meter Shop
Business Case Owner | Sponsor	Geena Duczek | David Howell
Sponsor Organization/Department	A50/Electric Operations
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

1. CURRENT STATE/BUSINESS PROBLEM/RISK

The meter minor blanket is used to charge the labor associated with new electric meter installations in Washington and Idaho due to the replacement of failed plant (meters) that can no longer gather or communicate accurate consumption data. Failed plant is a result of various reasons including but not limited to, age, weather/environmental damage, hardware failure, or radio communication failures. A meter must be installed as soon as possible to accurately capture customer energy consumption data. For this reason, Avista must sustain a continuous stock of each electric meter type and budget the required labor to install these meters. The Meter Minor Blanket Business Case is driven by tariff requirements that mandate Avista's obligation to serve existing customer load within our franchised area.

1.1 What is the current or potential problem/risk that is being addressed?

Replacement of failed electric meters. If the meter has failed the customer will not be able to see their usage data online. This data helps customers make wise decisions on their daily usage and may even encourage conservation.

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.

Major Driver – Failed Plant. It is necessary to have an operating meter to properly bill our customers and provide customers benefits in areas with AMI (Automatic Meter Reading).

1.3 Identify why this work is needed now and <u>what risks continue or develop</u> if funding is not approved or deferred.

The work is required, when there is a failed meter to better understand the customer is facing if there is an outage as well as to properly measure and charge customers for electric energy services.

1.4 Identify measures that will be used to determine whether that the investment will successfully mitigate the problem/risk(s) listed above.

Electric meters are approved by the commission to monitor and charge customers for usage as well as provide customer benefits related to AMI services.

1.5 Supplemental Information

1.5.1 Please summarize and reference any studies that support the problem/risk(s)

Using historical averages, the cost of labor and materials related to meter replacements following failures is approximately $250,000 per year. If the new RIVA meter fails, it likely will not display a read at all, making making reads impossible. Avista can typically can however, identify a failed RIVA meter within days of it failing vs. when the meters were manually read, that could result in a delay of a month or more.

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

2. RECOMMENDED SOLUTION, ALTERNATIVES, IMPACT TO O&M BUDGET AND OFFSETS

Option	Option Desc	Capital Cost	Start	Comp
Replace the meter in kind		*$250,000*	*01/2023*	*Ongoing*
[Recommended Solution]		*$M*	*MM YYYY*	*MM YYYY*
[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.

Request is based on historical trends of replacing failed meter.

Estimated cost of $100+ loaded costs to roll a truck out to check a meter or get a manual read.

Direct Offset - N/A – Replacement of failed plant.

Indirect Offset – Replacement of an older asset with a newer asset. Potential for an extended life

2.2 Describe how the requested capital amount will be spent during the life of the project/program. (i.e. what are the expected functions, processes or deliverables that will result from the capital spend

Funds will be spent in the replacement of failed electric RIVA meters.

2.3 Describe how any other business functions, processes, projects or programs may be impactedby the recommended solution.

The replacement of failed meters supports the billing department to enable them to properly bill customers for usage as well as enables the customers to obtain the benefits from the Riva meters.

2.4 Discuss each alternatives that was considered, the benefits, risks, ROI, and potential offsets for each alternative

Refurbish and repair in-house: This is no longer a viable option. To refurbish and reuse the RIVA meters, they must be sent back and rebirthed through Itron. When these refurbished meters come back to Avista and get deployed back into the field, they do not mesh to the HES or perform correctly.

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.

This business case is a program that is ongoing each year. Transfers to plant occur monthly.

2.6 Discuss how the recommended solution aligns with strategic vision, goals, objectives and mission statement of the organization. How does it benefit the customer (external/internal).

This work is required to ensure Avista properly bills our customers for electric energy consumption and meets the

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

2.8.2 Identify any related Business Cases

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The meter minor blanket business case is reviewed as part of the Operations Round Table (ORT) capital project steering committee monthly.

3.2 Provide and discuss the governance processes and people that will provide oversight

The manager of the electric meter shop is responsible for director oversight of the business case and to ensure project charges are appropriate. The overall business case performance is the responsibility of the Electric Operations Director and administered through the Operations Round Table capital project steering committee.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Changes to the process to manage the business cased will be documented within this business case.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Meter Minor Blanket 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:	Geena Duczek	Date:	10/17/22
Print Name:	Geena Duczek		
Title:			
Role:	Business Case Owner		

Signature:	David Howell	Date:	10/17/2022
Print Name:	David Howell		
Title:			
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

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 energy losses due to inefficiencies due to age and vintage of materials and technology, increased outages that take longer to restore and fall short of modern expectations that utilities face.

The Grid Modernization Program is a capital program that was established in 2013 to holistically evaluate and address the improvement of Avista's approximately 11,3000 circuit miles of overhead and underground primary electric distribution infrastructure. The goals of the program address service reliability and cost avoidance.

Service Reliability
Increase system and service reliability through targeted replacement of aging and failed infrastructure, removal of low reliability equipment and construction practices, relocation or reconfiguration of high risk outage locations, and the addition of devices and equipment that improve service continuity.

Avoided Costs
Increase energy efficiency efforts through the replacement of equipment and materials that have increased energy losses, improvement of line losses through voltage and VAR optimization, load balancing, and the addition of devices and equipment that improve circuit efficiency.

The program was updated and approved in 2020 with a recommended solution based on an updated average cost per mile requiring a $28.88M annual investment to achieve a 60 year cycle. $77M in funding was requested over a 5 year duration as a ramp up to recommended funding levels. Since approval, priority and resources have been re-allocated to mitigate wildfire risk which includes approval and execution of Grid Hardening projects under the Wildfire Resiliency Program. The Grid Modernization program schedule was updated to account for reduced budget allocation by extending project design and construction duration.

Upon the completion of GMP projects, Washington and Idaho 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 Avista's Wood Pole Management Program (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.

This Business Case plan was created by the Business Case Owner and Sponsor, the Asset Maintenance Manager and Grid Modernization Program Manager and approved by Business Case Owner and Sponsor.

VERSION HISTORY

Version	Author	Description	Date	Notes
3.0	*Robb Raymond*	*2022 Business Case Update*	*9/2/2022*	
2.0	*Heather Webster*	*2020 Business Case Update*	*7/31/2020*	
1.0	*Laine Lambarth*	*First Grid Mod Business Case submission*	*4/14/2017*	
0.0	*Troy Dehnel*	*Grid Modernization Charter*	*5/29/2013*	

GENERAL INFORMATION

Requested Spend Amount	$10M
Requested Spend Time Period	5 Years
Requesting Organization/Department	Asset Maintenance
Business Case Owner | Sponsor	David Howell
Sponsor Organization/Department	Asset Maintenance
Phase	Execution
Category	Program
Driver	Performance & Capacity

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The Grid Modernization Business Case (GMP) was developed to address the aging and failing infrastructure found throughout the electric distribution system. Other issues that are 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, 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 and the benefits to the customer

The GMP business case is driven by asset condition, performance and capacity. Customers benefit from improvements in electric distribution infrastructure in the following ways:

Grid Reliability
Replacing aging and failed infrastructure that has high likelihood of creating customer outages. This also increases unplanned callouts which cost more than planned work. Ultimately higher costs associated with this are passed on to the customers.
Without programs like Grid Modernization and Wood Pole Management, there would be an average of 40 pole failure events per year effecting an average of 80 customers for 4.8 hours per event. The total customer impact value of these events is approximately $24,000 per event totaling $960,000 per year. *(2017 Wood Pole Management Program Review and Recommendations, Rodney Pickett).*

Energy Efficiency
Replacing equipment such as old or undersized conductor and transformers that have high energy losses with new equipment that is more energy efficient and with better performance.

Operational Ability
Replacement of conductor and equipment that hinders outage detection and install automation devices that enable isolation of outages.

a. This leads to shorter duration of outages for customers because areas that have failed can be more quickly identified and there is a potential to reroute power automatically.
b. Installation of automated line devices on a feeder of 1,600 customers reduces an average outage duration from 3 hours to 5 minutes for 1,200 of those customers.
c. Potential reduction in hotline holds.

Safety
Focus on public and employee safety through smart design and work practices.

a. Replacing aging and failed infrastructure puts employees and customers at risk
b. Infrastructure is brought up to current National Electric Safety Code
c. Eliminating PCB risk to the public and environment by eliminating transformers with known PCBs.
d. Lowers risk of high severity safety (S4) events, defined below as follows
    - Having potential for multiple serious injuries or loss of an individual life, major damage to property or business, and a public health infrastructure impact up to 72 hours.
    - Base case (do nothing) has the risk of 10 S4 events every 50 years with a total cost of $52.3 million. Grid modernization brings this risk down to 2 events in 50 years with a total cost of $10.4 million (2017 Wood Pole Management Program Review and Recommendations, Rodney Pickett.
e. Address Washington State's Department of Transportation (WSDOT) Target Zero requirements, which states that utilities move all non-breakaway structures such as power poles and pad mount transformers out of highway clear zones as defined in the 10/2005 AASHTO "A guide for Accommodating Utilities Within Highway Right-of-Way". Washington law requires that this task is completed by 2030. Additional control zone justifications are included in following Washington Administrative Codes (WAC) and Revised Codes of Washington (RCW):
    - WAC 468-34-350- Control Zone Guidelines
    - WAC 468-34-300- Overhead Lines Location
    - RCW 47.32.130 Dangerous Objects and Structures as Nuisances
    - RCW 47.44.010 Wire and Pipeline and Tram and Railway Franchises- Application- Rules on Hearing and Notice
    - RCW 47.44.020 Grant of Franchise- Condition- Hearing

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

CEMI3 is the percentage of customers experiencing 3 or more interruptions per year. The data shows 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.

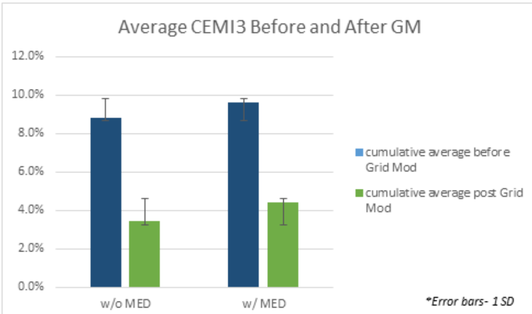


Figure 1.2A: Average CEMI3 on feeders that have been fully addressed by GMP. This includes all the feeders completed through the end of 2018.

SAIFI is the **S**ustained **A**verage **I**nterruption **F**requency **I**ndex. The data shows that customers on feeders addressed by the GMP experience a 51% reduction (with MED) and a 64% reduction in the duration of power interruptions.

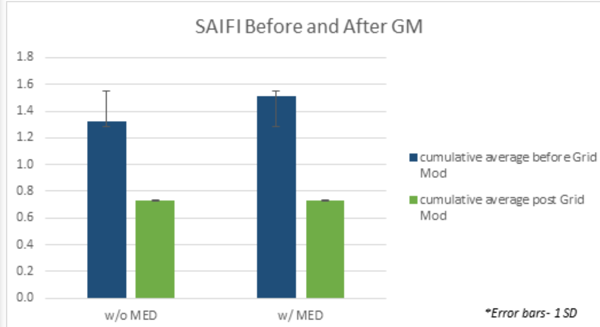


Figure 1.2B: SAIFI before and after Grid Modernization on feeders completed through the end of 2018.

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.

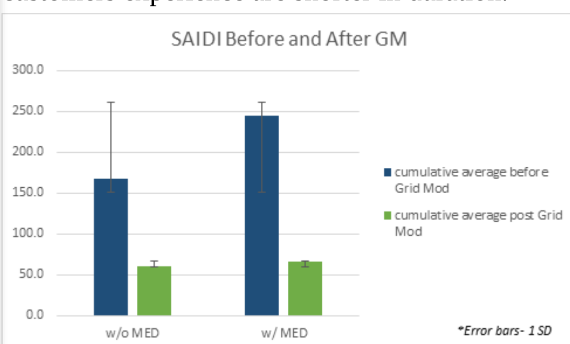


Figure 1.2C: SAIDI before and after GMP for feeders completely addressed by the end of 2018

CAIDI is the **C**ustomer **A**verage **D**uration **I**ndex, 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.

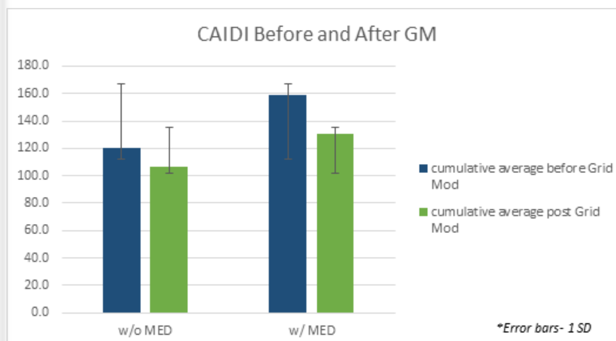


Figure 1.2D: CAIDI before and after being addressed by the Grid Modernization Program.

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, continued 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.

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, then select the specific feeder folder in question, and finally the ~Admin and Wood Pole Mgmt folders.

Feeder Assessment, Selection and Grid Modernization Execution

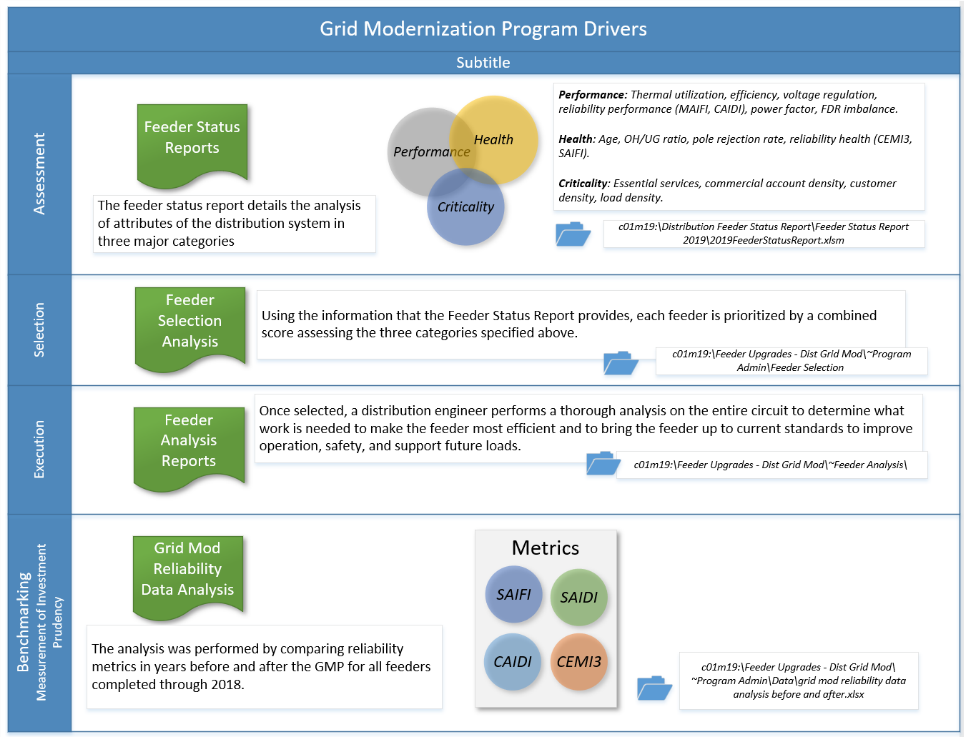


Figure 1.5 – Feeder Assessment, Selection and Execution Summary

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
[Recommended Solution] Follow Scope as stated in the Business Case and extend schedule thus reducing 5 year budget request. Priority and resources have been re-allocated to mitigate wildfire risk which includes approval and execution of Grid Hardening projects under the Wildfire Resiliency Program. Revise funding request down to $10M over 5 years to reflect change in capital prioritization.	$10M 5yrs	01 2023	Perpetual
[Alternative #1] Follow scope as stated in the Business case and follow the budget and timeline request stated in the 2020 BCJN as the recommended solution. The 2020 BCJN recommended solution was based on an average cost per mile requiring a $28.88M annual investment to achieve a 60 year cycle.	$28.88M Annually	01 2023	12 2072
[Alternative #2] 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	01 2023	Perpetual

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Reference key points from external documentation, list any addendums, attachments etc.

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. The artifacts stated in section 1.51 and summarized in Figure 1.52 where used to develop a feeder list to address and resulting design and construction work plan.

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 2023 through 2026 plan addresses approximately 30 circuit miles on the following feeders that have been designed.

Beacon (BEA12F2)	Moscow (M15514)	Spokane Industrial Park (SIP12F4)	Orofino (ORO1282)	Ross Park (ROS12F4)	TBD (2027)

The capital cost of the Program is spread across numerous projects that typically span at least two years in a process summarized in Figure 2.2.

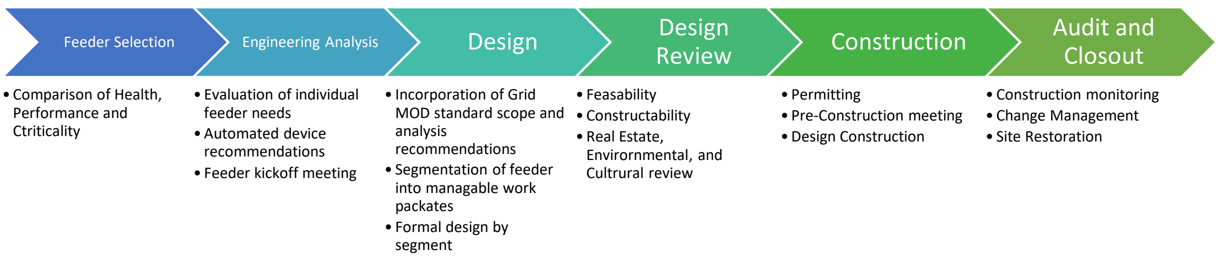


Figure 2.2 Grid Modernization Project Workflow

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.

Capital Offsets

Future O&M costs are reduced by relocating, removing, converting, or refreshing sections of Avista facilities that present an opportunity to improve the feeder's performance as stated above. Prudency and valuation of Grid Modernization efforts have been categorized into three areas. 1) The value approaching feeder improvements holistically; 2) Feeder Health; 3) Feeder Performance.

Integrated Refresh Planning and Execution

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.

Grid Modernization, Wood Pole Management and Transformer Change Out programs were analyzed and Customer Internal Rate of Return (CIRR) was utilized to compare different program refresh models and integrating the three provided the highest value to the customer. Avista provided results of such a financial analysis in response to PC-DR-221, Attachment A, which is the Company's 2017 Wood Pole Management Program Review and Recommendations (see Exh. JD/LL-2, pages 2-94).

The lifecycle cost analyses reported were based on the output of 172 different Availability Workbench models integrated together to provide optimized solutions for individual assets and programs including the transformer changeout work as part of the Wood Pole Management and Grid Modernization programs, which is identical to its application in Distribution Minor Rebuild. Including transformer changeouts with the program reduced the total lifecycle cost to customers by $18.3 million in direct costs and by $46.9 million in risk costs, for a combined reduction in lifecycle costs to customers of $65.2 million, compared with the "Run-to-Fail" alternative of allowing the transformers and attached equipment, including the cutout to fail in service and returning to the feeder later to replace them one at a time. (see Exh. JD/LL-2, pages 52-54).

Health

Feeder health addresses how asset condition affects reliability where there are direct O&M savings due to a reduction in the average number of equipment outage events incurred per year based on asset condition.

Capital offset figures are estimated by feeder based on feeder analysis information provided to the Commission in PC-DR-110 (referenced in WUTC Rebuttal 200900-901-AVA-Exh-JD-LL 1-T_05_26_2021) Docket No. UE-200900, UG-200901, UE-200894).

The following O&M Outage sub-reason events were considered

1. Conductor – Primary	6. Lightning	10. Undetermined
2. Conductor – Secondary	7. Pole Fire	11. Weather
3. Connector – Primary	8. Regulator	12. Wildlife Guard
4. Connector - Secondary	9. Snow/Ice	13. Wind
5. Elbow		

Performance

Indirect Savings attributable to Grid Modernization is the replacement of equipment such as old conductor and transformers that have high energy losses with new equipment that is more energy efficient and improve the overall feeder energy performance. This creates the need for less power generation or acquisition and equates to lower rates for customers. Estimates are derived from the initial assessments noted in the feeder baseline reports found in PC-DR-110 Attachment A-O. The primary reconductor savings are for trunk reconductor work only.

Another important benefit of work done is the O&M savings of each automated device that is installed. For example, using a twenty nine month long span of data between 2017 and 2019, the devices installed by GMP has saved the company $751,465.

Automation device activation data and hard O&M costs for 2020-2022 BCJNs.xlsx

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.

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 2.2 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

The following Business Cases are affected by holistically performing Grid Modernization work:

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		

Efforts in these Business cases require refreshing/extending inspection and refresh years. Effort and thus cost requirements in these programs are reduced.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The steering committee is comprised of the Project Sponsor, Asset Maintenance Manager, Director of Operations, Operations Engineering, and the Program Manager. This group meets as needed, usually quarterly, 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.

3.2 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 managed on the Grid Modernization TEAMS site.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Decision making is documented in Meeting Minutes and Program log in the Grid Modernization TEAMS site.

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.

4. APPROVAL AND AUTHORIZATION

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: Sep-23-2022 | 9:13 AM PDT

Print Name: DocuSigned by: Heather Webster A4EC470DF0D24E5...

Title: Asset Maintenance Manager

Role: Business Case Owner

Signature: Robb Raymond Date: Sep-23-2022 | 9:11 AM PDT

Print Name: DocuSigned by: Robb Raymond 6EF8DBDFC86140E...

Title: Asset Maintenance Project Mgr.

Role: Business Case Owner

Signature: DocuSigned by: David Howell 8A3FC650718B488... Date: Sep-23-2022 | 9:23 AM PDT

Print Name: David Howell

Title: Director of Operations

Role: Business Case Sponsor

EXECUTIVE SUMMARY

Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in a reliable condition for customers and safe conditions for workers. It ensures responsiveness to unplanned damages on distribution assets not related to weather events, as well as small customer driven rebuilds. Throughout the entire distribution system minor rebuilds or replacements of asset units are needed to maintain system reliability and safety. This work impacts customers in both Washington and Idaho. If not funded, the business will impact various types of work that will need to be absorbed into 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 burned-up transformer, and a myriad of other safety related projects.) Also, if not funded, the business will affect the ability to respond to customers' needs for modifications to their electrical service. Lastly, it is acknowledged that if some minor rebuilds are left unrepaired it will not result in immediate catastrophic failures to the distribution system. However, over time an adverse accumulation of unrepaired assets would greatly put line workers and the public at risk as minor asset failures begin to deteriorate pockets of the distribution system.

The steady increase in costs for unplanned minor rebuild work is due to multiple reasons, which includes many assets on the distribution system being past their end-of-life cycle. The 3-year average actual spend for minor rebuild work is $12.4m per year. This is expected to continue for the next 5 years. Minor Rebuild spends approximately $1m per month.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Katie Snyder	5 Year planning update	06/10/2022	
1.1	Katie Snyder	In Year Change Request	07/13/2022	
1.2	Katie Snyder	Business Narrative Update	07/19/2022	

GENERAL INFORMATION

Requested Spend Amount	$13,500,000
Requested Spend Time Period	1 year
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Katie Snyder | 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 a reliable condition for customers, safe conditions for workers, ensuring responsiveness to unplanned damages on distribution assets not related to weather events, as well as 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 failed asset replacements, small mandatory or compliance driven 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.

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, safe conditions for the workers, ensures responsiveness to unplanned damages on distribution assets not related to weather events, as well as 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 is an ongoing program that focuses on keeping the distribution system in a reliable condition for customers, safe conditions for workers, ensuring responsiveness to unplanned damages on distribution assets not related to weather events, as well as 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.

If not funded it could impact 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 public. 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 a myriad of other safety related projects. If not funded, this will also impact our ability to respond to customers' needs for modifications to their electrical service. It is awknowledged that if some minor rebuilds are left unrepaired it will not result in immediate catastrophic failures to the distribution system. However, over time an adverse accumulation of unrepaired assets would greatly put line workers and the public at risk as minor asset failures begin to deteriorate pockets 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 budgeted general activities, which embody the major types of work performed. This division will allow for improved clarity with 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. The costs associated with the work are typically reimbursed by the requesting party. Examples include, but are not limited to: Customer requested reroute, overhead to underground line conversion, or customer load increase.
- **Trouble Related Rebuilds** – Emergency work required to repair damaged facilities caused by 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 pie chart of the estimated spend by general activity. The new general activities were implemented in January 2020.

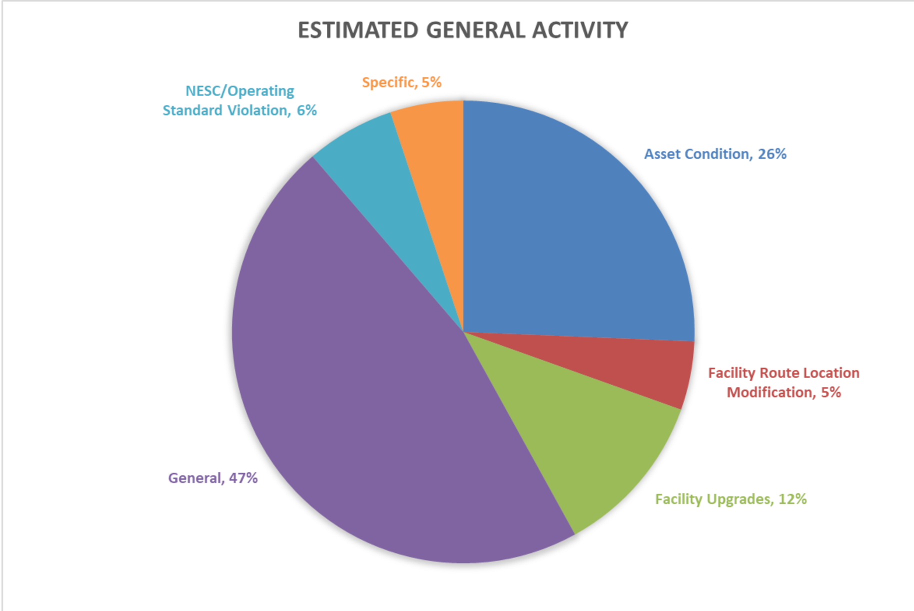


Figure 1: Estimated General Activity split by cost

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)	$13,500,000	Continuous Program	
Roll needed work into another program	$13,500,000	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 $12.4m. This is expected to continue for the next 5 years.

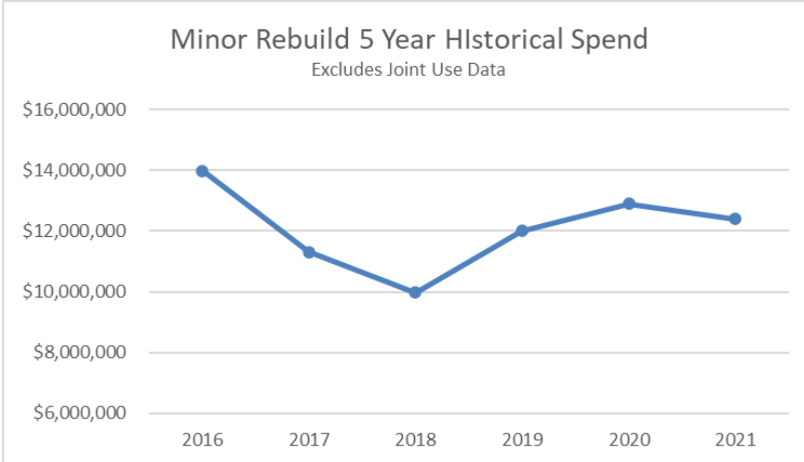


Figure 2: Minor Rebuild Historical Spend

Figure 2 shows a steady increase from 2018 to 2020 and then remained consistent through 2021 with an average spend of $12.4m.

In 2021, 2,360 work orders were created with the average cost equaling $3,349, which demonstrates the work is made up of thousands of small dollars, critical non-discretionary jobs. Occasionally larger rebuild projects, such as small reconductor project, are undertaken as Distribution Minor Blanket projects if prioritized by the Area Ops Engineers. Only 40 (1.8%) of the 1,379 work orders created in 2021 were over $25,000. Those 40 work orders averaged $65,452.

Figure 3 displays a breakdown of the different types of charges that occur in the Minor Rebuild. 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.

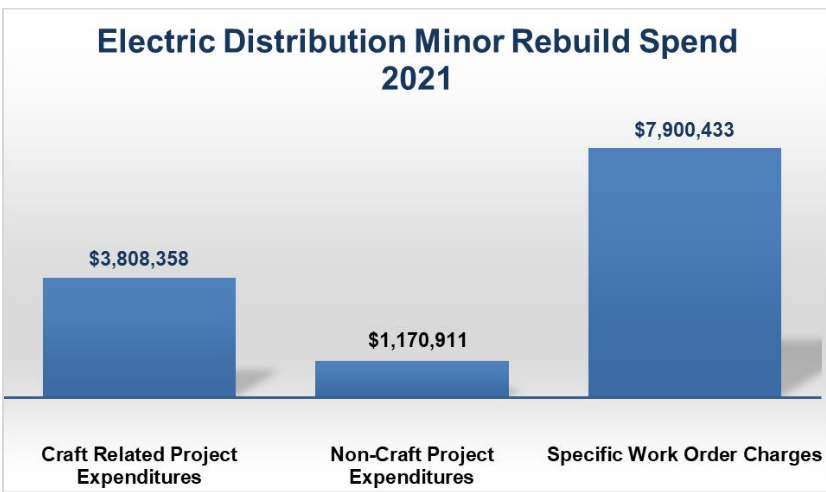


Figure 3: Types of Charges to Minor Rebuild (2021)

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 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, safe conditions for the workers, provides responsiveness to unplanned damages to distribution assets not related to weather events, as well as 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 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.

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. While the work is unplanned, minor rebuilds to the distribution system occur on a regular basis every year and make up a significant portion of the business within Engineering and Operations. While unplanned and isolated minor rebuilds will always exists in the distribution system, unplanned work is minimized to the greatest extent through other systematic infrastructure programs.

By not funding this business case, work will need to be absorbed into some other business case due to the necessity of the work (i.e. the replacement of a car-hit pole in the alley, a broken cross-arm, a burned-up transformer, and a myriad of other safety related projects.)

Also, by not funding, the business will affect the ability to respond to customers' needs for modifications to their electrical service.

Lastly, 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 public at risk as minor asset failures begin to deteriorate pockets of the distribution system.

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 some other business case.

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.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Distribution Minor Rebuild work is one of the many components that contribute to 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 public. The minor rebuild business funds the replacement of a car-hit pole in the alley, a broken cross-arm, a burned-up transformer, and a myriad of other safety related projects. By not funding the business will also affect the ability to respond to customers' needs for modifications to their electrical service. Lastly, 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 pockets of 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

Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in reliable condition for customers, safe conditions for workers, provides responsiveness to unplanned damages to distribution assets not related to weather events, as well as 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.

Distribution Minor Rebuild work is one of the many components that contribute to 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 a myriad of 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. Lastly, 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 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 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 sets forecasted budgets, monitors 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:	Katie Snyder	Date:	07/25/2022
Print Name:	Katie Snyder		
Title:	Asset Maintenance Business Analyst		
Role:	Business Case Owner		

Signature:	David Howell	Date:	7/28/2022
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 $300,000 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
1.0	*Katie Snyder*	*5 Year Planning Draft*	*06/10/2022*	*Draft*
1.1	*Katie Snyder*	*Business Narrative Update*	*07/25/2022*	*Draft*

GENERAL INFORMATION

Requested Spend Amount	$300,000
Requested Spend Time Period	1 Year
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Katie Snyder | 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)	$300,000	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	1/1/2022	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 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 replaces LED lights upon failure (burn-out). Funding calculations are based on historical spend (2020 spend was approx. $411,000). We anticipate as more bulbs are replaced due to failure, there will be less spend each year.

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 projects are 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 Operations Roundtable (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:	Katie Snyder	Date:	07/25/2022
Print Name:	Katie Snyder		
Title:	Asset Maintenance Business Analyst		
Role:	Business Case Owner		

Signature:	David Howell	Date:	7/28/2022
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

Asset Management and Distribution Engineering provided the analysis of Avista's 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. This analysis is documented in the 2017 Wood Pole Management Program Review and Recommendations, it is reiterated in the Avista Utilities Electric Distribution Infrastructure Plan June 2017, and the 2021 Wood Pole Management (Distribution) Inspection Cycle Analysis. Starting in 2021 the cycle was shortened to seventeen- years for the next ten-years to help ensure poles were inspected and failed assets replaced before Grid Hardening Programmatic work occurs. The seventeen-year cycle analysis is discussed in the Wood Pole Management (Distribution) Inspection Cycle Analysis. Asset Maintenance manages and tracks the work, budget, and schedule. The major drivers for the program are system reliability, improved cost performance, and reduced customer outages. These drivers are achieved by replacing defective poles, associated hardware, and equipment when the condition of the asset requires replacement. The National Electric 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 214 details documentation and correction of the pole inspection results. We have also communicated to our insurance carrier Aegis that we are committed to staying on cycle and completing the work in a timely manner. The service code for this program is Electric Direct and the funding is tracked under ER2060.

WPM work encompasses Avista's electric distribution overhead facilities in Washington, Idaho, and Montana. In order to maintain a seventeen-year cycle for the next ten years, approximately 13,000 poles need to be inspected and follow-up work completed annually. The work plan was developed to complete 66% of the poles in the State of Washington and 33% of the poles in the State of Idaho each year. The average cost on a feeder basis to replace defective poles, cross arms, equipment, and hardware is $1352/pole . To stay on a seventeen-year cycle requires $17,576,000 per year which also benefits the Grid Hardening efforts by replacing identified defective assets before they complete their work. The requested amount is $3,000,000 under the funding required as that funding will be charged to the Grid Hardening Sponsored Program. Our customers will benefit by reducing unplanned outages, replacing assets under capital funding, and increasing safety for our line workers and the public. The risk of not approving this Business Case means we will run our facilities in a run-to-failure mode as identified rejected assets are not replaced in a timely manner, safety for our line hands and the public decreases, and our Operating and Maintenance Costs increase.

VERSION HISTORY

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 original business case*	*7/31/2020*	*Full amount approved*
3.0	*Mark Gabert*	*Business Case Refresh*	*8/31/2022*	

GENERAL INFORMATION

Requested Spend Amount	$14,576,000 WPM - $3,000,000 GH
Requested Spend Time Period	1 year
Requesting Organization/Department	Asset Maintenance/WPM
Business Case Owner | Sponsor	Mark S. Gabert - Heather Webster - David Howell
Sponsor Organization/Department	M51/WPM
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

The Wood Pole Management (WPM) program historically inspected and maintained the distribution wood poles on a twenty-year cycle and the transmission poles on a fifteen-year cycle. In 2021 we moved the distribution inspection cycle to seventeen years to support the Grid Hardening work plan Avista has approximately 227,000 distribution poles and to meet the seventeen-year cycle approximately 13,000 poles need to be inspected and replacement work completed annually. Approximately 26 percent of the poles are older than 60 years of age which will increase over time. The Mean Time To Failure (MTTF) for wood poles is seventy-nine years, but Distribution Engineering recommends replacement at sixty years of age due to the time element of the next cycle and the above groundline decay characteristics of butt-treated wood poles, more specifically pole tops where our hardware is attached. Currently, we only replace poles that fail the inspection process and do not use age as the criteria for replacing poles under the Wood Pole Management budget. If we used age and pole failure as a guideline it would require a significant increase in budgeted funding. Along with inspecting poles, WPM inspects distribution transformers, cutouts, insulators, wildlife guards, lightning arrestors, cross arms, 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 assets should be replaced. The asset condition is observed and documented during the pole inspection process as indicated in S-622 Specification for the Inspection of Poles. Designs and work plans are then created to replace the aging infrastructure that fails the inspection process. 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 and reduces issues such as outages, safety 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, equipment, and hardware safe for employees and the general public while maintaining a high level of customer satisfaction. Starting in 2020 the Grid Hardening program impacted the twenty-year cycle. To complete Grid Hardening efforts Wood Pole Management moved feeders in high fire risk areas to a seventeen-year reinspection cycle. This decreased inspection cycle enables Grid Hardening to complete its work by replacing poles with the potential for failure ahead of Grid Hardening construction. If Wood Pole Management is underfunded it will push some feeders past the seventeen-year cycle which may impact Grid Hardening efforts.

1.2 Discuss the major drivers of the business case 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 the 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-nine-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 under a planned capital 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 spills, 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 the potential for serious injury for crews or the public, significant damage to equipment, property of businesses, and public health infrastructure impact of 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.

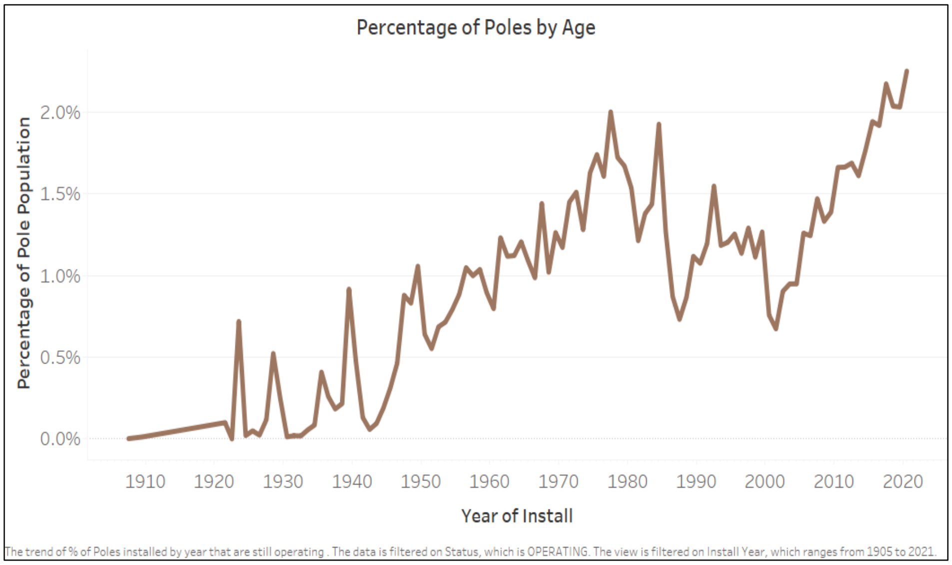


Figure 1-Pole Age Profile

The Outage Management Tool (OMT) is used by Asset Management to track asset condition and show trends of failure 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 40% from 2009 to 2021. This reduction in outage events results in significant customer benefit. The 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.

	WPM Goal Related Number of OMT Events	Actual WPM Related Number of OMT Events	Projected Poles Follow-Up Work	Actual poles Follow-Up Work
2009	1460	1320	11400	11548
2010	1460	1004	11400	12010
2011	1460	1004	11400	10461
2012	1460	1013	11400	14530
2013	1460	816	11400	10763
2014	1460	905	11400	10588
2015	1460	760	11400	12018
2016	1460	717	11400	13244
2017	1460	888	11400	12996
2018	1460	751	11400	11532
2019	1460	742	11400	10902
2020	1460	745	11400	8694
2021	1460	868	11400	11404

Table 1: Event Reduction Results

The type of OMT events are broken down into more detail in Figure 2. Note there are significant improvements to some events such as squirrels being reduced on average from nearly 750 in 2008 to 250 events today. This improvement has been realized by adding wildlife guards to the top of the transformer bushings 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. In 2017 the calculated cost to customers for a pole failure is $24,400 based on an average duration of 4.8 hours for 80 customers. The combined cost impact to customers in 2015 alone for those events was $2,265,600. Also approximately ten years ago Avista moved to using fiberglass cross arms which is beginning to reduce the average annual number of pole top fires. This reduction should accelerate as Grid Hardening began replacing wood cross arms in high-risk WUI areas in the second half of 2019.

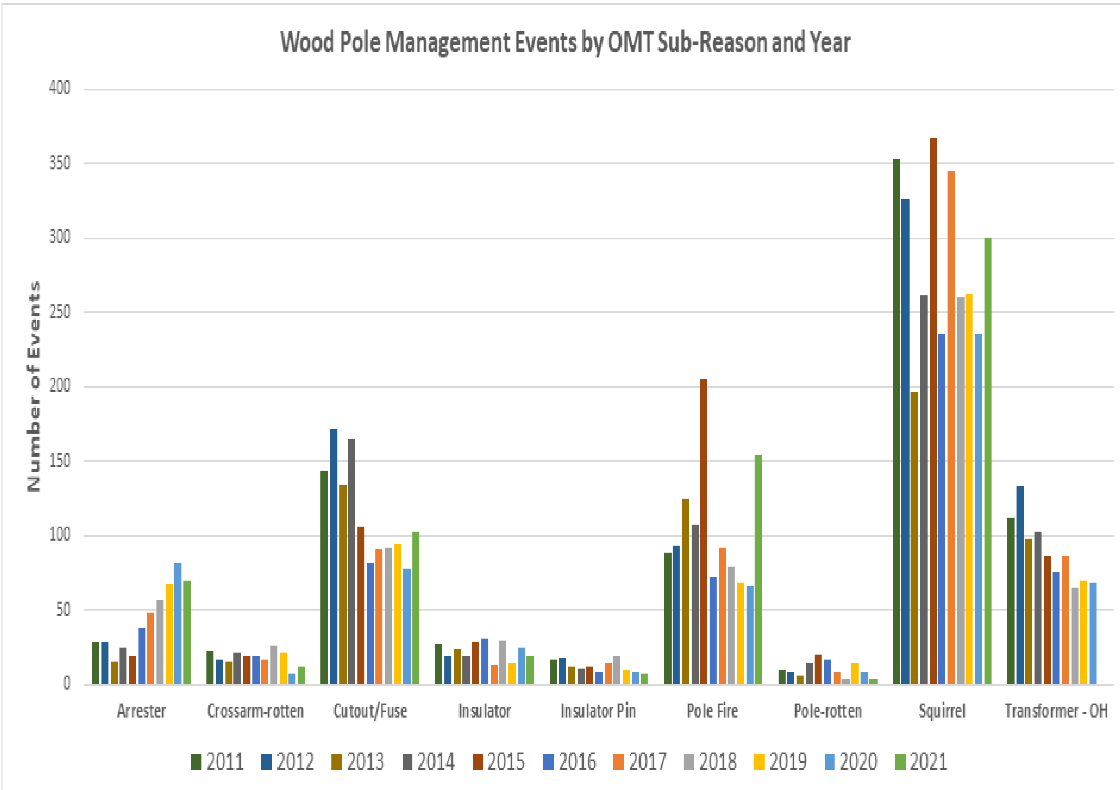


Figure 2 - OMT Events

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.

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 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).

Projected Metric Description	Projected WPM Contribution to the Annual SAIFI Number	Projected Number of Dist Poles Inspected	Projected Number of Pole Rotten OMT Events	Projected Number of Crossarm OMT Events
2009	0.214024996	11,400	137	32
2010	0.208489356	11,400	137	32
2011	0.211022023	11,400	137	32
2012	0.211022023	11,400	137	32
2013	0.211022023	11,400	137	32
2014	0.211022023	11,400	137	32
2015	0.211022023	11,400	137	32
2016	0.211022023	11,400	137	32
2017	0.211022023	11,400	137	32
2018	0.211022023	11,400	137	32
2019	0.211022023	11,400	137	32
2020	0.211022023	11,400	137	32
2021	0.211022023	13,116	137	32
Actual Metric Description	**Actual WPM Contribution to the Annual SAIFI Number**	**Actual Number of Dist Poles Inspected**	**Actual Number of Pole Rotten OMT Events**	**Actual Number of Crossarm OMT Events**
2009	0.1863468	14,430	44	25
2010	0.19916836	14,992	37	23
2011	0.202462739	14,980	35	28
2012	0.16613099	14,406	52	19
2013	1.15640942	11,903	34	18
2014	0.241571914	11,879	55	26
2015	0.225273848	7,835	43	23
2016	0.132313511	11,636	57	23
2017	0.12662277	10,595	39	22
2018	0.128829384	16,044	25	31
2019	0.126544503	11,187	44	26
2020	0.116836918	9,627	53	15
2021	0.210971466	12,066	45	17

Table 2: SAFFI Metrics

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, The Electric Distribution Infrastructure Plan June 2017 and the Wood Pole Management (Distribution) Inspection Cycle Analysis January 2021 are located on 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.

WPM is an ongoing cyclical program that proactively replaces assets identified for replacement during the inspection process. By replacing assets before they fail, outages are reduced, and replacement costs are reduced through planned work. Investing in the infrastructure increase 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 on before and after WPM work. The peak of events per mile shown in the graph is from

2011 when there were nearly .3 events per mile. The results after the program show performance as low as .1 events per mile of feeder, a significant improvement.

If funding were to be reduced, expected outages would increase. The team would then need to prioritize which components would be replaced and which would be left. This would increase the likelihood that crews would need to visit the same pole later if a remaining component were to fail.

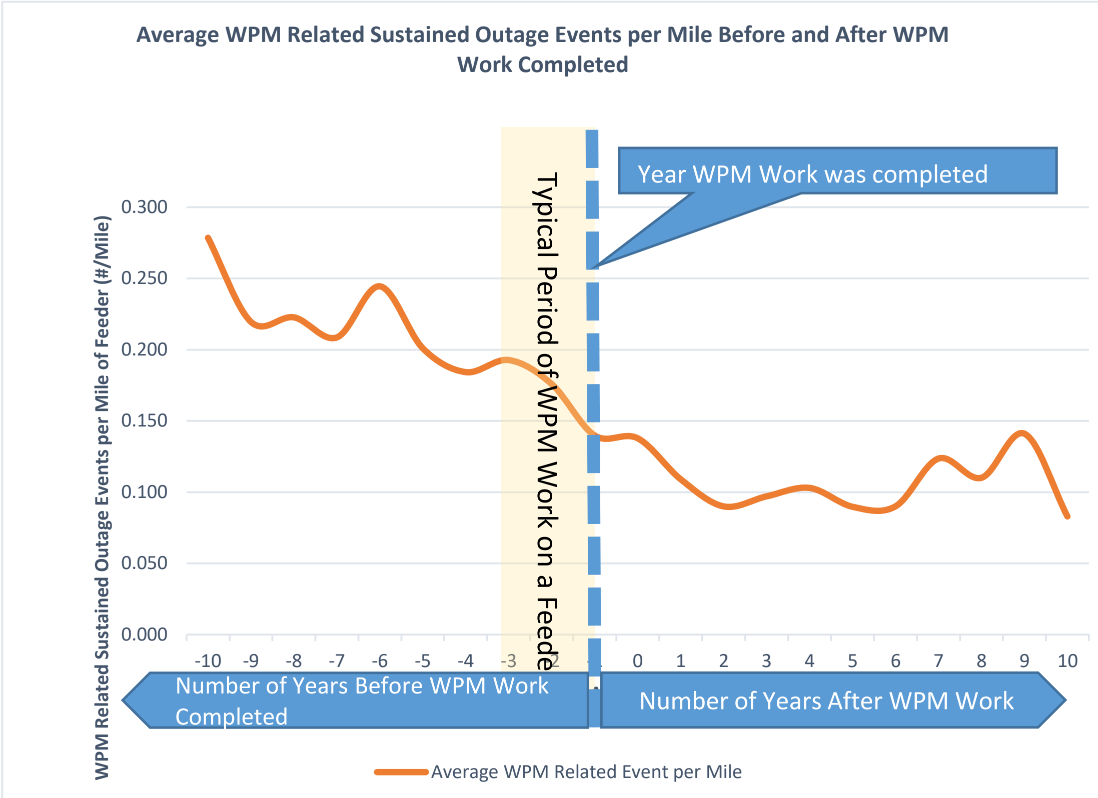


Figure 3

2. PROPOSAL AND RECOMMENDED SOLUTION

Based on the analysis in 2017, the current twenty-year cycle delivers the best life cycle value for the funding level. For perspective, the industry average for inspecting and maintaining distribution assets is ten years. In 2021 Asset Managements “Wood Pole Management (Distribution) Inspect Cycle Analysis “ Compared the Avista utility peer group, shown below, indicates that Avista is a more rural utility and therefore has far fewer customers per pole (approximately 1.5 vs. 10), making it economically feasible for the peer group to inspect poles more frequently. The ten-year cycle delivers a better rate of return but any reduction in cycle time requires an increase in expenses to pay for the increased number of poles inspected each year, and a corresponding increase in requirements for capital replacements. Asset Management and Distribution Engineering monitor system reliability to determine if adjustments in the scope of work are needed in the future. They also need to determine the funding level required to make those adjustments so Asset Maintenance can document those changes as a new alternative in the Business Case for funding approval by the Capital

Planning Group. If the Capital Planning Group does not approve the new alternative it is not incorporated until at such time funding is approved.

DISTRIBUTION – WOOD POLE

COMPANY	CUSTOMERS/POLE	INSPECTION	INSPECTION CYCLE (IN YEAR)
Avista	1.54	Contractor	20
BC Hydro	2.21	Contractor	10
ENMAX	10.65	Contractor	10
PGE	4.15	Contractor	10
PSE	3.67	Contractor	10
SMUD	4.80	Internal	5
SRP	9.33	Both	10

Option	Capital Cost	Start	Complete
Recommended Solution]: Distribution Wood Pole Management Program inspects all feeders on a twenty-year cycle and replaces inspection failed wood poles, cross arms, missing lightning arresters as necessary, missing/stolen grounds, bad cutouts, broken insulators, leaking transformers, and replace guy wires not meeting current code requirements when the pole is replaced. This includes increasing the pole inspections and replacement work on a seventeen-year cycle for the next ten years on high risk WUI feeders to meet the requirements of the Grid Hardening program. The $3M in additional funding will be in the Grid Hardening budget to expedite inspections and replacement work. Total $17.5M	*$14,576,000*	*01/2023*	*annually*
Alternative #1]	*$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.

The metrics, data, and analysis are documented in the 2017 Wood Pole Management Program Review and Recommendations, Electric Distribution Infrastructure Plan June 2017, and the Wood Pole Management (Distribution) Inspection Cycle Analysis January 2021. That data, analysis, and information was considered and documented throughout this 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). 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 feeders on 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 fourteen months from start to finish. This work is incorporated into some of the office's work plans and allows the company to efficiently utilize resources under Capital funding. By completing this work, the overall unplanned O&M costs required to replace failed poles, equipment, or hardware such as cross arms attached to the pole will be reduced.

Direct savings-between 2005 and 2009 the average number of OMT events related to Wood Pole Management was 1,460 per year. Between 2009 and 2021 the average number of OMT events has been reduced to an average of 887 events per year. This is an average reduction of 573 OMT events per year related to WPM work. The average OMT event takes 3.5 hours to retore at a straight time cost of $500 per hour for a total of $1,750 per event. Based on this information we see a direct savings of $1,002,750 annually by preventing the 573 outages related to Wood Pole Management activities. This does not include the material or any overtime costs. It is anticipated that the average number of OMT events will continue to be reduced as feeders are completed and there are no funding or labor resource delays.

Indirect Savings-based on the ICE calculator (Interruption Cost Estimate) Asset Management looked at pole-rotten data for 2014-2019. Total hours per incident is 157.5 hours (average # of customers impacted (45) * the average outage time (3.5)). The ICE cost is $116.15. Therefore, your indirect benefit per incident is $18,294. Wood Pole Management work on average avoids 573 events per year therefore the annual indirect benefit is $10,482,462.

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 current WPM Program has been in place since 2008 so any impacts on other business functions have already been realized. There is however 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 Grid Hardening on track to be completed on time. 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.

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 completing 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. This is in alignment with the NESC requirement to inspect and maintain our facilities in a timely manner. This work reduces the company's risk associated with owning overhead distribution electric facilities. This business case is reviewed and updated with each requested business case refresh. The information is also reviewed by our Rates Department and the Washington and Idaho Utility Commission's for rate case purposes. In addition, the information is utilized by the Capital Budget Committee to determine funding levels based on company priority.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electric Distribution customers, Grid Hardening, Grid Modernization, Distribution Engineering, Asset Management, Joint Use Projects, and Construction Offices. Please note that with the sunsetting of TCOP some internal crews incorporate WPM as part of their work plan.

2.8.2 Identify any related Business Cases

Grid Hardening Program, WSDOT Control Zone Mitigation Program, and the Grid Modernization Program.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Asset Management and Distribution Engineering provide ongoing analysis of distribution asset conditions. 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 in the recommended solution are documented in the DFMP-Distribution Feeder Management Plan-Design Criteria Manual-Applicable to Wood Pole Management.

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, Distribution Engineering, Asset Maintenance, Distribution Engineering, Director Of Operations, WPM Program Manager, and WPM inspectors. Status updates on progress towards yearly goals are documented and updated on the monthly 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 reviewed and approved by the inspector and program manager before construction. Those approved changes are also documented by the inspectors during the audit process

4. APPROVAL AND AUTHORIZATION

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:	8/31/2023
Print Name:	Mark S. Gabert		
Title:	WPM Program Manager		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	David Howell		
Title:	Director Of Operations		
Role:	Business Case Sponsor		

Signature:	Heather Webster	Date:	31.Aug.2022
Print Name:	Heather Webster		
Title:	Asset Maintenance Manager		
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 Hardening, 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 operations engineers for their regional areas within Washington, Idaho, and Montana and they are prioritized against each other with input from the distribution planning engineers.

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."*
2.1	*Cesar Godinez*	*Minor updates.*	*01/04/2022*	*Updated "Steering Committee or Advisory Group Information" in section 3 "Monitor and Control."*
3.0	*Cesar Godinez*	*Updated narrative.*	*08/31/2022*	*Business case refresh 2022; revised Executive Summary and incorporation of 'offsets' information.*

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 seventy (370) discrete primary electric circuits encompassing over 19,300 miles of overhead conductors and underground cables. The distribution grid is managed by division or 'operations engineers' and centralized distribution planning.
Load Demands on the grid are dynamic with load patterns changing because 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. Our System Planning group is also starting to export AMI load data into Synergi to use it 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 like 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 System Planning (John Gross).
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. Feeder Automation Strategy – a design guide to assist the CPC/Engineer when making decisions involving automated devices (Distribution Engineering).
6. 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.
7. 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.
8. 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. Like 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).

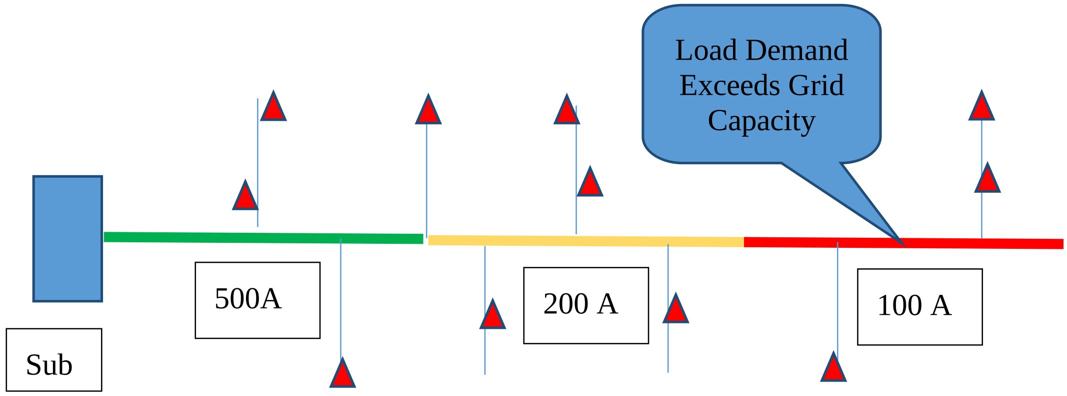


Illustration of Distribution Grid Capacity Constraint

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.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Description	Consequence
Reactionary Approach	Reacting only when an issue occurs 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 most direct approach 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. Reactionary Approach 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 2022.

https://sp2016.corp.com/sites/sp/enso/dist/_layouts/15/start.aspx

Region	2022	2023	2024	2025	2026
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. There are also significant capital investment offsets created by the work this business case accomplishes. Our quantified direct saving offsets calculated for 2022 and 2023 are $1,207,740 and $929,094 respectively. Our quantified indirect savings have been calculated to about $28,683 yearly. The detailed writeup for the calculated offsets can be found here: Capital Investment Offsets Form - Distribution System Enhancements.

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.

3. MONITOR AND CONTROL

Steering Committee or Advisory Group Information

Distribution Area/Operations Engineers and Distribution System Planning.

Marc Lippincott, Caitlin Greeney, & Knute Rognaldson – Spokane and Deer Park

Marshall Law & Marc Lippincott – East Region (CDA, Kellogg, St. Maries, Sandpoint)

Dan Knutson – Othello, Davenport

Tyler Dornquast – Colville

Chris Dux – South Region (Pullman, Clarkston, Grangeville)

John Gross & Damon Fisher – Distribution System Planning

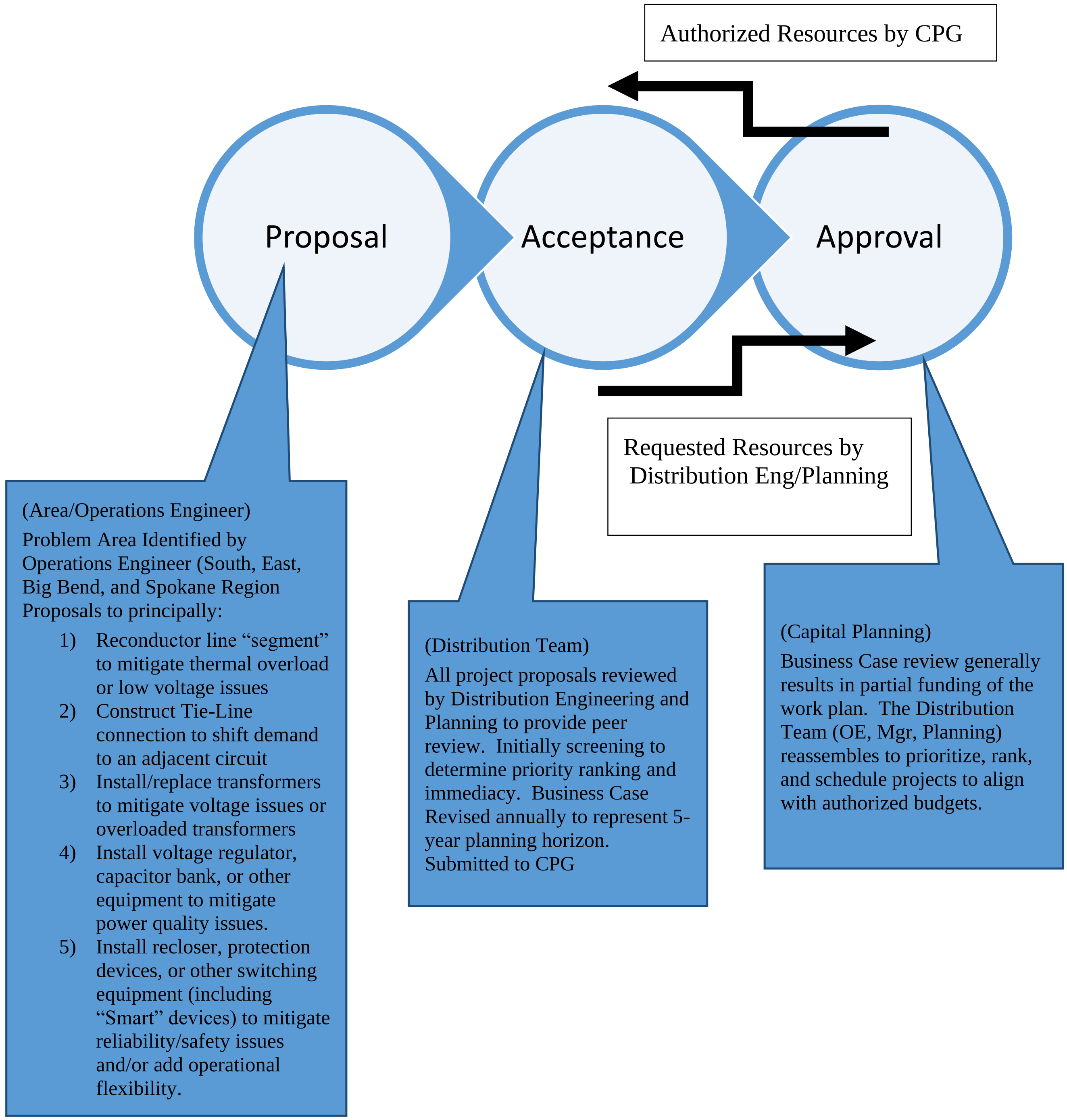
Cesar Godinez – Distribution Engineering Manager

The steering committee meets monthly to review projects and construction processes and discuss near term operating conditions. The team also meets annually 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” except for distribution substations and other larger distribution projects on occasion.*

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/Operations Engineer)
Problem Area Identified by Operations 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 (OE, Mgr, Planning) reassembles to prioritize, rank, and schedule projects to align with authorized budgets.

4. APPROVAL AND AUTHORIZATION

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.

8/31/2022

Signature: ______________________ 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 Recalc

BEACON Temperature Was: 98.1 F

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

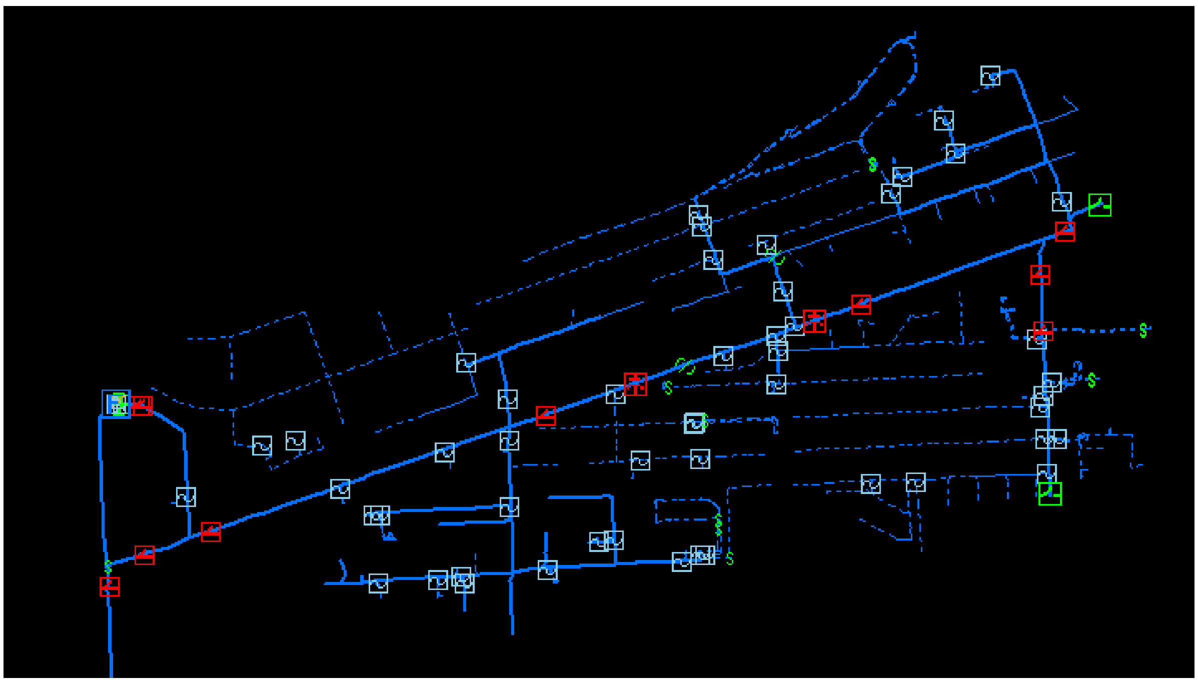
Non-Avista & Customer dedicated FDRs omitted		
# by Area Engr	FDR Count	DMS
Spokane	129	3PH SCADA
South	94	1PH SCADA
East	77	
Colville	26	
Big Bend	31	
Total	**357**	

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



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) NEEDS ASSESSMENT- a synopsis of the problem, the current state and recommended solution
2) COST- the cost of the recommended solution
3) DOCUMENT SUMMARY- benefit to the customer
4) RISK- of not approving the business case
5) APPROVALS- who reviewed and approved the recommended solution

<< 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.

This Business Case includes the following Expenditure Requests:

- 2274: New Substations
- 2606: SCADA to All Substations

Service: ED – Electric Direct

Jurisdiction: Various. Each project has its own Jurisdiction.

Engineering Roundtable Request Number: Various. Each rebuild project has its own ERT Request.

See the 5-year Funding Request for current budget requests.

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	
2.1	Karen Kusel	Update to 2022 Template	06/2022	

GENERAL INFORMATION

Requested Spend Amount	$10,000,000 - $30,000,000 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

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.]

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:	DocuSigned by: Glenn J Madden 7D4B3DF5CBD8463	Date:	Jun-28-2022 | 3:49 PM PDT
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Josh DiLuciano A3C71874F6564DB	Date:	Jul-05-2022 | 7:48 AM PDT
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		

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

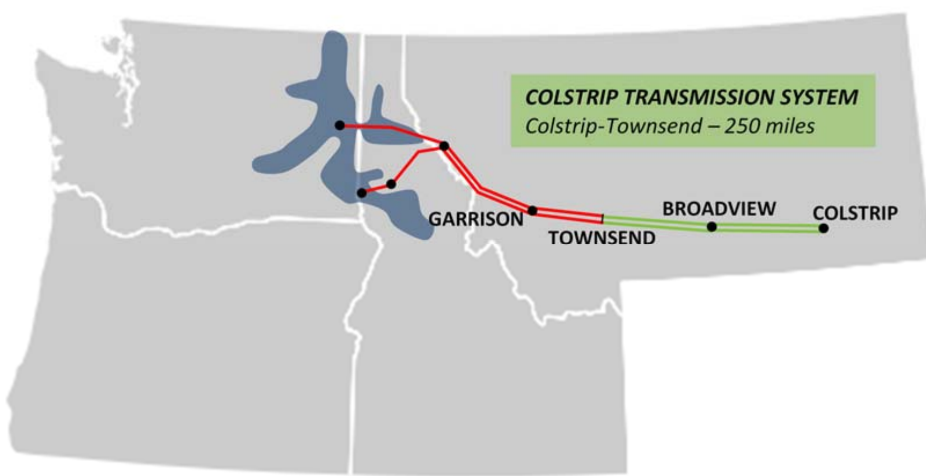
Version	Author	Description	Date	Notes
1.0	*Jeff Schlect*	*Initial narrative drafted from pre-existing approved case*	*7/30/2020*	*Existing Approved Case*

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] Failure to fund Colstrip Transmission expenditures would be a breach of the Company's obligations under the Agreement.

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. At such time as the Company may no longer attain output from Colstrip Project Units 3 and 4, the Company's ownership in the Colstrip Transmission System may facilitate access to new resource acquisition opportunities in the state of Montana.

Colstrip Transmission program capital expenditures have averaged $350,000 over the ten-year period from 2012-2021. Each year NWE develops a five-year capital plan for necessary capital improvements, renewals and replacements for the Colstrip Transmission System; future program requirements are expected to remain roughly commensurate with past expenditures. 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
2.0	*Jeff Schlect*	*Initial narrative drafted from pre-existing approved case*	*7/28/2020*	*Existing approved case*
2.1	*Jeff Schlect*	*Business Case refresh*	*5/26/2022*	*Various updates*

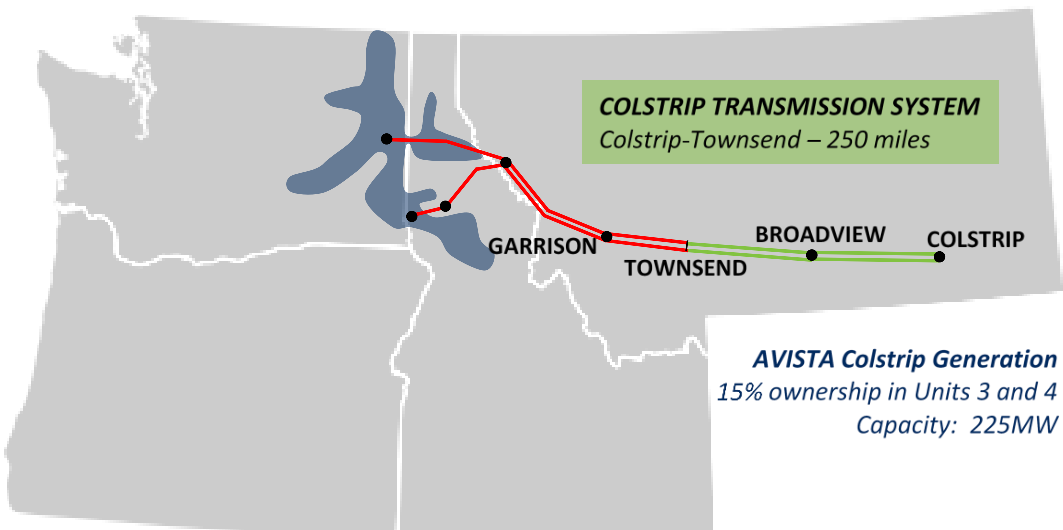
[1] Avista owns a 10.2% share in the Colstrip-Broadview segment and a 12.1% share in the Broadview-Townsend segment.

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.

Option	Capital Cost	Start	Complete

[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.

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 equipment at the Colstrip 500/230kV Substation
- Broadview 500kV Series Capacity replacements
- 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
- Microwave communications and 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

EXECUTIVE SUMMARY

The Company must provide for the interconnection of new generation resources with its Transmission System under the terms and conditions of its Open Access Transmission Tariff ("Tariff") under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). In compliance with federal statute, the terms and conditions of the Tariff, and FERC rules and regulations, the Company must study, design and construct the necessary facilities ("Network Upgrades") to provide Interconnection Service to all eligible generation projects, regardless of whether such generation is intended to serve bundled retail native load customers of Avista or any third-party load. All aspects of the generation interconnection process, including application, studies, evaluation of new or upgraded facilities, construction of new or upgraded facilities, cost allocation of new or upgraded facilities, and repayment of advanced amounts are prescribed by the Tariff and FERC rules and regulations. This Business Case provides for the ongoing capital funds required to study, design and construct Network Upgrades, including repayment and capitalization of any advanced amounts, that are required to provide Interconnection Service in compliance with the Tariff and all other applicable FERC rules and regulations.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Jeff Schlect*	*Initial justification narrative*	*3/23/2022*	

GENERAL INFORMATION

Requested Spend Amount	Determined on a yearly basis
Requested Spend Time Period	Ongoing
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

In compliance with federal statute, the terms and conditions of the Tariff, and FERC rules and regulations, the Company must design and construct new or upgraded transmission facilities to provide for the reliable interconnection of new generation projects. Upon completion of a FERC-prescribed study process, the Company must tender a standard form of Small Generator Interconnection Agreement ("SGIA") (for projects less than or equal to 20MW in capacity) or Large Generator Interconnection Agreement ("LGIA") (for projects greater than 20MW in capacity) to the generation project developer ("Interconnection Customer"). Consistent with the study process and FERC's cost allocation principles, the SGIA or LGIA must specify the Network Upgrades associated with each generation project. Network Upgrades are those new or upgraded facilities that must be funded by the Company. See attached documentation providing justification and documentation of FERC rules and requirements regarding the funding of Network Upgrades associated with generation interconnection projects: *Business Case Justification – Generation Interconnection Attachment A*.

1.1 What is the current or potential problem that is being addressed?

Pursuant to the Company's mandatory federal compliance requirements under the Tariff and applicable FERC rules and regulations, the Company must fund the design and construction of new and/or upgraded transmission facilities to provide generation interconnection service under the Tariff.

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 is *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 design and construction funding for these projects would be: (i) an act of default under the applicable Small Generator Interconnection Agreement ("SGIA") or Large Generator Interconnection Agreement ("LGIA") for each project, and (ii) a violation of the Tariff and FERC rules and regulations pursuant to which the Company could incur compliance penalties of up to $1 million per day. Failure to provide design and construction funding for these projects would be inconsistent with the *Ethical Decision Making* policy under the Company's *Code of Conduct*.

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.

Attachment 4 to each SGIA and Appendix B to each LGIA outline the required construction milestones for each project.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

Each generation interconnection project must be studied consistent with the generation interconnection procedures under the Tariff. The applicable study reports must be made available to the Interconnection Customer and any other Eligible Customer under the Tariff who requests the study.

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 Network Upgrades associated with generation interconnection projects in compliance with the Tariff, the applicable SGIA or LGIA, and FERC rules and regulations.

Consistent with FERC rules and regulations regarding the funding of Network Upgrades, the Company may elect to fund all such costs up front or may require the Interconnection Customer to provide initial advanced funding for Network Upgrades, for which the Company must provide repayment (or Transmission Service credits) to the Interconnection Customer over a specified period of time not to exceed twenty years after the generating facility commences commercial operation. All repayment or Transmission Service credits must include FERC interest. While the Company must ultimately fund all Network Upgrades, the Company is able to manage its overall capital obligations, and correlating transfers to plant, under this Business Case over a period of time following the commercial operation date, to be set forth in either the SGIA, LGIA, or a separate Network Upgrades funding and repayment agreement. The Company's election to require the Interconnection Customer to provide advanced funding of Network Upgrades is outlined in *Business Case Justification – Generation Interconnection Attachment B*.

Determination of repayment schedule, and resulting capital additions, will be made in consultation with the Company's Financial Analysis, Treasury and Accounting groups. Annual amounts requested under this Business Case will reflect both committed and planned capital funding consistent with such collaborative determination.

Option	Capital Cost	Start	Complete
Fund Network Upgrades under SGIA or LGIA	*Determined Yearly*	*06 2022*	*Ongoing*
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.

This is an ongoing program to accommodate the capital requirements associated with generation interconnection projects. Requested capital amounts will cover the cost of design and construction of required Network Upgrades for each project. Actual yearly capital amounts will be determined by project requirements and repayment obligations of CIAC amounts initially funded by project developers.

No related O&M reductions are expected with these projects.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Company Engineering and construction labor resources may be impacted. Project impacts and scheduling are coordinated through the Company's Engineering Roundtable group. Transmission Services must coordinate with Company Financial Analysis, Treasury and Accounting groups to determine timing of CIAC repayments to developer and resulting transfers to capital.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See 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.

Ongoing program year-to-year dependent upon project status and CIAC repayment requirements.

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 *Ethical Decision Making* policy under the Code of Conduct. Investment complies with applicable SGIA and LGIA contract obligations, the Tariff, and FERC rules and regulations. Timing of repayments to Interconnection Customers (with associated transfers to capital) provides the Company with some flexibility in the planning of its capital funding requirements.

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 and regulations. As outlined in 1.3 above, failure by the Company to provide design and construction funding of generation interconnection Network Upgrades would be: (i) an act of default under the applicable SGIA or LGIA for each project, and (ii) a violation of the Tariff and FERC rules and regulations 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

Customers: SGIA and LGIA Counterparties (generation project developers)
Transmission Customers (purchasers of generation output)

Avista Financial Analysis, Treasury and Accounting Groups: Coordination to determine timing of CIAC repayments and resulting transfers to capital

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

Not applicable

3.2 Provide and discuss the governance processes and people that will provide oversight

Design and construction scheduling are coordinated through the Engineering Roundtable. Capital funding is coordinated with the Financial Analysis, Treasury and Accounting groups with final determinations made through the Capital Planning Group. The Company's Transmission Services group administers all SGIAs and LGIAs. The Company's Substation Project Delivery group provides project management services for all major generation interconnection projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Transmission Services coordinates with Substation Project Delivery staff to determine the need for any adjustments to project capital. Project milestones, scope, and cost changes are documented through administration of the applicable SGIA or LGIA with each Interconnection Customer. All material adjustments will be managed through in-year change requests submitted to the Capital Planning Group.

The undersigned acknowledge they have reviewed the 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.

3/24/2022

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

ATTACHMENT A
BUSINESS CASE JUSTIFICATION – GENERATION INTERCONNECTION
SUPPLEMENTAL JUSTIFICATION AND BACKGROUND

A. FERC Transmission Pricing Policy for Generation Interconnections

The Federal Energy Regulatory Commission ("FERC") codified its cost allocation treatment of transmission system upgrades associated with generator interconnection in Order No. 2003, issued July 24, 2003. In its order, which also included its required form of *Standard Large Generator Interconnection Agreement*, FERC defined two types of facilities associated with generation interconnection that are to be owned and operated by the Transmission Provider: Transmission Provider Interconnection Facilities and Network Upgrades. Transmission Provider Interconnection Facilities are limited to only those facilities between the point of change of ownership with the Interconnection Customer's facilities and the Point of Interconnection. Such facilities must be used solely by the Interconnection Customer and may not include any facilities that may be deemed Network Upgrades. Network Upgrades consist of all new or upgraded facilities that are "required ***at or beyond*** the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System [emphasis added]." Interconnection Facilities may be directly assigned to the Interconnection Customer while Network Upgrades may not.

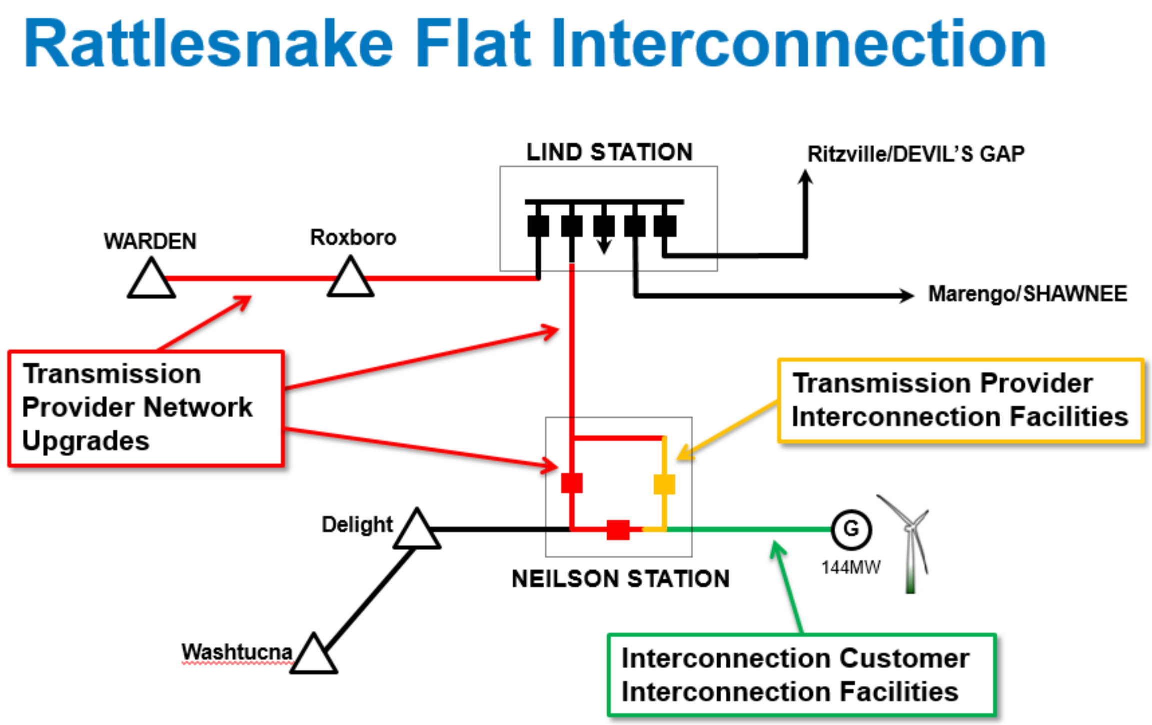
FERC's affirmation of its interconnection facilities pricing policy is outlined in the introduction to Order No. 2003:

> The Commission's interconnection cases have drawn the distinction between Interconnection Facilities and Network Upgrades. Interconnection Facilities are found between the Interconnection Customer's Generating Facility and the Transmission Provider's Transmission System. The Commission has developed a simple test for distinguishing Interconnection Facilities from Network Upgrades: Network Upgrades include only facilities at or beyond the point where the Interconnection Customer's Generating Facility interconnects to the Transmission Provider's Transmission System… Most improvements to the Transmission System, including Network Upgrades, benefit all transmission customers, but the determination of who benefits from such Network Upgrades is often made by a non-independent transmission provider, who is an interested party. In such cases, the Commission has found that it is just and reasonable for the Interconnection Customer to pay for Interconnection Facilities but not for Network Upgrades [Order No. 2003, ¶ 21].

Similarly, in Order No. 2003-A (issued March 5, 2004) FERC re-affirmed its cost allocation treatment (or "pricing policy") for generation interconnections [see Order No. 2003-A, ¶ 579-590] and its legal justification therefore [see Order No. 2003-A, ¶ 591-602].

> …we do not believe that the costs of Network Upgrades required to interconnect a Generating Facility to the Transmission System of a non-independent Transmission Provider are properly allocable to the Interconnection Customer through direct assignment because upgrades to the transmission grid benefit all customers… [Order No. 2003-A, ¶ 599]

<u>Illustrative Example of FERC Transmission Pricing Policy for Generation Interconnections</u>



Per FERC policy any facilities beyond the point of interconnection are Network Upgrades. The point of interconnection for the example generation project is its line interconnection bay at the Neilson Station. Neilson is a three bay, ring-bus configuration station, therefore the example generation project is allocated one-third of the overall station cost (see facilities in yellow). The remaining two-thirds of the station and all upgraded facilities beyond (see facilities in red) are Network Upgrades. FERC asserts that all Network Upgrades benefit all transmission customers, including a Transmission Provider's native load retail customers. Interconnection Customer Interconnection Facilities are the sole cost and responsibility of the generation project developer.

B. Background Q & A Regarding FERC Compliance Requirements

1. *Please explain the differences between "Network Resource" and "Energy Resource" Interconnection Service and explain why it was selected as such, and further what were the implications to Avista given the selection.*

   All non-PURPA generation interconnection projects must be processed pursuant to the Company's Open Access Transmission Tariff ("Tariff") and applicable FERC rules and practices. The difference between Network Resource Interconnection Service ("NRIS") and Energy Resource Interconnection Service ("ERIS") is subtle.[1] Both NRIS and ERIS must be studied such that the interconnected resource can be operated at full output. Beyond this commonality, FERC outlines the difference between NRIS and ERIS in its Order 2003 as follows:

   FERC Order 2003 – Paragraphs 753-754

   > As proposed, Energy Resource Interconnection Service would allow the Interconnection Customer to connect its Generating Facility to the Transmission System and be eligible to deliver its output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis… The Interconnection Studies to be performed for Energy Resource Interconnection Service would identify the Interconnection Facilities required *as well as the Network Upgrades needed to allow the proposed Generating Facility to operate at full output* [emphasis added].
   >
   > In contrast, Network Resource Interconnection Service would require the Transmission Provider to undertake the Interconnection Studies and Network Upgrades needed to integrate the Generating Facility into the Transmission System in a manner comparable to that in which the Transmission Provider integrates its own generators to serve native load customers.

   Additionally, with respect to NRIS:

   FERC Order 2003 – Paragraph 768

   > Network Resource Interconnection Service is intended to provide the Interconnection Customer with an interconnection of sufficient quality to allow the Generating Facility to qualify as a designated Network Resource on the Transmission Provider's system without additional Network Upgrades. This means that Network Resource Interconnection Service entitles the Generating Facility to be treated in the same manner as the Transmission Provider's own resources for purposes of assessing whether aggregate supply is sufficient to meet aggregate load within the Transmission Provider's Control Area, or other area customarily used for generation capacity planning. Thus, with Network Resource Interconnection Service, the Interconnection Customer would be eligible to obtain Network Service under the Transmission Provider's OATT… *without the need for additional Network Upgrades* [emphasis added].

   Accordingly, any new transmission facility or upgraded transmission facility that is necessary for the resource to operate reliably at full output must be identified in the generation interconnection study process as Network Upgrades. FERC further outlines the subtle

[1] FERC differentiates between NRIS and ERIS only in its Large Generator Interconnection Procedures (i.e. those greater than 20MW).

difference between NRIS and ERIS which, on the Avista system, suggests very little difference between the two types of Interconnection Service:

FERC Order 2003 – Paragraph 784

> The principal difference between the study requirements for Energy Resource Interconnection Service and Network Resource Interconnection Service is that the study for Network Resource Interconnection Service identifies the Network Upgrades that are needed to allow the Generating Facility to contribute to meeting the overall capacity needs of the Control Area or planning region whereas the study for Energy Resource Interconnection Service does not. The study for Energy Resource Interconnection Service includes short circuit/fault duty, steady state (thermal and voltage) and stability analyses to identify the Network Upgrades needed to allow the output of the Generating Facility to be injected into the Transmission System using capacity on an "as available" basis. By contrast, the study for Network Resource Interconnection Service includes similar analyses but also assumes that the output of the Generating Facility may displace the output of certain other Network Resources on the Transmission System. The study then identifies the Network Upgrades that would be required to allow the Generating Facility to be counted toward system capacity needs in the same manner as the displaced resources.

To date, Avista has never received a request for only ERIS on the Avista Transmission System.

2. *Who decides on the type of resource interconnection service?*

   As noted in (1), the Interconnection Customer requests which type of resource interconnection service, or both, is/are to be studied. Per Article 4.1 of the FERC pro forma Large Generator Interconnection Agreement ("LGIA"), the Interconnection Customer ultimately elects either NRIS or ERIS (see also, FERC Order 2003 – Paragraph 786).

3. *Are there any other resource interconnection service types beyond the two listed above?*

   No, not under FERC jurisdiction.[2]

4. *Who decides, and at what point does the Company as a transmission provider become obligated to provide transmission to interconnect a new generating resource?*

   Note: the word "transmission" in this question may refer to either "transmission service" or "new or upgraded transmission assets." Responses are provided based upon both meanings.

   With respect to providing Transmission Service:
   Technically, requests for Interconnection Service and Transmission Service are separate and distinct. Interconnection Service does not in and of itself convey Transmission Service. However, because NRIS requires the resource to be studied such that it can be operated as if it were a Network Resource serving the Company's native load customers, in many cases, with respect to the identification of Network Upgrades, the distinction is effectively in letter only,

[2] There are no 'types' of resource interconnection service for generation interconnections under PURPA.

not substance. Where the distinction becomes substantive with respect to Network Upgrades are for those instances where the new resource intends to deliver its output *off-system* at a specific point of delivery. If sufficient Available Transfer Capability ("ATC") to the requested point of delivery is not available, additional Network Upgrades (beyond those identified in the Generation Interconnection process), may be necessary to provide the requested Transmission Service.

With respect to providing new or upgraded transmission assets:
The Company bears no obligation to provide new or upgraded transmission assets (Network Upgrades or Transmission Provider Interconnection Facilities) in association with a generation interconnection project until such time as a Large Generator Interconnection Agreement ("LGIA") or Small Generator Interconnection Agreement ("SGIA") is executed. Once an LGIA or SGIA is in place, both parties bear obligations with respect to project milestones, construction and financing.

5. *Please explain the conditions where the Company as a transmission provider is obligated to <u>upgrade existing transmission</u> to provide interconnection to a new generating resource.*

The Company is obligated to construct new transmission facilities and/or upgrade existing transmission facilities if any such facilities are identified as Network Upgrades or Transmission Provider Interconnection Facilities in the study process for such interconnection. All studies are performed, and Network Upgrades and Transmission Provider Interconnection Facilities identified, consistent with applicable mandatory federal reliability standards established by FERC and the North American Electric Reliability Corporation ("NERC"). The results of all such studies, and their respective Network Upgrades and Transmission Provider Interconnection Facilities, are outlined in both summary and detailed format in the applicable study reports associated with each generation interconnection request.

Generation Interconnection Facilities Allocation Practice
Transmission Provider Interconnection Facilities vs. Network Upgrades

March 22, 2022 – Jeff Schlect and Randy Gnaedinger

Key Factors

- Comply with the Tariff and FERC Rules - Limit retail customer costs - Enable cost effective renewables

Updated Practice

In association with Avista's work related to Project #60 where the Interconnection Customer (IC) is seeking an interconnection at the Dry Creek 230kV Station, the Company has reviewed its NU versus TPIF allocation practices. To comply with FERC rules and regulations as outlined in FERC Order 2003 and to mitigate as best as possible the potential cost impacts to retail customers, Avista is updating its practice in how the cost of generation interconnection facilities are allocated between NU and TPIF.

Past Practice

Under the generation interconnection procedures of its Open Access Transmission Tariff (Tariff), Avista has historically sought to allocate a portion of new or upgraded interconnection station facilities to generation project developers as direct-assigned facilities, or Transmission Provider Interconnection Facilities (TPIF). The remainder of these station costs are designated as Network Upgrades (NU) which must be funded by the Transmission Provider. Avista has reached mutual agreement with its ICs regarding the allocation of facilities required for interconnection and has typically elected to self-fund the NU portion. In instances where two breakers were required to reliably integrate the IC's Project, Avista has designated one breaker as NU and the other as TPIF. In instances where multiple line terminals are established in a new interconnection station, a pro rata sharing of the overall station cost was used to determine the allocation between NU and TPIF.

Compliance with FERC Regulations

The language of Order 2003 explicitly defines Network Upgrades to "include only facilities at or beyond the point where the Interconnection Customer's Generating Facility interconnects to the Transmission Provider's Transmission System."[1] Accordingly, it is apparent that only those facilities connecting the Generating Facility to the Transmission System *that are radial in nature* can be designated as TPIF. Specifically, for generation interconnection stations with either ring bus or double-breaker double-bus configurations, all breaker positions are to be designated as NU. Avista's Updated Practice is necessary to be in compliance with FERC regulations. FERC has gone so far as to emphasize that any agreements between an Interconnection Customer and Transmission Provider that have classified Network Upgrade facilities as Interconnection Facilities have not been found to be just and reasonable and have been rejected by the Commission.[2]

[1] FERC Order 3003, paragraph 21.
[2] Id.

Impact Upon Retail Customers – Summary

While the Updated Practice is necessary to be in compliance with FERC rules, Avista also assessed the Updated Practice's impact upon retail customers using Project #60 as a case study. While the Updated Practice may not always produce the *maximum* benefit to retail customers, it is clear that the Updated Practice will in nearly all cases accrue positive benefits to retail customers and, in most cases, would accrue greater benefits to retail customers than the Past Practice.

- Primary driver is to focus on achieving the lowest energy rates for our retail customers
- This can be achieved by either of the following:
  (i) Obtaining the lowest energy cost possible (i.e. lower PPA pricing), or
  (ii) Attaining wheeling revenue that offsets required transmission plant investment
- Allocating transmission upgrades as TPIF to a developer results in a higher PPA price
- A higher PPA price due to transmission upgrades being allocated as TPIF limits the potential of a project to be sold to a third-party, thereby reducing the likelihood of Avista retail customers benefiting from wheeling revenue
- By allocating the majority of the upgrades as Network Upgrades, Avista may exercise an additional opportunity to have the developer front those costs, which affords capital flexibility as Avista repays those funds over a 5-20 year period
- As Network Upgrades, the highest possible level of transmission costs are allocated to third-party wholesale transmission customers
- Updated Practice option (b) facilitates benefits to Avista's retail customers in five ways:
  (i) lower PPA pricing
  (ii) increasing the chance of an off-system wheel due to lower PPA pricing
  (iii) lower initial capital investment
  (iv) flexible timing for capital repayment
  (v) third-party transmission customers are allocated ~20% of network upgrades

Impact Upon Retail Customers – Project #60 as a Case Study

When applying the Updated Practice to Project #60, it is apparent that this approach is in the best interest of Avista's retail customers. Were a third party to ultimately purchase the output of Project #60, both practices provide a benefit to Avista's retail customers. In the event Avista is the ultimate purchaser, however, Past Practice would result in approximately 70% greater cost being allocated to Avista's retail customers. Since the cost to wheel a renewable resource off-system represents an approximately 40%-45% adder to current long-term resource costs, it is expected that Avista would likely be the purchaser of an on-system project such as Project #60, at least over a near term planning horizon of approximately ten years. Additionally, considering that Avista's retail customers are expected to most benefit when an IC finds a non-Avista buyer and purchases transmission service from Avista, Updated Practice options (a) and (b) would facilitate a lower PPA price, thereby making an off-system sale of a renewable resource more likely. These considerations point to the Updated Practice as being in the best interest of Avista's retail customers**.** Of the two alternatives available for the Updated Practice, having the IC provide initial up-front funding of the NU is expected to provide a lower long-term cost to retail customers and greater capital funding flexibility.

<u>Project #60 Details</u>

- Total cost of the Dry Creek 230kV generation interconnection project is approximately $3.8 million.
- It is generally understood that any costs attributed to an IC as TPIF will be reflected in, and recovered through, the IC's power sales agreement with its off-taker.
- Annualized cost of capital investment to Avista retail customer is understood to be approximately 11%
- It is estimated that, for purposes of allocating the capital cost of NU transmission assets, approximately 20% of such costs are allocated to Avista's wholesale transmission customers through transmission rates, while approximately 80% of such costs are allocated to Avista's native load customers through retail rates.
- Annual wheeling revenue for a non-PacifiCorp third-party off-taker would be approximately $3.6 million.
- Annual wheeling revenue in the event PacifiCorp is the off-taker is expected to be approximately $330,000 [3].
- Solar projects with a 20% capacity factor must spread transmission costs over 1/5 of all hours ($3.6 million) / (150 MW * 20% * 8760 hrs) = a $13.70/MWh adder for transmission service.

<u>Past Practice – Single TPIF Breaker</u>

This approach allocates the first breaker and metering facilities to the IC as TPIF and the second breaker is allocated to Avista as a Network Upgrade. This option is understood to be inconsistent with FERC policy. This allocation results in a 79%/21% split of the TPIF/NU facilities where the IC would fund $3 million in TPIF and Avista would fund $800,000 in Network Upgrades.

- Annualized cost allocated to Avista retail customers if Avista purchases output - $400,400
- Annualized cost allocated to Avista retail customers if third party purchases output - $70,400 (offset by $3.6 million annually in wheeling revenue)
- Annualized cost allocated to Avista retail customers if PacifiCorp purchases output - $70,400 (offset by ~$330,000 annually in wheeling revenue)

[3] Expected use-of-facilities (UOF) arrangement for Dry Creek 230kV facilities is presumed to, at a minimum, recover annualized capital costs (i.e. 11% of $3 million, or $330,000).

Updated Practice – Designate Both Breakers as Network Upgrades

This approach is understood to be in compliance with FERC policy. Line termination and metering structures would remain as TPIF. This allocation results in a 29%/61% split of TIPF/NU facilities where the IC would fund $1,100,000 in TPIF and Avista would fund $2.7 million in Network Upgrades.

Updated Practice Option (a) – Avista Funds all Network Upgrades: Avista can elect to self-fund the Network Upgrades. Costs will be incorporated into both Avista's state retail and federal transmission rates at time of next rate filing.

- Annualized cost allocated to Avista retail customers if Avista purchases output - $237,600
- Costs allocated to Avista retail customers if third party purchases output - $237,600 (offset by $3.6 million annually in wheeling revenue)
- Costs allocated to Avista retail customers if PacifiCorp purchases output - $237,600 (offset by ~$330,000 annually in wheeling revenue)

Updated Practice Option (b) – IC Provides Initial Funding – Avista Refunds over Time: Avista can elect to have IC provide up-front funding of the Network Upgrades, resulting in no immediate impact to Avista's capital budget or retail rates. Only the carrying costs for the advanced funding would presumably flow through a power sales agreement. IC-funded Network Upgrade costs must be credited or refunded back to IC over a period of no more than 20 years (Section 11.4.1 LGIA). Once credited or refunded, these Network Upgrade costs would be added to Avista's asset base and included in state retail and federal transmission rates. Long-term cost allocations under Option (b) are comparable to Option (a), except for the following considerations:

- Deferred cost allocation to state retail and federal transmission customers
- Cost of money (i.e. FERC interest rate) is expected to be less than Avista's carrying cost of capital, resulting in overall lower costs allocated to both retail and transmission customers

This Updated Practice has been presented to and acknowledged by the Financial Planning and Analysis, Plant Accounting, and Rates groups, the Assistant Treasurer, and the Senior Vice President, Energy Delivery.

References

FERC Order 2003 – Paragraphs 21-22 (abridged, footnotes omitted)
Interconnection Facilities are found between the Interconnection Customer's Generating Facility and the Transmission Provider's Transmission System. *The Commission has developed a simple test for distinguishing Interconnection Facilities from Network Upgrades: Network Upgrades include only facilities at or beyond the point where the Interconnection Customer's Generating Facility interconnects to the Transmission Provider's Transmission System.* The Commission has made clear that Interconnection Agreements are evaluated by the Commission according to the just and reasonable standard. Most improvements to the Transmission System, including Network Upgrades, benefit all transmission customers, but the determination of who benefits from such Network Upgrades is often made by a non-independent transmission provider, who is an interested party. In such cases, the Commission has found that it is just and reasonable for the Interconnection Customer to pay for Interconnection Facilities but not for Network Upgrades. *Agreements between the Parties to classify Interconnection Facilities as Network Upgrades, or to otherwise directly assign the costs of Network Upgrades to the Interconnection Customer, have not been found to be just and reasonable and have been rejected by the Commission.*

Regarding pricing for a non-independent Transmission Provider, the distinction between Interconnection Facilities and Network Upgrades is important because Interconnection Facilities will be paid for solely by the Interconnection Customer, and while Network Upgrades will be funded initially by the Interconnection Customer (unless the Transmission Provider elects to fund them), the Interconnection Customer would then be entitled to a cash equivalent refund (i.e., credit) equal to the total amount paid for the Network Upgrades, including any tax gross-up or other tax-related payments. The refund would be paid to the Interconnection Customer on a dollar-for-dollar basis, as credits against the Interconnection Customer's payments for transmission services, with the full amount to be refunded, with interest within five years of the Commercial Operation Date (emphases added).

FERC Order 2003 – Paragraph 694
The Commission recognizes that its policy of requiring refunds to be paid to an Interconnection Customer for the cost of Network Upgrades constructed on its behalf is a controversial one. However, the Commission instituted this policy to achieve a number of important goals. First, consistent with the Commission's long-held policy of prohibiting "and" pricing[4] for transmission service, the crediting policy ensures that the Interconnection Customer will not be charged twice for the use of the Transmission System. The Commission determined that it is appropriate for the Interconnection Customer to pay initially the full cost of Interconnection Facilities and Network Upgrades that would not be needed but for the interconnection, but once the Generating Facility commences operation and delivery service begins, it must receive transmission service credits for the cost of the Network Upgrades. This ensures that the Interconnection Customer will not ultimately have to pay both incremental costs and an average embedded cost rate for the use of the Transmission System. Second, the Commission's crediting policy helps to ensure that the Interconnection Customer's interconnection is treated comparably to the

[4] When a Transmission Provider must construct Network Upgrades to provide new or expanded transmission service, the Commission generally allows the Transmission Provider to charge the higher of the embedded costs of the Transmission System with expansion costs rolled in, or incremental expansion costs, but not the sum of the two. Hence, "and" pricing is not permitted.

interconnections that a non-independent Transmission Provider completes for its own Generating Facilities. The Transmission Provider has traditionally rolled into its transmission rates the cost of Network Upgrades required for its own interconnections, and the Commission's crediting policy ensures that Network Upgrades constructed for others are treated the same way. Finally, the policy is intended to enhance competition in bulk power markets by promoting the construction of new generation, particularly in areas where entry barriers due to unduly discriminatory transmission practices may still be significant. The policy is therefore consistent with the Commission's long-held view that competitive wholesale markets provide the best means by which to meet its statutory responsibility to assure adequate and reliable supplies of electric energy at just and reasonable prices.[5]

Avista Tariff – LGIA 11.4 Transmission Credits.

11.4.1 Repayment of Amounts Advanced for Network Upgrades. Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection Customer pursuant to Article 5.17.8 or otherwise, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Large Generating Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date: (1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or (2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.

[5] The Commission's crediting policy has also withstood judicial review. In an opinion issued February 18, 2003, the D.C. Circuit Court of Appeals affirmed Commission orders requiring a Transmission Provider to provide credits to Interconnection Customers for the cost of short-circuit and stability Network Upgrades. Entergy Services, Inc. v. FERC, 319 F.3d 536 (D.C. Cir. 2003). The court stated that "[t]he Commission's rationale for crediting network upgrades, based on a less cramped view of what constitutes a 'benefit,' reflects its policy determination that a competitive transmission system, with barriers to entry removed or reduced, is in the public interest." Id. at 543-44. The court concluded that "the Commission has reasonably explained that its crediting pricing policy avoids both gold plating and less favorable price signals such that the enlarged transmission system, which it views as a public good, can function reliably and continue to expand." Id. at 544

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:		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

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) NEEDS ASSESSMENT- a synopsis of the problem, the current state and recommended solution
2) COST- the cost of the recommended solution
3) DOCUMENT SUMMARY- benefit to the customer
4) RISK- of not approving the business case
5) APPROVALS- who reviewed and approved the recommended solution

<< 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 two 30MVA transformers. The business case also includes substantial 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 that they can continue to have the reliability of the electric system that they have become accustomed to receiving. This project has been approved and prioritices by the Engineering Roundtable Committee.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2017-64

Cost of Solution: $43,800,000

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	
2.1	Karen Kusel	Project Cost Update, 2022 Template	6/2022	

GENERAL INFORMATION

Requested Spend Amount	$43,800,000
Requested Spend Time Period	6 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]

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 levels 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.]

2018 $1,100,000

2019 $3,000

2020 $2,300,000

2021 $28,000,000

2022 $10,600,000 (Expected Spend)

2023 $1,950,000 (Forecast)

2023 – 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:	DocuSigned by: Glenn J Madden 7D4B3DF5CBD8463	Date:	Jun-28-2022 | 3:50 PM PDT
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Josh DiLuciano A3C7187456584DB	Date:	Jul-05-2022 | 7:43 AM PDT
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 >>

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:	Glenn J Madden	Date:	1-3-2022
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	[illegible]	Date:	1/4/2022
Print Name:	Josh DiLuciano		
Title:	Director, Electrical Engineering		
Role:	Business Case Sponsor		

Signature:	Damon Fisher	Date:	1/4/2022
Print Name:	Damon Fisher		
Title:	Principle Engineer		
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

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 $2,000,000 is needed to complete the planned 2023-2027 projects . This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North.

The Business Case contains two projects:

- *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*	*5/02/2022*	
1.0				
1.1				
2.0				

GENERAL INFORMATION

Requested Spend Amount	$2,000,000
Requested Spend Time Period	*1 year*
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

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.

1.1 What is the current or potential problem that is being addressed? *NERC Reliability Standards and NESC loading capacities.*

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: Customer benefits by having a Transmission System in compliance with Federal Code and State Law.*

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

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.

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-Built confirmation of mitigation measures.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

CAI Structure Analysis Results_BEA-BLD.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.

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")*	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.

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)]

Option	Capital Cost	Start	Complete
[Recommended Solution]	*$2.0M*	*01-2023*	*12-2027*
[Alternative #1]	*$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.

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.

Beacon-Boulder #1 115kV Rebuild (east of Irvin): 2020-2023
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. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

3.2 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.

3.3 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.

4. APPROVAL AND AUTHORIZATION

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:	APPROVED By Ken Sweigart at 11:38 am, Sep 09, 2022	Date:	
Print Name:			
Title:			
Role:	Business Case Owner		

Signature:		Date:	9/9/2022
Print Name:	Josh DiLuciano		
Title:	Vice President - Energy Delivery		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

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 2024.

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 $3,500,000 is needed to complete the mitigations by 2024. 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*	*4/28/2022*	
1.0				
1.1				
2.0				

GENERAL INFORMATION

Requested Spend Amount	$3,500,000
Requested Spend Time Period	*2 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

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).

1.1 What is the current or potential problem that is being addressed? *Clearance violations.*

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: Customer benefits by having a Transmission System in compliance with Federal Code and State Law.*

1.3 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 2024 will show us taking eleven 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.*

1.4 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-Built confirmation of mitigation measures.*

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

CAN-0009_FAC-008 FAC-009.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.

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.

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)]

Option	Capital Cost	Start	Complete
Mitigate Violations	*$3.5M*	*01-2023*	*12-2024*
[Alternative #1]	*$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.

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. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

3.2 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.

3.3 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.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Low Priority Rating 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: **APPROVED** *By Ken Sweigart at 11:35 am, Sep 09, 2022* Date: ____________
Print Name:
Title:
Role: Business Case Owner

Signature: ____________ Date: 9/9/2022
Print Name: Josh DiLuciano
Title: Vice President - Energy Delivery
Role: Business Case Sponsor

Signature: ____________ Date: ____________
Print Name:
Title:
Role: Steering/Advisory Committee Review

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, which benefit all of Avista's electric customers. 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. Historical 4-year annual costs have averaged just under $400k.

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.

Without capital funding the acquisition of these permits would still take place and O&M funding would be utilized.

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	*Toni Pessemier*	*Update template Version 04.21.2022*	*8/31/22*	

GENERAL INFORMATION

Requested Spend Amount	$400,000
Requested Spend Time Period	annually
Requesting Organization/Department	American Indian Relations
Business Case Owner | Sponsor	Toni Pessemier | Latisha Hill
Sponsor Organization/Department	/ Community & Economic Vitality
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 *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

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. The renewal process on both the Spokane and Colville reservations is underway with support from BIA and Tribal Realty offices. While some permits may be obtained for the appraised value, other permits may require additional effort, mediation and compensation.

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.

2. PROPOSAL AND RECOMMENDED SOLUTION

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	400,000	01 2023	12 2023
Relocate transmission lines off of the SpokaneTribal land	$61,190,000	01 2023	12 2023

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The 400,000 is a placeholder for permitting costs which has run historically:

	2018	2019	2020	2021	
	Actuals				average
Coeur d'Alene Benewah-Pine Creek 230kV Trans	5,311	5,335	5,943	6,006	
Nez Perce 115 Distribution	39,944	28,484	21,292	19,875	
onfederated Salish & Kootenai Tribes Transmission	63,816				
Spokane Tribe Distribution	73,911	80,062	42,643	253,983	
Spokane Tribe 115kV Transmission	103,083	205,060	44,952	36,876	
Colville Tribe Distribution	43,792	99,932	47,136	50,733	
	329,857	418,873	161,966	367,473	319,542

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 increased.

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.

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. MONITOR AND CONTROL

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 VP of Community & Economic Vitality along with the Sr. VP of Environmental & Real Estate provide oversight with periodic engagement of the VP General Counsel and VP Chief Regulatory Counsel as needed.

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.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Tribal Permits and Settlements 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: Toni Pessemier C3A839FC59C3476...	Date:	Sep-02-2022 | 6:50 PM PDT
Print Name:	Toni Pessemier		
Title:	American Indian Relations Advisor		
Role:	Business Case Owner		
Signature:	DocuSigned by: Latisha Hill 32D513B5347E434...	Date:	Sep-06-2022 | 7:14 AM PDT
Print Name:	Latisha Hill		
Title:	VP Community & Economic Vitality		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			

Title:	
Role:	Steering/Advisory Committee Review

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) NEEDS ASSESSMENT- a synopsis of the problem, the current state and recommended solution
2) COST- the cost of the recommended solution
3) DOCUMENT SUMMARY- benefit to the customer
4) RISK- of not approving the business case
5) APPROVALS- who reviewed and approved the recommended solution

<< 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). This project is approved and prioritized by the Engineering Roundtable Committee.

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: $26,200,000

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	$26,200,000
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. (2022 Note: Project is scheduled to complete in 2024 because of delays for getting planned outages.)

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.

DocuSigned by:

Signature: Glenn J Madden   Date: Jun-28-2022 | 3:36 PM PDT

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Print Name: Glenn Madden

Title: Manager, Substation Engineering

Role: Business Case Owner

DocuSigned by:

Signature: Josh DiLuciano   Date: Jul-05-2022 | 7:41 AM PDT

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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 North Lewiston 230/115 kV Transformer 1 (McGraw-Edison Serial Number C-06237-5-2) located in Lewiston, ID failed in February 2021. A replacement transformer has been ordered and will be installed in 2022. The North Lewiston 230/115kV Transformer 1 provides the transformation capacity needed for the system to meet performance requirements as defined by System Planning and System Operations.

The North Lewiston 230/115 kV Transformer 1 was 40 years old when it failed. Following the failure, an investigation was performed with testing and an internal inspection. The investigation concluded the transformer had a failed winding. The decision to replace the 230/115 kV Transformer 1 was made based on an evaluation of alternatives which also included rebuilding the existing transformer and utilizing a spare transformer within Avista's system.

Service Code: Electric Direct

Jurisdiction: Allocated North

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Karen Kusel	Draft, Preliminary Dollars	04/26/2021	
Draft_SK	Sara Koeff	Revision	06/1/2021	
Draft_rev2	Keri Gross	Revision	06/07/2021	

GENERAL INFORMATION

Requested Spend Amount	$4,100,000
Requested Spend Time Period	2 Years
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | Heather Rosentrater
Sponsor Organization/Department	M08 / Substation Engineering
Phase	Planning
Category	Project
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The night of 2/27/2021 there was a B to ground fault on the North Lewiston tap of the Lolo-Pound Lane 115 kV line. The following morning, 2/28/2021, a major alarm came in on the North Lewiston 230/115kV Transformer 1. The alarm was driven by the Online Dissolved Gas Analysis (DGA) Monitor. The DGA showed an increase in multiple gasses coinciding with the timing of the transmission line fault. Due to the increase in gasses, the transformer was taken out of service to perform electrical testing on it. The excitation current and sweep frequency response analysis (SFRA) tests had irregularities in the test results. An internal inspection was performed, which confirmed that there was a H2 (B phase) winding turn-to-turn fault and at least one parallel winding strand that had broken open. The North Lewiston 230/115 kV Transformer 1 was deemed to have a failed winding and unable to be put back into service. For complete details on the investigation effort see “North Lewiston Auto 1 Investigation Analysis” report.

1.2 Discuss the major drivers of the business case

The major driver for this project is Failed Plant & Operations. The North Lewiston 230/115 kV Transformer 1 provides the transformation capacity needed for Avista's system to meet performance requirements as defined by System Planning and System Operations.

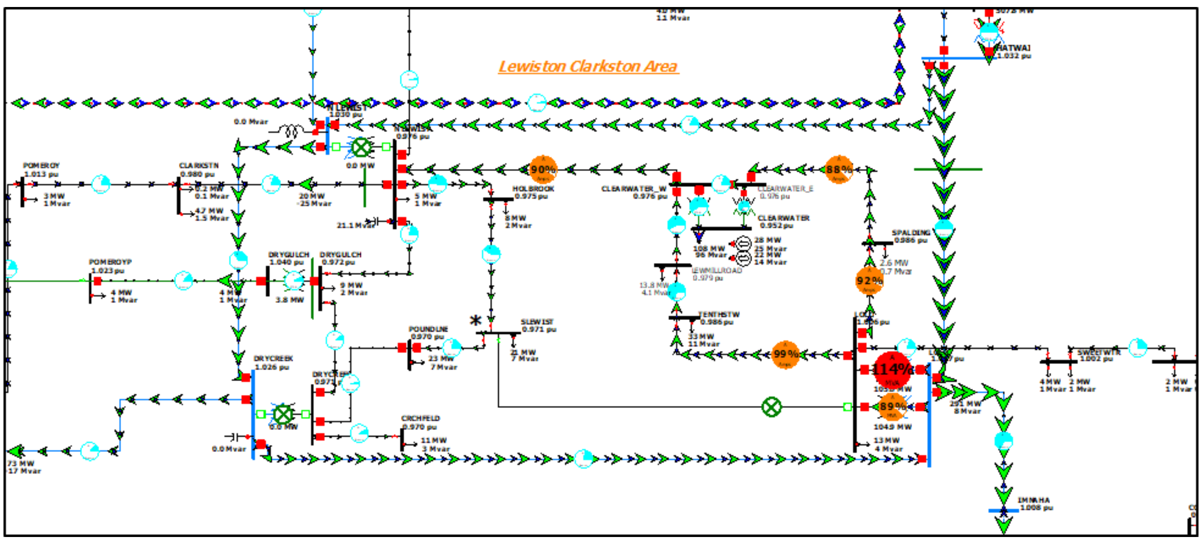
1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The 2019-2020 Avista System Assessment, Appendix D documents the studies performed by System Planning showing what may result on Avista's system with the loss of the North Lewiston 230/115kV Transformer. Studies were performed according to NERC standard TPL-001-4 requirement R2.1.5; below is a summary from the Assessment.

• Overload of the Lolo #1 230/115kV Transformer for outages involving the Dry Creek 230/115kV Transformer, Lolo #2 230/115kV Transformer or the Dry Creek 115kV bus. (See below figure)

• Overload of the Dry Creek – North Lewiston 115kV Transmission Line for outages involving the Lolo 115kV bus.

• Area low voltage for outages involving the Lolo 115kV bus.



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.

Replacing the North Lewiston 230/115 kV Transformer 1 will return the electric system in the Lewiston / Clarkston area to normal operating conditions.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Avista crews performed initial testing of the North Lewiston 230/115 kV Transformer. The test results indicated performance issues and further testing was needed. North American Substation Services (NASS) performed a Sweep Frequency Response Analysis (SFRA). Doble Engineering analyzed the Avista and NASS test results. An internal inspection of the transformer showed evidence of broken winding coil and coil movement.

See the “North Lewiston Auto 1 Investigation Analysis” attachment for inspection and testing details.

See the “2019-2020 Avista System Assessment - V2 - Appendix D” attachment for details of system performance concerns associated with the transformer outage.

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 North Lewiston 230/115 kV Transformer had a H2 (B phase) winding turn-to-turn fault and at least one parallel winding strand broke open. The transformer was deemed to have a failed winding and unable to be put back into service.

See the “North Lewiston Auto 1 Investigation Analysis” for details on the condition of the failed transformer.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
[Recommended Solution] Replace 230/115 kV Transformer	$4.1M	02-2021	6-2022
[Alternative #1] Repair 230/115 kV Transformer	Unknown	02-2021	Unknown
[Alternative #2] Relocate 230/115 kV Transformer to NLW	N/A	02-2021	N/A

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Project cost and project completion date were priority considerations for restoring the transmission system to meet performance requirements in the Lewiston/Clarkston area. Replacing the failed North Lewiston 230/115 kV Transformer has the lowest project cost and restores the transmission system with the shortest and most predictable timeline.

See “North Lewiston Auto Transformer Failure and Replacement” for analysis of the project 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.**

2021 – Purchase new transformer, remove old transformer and associated equipment, engineering / drafting costs. (~$ 3.35M)

2022 – Receive new transformer at North Lewiston Substation, install new transformer and associated equipment, test and commission new transformer, engineering / drafting costs. (~$ 0.75M)

There will be no substantial increase in O&M expenses after this transformer 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.

This business case impacts work within Transmission and Distribution by postponing a few projects about two months.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Alternative #1: The option to repair the existing failed transformer has an unknown cost and project completion due to the difficulty of locating a domestic facility capable of repairing the atypical design. If a repair facility is located, there are concerns if the repair could bring the existing transformer to current component specifications as quick as or quicker than purchasing a new transformer. Additionally, there are cost and timeline concerns with the round-trip transportation of the existing transformer, including possibly to an overseas facility, due to the present worldwide pandemic restrictions and shipping interruptions.

Alternative #2: Avista does not own a spare 230/115 kV Transformer or have sufficient capacity in the remaining parts of the system to relocate an already in service 230/115 kV Transformer.

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.

February/March 2021 – Inspection, testing, and analysis of options leading to decision to replace autotransformer

Remainder of 2021 – Order replacement transformer. Engineering to scope and design replacement. Remove/recycle failed transformer by contractor. Site prep work is completed before installation begins.

2022 – New transformer is received onsite. Avista crews complete installation of transformer. Testing and Commissioning is completed. Autotransformer is energized by mid-year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Perform:

The proposed investment is critical to serving our customers well. The North Lewiston 230/115 kV Transformer is required to safely and responsibly serve our customers. Once it was determined to have failed, Avista performed timely and necessary analysis to determine the most affordable path forward. Purchasing a new transformer to replace the failed transformer provides 'Better Energy for Life'.

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

Based on System Planning's 2019-2020 System Assessment, the North Lewiston 230/115 kV Transformer is necessary to meet performance requirements. Replacing the transformer will return the system to its normal operating condition.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Substation Engineering, Protection Engineering, GPSS Electric Shop, GPSS Mechanical/Structural Shop, GPSS Relay Shop, Drafting Department, System Planning, System Operations, Network Communications, Project Accounting, SCADA Support, Asset Management.

2.8.2 Identify any related Business Cases

There are no related Business Cases.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Capital Planning Group, Engineering Roundtable

3.2 Provide and discuss the governance processes and people that will provide oversight

Any major changes to the project will go to the Engineering Round Table (ERT). The Substation Engineering Manager and System Operations will provide oversight to the project.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The Lead Substation Engineer will coordinate decisions through those who provide oversight and document those decisions as necessary.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the North Lewiston Auto Transformer Replacement 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:	1-3-2022
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	Heather Rosentrater	Date:	1-4-2022
Print Name:	Heather Rosentrater		
Title:	Senior VP, Energy Delivery		
Role:	Business Case Sponsor		

Signature:	Damon Fisher	Date:	1/4/2022
Print Name:	Damon Fisher		
Title:	Engineering Roundtable		
Role:	Steering/Advisory Committee Review		

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, TSA directives, 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 $4.5M. 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 on asset condition, life-cycle management, technology enhancements, and requests by affected stakeholders including System Operations, Distribution Operations, and Power Supply.

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	
0.2	Craig N Figart	Draft version of 2020 business case	07.17.2020	Updated Executive Summary
1.0	Craig N Figart	Final version of 2020 business case	09.21.2020	Based on Magruder input.
2.0	Jeremiah Webster	formatting to keep the fonts consistent, removed some of the blue help text, and deleted the comments	12.15.2020	
3.0	Craig N Figart	Updated per $350k capital funding increase for 2021 due to EMS upgrade	07.05.2021	
4.0	Craig N Figart	Updated per $490k capital funding increase for 2021 due to EMS upgrade multi-year budgeting, firewall refresh, file storage expansion	09.10.2021	2021-2025 total revised from $4.35M to $4.84M.
5.0	Craig Figart	Updated version for 2022 business case	08.03.2022	

GENERAL INFORMATION

Requested Spend Amount	$4,500,000
Requested Spend Time Period	*5 years*
Requesting Organization/Department	T&D - SCADA/EMS/DMS - System Operations
Business Case Owner | Sponsor	Craig N Figart | Michael 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. Other drivers are Customer Service Quality & Reliability and Performance & Capacity. 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

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

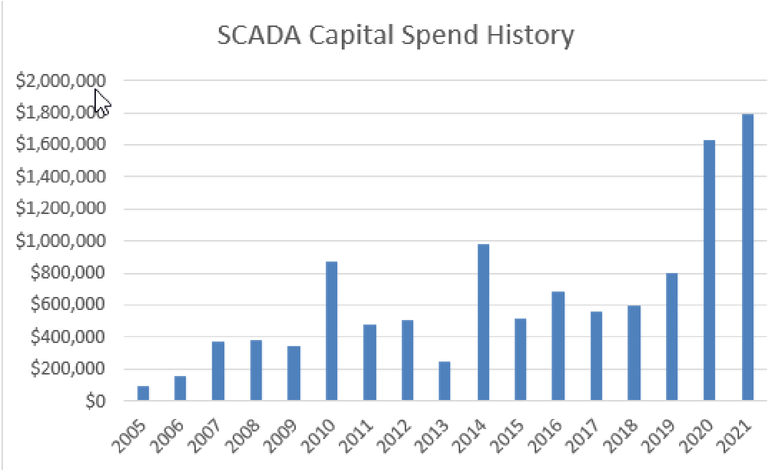
2. PROPOSAL AND RECOMMENDED SOLUTION

[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)]

Option	Capital Cost	Start	Complete
Fully Funded "SCADA – SOO and BuCC" business case	$1.1 M (reqst'd) $0.9M (apprvd)	01 2022	12 2022
Do Nothing	*$0*		

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

This capital request was prepared based on typical average annual $700k costs required to meet the needs for this business case. Additional $1M funding is included beginning in 2027 when we plan to upgrade our main EMS system recently upgraded in 2021.



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 requested capital will be spent on such efforts as refresh of network equipment, disk storage and backup systems, computer hardware and related software applications and systems, database backend systems, SCADA telemetry head-end equipment, SCADA UPS and battery backup systems, etc.. And of course, this business case also includes costs to meet security and NERC/CIP compliance related objectives and obligations.

One project that will reduce annual O&M by $30,000 is the Operator Training Simulator (OTS) project that will take advantage of the Avista's existing GE SCADA system to add OTS functionality requiring much cheaper annual licensing than the current disparate IncSys power system training simulator.

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, like most projects in this business case, is required to be completed in order to upgrade hardware and software that is no longer supported.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Not applicable

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.

This business case is comprised of multiple individual capital projects that all close upon completion over the course of the next five years, at which time they are transferred to plant and become used-and-useful.

There are two "revolving" projects, however, SCADA Hardware Refresh and SCADA Expansion, that are for minor refresh and expansion items like computer desktop pcs, monitors, etc. These projects are placed into service immediately and become used-and-useful right as they are purchased and deployed.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

As previously mentioned, Asset Condition is the major driver of the business case. Other drivers are Customer Service Quality & Reliability and Performance & Capacity. 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.

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 capital requested above is considered a prudent investment as it is required 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 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, TSA directives, 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).

Further justification of the need of this business case is listed below.

o There are numerous mandates in effect which compel these expenditures, numerous NERC Standards, and PHMSA’s Control Room Management rule, in particular (49 CFR Parts 192 and 195).

o There is no practical risk mitigation should we fail to meet these requirements.

o This is a continuous program. Work is started and completed throughout each year, and in some cases, such as major upgrades, spans multiple years.

o 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.

o 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.”

o The amount requested is based partially upon historical spending needs, and partially on known upcoming major projects.

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 Operators
    - Gas Controllers
    - Energy Accounting & Risk Management
    - Neighboring utility control centers
    - RC West 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

Not applicable

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The steering committee/advisory group for initial and ongoing vetting and department priorization process includes the members from the entire SCADA team as needed, but more notably the following:

- Director of System Operations and Planning

- Manager of Energy Management Systems (EMS/DMS)
- Senior System Operations Project Manager
- Sr Security Engineer

3.2 Provide and discuss the governance processes and people that will provide oversight

Individual projects are governed by the SCADA team member assigned to the project as project lead who is tasked with scheduling and coordinating all the work associated with the project.

Project oversight is provided by the SCADA manager primarily, but also to the assigned project lead.

The steering committee provides governance and oversight of this business case. The Manager of EMS/DMS has monthly meetings scheduled within the Energy Management Systems group to track progress of the various capital projects that comprise the total business case.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Decision-making, prioritization, and change requests at the individual capital project level are taken care of within the Energy Management Systems group under manager supervision.

Any need for substantial change requests to capital projects that would deviate from the original Capital Project Request (CPR) are documented and submitted to Project Accounting as a revised CPR. Change requests and resulting decisions that lead to significant changes in project scope are documented in the project charter documentation and revisions to the original version and stored in SCADA's SharePoint site.

Prioritization for each individual project within this business case is performed by the SCADA manager as part of the on-going updates to SCADA's annual capital budget spreadsheet. If the sum total of all SCADA capital projects is expected to exceed the approved Business Case funding, then a Business Case Change Request must be approved by the Steering Committee and submitted to Project Accounting.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *SCADA – SOO and BuCC 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:	Craig N Figart	Date:	Aug 22, 2022
Print Name:	Craig N. Figart		
Title:	Mgr Energy Mgmt Systems		
Role:	Business Case Owner		

Signature:	Michael A Magruder	Date:	Aug 22, 2022
Print Name:	Michael Magruder		
Title:	Dir Trans Ops & Sys Planning		
Role:	Business Case Sponsor		

Signature:	Bradley T Calbick	Date:	Aug 22, 2022
Print Name:	Brad Calbick		
Title:	Sr Sys Ops Project Mgr		
Role:	Steering/Advisory Committee Review		

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) NEEDS ASSESSMENT- a synopsis of the problem, the current state and recommended solution
2) COST- the cost of the recommended solution
3) DOCUMENT SUMMARY- benefit to the customer
4) RISK- of not approving the business case
5) APPROVALS- who reviewed and approved the recommended solution

<< 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.

This Business Case includes the following Expenditure Requests:

- 2000: Substation – Capital Spares
- 2204: Substation Rebuilds
- 2215: Substation Asset Mgmt Capital Maintenance

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.

See the 5-year Funding Request for current budget requests.

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	
2.1	Karen Kusel	Cost update, 2022 Template	6/2022	

GENERAL INFORMATION

Requested Spend Amount	$25,000,000 - $50,000,000 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.

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.

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:	DocuSigned by: Glenn J Madden 7D4B3DF5CBD8488...	Date:	Jun-28-2022 | 3:47 PM PDT
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Josh DiLuciano A3C71874F6564DB...	Date:	Jul-05-2022 | 8:26 AM PDT
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		

EXECUTIVE SUMMARY

The Transmission Minor Rebuild 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 $4,350,000 is needed to complete the mitigations as follows:

- *ER 2057, BI AMT12 and AMT13 ($2,000,000): Wood and Steel Pole Inspections (FAC-501-WECC-1, TMIP)*
- *ER 2057, BI XT902 ($2,000,000): Aerial and ground inspections (FAC-501-WECC-1, TMIP, and Ad Hoc)*
- *ER 2254, BI AMT10 ($350,000): 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*	*4/28/2022*	
1.0				
1.1				
2.0				

GENERAL INFORMATION

Requested Spend Amount	$21,750,000
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	Multiple (see Executive Summary)

1. BUSINESS PROBLEM

The Transmission Minor Rebuild 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: $2.0M) in previous years was funded through the Operations Storms blanket Business Case.

1.1 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.*

1.2 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, 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.*

1.3 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.*

1.4 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-Built confirmation of mitigation measures.*

1.5 Supplemental Information

1.5.1 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

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

	A	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	1
3	0	8	Replace		Confirmed, H w 1 SG	3	str	5
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		

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)]

Option	Capital Cost	Start	Complete
Mitigate Deficiencies	*$21.75M*	*01-2023*	*12-2027*
[Alternative #1]	*$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.

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. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

3.2 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.

3.3 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.

4. APPROVAL AND AUTHORIZATION

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:	APPROVED By Ken Sweigart at 11:37 am, Sep 09, 2022	Date:	
Print Name:			
Title:			
Role:	Business Case Owner		

Signature:		Date:	9/9/2022
Print Name:	Josh DiLuciano		
Title:	Vice President - Energy Delivery		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

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 $50,000,000 is needed to complete the projects as follows:

- *ER 2629, BI PT108 ($5,500,000): Hatwai-Moscow 230kV Transmission Line Rebuild*
- *ER 2596, BI LT900 ($44,500,000): 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*	*5/02/2022*	
1.0				
1.1				
2.0				

GENERAL INFORMATION

Requested Spend Amount	$50,000,000
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

The Transmission Major Rebuild – Asset Condition Business Case covers investments 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.

1.1 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.

1.2 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: Customer benefits by having a reliable Transmission System capable of supporting service needs.

1.3 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.

1.4 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 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.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

2016 Lolo-Oxbow 230kV Model Asset Management Plan Rev a.docx
LOL-OXB – model results.pptx
HAT-MOS TT Data Breakdown.xlsx
Palouse (Pullman-Moscow) Transmission Reinforcement Program (2016 Summary).docx

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.

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
	Ninth & Central			Spokane					

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

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.

The Hatwai-Moscow 230kV Line is further down on the Asset Condition Risk Index, but recent Test & Treat data shows that 20%-25% of the line structures need to be replaced in the very short term. This line is the same vintage as the Benewah-Moscow 230kV that was rebuild due to Asset Condition in 2018.

2. PROPOSAL AND RECOMMENDED SOLUTION

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
Recommended Solution	*$50M*	*01-2023*	*12-2027*
[Alternative #1]	*$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 2629, BI PT108 ($5,500,000): The Hatwai-Moscow 230kV Transmission Line Rebuild Project is scheduled to design and construct between 2022-2023.*
- *ER 2596, BI LT900 ($44,500,000): The Lolo-Oxbow 230kV Transmission Line Rebuild Project began construction in 2020, and will complete in 2027. Used and Useful and Transferred to Plant in Fall/Winter of each year between 2023 and 2027.*

[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.

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. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

3.2 Provide and discuss the governance processes and people that will provide oversight

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain.

3.3 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.

4. APPROVAL AND AUTHORIZATION

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: APPROVED
By Ken Sweigart at 11:39 am, Sep 09, 2022 Date:
Print Name:
Title:
Role: Business Case Owner

Signature: Date: 9/9/2022
Print Name: Josh DiLuciano
Title: Vice President - Energy Delivery
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

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) NEEDS ASSESSMENT- a synopsis of the problem, the current state and recommended solution
2) COST- the cost of the recommended solution
3) DOCUMENT SUMMARY- benefit to the customer
4) RISK- of not approving the business case
5) APPROVALS- who reviewed and approved the recommended solution

<< Both the Executive Summary and Version History should fit into one page >>

The Cabinet 230kV Bus Isolating Breakers Project is comprised of installing two breakers to isolate the 230kV bus at Cabinet from the GSUs (Generation Step-Up transformers). Several times in the last few years an issue with a GSU has caused an entire bus outage at Cabinet Gorge HED which has limited generation output and caused several operational issues. These new breakers will isolate future GSU issues to just that particular equipment without affecting the whole bus. This project has been approved and prioritized by the Engineering Roundtable group. This project is important to customers because it will help to ensure that efficient and affordable clean energy from hydro-generation units is utilized when available.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2017-71

Cost of Solution: $2,550,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart / Jeff Schlect	Initial Version	4/14/2017	Initial Version
2.0	Karen Kusel / Glenn Madden	Update to 2020 Template	6/2020	
2.1	Karen Kusel	Project Cost Update, 2022 Template	6/2022	

GENERAL INFORMATION

Requested Spend Amount	$2,550,000
Requested Spend Time Period	3 years
Requesting Organization/Department	Transmission Operations
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Initiation
Category	Project
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]

Transmission Operations has identified reliability issues with the existing 230 kV circuit breaker arrangement at Cabinet substation. This is an ongoing issue (last identified in 2011), but recent outages and reliability history are driving a system correction. The latest redesign in the late 90's incorporated the Cabinet Gorge hydro facility into the 230 kV Western Montana Hydro transmission system, but did not include 230 kV breakers to isolate the generation from the transmission system, which resulted in one zone of protection encapsulating both the GSU's and the 230 kV bus. The deficiency with this design is that it is not selective enough and drops all 230 kV lines, the 230/115 kV autotransformer and all Cabinet Gorge generation for issues with the GSU's. This project proposes a reliability upgrade to Cabinet substation consisting of a new 230 kV breaker for each GSU, relocating (2) termination towers and adding new 230 kV bus and GSU relay protection.

The primary issues with the existing arrangement are as follows:

- A GSU fault or mis-operation, which should only isolate a single GSU and two hydro units (~130 MW), currently clears the 230 kV bus resulting in loss of four hydro units (~260 MW), loss of both 230 kV lines, generation restrictions at Noxon, triggering a Remedial Action Scheme (RAS) and the loss of the primary 115 kV source into the Sandpoint area.
- During a planned outage to the Cabinet-Bronx-SandCreek 115 line, a GSU fault results in the above mentioned issues plus the loss of all connected 115 kV load and the Cabinet Gorge primary and backup station service. This leaves Cabinet Gorge on a single diesel generator.
- A complete plant outage including the loss of Primary and backup station service puts the plant at risk for over-topping the spill gates and greatly reduces reliable operations of the plant subsystems due to the reliance on a single diesel generator. This project does not correct this issue for a 230 bus outage, but corrects it for unplanned GSU outages.

- Lack of a GSU high side circuit breaker requires unit testing or energization from a single 230 kV line. This requires an outage of the remaining 230 kV line and the autotransformer and subsequent impacts to those systems.

Seven recent Cabinet outages have resulted in NERC Event Reports. This project would reduce the average amount of generation lost, reduce the number of Bulk Electric System (BES) elements impacted and reduce customer load lost per event. The project also reduces the number of events that require NERC reporting and would better isolate and identify issues when they occur.

Cabinet unit #1 failed during a full load rejection on April 4th, 2017 due to a Sudden Pressure Relay misoperation on GSU B. Though unit #1 may have failed under any plant wide full load rejection, in this instance, a GSU B high side circuit breaker would have isolated the trip to only units #3 & #4 allowing units #1 & #2 to continue operating though the event. The estimated lost opportunity cost alone, through the end of 2017 was $2.8M.

Again, two 230 kV circuit breakers should have been installed between the Cabinet 230 kV bus and the GSU's for system isolation during plant construction (or during the last substation improvements). Given they were not in the initial designs, they need to be included to improve the reliability of these facilities going forward.

1.1 What is the current or potential problem that is being addressed?

A GSU fault causes an outage of the 230kV bus and all hydro units in the Cabinet Gorge Hydro Electric Dam (HED).

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 & Capacity – Installing breakers to isolate service to smaller portions of the HED and switchyard to allow for safer performance of the local system.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

After several ouages it is time to fix this issue so that future outages are avoided.

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.

Ability to isolate and control smaller portions of the station will provide the ability to test and maintain all equipment efficiently.

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]

Event Reports – refer to System Operations SharePoint Site (non-public information).

Summer and Winter Seasonal Operating Studies – 2205 to present (non-public information).

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 operational issues and loss of generation associated with a GSU transformer failure.

Alternative 2 – Install 230kV Bus Isolating Breakers:
This alternative installing two breakers to isolate the 230kV bus at Cabinet from the GSU transformers. This will isolate future issues with the GSUs and not create an outage on the entire 230kV bus. This is the recommended alternative.

Alternative 3 – Rebuild Cabinet Substation:
This alternative is not recommended because of physical constraints. The space is very limited and insufficient to improve the breaker arrangement to any acceptable design without converting to a cost prohibitive Gas Insulated Bus arrangement ($15M).

Alternative 4 – Build New Switching Station South of the River:
This alternative is not recommended because it is cost prohibitive and does not resolve the issues identified. This option still requires installing a circuit breaker on the high side of each GSU, but would add the additional cost of connecting from the existing yard to a new station south of Cabinet Gorge on the 230 kV corridor ($7M). This does have additional benefits, but requires the same initial buildout as the recommended solution.

Transmission Operations recommends correcting the initial design at Cabinet substation by installing (2) new 230 kV breakers (one for each GSU), relocating the (2) existing termination towers and updating 230 kV bus and GSU relay protection.

Benefits include: 1) increased reliability and reduced exposure to GSU faults and mis-operations 2) improved Cabinet Gorge availability of primary and backup station service 3) improved flexibility in operations between the 230 kV bus and each GSU and 4) true isolation between generation and transmission facilities and operations.

There is no impact to equipment fault duty and this alternative does not result in any additional equipment issues.

This alternative is the most cost effective option considered and provides the most operational flexibility, reliability and resiliency. This alternative mitigates identified operational issues for both Transmission Operations and Generation Operations.

Option	Capital Cost	Start	Complete
Install 230kV Bus Isolating Breakers	$2.6M	2023	2024
Alternative 1 – Do Nothing / Status Quo:	$0M		
Alternative 3 – Rebuild Cabinet Substation	$15M		
Alternative 4 – Build New Switching Station South of the River	$7M		

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.

Installing isolating breakers is the most cost effective option.

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.]

2021 - $1,500,000

O&M will increase due to the addition of equipment to inspect and maintain but unplanned major outages will be reduced.

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?]

The outcome of this business case when fully implemented will limit the generation lost due to other outages thereby improving the generation part of the business.

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 is scheduled for 2021 and the project will closeout in 2022.

Transfers to plant will complete when breakers are 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

Since this is a hydroelectric location, this project will help to provide reliable energy from generation to transmission line.

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 estimated lost opportunity cost, through the end of 2017 was $2.8M for an outage due to a GSU misoperation. This project is clearly a prudent investment when the cost of a single outage could have paid for the project.

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 is designated as the Steering Committee for this project and is responsible for prioritization of this project compared to other transmission and substation requests.

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 Cabinet 230kV Bus Isolating Breakers 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: Glenn J Madden 7D4B3DF5CBD8463...	Date:	Jun-28-2022 | 3:51 PM PDT
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Business Case Owner		

Signature:	DocuSigned by: Josh DiLuciano A3C71874F6564DB...	Date:	Jul-05-2022 | 12:54 PM PDT
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

Within the natural gas distribution system of all three states, there are sections of gas pipelines that are located above grade at crossings such as bridges, small ditches, irrigation canals, etc. These above grade crossings have a variety of construction techniques and supporting structures which vary in age, condition, design, compliance, and overall risk. This Business Case provides capital expenditure for remediating those sites where regular O&M maintenance activities (e.g. replacement of pipe supports and/or pipe wrap) are no longer adequate. Facilities needing capital remediation will be identified and prioritized by applying a risk-based scoring methodology to all known above grade crossing locations. Each identified location will be unique in how it is remediated and the costs will vary depending on the complexity of the project. These projects will typically involve either installing new pipe below grade or rebuilding the existing crossing.

It is recommended to spend $750,000 (plus 3% inflation) per year mitigating these sites. In general, this is enough to fund one or two large directional drill projects, three to five medium directional drill projects, or possibly between 10 and 15 small directional drill or rebuilt crossing projects per year. This mitigation work will ensure our gas pipeline facilities continue operating with reduced risk, resulting in a safe, compliant, and reliable system for our communities and customers. If this program is not started, Avista will be at risk of:

- fines from the State PUC's for being out of compliance with federal safety codes,
- pipeline failures if support structures fail,
- environmental fines if a pipeline failure results in a release of gas, and
- temporary loss of service to downstream gas customers.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial submission of original business case	7/8/21	
2.0	Mike Yang	Updated for 2022, used new template	8/26/2022	

GENERAL INFORMATION

Requested Spend Amount	$750,000 per year
Requested Spend Time Period	*> 5 years*
Requesting Organization/Department	Gas Engineering, B51
Business Case Owner | Sponsor	Jeff Webb / Mike Yang | Jody Morehouse
Sponsor Organization/Department	B51 / Gas Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

Within the natural gas distribution system of all three states, there are sections of gas pipelines that are located above grade. Some of these sites are no longer compliant with current safety codes and design practices, or the support structures are failing. Like other areas of the gas and electric system, over the years construction practices have changed due to stricter standards and improved construction methods. As a result, these above grade crossings have a variety of construction techniques and supporting structures with varying degrees of risk associated with each of them.

This Business Case addresses capital expenditures associated with remediating these sites. Each location will be unique in how it is his corrected and the costs will vary depending on the complexity of the project. Resolution will typically involve either installing new pipe below grade using a horizontal directional drill (HDD) method or rebuilding the existing crossing. There are times when the best solution will be classified as an expense (O&M), in those cases this program will help risk rank those sites and work with the District Manager to get the work completed under their O&M plans.

There are several issues that are typical of these sites that needs to be addressed. Each of these cause Avista to be out of compliance with federal safety standards:

- the pipe wrap may have failed or deteriorated to the point of no longer being effective,
- the support hangers may be dislodged from their support structure (normally a bridge),
- the support hangers may be the style that do not allow a complete inspection for atmospheric corrosion,
- the pipe may have active atmospheric corrosion,
- the support structure may be failing, and no longer able to provide adequate support for the gas pipe, or
- the warning signs may be missing.

The Oregon PUC delivered to Avista a Notice of Probably Violation (NOPV) for a bridge crossing in Roseburg, Oregon in their 2021 safety audit that requires action on the part Avista to remediate. If we have this program approved and in place, this will show to the PUC in all three states (OR, WA, and ID) that Avista recognizes the shortcomings and has a plan to address them.

In 2019, Gas Engineering assessed all known above grade pipe locations in the state of Oregon by visiting each site in person, taking pictures, evaluating the condition of the pipe, coating, and support structures, reviewing the area for possible remediation options, and then finally using a risk scoring matrix developed with Gas Integrity to risk rank all 162 sites. Of these sites, 34 of them were classified as high risk, requiring remediation. The plan will be to do a similar review of the above grade pipe in both Washington and Idaho in 2022 & 2023. That data will then be added to the existing evaluation matrix, which will be used to determine the project list for each year. Based on subject matter experts, it is expected that we will have far fewer sites in Washington and Idaho to remediate then we do in Oregon.

Aboveground piping is required to be inspected once every three years for atmospheric corrosion per CFR 192.481. To properly inspect for corrosion, the entirety of the pipe must be available for visible assessment. Some legacy sites have pipe that is installed in a manner that makes it impossible to do a proper inspection. This program will address this deficiency.

Gas mains in places or on structures with the potential for physical movement (i.e. bridges) must be patrolled 4 times a year in business districts and 2 times a year outside of business districts per CFR 192.721. The intent of these patrols is to ensure sound structures and hanging supports. Some of the sites on the list have hanger systems that are failing due to corrosion or concrete deterioration, resulting in improper support of gas pipes. This program will address these deficiencies also.

If the site is remediated by installing the pipe below grade, Avista reduces the O&M expense of the once every three-year atmospheric corrosion inspection and the quarterly bridge inspection. Additionally, the Distribution Integrity Management Program (DIMP) will assess a lower risk score since below grade installation have much less of a chance of being damaged by an earthquake, flood, or vehicle incident.

1.1 What is the current or potential problem that is being addressed?

Above grade gas pipeline crossings that are not in compliance with federal safety codes or have been deemed high risk through a risk evaluation performed by Gas Engineering and Gas Integrity.

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 is Mandatory & Compliance. This remediation is necessary to stay in compliance with CFR 192 safety codes. Customer Service Quality & Reliability and Asset Condition are additional drivers for remediating high risk above grade piping.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This work is necessary now because we currently have pipeline crossings that are not in compliance, are at risk of failing, and are at risk of fines from State PUC Safety Departments.

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.

Success will be measured by a reduction in the number of sites in need of remediation from the original 34 on the current risk matrix.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The assessment work conducted by Gas Engineering in 2019 is all stored on the corporate network drive: c01d44\GASENGINEER\GAS DESIGN DOCUMENTATION\Engineer Documentation\Heidi Plough\Oregon Above Ground Crossings

2. PROPOSAL AND RECOMMENDED SOLUTION

It is recommended to spend $750,000 (plus 3% inflation) per year mitigating these sites. In general, this is enough to fund one or two large directional drill projects, three to five medium directional drill projects, or possibly between 10 and 15 small directional drill or rebuilt crossing projects per year. This mitigation work will ensure our gas pipeline facilities continue operating with reduced risk, resulting in a safe, compliant, and reliable system for our communities and customers. If this program is not started, Avista will be at risk of:

- fines from the State PUC's for being out of compliance with federal safety codes,
- pipeline failures if support structures fail,
- environmental fines if a pipeline failure results in a release of gas, and
- temporary loss of service to downstream gas customers.

Below are the top ranked project locations and their initial estimates. These projects total $2,160k, that's about three years' worth of projects averaging $720k per year. Due to the magnitude of the Rogue River Bridge site, some shifting of funds and projects will need to happen to ensure timely completion. As we learn more about each of these sites from the maturing of the designs and permits, the project list may change as appropriate to balance available funds and risk mitigation.

- Hwy 99 S/Bridge – S Umpqua River – 6" IP Main – $450,000
- Riverside Dr/Bridge – Days Creek – 2" IP Main - $10,000
- 1812 Talent Ave – Canal Crossing – 6" HP Main - $90,000
- 1985 Taylor Bridge #121 – Griffin Creek – 6" IP Main - $100,000
- Washington St/Bridge – S Umpqua River – 6" IP Main - $170,000
- Rogue River Bridge – 10" HP Main - $1,250,000
- S Main Elliot St/Bridge – Canyon Creek – 2" IP Main - $75,000
- 335 Pleasant View Dr – Canal Crossing – 2" IP Main - $15,000

If the program is funded at a lower level, then the risk to the gas system and our customers will be reduced at a slower pace. The "Do Nothing" option is not a good approach to this Business Case since we are currently aware of existing deficiencies on our system (listed above) and have identified parts of the system that are currently in need of remediation to meet federal safety codes. See below for a breakdown of the risks over time associated with doing nothing.

Option	Capital Cost	Start	Complete

Remediate at a level of $750k/year	$750,000	01 2023	TBD
Remediate at a level of $500k/year	$500,000	01 2023	TBD
Do Nothing	$0	MM YYYY	MM YYYY

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time (years)					Cost Estimate
		1	2	5	10	15+	
1	Regulatory Fines*	VL	L	P	H	VH	$225,134 per day per violation (Max) $2,251,334 Total (Max)
2	Pipeline Leak	VL	VL	L	P	H	$5,000 to $150,000 per site (site dependent)
3	Pipeline Failure & Outage	VL	VL	L	P	H	$150,000 to $3,000,000 per site (site dependent)
4	Negative Reputation	VL	L	P	VH	VH	Erosion of PUC and Public trust
5	Employee & Public Safety	VL	VL	L	L	P	Lost time, healthcare, lawsuits, etc. (varies)

*Reference Offset Calcs spreadsheet on department drive c01d44:\GASENGINEER\GAS DESIGN DOCUMENTATION\Budget\Business Cases Updates\ER 3009 Gas Above Grade Pipe Remediation

2.1 Describe what metrics, data, analysis, or information was considered when preparing this capital request.

In 2019, Gas Engineering assessed all known above grade pipe in the state of Oregon by visiting each site in person, taking pictures, evaluating the condition of the pipe, coating and support structures, reviewing the area for possible remediation options, and then finally using a risk scoring matrix developed with Gas Integrity to risk rank all 162 sites. 34 of the sites were classified as high risk, requiring remediation.

The Oregon PUC delivered to Avista a Notice of Probably Violation (NOPV) for a bridge crossing in Roseburg, Oregon in their 2021 safety audit that requires action on the part Avista to remediate. If we have this program approved and in place, this will show to the PUC in all three states (OR, WA, and ID) that Avista recognizes the shortcomings and has a plan to address them.

See risk matrix above under Section 2 header and O&M cost offset below under section 2.2 for more metrics, data, and 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.**

Capital spend will go directly toward bringing above grade crossings that need remediation up to current federal safety codes. As described above, if the remediation project will install the pipe below grade, then the once every three-year atmospheric corrosion inspections and the quarterly bridge inspections will no longer be required, resulting in yearly O&M reductions. Expected total cost avoidance over a 15 year window is about $76,000 in labor and truck costs.

Installing below grade pipe also eliminates periodic future O&M work to repair pipe coatings and bridge hangers. In addition, installing new above grade piping with modern coatings and pipe hangers can also reduce the amount of future O&M work since old hangers and coatings would be eliminated from the system. Expected total cost avoidance over a 40-year window is approximately $87,500 in labor and equipment costs.

See below for a breakdown of O&M cost avoidance associated with eliminating inspections and maintenance. Calc spreadsheet and assumptions for this can be found on department drive c01d44:\GASENGINEER\GAS DESIGN DOCUMENTATION\Budget\Business Cases Updates\ER 3009 Gas Above Grade Pipe Remediation

Cost avoidance due to eliminated O&M inspections (15 years):

Years	Sites Eliminated	Cost / Site Visit ($)	Visits per year per site	Cumulative Time Saved over 15 yr window (HRs)	Cumulative O&M Cost Savings over 15 yr window ($)
1	1.80	$ 100.50	4	100.8	$ 10,130.40
2	1.80	$ 100.50	4	93.6	$ 9,406.80
3	1.80	$ 100.50	4	86.4	$ 8,683.20
4	1.80	$ 100.50	4	79.2	$ 7,959.60
5	1.80	$ 100.50	4	72.0	$ 7,236.00
6	1.80	$ 100.50	4	64.8	$ 6,512.40
7	1.80	$ 100.50	4	57.6	$ 5,788.80
8	1.80	$ 100.50	4	50.4	$ 5,065.20
9	1.80	$ 100.50	4	43.2	$ 4,341.60
10	1.80	$ 100.50	4	36.0	$ 3,618.00
11	1.80	$ 100.50	4	28.8	$ 2,894.40
12	1.80	$ 100.50	4	21.6	$ 2,170.80
13	1.80	$ 100.50	4	14.4	$ 1,447.20
14	1.80	$ 100.50	4	7.2	$ 723.60
15	1.80	$ 100.50	4	0.0	$ -
					$ 75,978.00

Cost avoidance due to eliminated O&M repair work (40 years):

Years	Sites Eliminated w/ BG Pipe	Sites Remediated w/ AG Pipe	Future O&M Cost / Maintenance Visit ($)	O&M Time Saved over next 40 years (HRs)	Cumulative O&M Cost Savings over next 40 years ($)
1	1.80	1.80	$ 1,080.00	43	$ 5,832.00
2	1.80	1.80	$ 1,080.00	43	$ 5,832.00
3	1.80	1.80	$ 1,080.00	43	$ 5,832.00
4	1.80	1.80	$ 1,080.00	43	$ 5,832.00
5	1.80	1.80	$ 1,080.00	43	$ 5,832.00
6	1.80	1.80	$ 1,080.00	43	$ 5,832.00
7	1.80	1.80	$ 1,080.00	43	$ 5,832.00
8	1.80	1.80	$ 1,080.00	43	$ 5,832.00
9	1.80	1.80	$ 1,080.00	43	$ 5,832.00
10	1.80	1.80	$ 1,080.00	43	$ 5,832.00
11	1.80	1.80	$ 1,080.00	43	$ 5,832.00
12	1.80	1.80	$ 1,080.00	43	$ 5,832.00
13	1.80	1.80	$ 1,080.00	43	$ 5,832.00
14	1.80	1.80	$ 1,080.00	43	$ 5,832.00
15	1.80	1.80	$ 1,080.00	43	$ 5,832.00
			40 year cost avoidance =		$ 87,480.00

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Instead of having each individual Operations District review, manage, and prioritize above grade piping projects within their respective areas, this new business case will centralize that responsibility under Gas Engineering. This includes both capital projects covered under this new business case as well as O&M projects historically managed under each individual district. This will ensure that above grade piping projects (both O&M and Capital) across all three states of Avista's territory are consolidated together, prioritized against each other, and then funded appropriately according to risk. Each Operation Districts will still be expected to help coordinate and complete the work assigned to each area, which does not differ from existing processes.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Since the identified above grade pipe in need of remediation does not currently meet federal safety codes, the only way to address this risk is to remediate each of the crossings. Each location is unique and will be analyzed to determine the best remediation approach. The lower funding alternative option slows the pace of remediation and the resultant reduction of known risk in the system. The do nothing approach results in no risk reduction, and leads to additional risk to Avista, including:

- fines from the State PUC's for being out of compliance with federal safety codes,
- pipeline failures if support structures fail,
- environmental fines if a pipeline failure results in a release of gas, and
- temporary loss of service to downstream gas 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.

Projects will be started each year, and in most cases will be complete within a year of beginning. Some sites may require unique permitting or specialty equipment that may extend that project timeline beyond a year. Once construction begins, an individual project will typically be completed (i.e. used and useful) within the same calendar year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Avista has a value of being Trustworthy, that means we do what's right. The right thing to do is take care of the pipeline facilities, make them as reliable as possible, keep the public safe, and ensure our facilities are not out 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

A funding level of $750,000 for the first several years will get this program underway. At this level, the current staffing of Engineers is adequate to support the program without having to contract out any of the design work. On an annual basis, this program will be compared to other Gas Programs to ensure the company is focusing on our highest risk areas.

Reference 5-year planning document for more detail. This can be found on department drive c01d44:\GASENGINEER\GAS DESIGN DOCUMENTATION\Budget\Business Cases Updates\ER 3009 Gas Above Grade Pipe Remediation

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Gas Engineering, District Operations support individuals (CPC's and Inspectors), Contracts, and Drafting are the main groups impacted by this program.

2.8.2 Identify any related Business Cases

None.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

This program will be administered by an Engineer within Gas Engineering. The program's spend and budget will be reviewed monthly by the Gas Engineering Prioritization Investment Committee (EPIC). The Engineer will ensure the highest risk projects are completed first.

3.2 Provide and discuss the governance processes and people that will provide oversight

The manager of Gas Engineering will provide oversight to the program.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Monthly budget changes will be documented via the existing CPG process, approved by the Manager of Gas Engineering and the Director of Natural Gas. The monthly Gas EPIC updates are captured via email.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Above Grade Pipe Remediation 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:	9/1/22
Print Name:	Jeff Webb / Mike Yang		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:		Date:	9/1/2022
Print Name:	Jody Morehouse		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

Cathodic Protection (CP) systems are used to stop corrosion on buried steel gas pipes. CP system compliance is mandated by Federal Rules within the Department of Transportation code 49 CFR 192, Subpart I. Some CP systems have been in service at Avista for extended periods of time, they have exceeded their useful service life, and are no longer functional (or are showing signs of imminent failure). These conditions warrant a replacement of those systems. 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, they deteriorate at differing rates, and can become ineffective when they are physically depleted. The estimated annual cost for this budget is based on past expenditures. Because of the unpredictable nature of these projects, it is not always known in advance how much of the funding will be allocated to each state.

Additional expenditures in this budget include the installation of system testing and monitoring equipment. These new technologies allow for remote monitoring and control of the CP systems. They alert technicians to system failures and reduce the number of trips needed to check system status.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Tim Harding	Initial version	4/03/2017	
1.1	Jeff Webb		4/4/2017	
2.0	Tim Harding	Revision for 2020 Oregon GRC filing	2/17/2020	
2.1	Tim Harding	Updated to the refreshed 2022 Business Case Template	8/31/2022	

GENERAL INFORMATION

Requested Spend Amount	$715,000
Requested Spend Time Period	Annually
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Tim Harding | Jody Morehouse
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?

The majority of this budget is used to install new cathodic protection (CP) anode beds. The sacrificial anodes are consumed as part of the CP process and the service life of one of these installations is approximately 20-30 years. There are approximately 250 anode beds installed across our service territory.

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 main drivers for this business case are Mandaroty & Compliance and Asset Condition. Properly functioning cathodic protection systems are required by federal code. This code requires the systems to operate within specific parameters. Those parameters can only be met when the CP systems are regularly maintained and replaced when the anodes are depleted.

Even if CP systems were not required by code, Avista would install them. They greatly reduce pipe corrosion and the chance of gas leaks. The cost to install, operate, and maintain a CP system is a small fraction of the financial benefit it provides. At a low relative cost, Avista is able to protect hundreds of millions of dollars worth of steel pipe infrastructure from corrosion, extending its useful life for decades.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The operations of Avista's CP systems are largely governed by code requirements. Not performing this work will put Avista out of compliance with state and federal codes. This will result in system integrity risks, as well as regulatory 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.

Avista tests and monitors the CP systems in accordance with State and Federal code. The results of this testing indicate what CP systems are deficient and therefore require equipment installation. A potential measurement to use to gauge the success of the program is to track code violations.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Project information is tracked by Gas Engineering. System maintenance records are housed in Maximo. Information is 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.

Anode beds get installed for two reasons. The first is to replace an existing anode bed that has failed. The second reason is to increase the available amount of cathodic protection current available. Additional current is required as the pipe coating degrades over time. Anode beds have a design life of approximately 25 years. With 250 anode beds in the system it would be expected that approximately 10 are replaced every year. Only 7 have been replaced in the last 5 years. This implies the anode beds are being replaced at 1/8 the expected rate. During the last 5 years 21 new anode beds were added to meet the increasing current requirement.

This information above should illustrate two points. First, anode beds are being replaced at a fraction of the expected rate. This implies there will be a time in future when failure rates will increase and more replacements will be needed each year. The second point to note is that the steel pipe in our gas systems, most installed in the 1950’s and 1960’s, has coating that is continuing to degrade. More anode beds will continue to be required to meet the growing current demand.

2. PROPOSAL AND RECOMMENDED SOLUTION

The requested level of spending is the lowest cost option to keep these systems functioning and compliant with state and federal code. As mentioned in the above section, equipment replacement rates are nearly an order of magnitude lower than expected. All of these anode beds will eventually fail and more analysis should be done to predict when that will happen. At some point in the future, failure rates will grow rapidly. A proactive approach that replaces the oldest or poorest performing anode beds would spread replacement costs out more evenly in the future and help avoid a future surge in failures.

Option	Capital Cost	Start	Complete
Recommended Solution, Replace equipment when it fails, and add new equipment to keep the system	$715,000	January	December

in compliance			
Alternative Solution, Replace equipment when it fails, and add new equipment to keep the system in compliance. Proactively replace aging anode beds to avoid a future rush of replacements.	$1.2M	January	December

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The requested amount is based on recent program spending. Expenditures are to replace failed equipment or to add new equipment to maintain system compliance. Since the actual spending requirement for each year cannot be predicted, mid-year adjustments are common.

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.**

Approximately 80% of the budget will be spent on anode bed replacements. The remaining 20% of the budget will be spent on the installation of new and replacement test stations and monitoring 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.

Properly operating CP systems reduce corrosion and corrosion leaks. It also extends the life of the gas system. This has in impact on Gas Operations and Compliance departments.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Per Federal code, CP systems are required on all buried steel gas pipes. The only alternative is to replace all steel piping with plastic pipe. A project like this would cost well over $1 billion.

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.

Anode beds are typically installed in the summer and fall. These projects will take between one week and two months. They become used and useful immediately at the end of the project. Special projects are undertaken some years. These can include the installation of test stations, and remote monitoring equipment. Those assets become used and useful when the final installation is complete, typically in Q4.

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, and reliably 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 budget primarily funds the installation of new and replacement anode beds. Cathodic protection systems are required by federal code, and the criteria under which they must be operated is specified in that code. Testing is performed on these systems annually. Any systems deficiencies must be addressed to remain in compliance.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Cathodic protection is a program that happens 'behind the scenes' and does not involve customer interaction. Customers benefit from the improved system safety, reliability, and longer asset service life.

Stakeholders include Gas Engineering, Gas Operations, and the Cathodic Protection group.

2.8.2 Identify any related Business Cases

N/A

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The General Foreman of the Cathodic Protection group oversees projects done by the group. This program will be monitored by an Engineer within Gas Engineering. The program's spend and budget will be reviewed monthly by the Gas Engineering Prioritization Investment Committee (EPIC), and annual the 5-year plan is reviewed.

3.2 Provide and discuss the governance processes and people that will provide oversight

Projects are proposed by the Cathodic Protectoin group and approved by the General Foreman. Gas Engineering sets up project accounts and reviews program spending on a monthly basis.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The General Foreman has the final say on project prioritization. These decisions are based on 30 years of experience in the field of cathodic protection.

Monthly budget changes will be documented via the existing CPG process, approved by the Manager of Gas Engineering and the Director of Natural Gas. The monthly Gas EPIC updates are captured via email.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Cathodic Protection 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:	Jeffrey A Webb	Date:	8/31/22
Print Name:	Jeff Webb / Tim Harding		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Jody Morehouse	Date:	8/31/2022
Print Name:	Jody Morehouse		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

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 20-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. This targeted 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.

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 Gas Facility Replacement Program (GFRP) was approved by the Vice President of Energy Delivery and 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 over 18,000 service tee transitions throughout Avista's service territories. The Aldyl-A main pipe replacement work includes Aldyl-A pipe that is 1-1/4" diameter through 4" diameter and with an install date prior to January 1, 1987, or a manufactured date prior to January 1985. The historical spending trend from 2016 through 2022 has been $20M-$23M 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 with full contractor complement and to adjust for the mileage that was not completed in 2020 and be in alignment with Distribution Integrity Management Program's (DIMP) prioritization recommendations. This also meets Avista's goal of investing in its infrastructure to achieve optimum life-cycle performance. GFRP paid inflation of 7% in 2022. Inflation of 5% has been planned for escalating annual costs during 2023-2027.

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*
7	*Karen Cash*	*Budget Change*	*2020*	*$1,000,000 deferred to 2021*
8	*Karen Cash*	*Budget Change*	*2020*	*$500,000 deferred to 2021*

GENERAL INFORMATION

Requested Spend Amount	$29,000,000 - $32,000,000 Annually
Requested Spend Time Period	9 years (2023 through 2031)
Requesting Organization/Department	Natural Gas / Gas Facility Replacement Program
Business Case Owner | Sponsor	Karen Cash / Jody Morehouse
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 over 18,000 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.

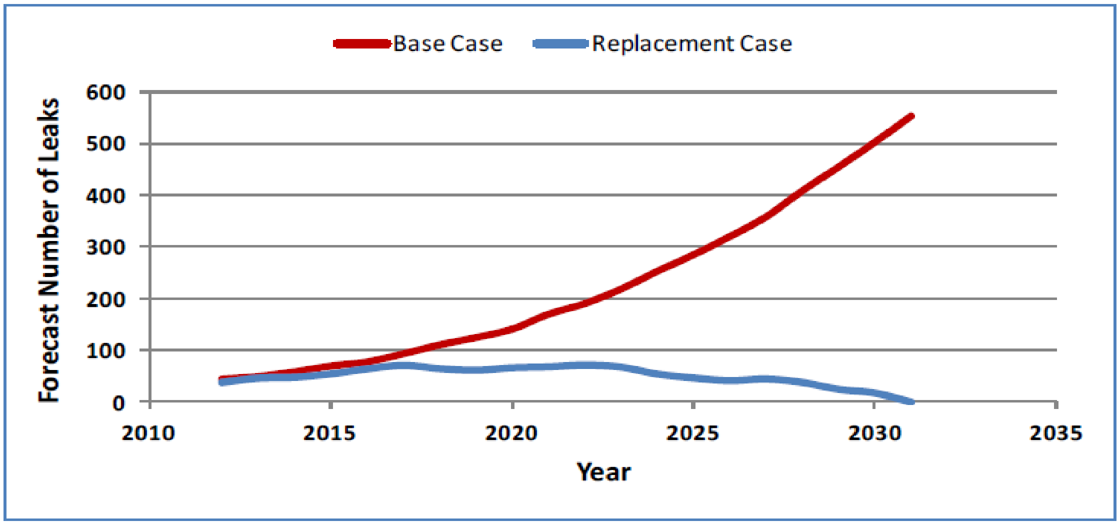
1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

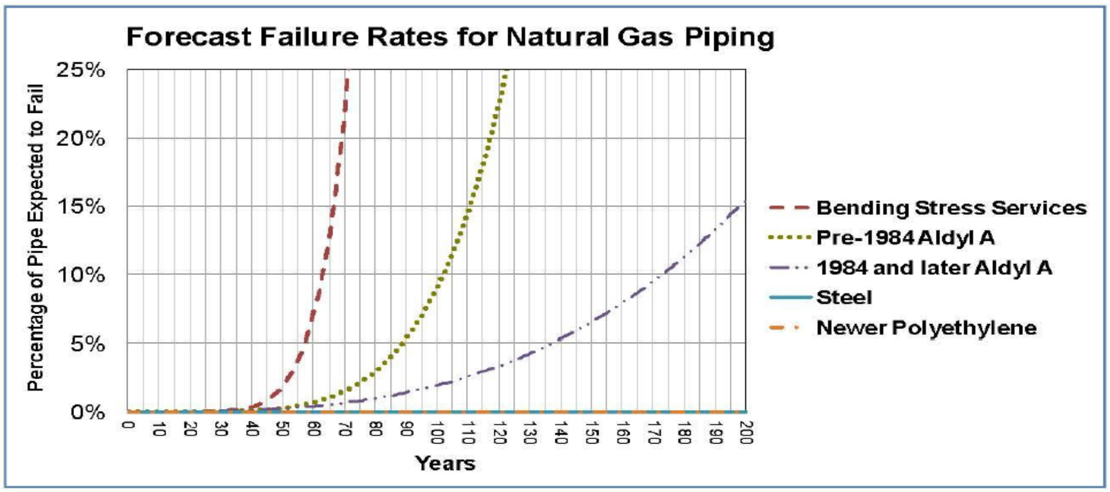
a. On December 31, 2012, the Washington Utilities and Transportation Commission (WUTC) issued its policy statement on Accelerated Replacement of Pipeline Facilities with Elevated Risks which requires gas utility companies to file a plan every two years for replacing pipe that represents an elevated risk 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.



2. PROPOSAL AND RECOMMENDED SOLUTION

"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 20-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. The offsets to the GFRP, include but not limited to, regulatory fines, pipeline leaks, pipeline failures and outages, negative company reputation, and elevated safety concerns. See below for a list of the relevant pipeline safety regulations pertaining to the GFRP, as well as a breakdown of each risk over time assuming nothing is done to remediate the Aldyl-A pipe.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Potential Cost of the "Do Nothing" Option:

Potential Risk	Potential Risk Over Time					Cost Estimate
	1 Year	2 Years	5 Years	10 Years	15+ Years	
Regulatory Fines	L	P	H	VH	VH	$225,134 per day per violation (Max)* $2,252,334 Total (Max)*
Pipeline Leak	H	H	VH	VH	VH	$5,000 to $150,000 per site (site dependent)
Pipeline Failure & Outage	L	L	P	P	VH	$150,000 to $3,000,000 per site (site dependent)
Negative Reputation	L	P	H	VH	VH	Erosion of WUTC and Public Trust
Employee & Public Safety	VL	L	P	H	VH	Lost time, healthcare, lawsuits, etc. (varies)

*Regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is at the discretion of the enforcement agency and is likely to be much lower due to Avista's ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e. failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties.

It has been determined that this type of pipe is at risk and is approaching unacceptable levels or reliability without prompt attention. The "Do Nothing" option exposes Avista to increased operational risks, decreased system reliability, and worse, is a potential harm to customers and the public through damage to life, property, and the environment. There would be a high likelihood of legal action against Avista, regulatory fines, and negative reputation. The 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 as identified above. GFRP would not be able to address some of the highest risk/threats in the natural gas distribution system by reducing the incident and leak rates. Per the *"Avista Study of Aldyl-A Mainline Pipe Leaks 2018 Update"*, which covered the entire program in Idaho, Oregon, and Washington, based upon the proactive replacements that have occurred, the number of leaks predicted from 2018 through 2088 has reduced to 12,335 with 246 catastrophic events if the system-wide 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 2016 through 2021 has been $20M-$23M 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 with full contractor complement and to adjust for the mileage that was not completed in 2020* and be in alignment with Distribution Integrity Management Program's (DIMP) prioritization recommendations. This also meets Avista's goal of investing in its infrastructure to achieve optimum life-cycle performance. GFRP paid inflation of 7% in 2022. Inflation of 5% has been planned for escalating annual costs during 2023-2027.

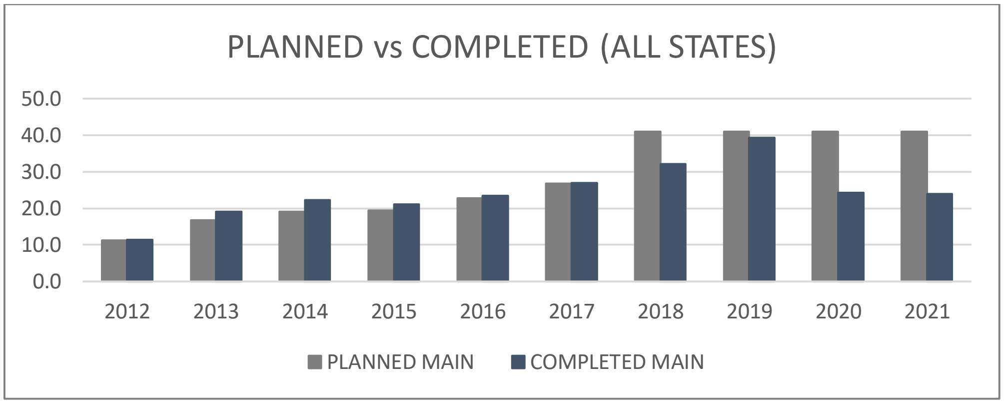
The following tables show the multi-year performance by state for main replacement from 2012 through 2021. Washington is at 93%, Oregon is 68%, and Idaho is 116% of completed main replacement. Overall the Program has completed 102.1% (difference of 5.1 miles) of the planned main replacement.

	IDAHO MAJOR MAIN MILEAGE		
YEAR	PLANNED MAIN	COMPLETED MAIN	%
2012	[redacted]		
2013			
2014	3.42	3.65	107%
2015	3.50	4.63	132%
2016	5.40	5.40	100%
2017	5.80	5.20	90%
2018	7.7	7.5	98%
2019	7.7	12.7	165%
2020	7.7	8.5	110%
2021	7.7	4.6	60%
TOTAL	41.2	47.6	116%

	WASHINGTON MAJOR MAIN MILEAGE		
YEAR	PLANNED MAIN	COMPLETED MAIN	%
2012	8.7	8.6	100%
2013	10.7	12.4	117%
2014	9.1	10.7	117%
2015	9.3	10.57	114%
2016	10.54	10.23	97%
2017	14.05	14.62	104%
2018	18.7	15.30	82%
2019	18.7	19.10	102%
2020	18.7	13.23	71%
2021	18.7	12.98	69%
TOTAL	137.1	127.8	93%

	OREGON MAJOR MAIN MILEAGE		
YEAR	PLANNED MAIN	COMPLETED MAIN	%
2012	2.7	2.7	103%
2013	6.0	6.7	111%
2014	6.5	8.0	123%
2015	6.6	5.9	89%
2016	6.8	7.9	117%
2017	6.9	7.1	103%
2018	14.6	9.23	63%
2019	14.6	7.42	51%
2020	14.6	2.62	18%
2021	14.6	6.39	44%
TOTAL	93.9	64.0	68%

	TOTAL MAJOR MAIN CONSTRUCTION MILEAGE IN GFRP		
YEAR	PLANNED MAIN	COMPLETED MAIN	%
2012	11.3	11.4	101%
2013	16.7	19.1	114%
2014	19.0	22.3	117%
2015	19.4	21.1	109%
2016	22.7	23.5	104%
2017	26.8	27.0	101%
2018	41.0	32.1	78%
2019	41.0	39.3	96%
2020	41.0	24.3	59%
2021	41.0	24.0	58%
TOTAL	238.9	244.0	102.1%



*There were several impactful events that were outside Avista's control which led to the program deferring $2,535,000 to 2021. Early part of 2020, the COVID-19 pandemic struck the nation and only essential work was able to continue. The NPL union employees went on strike starting on July 6, 2020 and the strike ended on August 26, 2020. Starting on September 8, 2020, in Jackson County Oregon, wildfires blazed in in the Ashland – Alameda Drive area. There were wildfires throughout Oregon (see map below). The wildfires spread due to high winds and the smoke created poor air quality conditions. The outcome of these events in Oregon was the completion of only 2.6 miles of the planned 15.1 miles by NPL.

In order to meet maintain optimal production with current personnel levels and account for approximately $3M a year for Minor Main/STTRs/Priority Services, and outlying municipal projects, below is the proposed mileage by state from 2023 through 2027.

MULTI-YEAR PERFORMANCE BY STATE & YEAR 2023-2027				
YEAR	WASHINGTON PLANNED MAIN	OREGON PLANNED MAIN	IDAHO PLANNED MAIN	SYSTEM PLANNED MAIN
2023	19.45	8.50	5.93	33.88
2024	18.48	8.50	6.17	33.15
2025	17.60	8.50	6.96	33.06
2026	15.25	8.50	6.71	30.46
2027	16.59	8.50	7.66	32.75
TOTAL	**87.37**	**42.50**	**33.43**	**163.30**

Based on the proposed mileage by state from 2023 through 2027, the estimated cost per mile by state and by year is shown below. Variations of the Cost/Mile are due to project location. For example, if a project requires significant Mobilization, Demobilization, crew travel expense, urban or rural locale, etc.

EST. COST/MILE BY STATE & YEAR 2023-2027			
YEAR	WASHINGTON	OREGON	IDAHO
2023	$ 15,690,800	$ 6,495,723	$ 4,628,481
2024	$ 15,843,671	$ 6,729,354	$ 4,938,609
2025	$ 15,474,054	$ 7,235,065	$ 5,826,908
2026	$ 13,773,174	$ 7,534,321	$ 6,222,444
2027	$ 15,469,116	$ 7,684,957	$ 5,398,664
TOTAL	**$ 76,250,815**	**$ 35,679,420**	**$ 27,015,106**

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.

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. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Gas Facility Replacement Program (GFRP) Advisory Group consists of the GFRP's Program Manager, Gas Operations Contract Construction Manager, Director of Natura Gas, Senior Manager of Gas Operations, 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, Gas Operations Contract Construction Manager, Director of Natura Gas Senior Manager of Gas Operations, 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.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas Facilities 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:	Karen Cash	Date:	5/16/22
Print Name:	Karen Cash		
Title:	GFRP Manager		
Role:	Business Case Owner		

Signature:	Jody Morehouse	Date:	9/7/2022
Print Name:	Jody Morehouse		
Title:	Natural Gas Director		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

In accordance with a Stipulated Agreement with Washington State, Avista implemented an “Isolated Steel Identification and Replacement Program” (Program) beginning in 2011. The goal of the Program has been to identify and remediate isolated steel within Avista’s Washington State gas pipeline systems. As part of the overall program, Avista has also begun to identify and remediate isolated steel within Oregon and Idaho natural gas pipeline systems. Work completed under this program results in a safer gas distribution system.

The annual budget through 2021 has been $1,400,000. Starting in 2022, the program budget was reduced to $850,000, due to the program ending in Washington State. Remediation efforts in Washington State were completed and approved by the WUTC as outlined within the closure letter for the stipulated agreement. Failure to complete the program on time would have been a direct violation of the stipulated agreement between Avista and the WUTC. Avista is now focusing on isolated steel in Oregon and Idaho to reduce the risk of continued deterioration of any isolated steel pipe in our distribution system. The recommendation to continue the program into Oregon and Idaho was approved and reviewed by:
.

- Jeff Webb – Manager of Natural Gas Design, Measurement and Planning
- Mike Faulkenberry – Director of Natural Gas (Retired)

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial Version	03/16/2017	
1.1	Jeff Webb	Revisions	04/07/2017	
1.2	Jenn Massey	2020 Revisions	02/05/2020	
1.3	Nick Messing	Updated Business Case Template	07/10/2020	
1.4	Nick Messing	Updated Business Case Template	05/05/2022	
1.5	Seth Samsell	Updated Business Case Template	08/25/2022	*Seth took over the program in 2022*

GENERAL INFORMATION

Requested Spend Amount	$850,000 – Annual Request
Requested Spend Time Period	10 years
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Seth Samsell | Jody Morehouse
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 address

The program objective is to identify and document isolated steel pipe sections, including isolated risers, that may not be cathodically protected and to replace each riser or pipeline section within a specified timeframe after its identification.

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

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, which has been satisfied. Moving forward, this program will continue to be conducted in OR and ID to assure cathodically isolated steel is identified and replaced as needed. Work completed under this program results in a safer gas distribution system.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Per the original 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 primarily being completed in OR and ID at this time. Work completed under this program results in a safer gas distribution system and failure to complete the program may result in financial penalties.

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 program will reduce the chances of corrosion on the steel piping system thereby reducing future leaks associated with these pipes. The Isolated Steel Replacement Program will be successful if the known isolated steel riser/service count drops to zero in all of Avista's service areas. This was a Washington requirement and is a best practice for Oregon and Idaho.

As of August of 2022, Washington has 0 known isolated steel services remaining, Oregon has 400 known isolated steel service replacement jobs open, and Idaho has isolated steel service replacement jobs open. It is important to note that Oregon's numbers reflect the number of isolated steel replacement jobs currently open. A ten year inspection began in July of 2021 to identify all isolated steel services in Oregon. Therefore, the job count in Oregon will fluctuate as that inspection program and replacements continue. Newly identified sites will be added to the Oregon number for remediation. The ten year program will review approximately 90,000 services identified in Avista's GIS system, which have been flagged for inspection.

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.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Proposal / Recommended Solution – Replace isolated steel pipe sections and risers that are not cathodically protected in all service areas as needed	$850,000 (2023-2030)	11/2011	12/2030
Alternative #1 - Complete OR only 2023 - & 90-day only orders in ID	$800,000	06/2023	12/2023
Alternative #2 - Complete only 90-day orders in OR/ID	$400,000	06/2023	12/2023

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The capital request was based on the number of remaining jobs in each state, the average replacement costs in each state, and by reviewing previous years' budgets. The original stipulated agreement requirements in WA along with best practices for Oregon and Idaho are factored in as well.

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.**

Based upon the Recommended Solution, the Isolated Steel Pipe Program will continue to identify and mitigate any isolated steel pipe in the gas piping systems of WA, OR, and ID. The project's goal is to remove all the isolated steel pipe in our system which will eliminate the need to monitor unprotected pipe, reduce corrosion, reduce leaks caused by corrosion, and create a safer gas distribution system. It will also reduce the number of issues encountered when identifying and repairing the cathodic protection system allowing cathodic employees to focus on long term protection of the pipelines. The local districts manage these projects with the goal of completing as much pipe replacement work as their allocated spend level will allow. Each month, the Program Manager and the Local Operations District Managers perform a check-in to update current capital spending levels for the Capital Planning Group to review. During this monthly process any additional spend requests or funding returns are made.

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.

Alternative #1 - Complete OR only 2023 & 90-day only jobs in ID.

Complete the full amount of planned inspections and replacements in Oregon State only along with any 90-day only jobs for Idaho. Delaying ID would reverse Avista's current best practice of mirroring the WUTC timeframe for Washington. Delaying isolated steel reduction in ID may lead to an increase of gas leaks identified within the system, due to the higher level of corrosion associated with isolated steel pipe, and could also result in additional compliance concerns.

Alternative #2 - Complete only 90-day jobs in OR/ID.

Complete only 90-day jobs for both Oregon and Idaho, delaying planned inspections and replacements. This would reverse Avista's current best practice of mirroring the WUTC timeframe for Washington. Delaying isolated steel reduction may lead to an increase of gas leaks identified within the system, due to the higher level of corrosion associated with isolated steel pipe, and could also result in additional compliance concerns.

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 Isolated Steel Replacement Program was started in 2011. Washington inspections and replacements were completed in 2021. Oregon and Idaho are targeted for completion by 2030. Customers will realize an immediate benefit due to reduced corrosion and leaks resulting in a safer natural gas distribution system. This program is set up to transfer to plant monthly as work is completed.

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 on our responsibility to maintain a safe and reliable infrastructure for all our customers and in each of our services territories.

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 spend level for the Isolated Steel Pipe Replacement Program has been based upon Avista’s agreement with Washington State and our commitment to provide a safe natural gas piping system in all service territories. A 10-year program is reasonable and aligns with other programs of similar scale from other utilities. Annual levels of spending may need to be adjusted in this program depending upon the needs of the system and changes in labor and material costs.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The current Program impacts Avista’s ORID territories. The majority of the customers benefiting from reduced risk are residential customers. The Gas Programs Manager and the Isolated Steel Program Manager work with each of the Gas Operations District Managers while also coordinating with Gas Engineering and Cathodic Protection Techs.

2.8.2 Identify any related Business Cases

N/A

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Gas Engineering and Gas Programs (Gas Compliance) act as the Steering Committee for the Isolated Steel Replacement Program.

Gas Programs and Gas Construction Management are responsible for identifying the work, completing the work and monitoring the annual budget. Gas Operations completes the work. The overall program budget is managed by Gas Programs. Any budget modifications or requests are coordinated through Gas Engineering.

3.2 Provide and discuss the governance processes and people that will provide oversight

The Program is currently overseen by a Program Manager along with a Program Administrator. Monthly reporting is used to identify whether budget targets are met and overall completion levels in each state. Software has been created to identify time constraints based on severity of potential risk.

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. The Program Manager is a part of this process.

Locations in Avista's system with known isolated steel pipe segments are submitted to each of our local Gas Operations District's. The Program Manager and Program Administrator work with each Gas Operations District Manager to determine a manageable level of work within the approved budget. Each Gas Operations District is allotted a manageable portion of the budget to complete targeted projects in their District. The individual projects for Isolated Steel Pipe are typically managed locally while the overall program budget is managed by the Program Manager with assistance from the Program Administrator. Any budget modifications or requests are coordinated through Gas Engineering.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Depending on compliance requirements higher risk projects will be completed first. A generalized workflow for Isolated Steel Identification/Replacement is provided in Image 1 below.

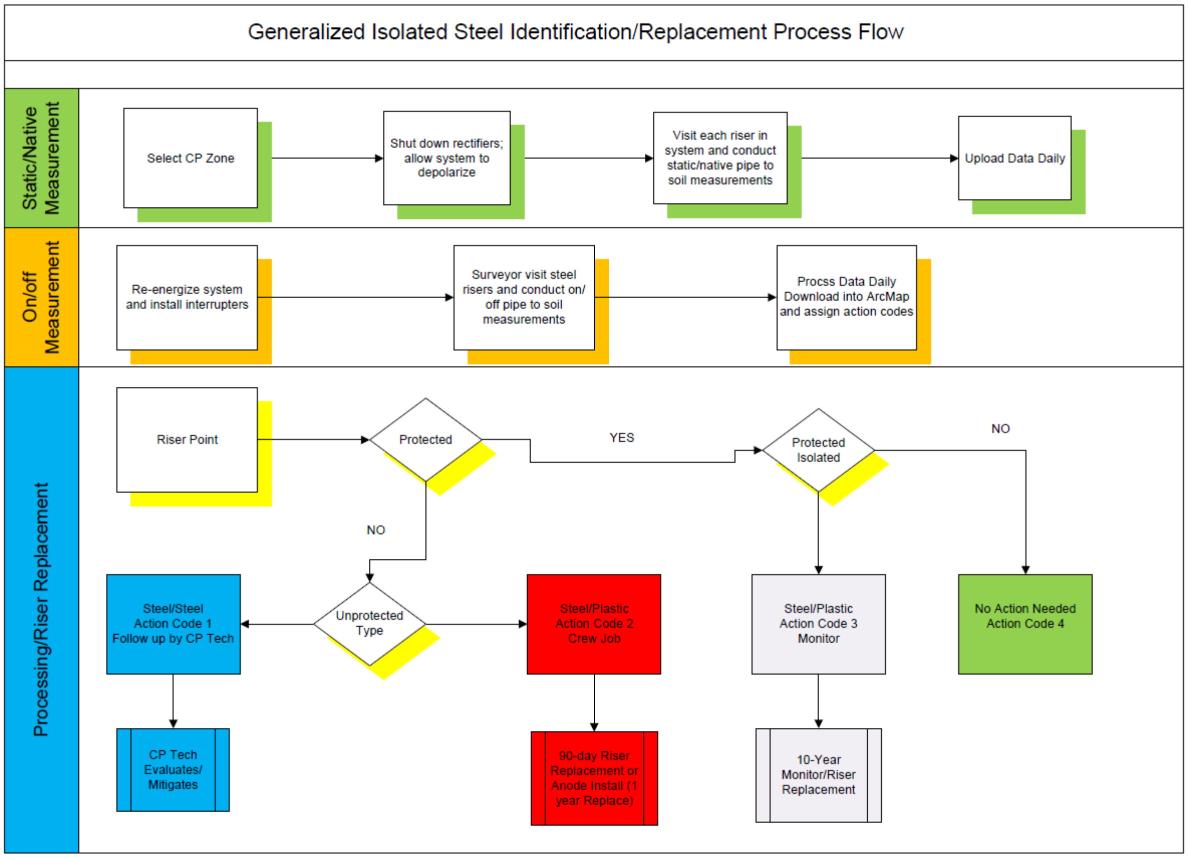


Image 1 – Generalized Workflow for Isolated Steel Identification/Replacement

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:		Date:	8/30/22
Print Name:	Jeff Webb / Seth R. Samsell		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:		Date:	8/30/2022
Print Name:	Jody Morehouse		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Cmt Review		

EXECUTIVE SUMMARY

Overbuilt pipe refers to gas pipes that either located directly under or very close to building structures. Except in rare case, Avista does not intentionally install gas pipes under structures. In most cases, overbuilt pipe occurs in mobile home parks where homes are moved over time. The close proximity of these structures makes gas system maintenance and inspection difficult, can be against state and federal code, and can be a potential safety hazard for the occupants.

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. As the number of known overbuilds in the company has decreased, the level of requested and approved funding has decreased as well.

This program is scheduled to be complete at the end of 2024.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Seth Samsell	Initial version	4/17/2017	
2.0	Seth Samsell	Revision for 2020 Oregon GRC filing	2/12/2020	
2.1	Tim Harding	Updated to the refreshed 2022 Business Case Template	9/1/2022	

GENERAL INFORMATION

Requested Spend Amount	$400,000
Requested Spend Time Period	Annually
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Tim Harding | Jody Morehouse
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Overbuild conditions usually occur when a structure is placed or constructed over an existing gas pipe. The close proximity of these structures makes gas system maintenance and inspection difficult, can be against state and federal code, and can be a potential safety hazard for the occupants.

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 main driver for this program is Mandatory & Compliance. Resolving overbuilt gas pipes keeps Avista compliant with state and federal codes, and increases the safety of customers in the immediate project areas.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Overbuilt gas pipes pose a safety risk for occupants in the area. Leaking gas can accumulate under mobile homes and storage sheds. Relocating the gas piping is the most straight-forward approach to resolving the issue.

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 locations of known overbuilt gas pipes have been catalogued and the completion of these projects is tracked by the DIMP Program Manager.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The DIMP study of known project locations can be obtained from the Gas Compliance group.

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.

This program replaces existing assets, however the asset condition is not generally a factor in project prioritization. This program replaces and relocates overbuilt gas pipes, regardless of the condition of the existing pipe.

2. PROPOSAL AND RECOMMENDED SOLUTION

The requested level of spending for this program is consistent with past years, and that level will allow the program to be complete at the end of 2024. A reduction in funding will extend the time required to complete all projects within the program.

Option	Capital Cost	Start	Complete
Recommended Solution, Complete planned projects at requested funding level	$400,000	January	December
Alternative Solution, Complete planned projects at a reduced funding level	$200,000	January	December

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

A DIMP risk analysis was performed on known overbuild projects by the Gas Compliance group. Information on this analysis is available from the Gas Compliance group.

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 capital program is focused on installing new gas mains and services, and retiring the previous overbuilt mains and services. This program does not significantly lower O&M costs. Instead, it is addressing a safety issue.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

None

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The alternative is to leave known overbuilds in place. This is a violation of code and standard practices. Only in rare cases is gas piping intentionally installed under a structure. The gas pipes addressed by this program were never intended to be built over, and therefore were not installed to comply with the special requirements needed to make such an installation compliant with code and Avista's Gas Standards.

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.

Projects completed within this budget will be transferred to plant upon completion, typically within the same year they are started.

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 addresses a known safety issue. A thorough evaluation was performed by the DIMP group to validate the need for this program. Construction on this program will be complete at the end of 2024.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders include Gas Engineering, Compliance, Integrity, and Operations.

2.8.2 Identify any related Business Cases

N/A

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

This program budget is overseen by Gas Engineering. Construction activities are overseen by Gas Operations. Projects are prioritized with input from the DIMP Program Manager, the impacted Operations Managers, and Gas Engineering.

3.2 Provide and discuss the governance processes and people that will provide oversight

DIMP risk scores are assigned to each proposed project. The highest-ranking projects are generally completed first, but some flexibility is required to ensure that specific operations groups are not overloaded during any given year. Gas Engineering oversees the program budget and reports on spending monthly.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

At the beginning of each year, the prioritization process is completed and the program budget is divided between offices. This information is formally handed off to the operations offices at that time. Rarely will anything change for the rest of the year. Gas Engineering reviews program spending with the operations offices on a monthly basis to keep within the program budget. Monthly updates are documented via email and fund requests are made using the appropriate forms from the CPG.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Overbuild Program ER 3006 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:	9/1/22
Print Name:	Jeff Webb / Tim Harding		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:		Date:	9/1/2022
Print Name:	Jody Morehouse		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

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 and accurate 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).

Avista would not be in compliance with state commission rules and tariffs in WA, ID, and OR if this program is not completed annually.

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	Dave Smith	Updated to the refreshed 2020 Business Case template	6/24/2020	
2.2	Dave Smith	Updated to the refreshed 2022 Business Case template	5-5-22	

GENERAL INFORMATION

Requested Spend Amount	$4,100,000 (2023)
Requested Spend Time Period	Annually
Requesting Organization/Department	Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Dave Smith | Jody Morehouse
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 also 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.

2. PROPOSAL AND RECOMMENDED SOLUTION

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	$4,100,000	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.

The PMC program was paused in 2022 due to inventory limitations in the meter manufacturing stream. There are not enough meters to support both growth and the PMC program, so a decision was made to use the meter we do have for new growth opportunities. The plan is to reinstate the program as soon as meter inventories return to an acceptable level. The assumption is we will be able to resume the program in 2023. The funds request for 2023 is higher than normal because it includes pulling meter families that would normally have been pulled in 2022 in addion to the anticipated number for 2023.

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 personnel 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.

Completing the annual PMC Program provides direct savings. Customers benefit from this program because it ensures their gas meter remains accurate throughout its service life. Meter families that have an accuracy outside of the acceptable range will be replaced. Most customers that have a failed family meter replaced will see a cost savings on their energy bill. See the file titled ER 3055 Cost Offset Calcs 2022-2023.xlsx showing the calculations for the direct savings shown below.

The estimated direct savings were calculated with the following assumptions:

1. The 2022 direct savings was calculated assuming that 50% of the R275_1994 failed family meters will be replaced in 2021 and the remaining 50% in 2022.
2. The Lifetime direct savings was calculated by assuming that the failed family meters being replaced would have remained in service for an additional 10 years.

[1]The direct savings for future years cannot be calculated until the program finishes and the meter accuracy data is complied.

Quantified direct savings:

	2022	2023	Lifetime
Capital:	-	-	-
Expense:	$38,000	[1]See Above	$153,000
Total:	$38,000	[1]See Above	$153,000

Completing the annual PMC Program also provides indirect savings. The program provides Avista with the data necessary to identify statistical trends in meter accuracy. If a particular meter family shows a consistent drift in mean accuracy, the meter family can remain in service and the customer's bill can be adjusted accordingly in the Meter Data Management system. This approach has allowed Avista to adjust leave approximately 67,000 meters in service that would have otherwise needed to be replaced. See the file titled ER 3055 Cost Offset Calcs 2022-2023.xlsx showing the calculations for the indirect savings shown below.

The estimated indirect savings were calculated with the following assumptions:

1. The average cost to replace a meter in 2022 and 2023 is estimated at $236 and $243, respectively. This estimated cost was calculated by taking the actual average cost to replace a meter in 2020 at $222 and then adding a 3% increase each year to account for a cost of living adjustment.

2. Per the failed family replacement timeframe defined in the PMC Program Standard Operating Procedure, 25% of the total 67,000 meters would need to be replaced each year starting in 2022 and ending in 2025.

Quantified indirect savings:

	2022	2023	Lifetime
Capital:	-	-	-
Expense:	$3,995,000	$4,114,000	$15,984,000

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

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. See below for breakdown of these risks:

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time (years)					Cost Estimate
		1	2	5	10	15+	
1	Regulatory Fines*	H	H	VH	VH	VH	$225,134 per day per violation (Max) $2,251,334 Total (Max)
2	Pipeline Leak	Not Applicable					Not Applicable
3	Pipeline Failure & Outage	Not Applicable					Not Applicable
4	Negative Reputation	H	H	VH	VH	VH	Erosion of PUC and Public trust
5	Employee & Public Safety	Not Applicable					Not Applicable

*Regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is likely to be much lower since Avista has an ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e. failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties (actual penalty amount is at the discretion of the state or federal agency).

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. MONITOR AND CONTROL

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.

4. APPROVAL AND AUTHORIZATION

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:		Date:	8/30/22
Print Name:	Jeff Webb / David Smith		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:		Date:	8/31/2022
Print Name:	Jody Morehouse		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

Virtually all of Avista's pipeline systems are located in public utility easements that are governed by local jurisdictional franchise agreements. In most cases, Avista is mandated under these agreements to relocate its facilities when local jurisdictional projects create a conflict.

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 after meeting, relocation of gas facilities are still required, then Avista must complete the work at our cost per the applicable franchise agreement.

It is very difficult to forecast year-to-year what the financial impacts in this category will be in each district and state. Budgets change each year for the municipalities, and their spending level is not directly tied to work for Avista. Some projects are more impactful than others to the buried gas facilities.

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 associated with project delays.

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.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial version	03/17/2017	
1.1	Jeff Webb	04/07/2017		
2.0	Jeff Webb	Revised for 2020 Oregon GRC filing	2/17/2020	
3.0	Jeff Webb	Revised for new BC format	8/30/22	

GENERAL INFORMATION

Requested Spend Amount	$3,610,000 – Annual Request
Requested Spend Time Period	10 years
Requesting Organization/Department	B51 / Gas Engineering
Business Case Owner | Sponsor	Jeff Webb | Jody Morehouse
Sponsor Organization/Department	B51 / Gas Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

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 our 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 companies 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 conflicts cannot be resolved, then relocation of gas facilities are required. Avista must then 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.

1.1 What is the current or potential problem that is being addressed?

Physical conflicts within a public right of way between natural gas facilities and roadways or other utilities.

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 is required to resolve conflicts within a public right of way, therefore this the driver is Mandatory and Compliance.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

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.

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 is required to resolve conflicts within a public right of way, therefore this the driver is Mandatory and Compliance.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

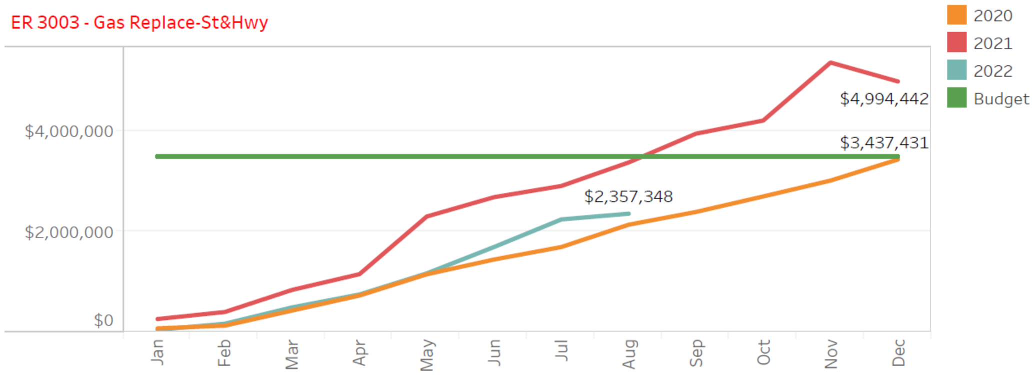
1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Recommended Solution – comply with franchise agreements	$3,610,000	01-2023	12-2033
Alternative #1 – Do nothing	$0	01-2023	12-2023
Alternative #2 – n/a	$M	MM YYYY	MM YYYY

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Budget numbers are based off historical spends and can vary significantly from year to year for each state. The graph below shows current 2022 spend plus the last two years as examples.



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 funding level for this program is based off of historical spend rates and then adjusted throughout the year to account for varying levels of work by district. It is very difficult to forecast year-to-year what the cost in this category will be for each state as the number and size of projects differs substantially from year to year.

There are no direct or indirect O&M saving related to this program.

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 often negotiates with the various municipalities in an attempt to reduce our conflicts and they are responsible to complete the construction work. Gas Engineering monitors spending and assists with complicated projects.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The numerous franchise agreements that Avista has with State, County, and City agencies determine the circumstances related to the gas facilities being located in their public right of ways. Should we violate those agreements by not relocating when required to do so, we would be liable for fines related to construction delays as well as tarnish the good working relationships we have with these entities.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time (years)					Cost Estimate
		1	2	5	10	15+	
1	Regulatory Fines	H	H	VH	VH	VH	Vary depeding on agency and circumstances
2	Pipeline Leak	VL	VL	VL	VL	VL	$5,000 to $150,000 per site (site dependent)
3	Pipeline Failure & Outage	VL	VL	VL	VL	VL	$150,000 to $3,000,000 per site (site dependent)
4	Negative Reputation	H	VH	VH	VH	VH	Erosion of PUC and Public trust
5	Employee & Public Safety	VL	VL	VL	VL	VL	Lost time, healthcare, lawsuits, etc. (varies)

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.

Projects are typically started and completed within the same calendar year and are placed into service the same month they become used and useful.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives, and mission statement of the organization.

Successful execution of this program ensures the integrity of Avista with the many jurisdictions we operate in, which in turns makes us a trustworthy partner.

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 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.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

None

2.8.2 Identify any related Business Cases

None

3. MONITOR AND CONTROL

3.1 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

3.2 Provide and discuss the governance processes and people that will provide oversight

The program's spend and budget will be reviewed monthly by the Gas Engineering Prioritization Investment Committee (EPIC). The manager of Gas Engineering will provide oversight to the program.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Monthly budget changes will be documented via the existing CPG process, approved by the Manager of Gas Engineering and the Director of Natural Gas. The monthly Gas EPIC updates are captured via email.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Replace Street & Hwy, ER 3003 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:	8/31/22
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:		Date:	8/31/2022
Print Name:	Jody Morehouse		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature: ______________________ Date: ______________

Print Name: ______________________

Title: ______________________

Role: Steering/Advisory Committee Review

EXECUTIVE SUMMARY

Avista has experienced safety issues, including fires at regulator stations and damaged equipment, due to transient voltage spikes from faults on adjacent electric transmission systems. The purpose of this program is to identify high pressure gas piping systems that are at risk of these conditions, identify gas systems that have high steady state voltage, and to then install mitigative measures to reduce the risk to both these scenarios on the pipelines. These efforts will protect the pipeline and equipment from being damaged and reduce the touch voltage exposure to below compliance limits, keeping our employees safe. Common approaches to this include the installation of grounding systems, gradient mats, and solid state decouplers.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial version	12/17/2021	
1.1	Tim Harding	Updated to the refreshed 2022 Business Case Template	9/1/2022	

GENERAL INFORMATION

Requested Spend Amount	$1,000,000 - 2023
Requested Spend Time Period	5-10 years
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Tim Harding | Jody Morehouse
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?

Buried steel natural gas pipes in close proximity to electric conductors can have high AC voltage present. The power lines induce this voltage on the pipe, either constantly, or during fault conditions. Industry standards, including AMPP Standard Practice SP0177 suggests that, for safety reasons, steady-state pipeline voltages should not exceed 15 volts. Systems experiencing voltages higher than this should be studied, and mitigation measures put in place to reduce system voltages.

Federal code CFR 49.192.467(F) requires that pipelines located near electric transmission systems must be protected from damage caused by faults on the transmission system. The mitigation schemes and equipment used to address fault voltage concerns often overlaps what is used to address steady-state voltage hazards. Fault incidents on nearby electric systems can lead to a significant voltage rise on the gas main – Hundreds or thousands of volts. Gas systems are not designed to support these voltage levels, and because of this electric arcing between components can occur. This arcing damages equipment, but also will burn holes through gas-carrying components, leading to gas leaks and fires. Personnel working on these gas systems during a fault event can be exposed to fatal voltage levels.

The constant presence of AC voltage on a pipeline can lead to corrosion. AMPP Standard Practice SP21424 addresses this issue and gives guidance on testing, monitoring, and mitigation of this issue. AC corrosion can occur on pipelines with less than 15 volts, so systems without shock hazard risks may still have this issue. Because of this, AC corrosion risks must be monitored separately from the other two risks listed above.

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 this business case is Mandatory & Compliance. This program addresses safety hazards and integrity concerns on high pressure steel gas mains. This benefits customers by reducing corrosion risks, as well as eliminating hazardous voltage levels on above-ground gas facilities – Facilities that sometimes are accessible to the general public.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

There are multiple gas systems with known high-voltage hazards present. Not mitigating these systems will result in the continued prevalence of electric fault incidents, as well as exposing employees to potentially hazardous steady-state pipeline voltages. Mitigation methods described in this program are a proven way to resolve these issues. This work must be done, and delaying the process puts system integrity and workers at an increased level of risk for each year of the delay.

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.

Incidents where electric faults cause damage to gas facilities are noted and investigated. The installation of mitigation equipment will reduce the prevalence of these incidents. The occurrence of these events is fairly random in nature and difficult to predict, but a reduction in fault damage will be noted in the long run.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

To date, two studies have been performed by consulting engineering firms on specific gas systems that have experienced multiple incidents. These studies have yielded reports and mitigation designs. As of September 2022, both projects are in different stages of construction. Reports from these studies are available from Gas Engineering.

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

2. PROPOSAL AND RECOMMENDED SOLUTION

The requested level of spending for this program allows the high priority projects to be completed. These projects are addressing serious system integrity and safety issues. A reduced level of funding will slow the installation of mitigation equipment, and delay resolving known system integrity and safety risks.

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	<$1,000,000	January	December

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The requested program budget was based on project cost estimates to address existing known integrity and safety risks. In the next two years extensive testing will be performed to determine how many other systems may have high voltage concerns. Future budget proposals will be based on the estimated project costs to mitigate those systems.

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 project budget is spent on the following: Consulting engineering design services, Avista engineering designs, mitigation materials (Including anodes, wire, grounding mats, decouplers, remote test stations, reference cells, coupons, etc.), Avista field installation labor, contractor labor, and installation services.

The installation of mitigation equipment reduced O&M expenses. The two main reductions in these costs are due to fewer fault damage incidents that require emergency response, and the reduced need to follow special safety procedures when doing construction or maintenance on the 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.

The completion of mitigation projects under this budget will have a positive impact on Gas Operations. Because there is currently a known safety issue, additional burdensome procedures are required when company personnel do construction and maintenance work on these systems. After the mitigation projects are complete, many of these additional safety procedures will no longer need to be followed.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

As mentioned in the previous section, systems with known voltage hazards require special safety procedures for construction and maintenance work. If these systems are left as-is with no mitigation, these procedures would have to be followed forever. Following these procedures is time consuming and requires ongoing training. Workers are required to lay out grounding equipment and use high voltage rated gloves for certain activities.

Not mitigating the system will result in the continued prevalence of electric fault incidents. During these incidents, electric arcing can occur on gas facilities. This can lead to gas leaks and fires. Knowingly allowing dangerous incidents like this to continue to occur is not acceptable.

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.

Projects that are performed under this budget can be both large and small. Smaller projects will typically transfer to plant monthly, while larger projects that take several months will transfer to plant upon project completion.

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 is addressing significant system integrity and personnel safety risks. For projects to be considered in this program, they must exhibit issues that would put them in violation of the Codes and Standards listed in Section 1.1 of this document. As projects are completed, these systems will become compliant with these requirements. As more systems are addressed, fewer will require mitigation and the program budget can be reduced.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders include Gas Engineering, Compliance, Operations, Cathodic Protection, and Safety.

2.8.2 Identify any related Business Cases

ER 3004 – Cathodic Protection: The mitigation of high AC pipeline voltages has ties to the field of cathodic protection. There are some overlaps between these programs, including testing procedures and equipment. Cathodic Protection technicians are involved with the installation and testing of AC mitigation systems.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

AC mitigation projects are proposed by the Gas Engineering and Cathodic Protection groups. In some cases, consulting engineers are hired to design mitigation systems. These engineers specialize in this field, and they provide subject matter expertise to the Company. Gas Operations is involved with project construction. Since Gas Operations benefits from the installations of the mitigation systems, they are included in project communications throughout the process, and they are given some say in how the installations are performed.

3.2 Provide and discuss the governance processes and people that will provide oversight

An engineer in the Gas Engineering group serves as the AC Mitigation Program Manager. The Program Manager oversees projects designs, construction, and the program budget. The Program Manager meets quarterly with representatives from Gas Engineering, Cathodic Protection, and Gas Compliance to review current and planned projects. Project are prioritized by the group.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

During the quarterly meeting mentioned in previous section, projects are discussed and prioritized. Meeting minutes are taken and stored on the program's SharePoint site.

Monthly budget changes will be documented via the existing CPG process, approved by the Manager of Gas Engineering and the Director of Natural Gas. The monthly Gas EPIC updates are captured via email.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Transient Voltage Mitigation 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:	Jeffy a Webb	Date:	
Print Name:	Jeff Webb / Tim Harding		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:		Date:	9/1/2022
Print Name:	Jody Morehouse		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

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.

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 work in thei program: 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, and farm tap elimination. 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. The business needs and solutions identified impact all gas customers in Avista's service territory.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	03/16/2017	03/17/2017	Initial version
1.1	Jeff Webb	04/05/2017		
2.0	Jeff Webb	2/17/2020	2/17/2020	Revised for Oregon 2020 GRC filing
3.0	Jeff Webb	Revised for new BC format	5/31/22	
1.0	Jeff Webb	03/16/2017	03/17/2017	Initial version

GENERAL INFORMATION

Requested Spend Amount	$9,400,000, annually
Requested Spend Time Period	10+ years
Requesting Organization/Department	B51 / Gas Engineering
Business Case Owner | Sponsor	Jeff Webb | Jody Morehouse
Sponsor Organization/Department	B51 / Gas Engineering
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 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, remediation of cathodic protection (CP) issues, 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. 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.

If a section of steel main is found to be isolated electrically from the CP system, a CP Technician will evaluate the concern and give directions to the district to fix. If the solution is a capital main replacement, it will fall under this program. Isolated steel services fall under ER 3007.

A single service farm tap (SSFT) installed on a high pressure 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.

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

Due to the majority of this work being unplanned replacement, it is considered Failed Plant & Operations. The percent of Customer Requested work is small compared to the other work in this program.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

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.

If not approved, Avista would experience higher instances of pipe damaged and associated gas leaks.

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 their time once on-site is the sensible way to operate. Betterments as described in above are driven by Company Standards and best practices.

In not approved, we would miss the opportunity to better the system while already on-site doing work. This 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.

Isolated mains (CP) – Electically isolated portions of main will be replaced as required to meet the requirements of Federal colde 49 CFR 192.455 & 192.457. This is a safety related requirement as a steel pipe will corrode if it does not have sufficient CP on it.

If not approved, we will be at risk of fines for being out of compliance and our steel piping system will not be safe for our employees and customers.

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 stations to provide a new source of gas. This allows the adjacent (old) 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.

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 maintenance 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, so having fewer of them on our system helps to improve safety.

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.

Customer satisfaction, or lack of complaints, due to not having multiple visits to the same address would indicate we are managing our system properly by bettering it when we have the opportunity.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

None

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.

None

2. PROPOSAL AND RECOMMENDED SOLUTION

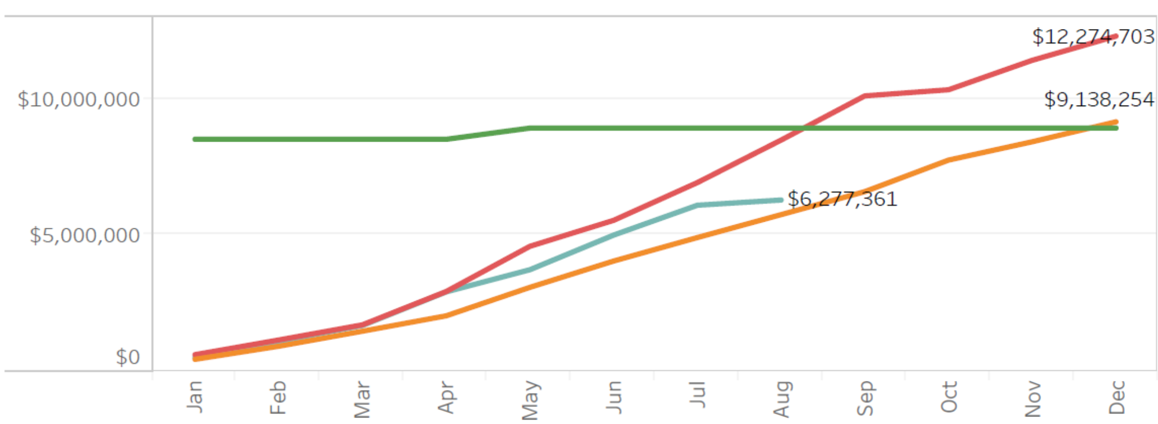
Option	Capital Cost	Start	Complete
Recommended Solution-Fully complete the program as described above.	$9,400,000	01 2023	12 2033
Alternative-Fund at a reduced level	<$9,400,000	01 2023	12 2033
[Alternative #2]-n/a			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

This program consists of hundreds of small individual projects completed across all three state each year. Budget levels are based on historical spend levels as the vast majority of this work is unplanned. The spend in 2021 has been adjusted to remove the one-time project of $2.8M and a 3% inflation factor has been applied.

2019	$ 9,430,000	
2020	$ 9,138,000	
2021*	$ 12,275,000	$ 2,800,000
3 yr avg	$ 9,347,667	
*2021 had an additional $2.8M allocated that was part of a one off specific project. The $2.8M is backed out of the number when calculating the average.		

ER 3005 - Gas Distribution Non-Revenue Blanket



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 work in this program is comprised of small projects that are typically completed within the same month they are started. As such, the funds transfer to plant each month throughout the year. The spending is fairly level each month as well as shown in the graph above.

There are no direct O&M savings associatd with completion of this program.

Indirect cost savings were calculated based on two presumptions:

1) that the Avista labor spent on this budget item would likely be charged to expense type work instead of this capital work if this work item was not available.

2) if this capital program is not funded, leaks will be repaired in a temporary manner as opposed to a permanent repair. When leaks are repaired temporarily, the permanent fix still needs to happen at some point in the future. So a leak repair will actually costs more to fix in the long run if it is not permanently fixed the first time.

All cost savings are in today's dollars.

Quantified indirect savings:

	2022	2023	Lifetime
Capital:	-	-	*
Expense:	$1,999,800	$1,999,800	*
Total:	$1,999,800	$1,999,800	*

* The program is in perpetuity, as such it is not possible to calculate a lifetime benefit.

CFR 192.465 & CFR192.720 determine how a gas utility manages leaks. The other portions of work associated with this Business Case are not mandated work. They consist of customer requested work, mitigating shallow gas facilities, and strategically replacing farm tap style regulators with IP main.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time (years)					Cost Estimate
		1	2	5	10	15+	
1	Regulatory Fines*	VL	VL	VL	L	L	$225,134 per day per violation (Max) $2,251,334 Total (Max)
2	Pipeline Leak	VL	L	L	P	P	$5,000 to $150,000 per site (site dependent)
3	Pipeline Failure & Outage	VL	VL	VL	L	L	$150,000 to $3,000,000 per site (site dependent)
4	Negative Reputation	VL	VL	VL	L	L	Erosion of PUC and Public trust
5	Employee & Public Safety	VL	L	L	P	P	Lost time, healthcare, lawsuits, etc. (varies)

*Regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is at the discretion of the enforcement agency and is likely to be much lower due to Avista's ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e. failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties.

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.

Risks to not funding this program as requested are discussed 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.

The work in this program is comprised of small projects that are typically completed within the same month they are started. As such, the funds transfer to plant each month 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 Avista's organizational focus to maintain a positive customer experience, and a safe and reliable infrastructure safely.

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 level of spending is appropriate for Avista to react to unplanned work that occurs on a regular basis across our gas system. As already discussed, if not fully funded, Avista could face fines and actually spend more on a project if not fixed properly the first time at the job site.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Gas Engineering and Operations are the main stakeholders to this program.

2.8.2 Identify any related Business Cases

none

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Gas Engineering monitors the spend and reports back to the district managers on a monthly basis.

3.2 Provide and discuss the governance processes and people that will provide oversight

Gas Engineering prepare the appropriate documents for the Director of Natural Gas to represent at the CPG should changes be needed throughout the year.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Monthly updates are provided to the director of Natural Gas, these are captured via email.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the ER 3005 Gas Non-Revenue Program 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:	Jeffry a Webb	Date:	8/31/22
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:		Date:	8/31/2022
Print Name:	Jody Morehouse		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

An Encoder Receiver Transmitter (ERT) is an electro-mechanical device that allows gas meters to be read remotely. These ERTs are powered by lithium batteries, which discharge over time and must eventually be replaced.

Most of the gas meters in Washington, Idaho, and Oregon have ERT modules. The large quantity of ERT installations will result in an unmanageable quantity of battery failures in the future if the ERT is not replaced at an optimized frequency. When batteries fail, the customer's usage is estimated and entered into the billing system manually. This manual process causes a high chance of customer dissatisfaction because of potential billing errors associated with bill estimation. Customers often express their dissatisfaction through commission complaints when this happens.

In most areas of Washington, the ERT modules were replaced in 2019 as part of the Advanced Metering Infrastructure (AMI) project. These ERTs will not need to be replaced for approximately 15 years unless they experience a premature battery failure. This business case also covers instances where the ERT module is not communicating with the AMI network as intended, causing a replacement that is compatible with the mobile meter read routes. This will ensure reliable metering reading and billing.

In Idaho the ERTs will likely be changed out in mass when the AMI project starts in 2024, however it is estimated that up to 30,000 40G ERT modules may have a battery failure in 2022 and 2023 due to their age. These 40G ERT modules may be replaced to avoid battery failure and billing issues before the AMI project is implemented.

In Oregon the ERTs will not be changed out in mass because the AMI project will not be implemented there, therefore the recommended solution is to replace the oldest 7,000 ERTs each year on a 15 year cycle. This replacement strategy was optimized by an Avista Asset Management study. The annual cost of this replacement strategy is $220,000 and it expected to increase approximately 5% per year to adjust for increased wages and materials.

If this program is not funded the amount of ERT battery failures will increase to an unsustainable level. If not replaced at the proposed rate, a peak of more than 20,000 ERTs are predicted to fail annually, each requiring an unplanned maintenance visit to replace, causing an undue burden on Operations personnel and equipment. This large number of failed ERTs will also cause an unreasonable number of meters that would need to be read manually and the customer's usage estimated resulting in estimated billing and a negative customer experience.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Dave Smith	Initial version	3/9/2017	
1.1	Dave Smith	Revised per initial review	3/24/17	
2.0	Dave Smith	Revised for 2020 Oregon GRC filing	2/7/20	
2.1	Dave Smith	Updated to the refreshed 2020 Business Case template	6/23/20	
2.2	Dave Smith	Updated to the refreshed 2022 Business Case template. Edited to include WA and ID in the program.	5-5-22	

GENERAL INFORMATION

Requested Spend Amount	$220,000
Requested Spend Time Period	Annually
Requesting Organization/Department	Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Dave Smith | Jody Morehouse
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?

An Encoder Receiver Transmitter (ERT) is an electro-mechanical device that allows gas meters to be read remotely. These ERTs are powered by lithium batteries, which discharge over time and must eventually be replaced. The average battery life for ERT modules is approximately 15 years. Most of the gas meters in Washington, Idaho, and Oregon have ERT modules. The large quantity of ERT installations will result in an unmanageable quantity of battery failures in the future if not replaced at an optimized frequency. When batteries fail, the customer's usage is estimated and entered into the billing system manually. This manual process causes a high chance of customer dissatisfaction because of potential billing errors associated with bill estimation. Customers often express their dissatisfaction through commission complaints.

Battery replacement was determined to not be the best approach because in order to replace just the battery, a technician needs to remove the module from the meter and bring it back to the shop where the battery can be replaced in a controlled environment. After the battery is replaced the technician needs to return to the meter to re-install the module. This results in twice the travel time and twice the labor time compared to replacing the entire module, negating any cost savings.

Another issue with replacing just the battery is that all of the potting gel surrounding the battery and circuity inside the module needs to be removed in order to access the battery, and once the gel is removed all of the electronic components inside the ERT are now subject to moisture damage in the field, resulting in additional failures. The manufacturer (Itron) does not recommend replacing the battery in ERT modules for these reasons.

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 usess a proactive and strategic method for addressing asset condition by replacing ERT modules before their battery fails. Replacing these assets before they fail will avoid a manual process of estimating a customer's gas usage and bill resulting in higher customer satisfaction. It is also more efficient and cost effective to proactively replace old ERTs rather than waiting until their battery fails and having to send out a servicemen to replace a failed ERT.

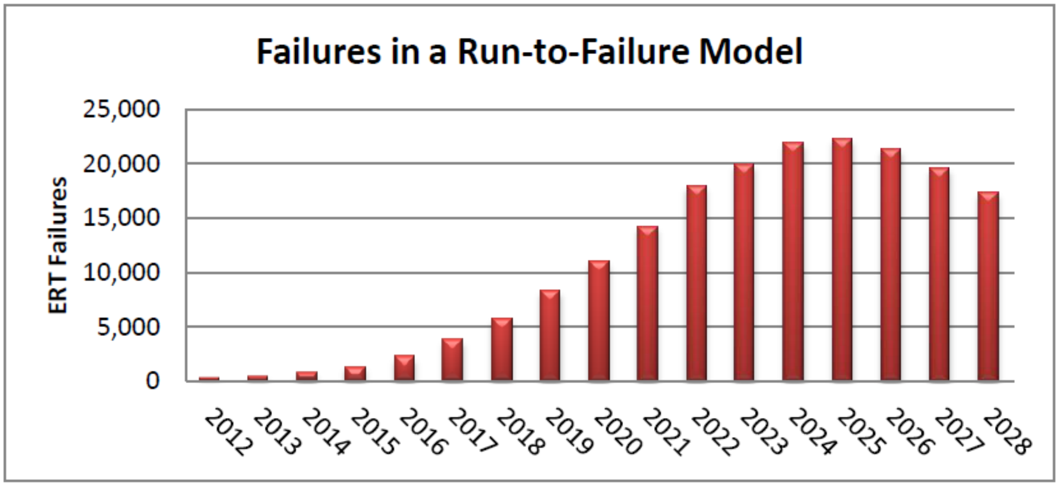
1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The work is needed now because many of the ERTs have reached their end-of-life and will begin failing or are not communicating with the AMI network as intended resulting in billing issues.

In most areas of Washington, the ERT modules were replaced in 2019 as part of the Advanced Metering Infrastructure (AMI) project. These ERTs will not need to be replaced for approximately 15 years unless they experience a premature battery failure. This business case also covers instances where the ERT module is not communicating with the AMI network as intended, causing a replacement that is compatible with the mobile meter read routes. This will ensure reliable metering reading and billing.

In Idaho the ERTs will likely be changed out in mass when the AMI project starts in 2024, however it is estimated that up to 30,000 40G ERT modules may have a battery failure in 2022 and 2023 due to their age. These 40G ERT modules may be replaced to avoid battery failure and billing issues before the AMI project is implemented.

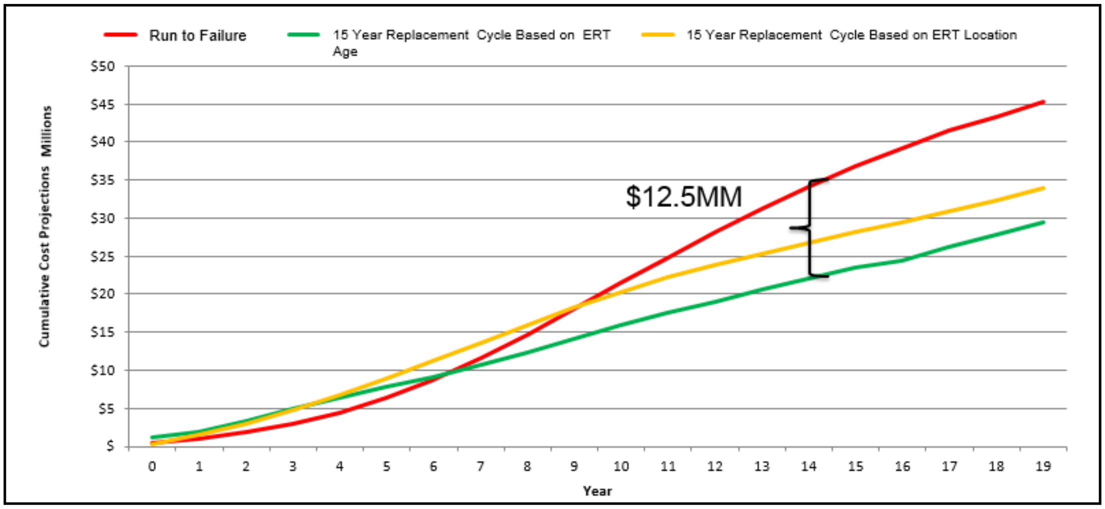
The graph below shows how many ERT modules are expected to fail annually in Oregon if they are not proactively replaced.



If this program is not funded the amount of ERT battery failures will increase to an unsustainable level. If not replaced at the proposed rate of 7,000 annually, a peak of more than 20,000 ERTs are predicted to fail annually, each requiring a maintenance visit to replace, causing an undue burden on Operations personnel and equipment. This large number of failed ERTs will also cause an unreasonable number of meters that would need to be read manually and the customer's usage estimated resulting in estimated billing and a negative customer experience.

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 Asset Management department was consulted by Gas Engineering for assistance in developing a strategic program to replace ERT modules in Oregon since the AMI program would not replace the modules there. The result of the study suggested the most efficient method for replacing these assets resulted in the highest customer satisfaction and the lowest cost. The graph below summarizes the cost savings associated with a proactive and strategic ERT replacement program over a 15 year cycle:



1.5 Supplemental Information

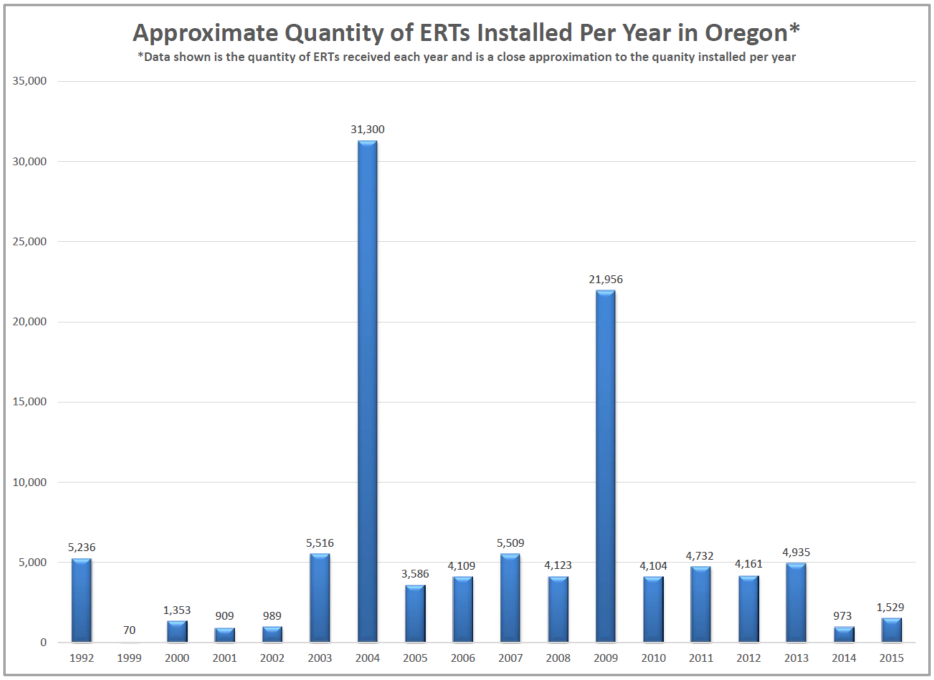
1.5.1 Please reference and summarize any studies that support the problem

The Asset Management study for the Oregon ERT Replacement Program is 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.

In Idaho the concern is the 2005-2007 vintage 40G ERTs failing before the AMI project commences in 2024. There are approximately 30,000 of these modules in the system. If we do not proactively replace these modules in 2022 and 2023 there is a high likelihood that their batteries will fail before AMI is implemented starting in 2024.

The graph below shows the quantity of ERTs installed per year in Oregon:



If these ERTs are run to battery failure there will be an unmanageable quantity of ERT failures each year.

2. PROPOSAL AND RECOMMENDED SOLUTION

The recommended solution for Idaho is to replace the 30,000 +/- 40G ERTs that are at end of life. This work will be completed in 2022 and 2023.

The recommended solution for Oregon is to continue replacing the oldest 7,000 ERTs each year on a 15 year cycle. This approach targets the oldest ERTs resulting in less battery failures and as a result fewer estimated customer bills.

Option	Capital Cost	Start	Complete
Recommended Solution:			
ID – Replace 30,000 +/- 40G modules in 2022 and 2023.	$570,000 (ID)	01/2022 (ID)	12/2023 (ID)
OR – Replace the oldest 7,000 ERTs each year on a 15 year cycle	$200,000 (OR)	01/2016 (OR)	04/2031 (OR)
Alternative Solution:			
ID – Run 40G ERTs to failure.	$5.41MM (ID)	N/A (ID)	N/A (ID)
OR – Replace 7,000 ERTs based on geographic location each year on a 15 year cycle	$126,040 (OR)	01/2016 (OR)	04/2031 (OR)

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Some factors that were considered when preparing this request are the number of ERTs in service, the average battery life of the ERT module, the effects on the customer's bill if the ERT fails, the cost to reactively replace the failed module, and the cost to proactively replace the asset before failure. Refer to the asset management study discussed in Section 1.4.

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.**

In Idaho the replacement of approximately 30,000 2005-2007 40G ERT modules will be replaced in 2022 and 2023. The exact timing is still being evaluated, taking into account supply chain limitations and expected failure rates.

At the beginning of each year the project team determines the location of the oldest 7,000 ERTs in the Oregon. Replacement ERT modules are then ordered. Due to the "pre-capitalization process" the cost of the ERT module will go against ER1053 (Gas ERT Minor Blanket). This program covers the labor and minor material cost for replacing the ERT. Work orders are created for the replacement of each ERT. A third party contractor is utilized to efficiently replace all 7,000 ERTs. The program is completed between January and December each year.

If an ERT battery fails the Mobile Collector will not download the monthly meter read. As a result a servicemen is dispatched to investigate the issue which results in a much higher cost than if the ERT was proactively replaced before the battery dies. This additional cost is primarily composed of personnel labor and travel wages, vehicle costs, and the cost to produce an estimated customer bill.

Reactive ERT Replacement Costs[1], Per Unit	
Avista personnel labor & travel time wages	$100.36
Avista vehicle corrective call out cost	$67.04
Cost to produce estimated bill when ERTs fail	$12.93
Total	***$ 180.34***

[1]These costs were calculated using the ERT Replacement Strategy Development study from 2012 and adjusted by adding a 2% annual inflation rate.

Washington & Idaho Proactive ERT Replacement Costs[2], Per Unit	
Contractor labor	$54.25
Project management	$0.75
Total	***$55.00***

Oregon Proactive ERT Replacement Costs[2], Per Unit	
Contractor labor	$25.00
Project management	$0.75
Total	***$25.75***

[2]These cost reflect 2022 contractor unit pricing per Avista Contract R-40780.

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 ERT modules 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.

In 2022, an alternative solution that was considered for Washington was to install Star Connected Grid Routers (CGR) devices in the gas only areas where the 500G modules were not able to communicate through the AMI mesh network. The Star CGR option would have taken much longer to implement and would have also been much more costly than replacing the ERT module, therefore the most timely and cost effective solution was to replace the 500G module with a 550G module that would allow mobile reading in the gas only areas.

An alternative solution for Oregon that was considered was to replace 7,000 ERTs based on it's geographic location each year on a 15 year cycle (represented by the yellow line in the graph in Section 1.4). This option involves replacing a geographic cluster of ERTs. The benefit to this approach is that the ERTs are located close to one another, which equates to less travel time in-between ERT locations. The disadvantage to this approach is that the oldest ERTs may not be replaced if they are outside of the geographic zone, so there would be a higher quantity of ERT battery failures and customer billing estimates. A third party contractor provided a cost estimate for both replacement strategies and the cost to replace the oldest ERTs was not significantly more than replacing the geographically located ERT clusters. However the overall cost increase to replace by location was significant, approximately $5,000,000 more over the life of the 15 year program, due to the high number of expected unplanned replacements using this method vs replace by age.

The run-to-failure cost to reactively replace the failed ERT modules was also considered for Idaho and Oregon. When an ERT is run to failure the customer's bill is estimated and then corrected the next month after the ERT is replaced. If this proactive replacement program is not funded there will be an unmanageable quantity of ERTs failing each year and it is likely that the failed ERT will not be replaced in one month's billing cycle resulting in billing estimates for multiple months. This will create customer dissatisfaction and loss of trust. See below for breakdown of these risks.

Assumptions:

1. Except for regulatory fines, cost estimates based on SME input.
2. Costs associated with each risk can vary significantly depending on site conditions.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time 1 Year	2 Years	5 Years	10 Years	15+ Years	Cost Estimate
1	Regulatory Fines	L	L	L	L	L	$225,134 per day per violation (Max)* $2,251,334 Total (Max)*
2	Pipeline Leak	L	L	L	L	L	$5,000 to $150,000 per site (site dependent)
3	Pipeline Failure & Outage	L	L	L	L	L	$150,000 to $3,000,000 per site (site dependent)
4	Negative Reputation	H	VH	VH	VH	VH	Erosion of PUC and Public trust
5	Employee & Public Safety	L	L	L	L	L	Lost time, lawsuits, healthcare , etc. (varies)

*Regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is likely to be much lower since Avista has an ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e. failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties (actual penalty amount is at the discretion of the state or federal agency).

Over the life of the 15 year program in Oregon the asset management study estimates that the cost of this run-to-failure approach would be approximately $12,500,000 more than if a proactive and strategic replacement program was executed. Refer to the cost analysis graph in Section 1.4 showing a comparison between the preferred and alternative solutions.

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 Idaho program is planned to be competed by the end of 2023. The Oregon program will be completed between January and December each year on a 15 year cycle. The ERT modules are purchased as a pre-capital material item under ER 1053 (Gas ERT Minor Blanket). The ERTs will become used and useful upon installation on the meter.

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 replacement strategy described herein was optimized by Avista's Asset Management department to levelized the asset replacement cost, to optimize the asset life-cycle, and to minimize the number of failed ERTs requiring customer billing estimates. The program costs will be monitored monthly by the program manager.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Avista gas customers benefit from the replacement of these ERT modules because they will receive reliable and accurate billing.

Business case stakeholders including the ERT Replacement Program manager, GIS Analyst, Sourcing Professional, Maximo Business Analyst, IT, Service Credit Dispatch, and Oregon Gas Operations all work together to ensure a successful program execution.

2.8.2 Identify any related Business Cases

ER 1053 Gas ERT Minor Blanket

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Asset Management department was consulted by Gas Engineering for assistance developing a strategic program to replace ERT modules before their battery expires. The result of the study suggested the optimized method for replacing these assets that resulted in the highest customer satisfaction and lowest cost.

3.2 Provide and discuss the governance processes and people that will provide oversight

Using the replacement strategy recommended by Asset Management the ERT Replacement Program manager works with GIS Technical Services to determine the location of the oldest 7,000 ERT modules in Oregon. Each year prior to starting work the oldest ERT locations are re-analyzed to ensure the most accurate and up to date information. The third party contractor performing the replacement work also provide field verification to ensure only old ERTs are replaced.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The ERT Replacement Program is documented in a business plan and prioritized in a spreadsheet. Each ERT replacement is documented in Maximo with a work order.

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.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas ERT Replacement Program, ER 3054 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:	8/31/22
Print Name:	Jeff Webb / David Smith		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:		Date:	8/31/2022
Print Name:	Jody Morehouse		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature: ______________________ Date: ______________

Print Name: ______________________

Title: ______________________

Role: Steering/Advisory Committee Review

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.

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.

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	1.0
1.1	Jeff Webb		4/07/2017	1.1
2.0	Jeff Webb	Revised for 2020 Oregon GRC filing	2/17/2020	2.0
2.1	Dave Smith	Updated to the refreshed 2020 Business Case template	6-24-20	2.1
2.2	Dave Smith	Updated to the refreshed 2022 Business Case template	5-5-22	2.2

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 | Jody Morehouse
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.

Project List/Capital Planning					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.

2. PROPOSAL AND RECOMMENDED SOLUTION

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 funding 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 replacement work is preferred over 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	$1,070,000	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.

Engineer	Sti	Prior	Project Estimate	Comments	Pressure Controlmen	State	Budgeted for 2022	Deferred to 2023
Anderson	115	5	$ 35,000	Odorizer Station Rebuild	Inouye	WA	$ -	$ 35,000
Anderson	24C18	1	$ 100,000	Carestream - Kirtland Road	Boskovich/Stimpert	OR	$ 100,000	$ -
Anderson	206	2	$ 60,000	Sandpoint DR	Finney	ID	$ 50,000	$ -
Anderson	221	3	$ 50,000	CDA East GS & RS 2210	Finney	ID	$ 95,000	$ -
Anderson	260	4	$ 30,000	Silverton Reg Station	Finney	ID	$ -	$ 30,000
Anderson	213	1	$ 80,000	McGuire GS	Finney	ID	$ 80,000	$ -
Harding	303	2	$ 10,000	High pressure DR, change to FT station	Salonen	WA	$ 10,000	$ -
Harding		5	$ 10,000	MSA Wood Grain Lumber Mill	Salonen	ID	$ 10,000	$ -
Harding	315	4	$ 40,000	Colton Gate Station	Salonen	WA	$ 30,000	$ -
Harding	420	1	$ 60,000	Lewiston DR	Salonen	ID	$ 60,000	$ -
Harding	322	3	$ -	Farm tap on Granland Rd	Salonen	ID	$ -	$ -
Harding		6	$ -	MSA at WSU downtown Pullman	Salonen	WA	$ -	$ -
~~Yang~~	~~24P04~~	~~1~~	~~TBD~~	~~CG-24P04, Campbell Rd, Medford (leak repair)~~	~~Boskovich/Stimpert~~	~~OR~~	~~$ -~~	~~$ -~~
Yang	24P23	2	$ 55,000	Payne Road Rebuild, Medford	Boskovich/Stimpert	OR	$ 55,000	$ -
Yang	2412	2	$ 125,000	Siskiyou & Willamette Rebuild/Relocate, Medford	Boskovich/Stimpert	OR	$ 125,000	$ -
Yang	8329	2	$ 85,000	WM Waste to Energy MSA Rebuild, Spokane	Gibson	WA	$ 85,000	
~~Yang~~	~~24F61~~	~~N/A~~	~~$ 33,000~~	~~Rebuild Reg #24F61 and Retire #24F60B~~	~~Boskovich/Stimpert~~	~~OR~~	~~$ -~~	~~$ -~~
Smith	31	1	$ 35,000	Nine Mile & Royal	Inouye	WA	$ 25,000	$ -
Smith	4577	7	$ 40,000	Trent & Harvard	Inouye	WA	$ -	$ 40,000
Smith	562	4	$ 70,000	Gold Creek Loop Rd	Inouye	WA	$ -	$ 60,000
Smith	51	6	$ 30,000	Expand easement and fence, fix outlet pipe settlement. Hwy 27 & 46th, Spokane Valley	Inouye	WA	$ -	$ 30,000
Smith	27	2	$ 85,000	Sprague & Molter, Liberty Lake	Inouye	WA	$ 85,000	$ -
Smith	36	3	$ 95,000	Airport Road	Inouye	WA	$ 95,000	$ -
Smith	33	8	TBD	Coeur d'Alene & Sunset	Inouye	WA	$ -	TBD
Smith	1850	4	$ 70,000	RA Hansen MSA	Gibson	WA	$ -	$ 70,000
Smith	7701	1	$ 35,500	Lakeland Village MSA	Gibson	WA	$ 25,000	$ -
Smith	5636	5	$ 15,000	Interstate Concrete Colville MSA	Gibson	WA	$ -	$ 15,000
Smith	6039	3	$ 15,000	Conoco-Phillips MSA	Gibson	WA	$ 15,000	$ -
		Total:	**$ 1,225,000**				**$ 945,000**	**$ 280,000**

Image 2 – Partial list of stations ranked by priority (only 2022-2023 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 will reduce O&M costs because stations that are at the end of the end of their service life and/or are not up to Avista's current standards typically take longer to maintain. Refer to spreadsheet titled ER 3002 Cost Offset Calculations 2022-2023.xlsx showing the calculations for the direct savings shown below.

The estimated direct savings were calculated with the following assumptions:

1. Average hourly maintenance rate is $85.00.
2. Cost of Living Adjustment rate is 3% per year.
3. Ten stations are replaced each year.
4. Rebuilding the station up to current standards saves an average of 1 hour of maintenance time per year.
5. The expected service life of a station is 40 years.
6. Avista's average labor overhead rate between 2014 to present is 94%.

Quantified direct savings:

	2022	Lifetime
Capital:	-	-
Expense:	$1,700	$265,500
Total:	$1,700	$265,500

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. The risk of not doing the work includes, but is not limited to, regulatory fines, pipeline leaks, pipeline failures and outages, negative company reputation, and employee and public safety. 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.

See below for breakdown of these risks:

Assumptions:

1. Except for regulatory fines, cost estimates based on SME input.
2. Costs associated with each risk can vary significantly depending on site conditions.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time (years)					Cost Estimate
		1	2	5	10	15+	
1	Regulatory Fines*	L	L	L	L	L	$225,134 per day per violation (Max) $2,251,334 Total (Max)
2	Pipeline Leak	L	P	P	H	VH	$5,000 to $150,000 per site (site dependent)
3	Pipeline Failure & Outage	L	L	P	P	H	$150,000 to $3,000,000 per site (site dependent)
4	Negative Reputation	L	L	L	P	P	Erosion of PUC and Public trust
5	Employee & Public Safety	L	P	P	H	H	Lost time, lawsuits, healthcare , etc. (varies)

*Regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is likely to be much lower since Avista has an ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e. failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties (actual penalty amount is at the discretion of the state or federal agency).

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 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.

3. MONITOR AND CONTROL

3.1 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.

3.2 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.

3.3 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.

4. APPROVAL AND AUTHORIZATION

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:	Jeffy a Webb	Date:	8/29/22
Print Name:	Jeff Webb / David Smith		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Jody Morehouse	Date:	8/29/2022
Print Name:	Jody Morehouse		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature: ______________________ Date: ____________

Print Name: ______________________

Title: ______________________

Role: Steering/Advisory Committee Review

EXECUTIVE SUMMARY

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. These deficient areas are given a risk ranking based on the severity and the number of customers impacted. 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. The business needs and potential solutions identified impact all gas customers in Avista's service territory. Spending per jurisdiction changes each year as the intent is to complete the highest risk projects first, regardless of which State it is in.

The proposed annual budget is consistent with expenditures from past years. There is currently a large backlog of projects. Significant progress has been made with reinforcement projects in the past decade. It is anticipated that the funding for this ER will be reduced in approximately five years, but not completely go away as reinforcements will always be needed as new customers are added.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial version	3/17/2017	
1.1	Jeff Webb		4/6/2017	
2.0	Jeff Webb	Revision for 2020 Oregon GRC filing	2/17/2020	
2.1	Tim Harding	Updated to the refreshed 2022 Business Case Template	9/1/2022	

GENERAL INFORMATION

Requested Spend Amount	$1,300,000
Requested Spend Time Period	Annually
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Jeff Webb/Tim Harding | Jody Morehouse
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?

This annual program will identify and provide for necessary capacity reinforcements to the existing natural gas distribution system in WA, ID, and OR. Avista has an obligation to serve existing Firm gas customers by providing adequate capacity on design day weather 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 smaller scope, lower cost projects may be completed under the blanket project numbers set up for each district.

Projects that are identified in this program are prioritized by a Gas Planning model, see Image 1 below for a list of high and medium priority projects. The prioritization is based on the computer model that analyzes actual meter usage data from each customer, extrapolates that data to predict a demand load at design temperature conditions, and then analyzes each gas distribution system to determine if reinforcements are necessary. If system capacities are not sufficient the model can also be used to determine the benefits of different types of reinforcement projects by running “what if?” scenarios. Once the projects are identified, they are risk ranked based on the number of customers affected and the temperature levels at which the risks begin.

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 for this business case is Performance and Capacity. Projects also improve the reliability of the gas system by reducing the possibility of outages. Customers benefit from this improved reliability.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

There are currently gas systems that will fail during extreme cold weather because the system capacity cannot meet peak demand. By upgrading these systems we reduce the chance of cold weather outages. At a minimum, outages are an inconvenience to customers. They can, however, become a serious health and safety concern because they tend to happen during extremely cold weather. System outages that cause customers to be without heat during extreme cold weather must be avoided.

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.

These system upgrades avoid system outages, as well as manual interventions required to keep these systems operating during peak system demand. Reductions in outage incidents and the reduction in field personnel intervention can be measured.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

On an annual basis, the Gas Planning group reviews system load studies and prioritizes future reinforcement projects. Below is an example of the 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

Image 1 – Prioritized list of reinforcements

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

2. PROPOSAL AND RECOMMENDED SOLUTION

The requested level of spending for this program allows some high priority projects to be completed every year. The list of new requests continues to grow as system deficiencies are discovered and as customer load growth increases. At a reduced funding level, project backlogs grow longer leading to a higher chance of gas outage incidents.

Option	Capital Cost	Start	Complete
Recommended Solution, Construct Reinforcement projects at requested funding level	$1,300,000	January	December
Alternative Solution, Construct Reinforcement projects at a reduced funding level	$800,000	January	December

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Gas planning uses load studies to predict system pressures during design day weather (extreme cold) conditions. These studies determine the likelihood of system outages, as well as how many customers are impacted. Avista has an obligation to serve Firm customers, and because of this, gas systems must be designed to meet these demands during all expected and planned weather conditions. The Company's cost to respond to a system outage can range from thousands of dollars to over one million dollars.

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 entire budget is spent annually on the installation of gas mains and regulator stations. The cost to respond to a system outage can easily exceed the cost of funding a capital construction project that would reinforce the system and avoid such an outage.

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 completion of reinforcement projects benefits the operations group. There is less field intervention during cold weather events, and cold weather outages are avoided. This reduces the chance of costly emergency responses that require involvement from Corporate Communications, Supply Chain, Gas Engineering, and others.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Without a Reinforcement Program, Avista does not have sufficient capacity to meet our obligation to serve existing Firm customer load on a design day scenario and is not able to support future customer growth.

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. The process of 're-lighting' after an outage and returning a gas system to service can cost over $1M in some cases.

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.

Projects are constructed year-round. Smaller projects will be transferred to plant on a monthly basis. Larger projects are transferred to plant upon project completion.

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. Completion of this project ensures gas service is "Always there for an always on world" and that we Perform by providing reliable gas service to our firm 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

Projects constructed within this program are specifically designed to address severe system deficiencies. These projects are to prevent customers from losing gas service (and heat) during extreme cold weather. They prevent costly outage emergencies. In the future it is anticipated that, because of this program, there will be fewer system deficiencies, and therefore a lower risk of system outages. This should allow for a reduction in the program budget in the future.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Customers in project areas will benefit from improved system reliability, as well as increased system capacity.

Stakeholders include Gas Engineer, Gas Planning, and Gas Operations.

2.8.2 Identify any related Business Cases

N/A

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Using computer-based load studies, Gas Planning identifies areas of concern that need reinforcement projects. Those projects are ranked by severity and the highest priority projects are sent to Gas Engineering. These projects are managed by the Gas Engineering group. Construction is completed by Gas Operations with company or contract resources.

3.2 Provide and discuss the governance processes and people that will provide oversight

The projects are managed by Gas Engineering and status updates are given to Gas Planning several times a year to ensure that the highest priority projects are being addressed first.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The list of projects to be constructed is assembled early in the year. If a new project is added mid-year, Gas Planning is asked to prioritize the new project against all un-completed projects. Late in the year the program budget is reviewed, and projects are added or cut from the year's schedule to keep the program on-budget. Gas Planning prioritizes all projects being added or removed to ensure that the highest ranked projects are constructed first.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Reinforcement Program, ER 3000 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:	Jeffy a Webb	Date:	9/1/2022
Print Name:	Jeff Webb / Tim Harding		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Jody Morehouse	Date:	9/1/2022
Print Name:	Jody Morehouse		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

ER 3117 provides funding for additions, improvements, and replacements to our Gas Telemetry system. The system provides safety related pressure monitoring including alarms at Gate Stations, Regulator Stations, Pipelines, Odorizers, and Transport Customers. It also provides significant data including consumption for gas procurement and billing, engineering analysis, and system operations. It is important to our customers for safe and reliable operation of our gas system and regulatory compliance for pressure monitoring.

Telemetry equipment includes flow computers, electronic volume correctors, and electronic pressure monitors at new or upgraded regulator and gate stations. Also, system pressure monitoring at ends of pipelines and multi-fed systems (required by Federal Code).

Some existing in-service equipment is obsolete and failing so replacements are required to maintain functionality. Risks if not upgraded include reduced reliability and increased maintenance costs to reactively repair sites. Regulatory compliance could be reduced and over or under pressure events may not be detected early enough for corrective action which could lead to a loss of gas service to customers or an overpressure event. Additionally, manual meter reads and/or bill estimates could be required for some billing sites.

A portion of the budget estimates are based on a five-year plan (four years to go) to upgrade most instruments with dial up modems by conversion to cellular communication through instrument replacement. By stretching the replacement out to five years, there is a compromise and some risk as addressed in the narrative below if the head end dial-up modem bank were to completely fail in the next 4 years. The remainder of the annual budget request provides for modest upgrades and additional system monitoring. Gas Engineering is responsible for prioritizing and approving specific projects within this program.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.1	*Dave Moeller*	*Business Case update for 2023*	*7-15-22*	

GENERAL INFORMATION

Requested Spend Amount	$295,000, 304,000, 313,000, 322,000, 200,000
Requested Spend Time Period	2023 - 2027
Requesting Organization/Department	Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Dave Moeller | Jody Morehouse
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?

Some existing Gas Telemetry equipment is obsolete, and failures are increasing so it needs to be replaced. This includes the dial-up telephone landline modem bank head end of the Gas Telemetry System. In order to upgrade this obsolete communication form, it's necessary to replace the field instruments with IP based (mostly cellular) communication. Once all the dial up field devices have been replaced, the head end modem bank can be retired.

Additional system monitoring is required for situational awareness, safety, compliance, new Gas Transportation Customers, and system improvements such as new or rebuilt gate and regulator stations.

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

ER 3117 provides capital funding for additions, improvements, and replacements for our Gas Telemetry system. The system provides pressure monitoring including safety related alarms and history for pressure, temperature, gas volumes, and gas flow rates at Gate Stations, Reg Stations, pipelines, odorizers, and for Transport Customers where applicable.

Equipment includes flow computers, electronic volume correctors, and electronic pressure monitors at new or upgraded regulator and gate stations. Also, system pressure monitoring at ends of pipelines and on multi-fed systems.

The system provides data to SCADA for Gas Control, to Nucleus for Gas Procurement, and to the PI data base for use by all departments including Gas Engineering, and Operations (Pressure Controlmen). It is important for safe and reliable operation of our gas system, regulatory compliance with pressure monitoring, operational monitoring, and billing data at gate stations and Transport Customers.

For many of the Transport Customers, when replacing the instrument, we are also improving safety by buying instruments with a second pressure transducer. The dual pressure monitors allow for monitoring both the metering and delivery pressure and can provide early warning to the Gas Control Room of an abnormal event that could negatively impact the customer.

Continued investment in our Gas Telemetry System is a benefit to our customers to continue to safely and efficiently operate and maintain our gas transmission and distribution systems as well as provide accurate and timely billing data.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

The requested funding is needed now to prevent extensive equipment failures and the associated reduced situational awareness, timeliness of billing data.

A portion of the budget estimates are based on a five-year plan (four years to go) to upgrade most instruments with dial up modems by conversion to cellular communication through instrument replacement. By stretching the replacement out to five years, there is a compromise and some risk as addressed in the narrative and below if the head end dial-up modem bank were to completely fail in the next 4 years. The remainder of the annual budget request provides for modest upgrades and additional system monitoring

In addition to field devices, the obsolete dial up modem bank in the head end of our system located in the SCADA area that communicates with field instruments is experiencing individual modem failures more frequently and could have a complete catastrophic failure any time. It is already operating with reduced capacity causing longer times to poll all instruments. Landline (POTS) dial up modems are obsolete, and parts are no longer available. At the Transport Customer end, many have switched to IP based phone systems which do not work well with dial up modems in the field, this creates extra work for our technicians. The electric side of Avista has upgraded to all IP with no remaining dial up modems

Significant failure of the POTS modem bank would seriously impair our ability to communicate with approximately 76, or 1/3 of our ~230 instruments. Communications needs to be upgraded to IP based with cellular being the best option. Replacing POTS with IP communication also allows for the transfer of all gas telemetry data to our Backup Control Center (BUCC) in CdA, Idaho. The POTS modem bank is not replicated at the BUCC. Failure of the head end communications (modem bank) would involve loss of visibility to critical system operating conditions and less timely data for Gas Procurement. Without this communication network in place, we'd need to rely on transport customers to call in daily readings (not the 4-5x/day and the early timing we normally get from our automated 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.

Our experience is that upgrading and replacing obsolete and failing instruments at this funding pace has been, and is, very effective and prudent.

Internal customers such as Gas Control, Gas Procurement, Billing, Gas Engineering, and Gas Operations all provide feedback on system performance.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

N/A

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.

Some existing in-service field equipment is obsolete and failing so replacements are required to maintain functionality. Risks if not upgraded include reduced reliability and increased maintenance costs to reactively repair sites. Regulatory compliance could be reduced and over or under pressure events may not be detected early enough for corrective action which could lead to loss of gas service to customers or an overpressure event. Additionally, manual meter reads and/or bill estimates could be required for some billing sites.

Approximately 76 of the field devices that communicate with the obsolete dial up modem bank in the head end of our system located in the SCADA area need to be upgraded to IP based (cellular) communications. That modem bank is experiencing individual modem failures more frequently and could have a complete catastrophic failure any time. It is already operating with reduced capacity causing longer times to poll all instruments. Landline (POTS) dial up modems are obsolete, and parts are no longer available. At the Transport Customer end, many have switched to IP based phone systems which do not work well with dial up modems in the field which creates extra work for our technicians. The electric side of Avista has upgraded to all IP with no remaining dial up modems.

Significant failure of the POTS modem bank would seriously impair our ability to communicate with approximately 76, or 1/3 of our ~230 instruments. Communications needs to be upgraded to IP based with cellular being the best option. Replacing POTS with IP communication also allows for the transfer of all gas telemetry data to our Backup Control Center (BUCC) in CdA, Idaho. The POTS modem bank is not replicated at the BUCC. Failure of the head end communications (modem bank) would involve loss of visibility to critical system operating conditions and less timely data for Gas Procurement. Without this communication network in place, we'd need to rely on transport customers to call in daily readings (not the 4-5x/day and the early timing we normally get from our automated system).

2. PROPOSAL AND RECOMMENDED SOLUTION

ER 3117 provides capital funding for additions, improvements, and replacements for our Gas Telemetry system. The system provides pressure monitoring including safety related alarms and history for pressure, temperature, and gas volumes and gas flow rates at Gate Stations, Reg Stations, pipelines, odorizers, and for Transport Customers where applicable.

76 dial-up instruments to be replaced with new with IP (cellular) comms x $7500 = $570,000 total over four years or $142,500 annually for 19 sites/year for three more years.

The sites with dial up modems often have AC power so these sites will take less labor to upgrade than a new site installation but similar costs for the materials for the basic instrument. Unit cost averaged across all 3 states is estimated at $7500 each.

3 sites/year upgraded to flow computers for a total of $50,000.

5 new pressure monitors/year for a total of $65,000.

5 other instruments to be replaced that are already on IP (cellular) annually as they become obsolete or fail for a total of $37,500.

Estimated Annual Totals $295,000 for year 1 with a 3% adder for inflation. Year 5 is less at $200,000, assuming that the instruments with dial up modems have all been replaced.

By state: WA 43%, OR 26%, ID 31%

Option	Capital Cost	Start	Complete
ER 3117 funding as described by year on page 2	$1.434M	1-1-23	12-31-27

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Typically estimates for desired work each year have been $400,000, however due to budget constraints and other work we have been limited to $200,000 for several years. This is catching up with us. We are experiencing more frequent failures with obsolete instrumentation and communication devices causing unplanned replacements of those items. This has caused the system to age beyond our ability to replace components. Proactively planned replacements are more efficient than the run to failure mode we are currently operating in.

In recent past, we've done capital work outside of ER 3117. For example, in 2019 all obsolete cellular 3G modems were replaced with 4G/LTE modems for approximately $200,000. In 2020-21 we added 25 new pressure monitoring instruments as part of the Dithaizine Mitigation Project. Prior years also included capital work that was done as part of the construction of a major gate stations, this type of work has slowed so most of our technician's time will be focused on ER 3117 capital projects and O&M moving forward.

O&M has increased as the instrument base has grown so now less than half of the Telemetry Technician's time is available for capital projects.

The requested annual amount starting at $295,000 is a compromise based on projected manpower availability and equipment purchases.

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.

76 dial-up instruments to be replaced with new with IP (cellular) comms x $7500 = $570,000 total over four years or $142,500 annually for 19 sites/year for three more years.

The sites with dial up modems often have AC power so these sites will take less labor to upgrade than a new site installation but similar costs for the materials for the basic instrument. Unit cost averaged across all 3 states is estimated at $7500 each.

3 sites/year upgraded to flow computers for a total of $50,000.

5 new pressure monitors/year for a total of $65,000.

5 other instruments to be replaced that are already on IP (cellular) annually as they become obsolete or fail for a total of $37,500.

Estimated Annual Totals $295,000 for year 1 with a 3% adder for inflation. Year 5 is less at $200,000, assuming that the instruments with dial up modems have all been replaced.

By state: WA 43%, OR 26%, ID 31%

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Support from IT is required for provisioning cellular modems and adding or canceling telephone land lines.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

When individual instruments including communications fail; periodic site visits are required to verify proper operation including pressures and injection type odorizer functions, Gas Control has to call the Interstate Pipelines to get info from their SCADA systems, and Gas Scheduling has to request Gas Transportation Customers to provide manual daily readings for procuring gas and billing. This all costs additional time and money and reduces situational awareness, safety, and compliance.

Additional information about a backup plan if a catastrophic failure of the dial up modem bank occurs before this work is completed:

Prioritize manual reads generally daily and dependent on weather and site type and availability of Interstate Pipelines' pressure and volume data. This on-site monitoring for gate and reg stations requires manpower to be re-distributed from their normal work and additional mileage so costs would increase, and other work may be deferred.

Ask Gas Transportation customers and Interstate Pipeline's to provide daily reads via email for daily consumption. Note that the majority of our most important / largest Transport Customers and Gate Stations instruments are already communicating via cellular modems.

Ask Gas Control to frequently contact the interstate pipelines' Gas Control to monitor pressures and alarms on their systems that affect Avista such as delivery pressure to Avista.

Request an emergency job authorization to provide for expedited procurement and installation of new field equipment with IP communication (cellular modems) and OT hours.

Note that our gas transmission and distribution system functions autonomously and is mechanically independent of any monitoring provided via telemetry. We do not control any gas facilities via telemetry or SCADA.

Note that timing of a potential failure, winter peak vs. warmer temps and regional gas supply, may have a significant impact on our Gas Supply Group and daily gas nominations which would need to be estimated until data via telemetry returns.

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.

A portion of the budget estimates are based on a five-year plan (four years to go) to upgrade most instruments with dial up modems by conversion to cellular communication through instrument replacement. By stretching the replacement out to five years, there is a compromise and some risk as addressed in the narrative and below if the head end dial-up modem bank were to completely fail in the next 4 years. The remainder of the annual budget request provides for modest upgrades and additional system monitoring.

Instruments are placed into service as they are installed, typically monthly.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Gas Telemetry supports Avista's goals of safe, reliable, cost effective, and efficient delivery of natural gas to 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

Typically estimates for desired work each year have been $400,000, however due to budget constraints and other work we have been limited to $200,000 for several years. This is catching up with us. We are experiencing more frequent failures with obsolete instrumentation and communication devices causing unplanned replacements of those items. This has caused the system to age beyond our ability to replace components. Proactively planned replacements are more efficient than the run to failure mode we are currently operating in.

In recent past, we've done capital work outside of ER 3117. For example, in 2019 all obsolete cellular 3G modems were replaced with 4G/LTE modems for approximately $200,000. In 2020-21 we added 25 new pressure monitoring instruments as part of the Dithaizine Mitigation Project. Prior years also included capital work that was done as part of the construction of a major gate stations, this type of work has slowed so most of our technician's time will be focused on ER 3117 capital projects and O&M moving forward.

O&M has increased as the instrument base has grown so now less than half of the Telemetry Technician's time is available for capital projects.

The requested annual amount of $295,000 is a compromise based on projected manpower availability and equipment purchases.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders and customers of the data provided by Gas Telemetry include Gas Control, Gas Operations, Gas Engineering, Gas Supply, Billing, Account Executives

2.8.2 Identify any related Business Cases

N/A

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Gas Engineering in consultation with other groups such as Gas Operations, Gas Control, Gas Supply, and Billing develops the planning, implementation, and performance of the system.

3.2 Provide and discuss the governance processes and people that will provide oversight

Gas Engineering in consultation with other groups such as gas operations, gas control, gas supply, and billing develops the planning, implementation, and performance of the telemetry system.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Gas Engineering is responsible for identifying and prioritizing the work, getting approval via the Capital Project Request (CPR) procedure, and initiating changes via the Gas Management of Change (GMOC) process where applicable such as any instrumentation sending data to SCADA for use by Gas Control.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the ER 3117 – Gas Telemetry 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 Webb (signature) Date: 8/30/22
Print Name: Jeff Webb / Dave Moeller
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: (signature) Date: 8/31/2022

Print Name: Jody Morehouse

Title: Director Natural Gas

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

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*
1.1	*Joe Brown*	*Reviewed for Approval*	*7/13/2021*	*No Changes Required*

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:	7/13/2021
Print Name:	Joe Brown		
Title:	Mgr Craft Training & OQ		
Role:	Business Case Owner		

Signature:	Jeremy Gall	Date:	7/19/2021
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

EXECUTIVE SUMMARY

Avista co-owns a natural gas storage reservoir, Jackson Prairie (JP) Underground Natural Gas Storage Facility (JP). The JP natural gas storage facility is a critical component of Avista's overall natural gas supply strategy. Avista does not own any natural gas wells or supply facilities. The Company purchases all gas supply on behalf of its customers from multiple market trading hubs including AECO, Sumas, and Rocky Mountains. Avista has also secured adequate gas pipelilne transport rights to ensure that all purchased gas can be reliably moved to serve customer load. In order to reduce the exposure to market prices, Avista also owns a third of the overall storage capacity at the JP gas storage facility in southwest Washington. Having gas storage allows Avista to inject gas when prices are lower and then withdraw gas duing the winter peak use months when market prices are historically higher in order to keep customer rates affordable. All three owners share equally in the annual expense costs to operate the facility and the capital investments to improve operations, meet regulatory requirements and reduce future risks.

The three owners have contracted with PSE to operate the JP storage facility. The plant operations management creates an annual and five year capital budget plan to ensure the storage facility is operated safely, reliably, and meets all federal and state regulatory requirements. Each owner has a representative that meets at least quarterly with the operating staff to review current operating performance, discuss current project spend and approve annual and five year budget plans. The Director of Energy Supply represents Avista on the Owners Committee and approves all annual and five year budgets after consulting with the Gas Supply department. The Manger of Gas Design is Avista's alternate representative on the Owners Committee and is also consulted on all budget decisions.

Without the JP gas storage facility, Avista customers would be completely exposed to market conditions that can be extremely volital at times. The ability to inject gas into storage during lower priced time periods and withdrawal gas during high prices or peak load periods allows Avista to reduce customers' exposure and risks to real-time market prices and improve reliable service to customers. Avista's one third share of JP allows the utility to meet 100 percent of its customers' peak winter demand with the facility's stored reserves.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Scott Kinney*	*Annual Business Case Update*	*08/23/2022*	

GENERAL INFORMATION

Requested Spend Amount	$11,606,000 *(Avista's 1/3 cost obligation)*
Requested Spend Time Period	5 Years
Requesting Organization/Department	Natural Gas Energy Resources
Business Case Owner | Sponsor	TBD | Scott Kinney
Sponsor Organization/Department	Energy Resourses
Phase	Execution
Category	Program
Driver	Performance & Capacity

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

This request is for the ongoing funding for the capital costs associated with the JP operations.

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 drivers for funding JP are Perfromance and Capacity. JP provides solutions for the following gas supply needs:

- Stored gas supply that enables Avista to reliably serve customers during peak load demand.
- Risk mitigation for shielding customers from extreme daily gas price volatility during cold weather or other events affecting the natural gas commodity market.
- A mechanism for purchasing gas at lower prices during off-peak periods for use during high cost periods.

All commodity price benefits resulting from the utilization of JP are passed along to the customer through the annual PGA filings.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

JP is a functioning natural gas storage project that has critical ongoing capital funding requirements for ensuring continuous safe and reliable operation of the facility. Not funding JP at the requested levels increases a number of risks for plant operations including, but not limited to, non-compliance with Pipeline and Hazardous Materials Safety Administration's underground storage safety mandates, deliverability during peak demand periods, reduced physical plant security, reduced efficiency of plant output, or increased likelihood of component failure resulting in 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 storage project is continually managed and monitored for optimal storage volume, injection and withdrawal performance, and other key operational metrics. An operations report is submitted to the JP Management Committee on a monthly basis. Additionally, the report provides a current and projected budget status.

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.

2. PROPOSAL AND RECOMMENDED SOLUTION

The JP natural gas storage facility is a critical component of Avista's overall natural gas supply strategy to ensure reliable and affordable delivery of gas to meet customer needs. Avista does not own any natural gas wells or supply facilities. The Company purchases all gas supply on behalf of its customers from multiple market trading hubs including AECO, Sumas, and Rocky Mountains. Having gas storage allows Avista to inject gas when prices are lower and then withdraw gas duing the winter peak use months when market prices are historically higher in order to keep customer rates affordable.

Option	Capital Cost	Start	Complete
Ongoing annual funding for JP capital budget	*2,370,000*	*01 2023*	*12 2023*
	2,421,000	*01 2024*	*12 2024*
	2,410,000	*01 2025*	*12 2025*
	2,410,000	*01 2026*	*12 2026*
	1,995,000	*01 2027*	*12 2027*
5 Year Total	*$11,606,000*	*01 2023*	*12 2027*
Rely on spot market for all gas purchases	*$Unknonw - High risk and depends on daily market price*	*01 2023*	*12 2027*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The budget and associated annual projects are prepared and developed by the JP facility operations team and provided to the Owners Management Committee for review and approval. Projects are informed by a number of supporting documents, including:

- Engineering studies and ongoing operational monitoring data
- Risk gap analyses and risk mitigation plan
- Actual operational performance results
- Safety compliance and other regulatory mandates and requirements
- Contractual obligations
- Asset maintenance and replacement schedules

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).

The capital dollars will be spent throughout the year according to the capital budget scheduling plan prepared by the JP operations team and approved by the Owners Management Committee. An updated budget status is provided monthly to track the spending. No O&M reductions are estimated as a result of this investment but the operation of JP helps provide reliable gas service to customers and reduces market exposure risk.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

JP is one third owned by Avista but operated by Puget Sound Energy. No impacts to other Avista business functions or processes are anticipated by this business case.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

No cost effective alternatives exist for replacing JP. Because JP is a unique solution that provides benefits/solutions for an array of supply needs, it would likely require multiple business solutions to replace the resource functionality provided by JP, none of which could fully duplicate the benefits of JP nor be cost competitive with JP.

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 annual capital spending for JP includes multiple capital improvement investments, which become used and useful at the end of each budget year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

JP is a critical integrated supply resource for our natural gas business. JP helps enable the delivery of natural gas energy safely, responsibly, and affordably to our customers. Without JP customers would be exposed to market price volatility risk and the need to acquire more pipeline transport capacity to the different gas supply regions.

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 capital budget amount is prudent and has been reviewed and approved by the JP Management Committee (described below). The capital budget amount will provide for and ensure the continuous operational performance contractually mandated by the JP owners, and licensed by FERC.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Internal stakeholders include the Director of Energy Supply, Gas Supply and Gas Engineering. External stakeholders who directly interface with the business case include the two other ownership partners; PSE and Williams-NWP. Additionally, the Pacific Northwest (PNW) natural gas market and pipeline operation are directly affected by JP operations. JP provides critical supply delivery funcationality to the PNW pipeline grid, especially during peak demand times.

2.8.2 Identify any related Business Cases

This business case replaces the 2022 Jackson Prairie Joint Project Business Case

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

A JP Owners Management Committee meets at least quarterly to review and approve the capital budget status for the current year as well as to review and approve any ongoing or future expenses. A business representative from each of the 3 ownership partners has final approval authority on the Committee. The decisions are documented in the minutes of the meeting. Occasionally, a decision is made through email correspondence and is retained by the JP general manager. A monthly report is provided to the owners that includes the budget statue. The Director of Energy Supply is the Management Committee representative for Avista and the Manger of Gas Supply is the alternate representative.

Avista's Risk Management Committee (RMC) oversees corporate decisions that affect joint energy resource projects including the Jackson Prairie Storage Project.

3.2 Provide and discuss the governance processes and people that will provide oversight

The Director of Energy Supply is responsible for management of the JP contract including Avista's ownership, operating rights, and budget. The Director of Energy Supply works with the Manager of Gas Supply to manage Avista's operational rights to fill and withdraw gas from the storage facility as governed by Avista's Risk Management Policy and the Risk Management Committee. The Manager of Gas Design and Planning also participates in the Owners Management Committee to provide input and feedback on proposed projects. Resource Accounting reviews and manages the monthly invoices received from the JP operator and prepares them for approval by the Director of Energy Supply.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The Director of Energy Supply reviews the monthly budget updates provided by the JP operator. The operator manages project spend to stay within owner approved budgets. However if any changes or adjustments to project spend are required the Director of Energy Supply will communicate change requests with the Capital Planning Group for discussion and approval.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Jackson Prairie Natural Gas Storage Facility 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:	(TBD)		
Title:	Director Energy Supply		
Role:	Business Case Owner		
Signature:	DocuSigned by: Scott Kinney 50D41B164A3B414...	Date:	8/23/22
Print Name:	Scott Kinney		
Title:	VP Energy Resources		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			

Title:	
Role:	Steering/Advisory Committee Review

EXECUTIVE SUMMARY

Avista manages 11 Federally regulated apprenticeships that require instructional aides, facilities and equipment deemed necessary to provide quality instruction. [Regulated by 29 CFR 29 & 30] The Joint Apprenticeship Training Committee (JATC) administers these apprenticeships supported by the Craft Training Department. These funds are used to purchase tools, materials, equipment and make minor facility improvements 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
1.0	*Joe Brown*	*Updated for Approval*	*8/25/2022*	*Full amt approved; updated*

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

[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?

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 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Ensure all apprentices receive training and support from instructors/journeyman in accordance with regulatory requirements and meet the minimum of 144-hours of related instruction.

Training Progam Metrics	2021	2020	2019
Apprentices — All Crafts:			
Total number of apprentices trained	69	80	74
Number of active programs	11	11	11
Hours of training on the job	140,033	132,838	153,920
Hours of classroom training	9,735	9,235	10,967
Journeyman Training:			
Electric/Generation	6,757	3,192	8,764
Gas refresher - hours	2,228	2,882	3,380

1.5 Supplemental Information

1.5.1 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; 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. [NA]

2. PROPOSAL AND RECOMMENDED SOLUTION

The recommended solution (Option 1) is to provide resources needed [tools, materials, facility] to ensure related instruction of craft personnel

Option	Capital Cost	Start	Complete
1. On-Going Capital Improvement Program	*$375,000*	*01 2023*	*01 2027*
2. Outsource All Training	*$2.4M*	*01 2023*	*01 2027*

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 improving 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 primary alternative for this program is to outsource all training. If this is done, at great expense, there will be significant impact on operating budgets, company culture, and possibly labor relations. These impacts may result in poor customer service and reduced reliability.

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 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 service Avista's customers. 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. MONITOR AND CONTROL

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.

4. APPROVAL AND AUTHORIZATION

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: 8/25/2022
Print Name: Joe Brown
Title: Manager, Craft Training
Role: Business Case Owner

Signature: Jeremy Gall Date: 8/29/2022
Print Name: Jeremy Gall
Title: Director, Safety & Craft Training
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

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 $2.5M.

Capital tools benefit customers by reducing labor cost due to improved efficiency and improving quality of the work by advanced performance of the tools. Customers 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
Draft	*Cody Krogh*	*Initial draft of original business case*	*2/11/2020*	
1.0	*Cody Krogh*	*Updated plan to new outline*	*7/13/2020*	
2.0	*Gary Shrope*	*Yearly Update*	*5/20/2022*	

GENERAL INFORMATION

Requested Spend Amount	$2,500,000.00
Requested Spend Time Period	*5 years*
Requesting Organization/Department	Supply Chain
Business Case Owner | Sponsor	Cody Krogh | Alicia Gibbs
Sponsor Organization/Department	H51 Supply Chain
Phase	Monitor/Control
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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 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

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

Attachment 5: Business Case Model / Offset Costs

NOTE: All files are stored in the "N-Drive" under "Capital Budget", then "Business Case Folder".

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 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 the 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.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
[Recommended Solution] Option 1	$2.5 M	01/2018	*NA*
[Alternative #1] (based on priority)	*Varies*	01/2018	*NA*
[Alternative #2] Rent 4% of total equipment & 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.

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.

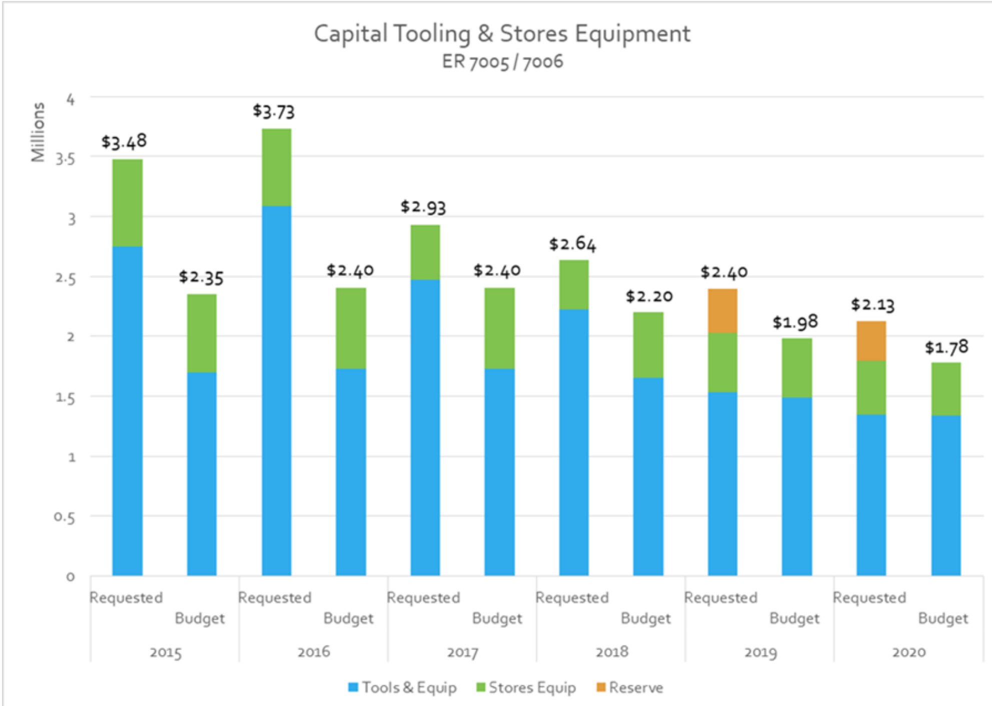


Figure 1

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.

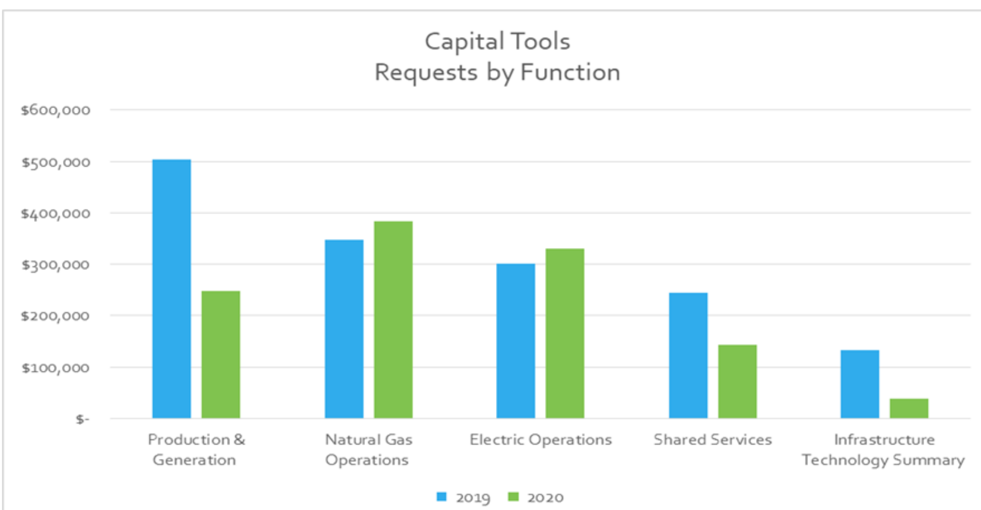


Figure 2

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 compliance standards and tools identified to improve safety or ergonomics (improved body posture, reduced exertion of force, and reduction in frequency).

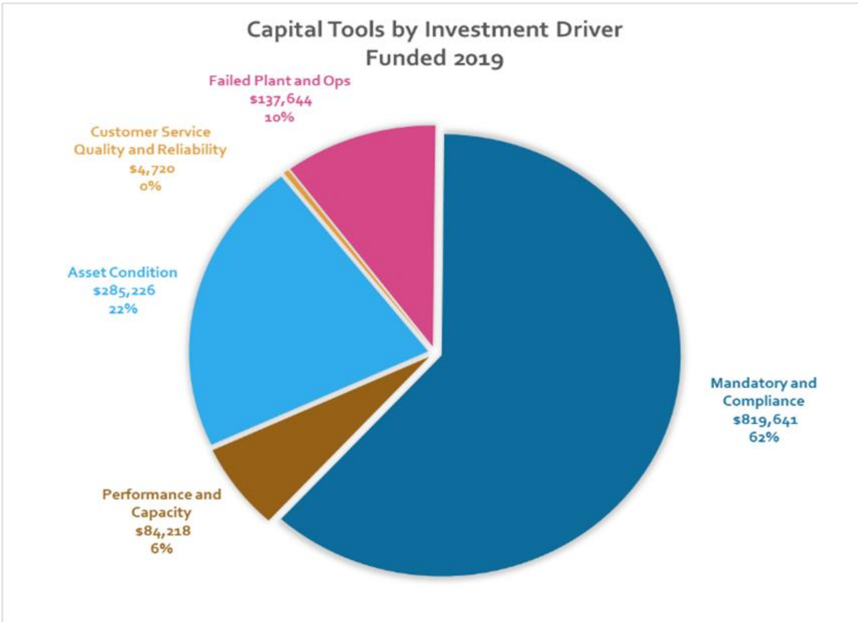


Figure 3

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.

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.

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 due 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 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.

Option 1 – Fund Program at Current Level (Recommended)

It is recommended that this Program be funded, annually, at its current level to ensure Avista has the proper capital equipment necessary to safely and efficiently perform all required work. This funding level 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.

Option 1 will provide an approximate annual savings of $15M over Option 3 below, as shown in Attachment 5: Business Case Model / Offset Costs.

Option 2 – Partially Fund Program based on priority

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 helps support improved processes and leads 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.

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.

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 downtime.

2.8.2 Identify any related Business Cases

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, Aldyl-A pipe replacement, and Wildfire Resiliency.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Capital Equipment Steering Committee

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. Purchasing begins executing purchases starting with the highest priority scoring.

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 on 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.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *<Business Case Name>* 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 72D171DBE3F04F8... Date: Jun-13-2022 | 8:04 AM PDT

Print Name: Cody Krogh

Title: Supply Chain Manager

Role: Business Case Owner

Signature: DocuSigned by: Alicia Gibbs 49C42833345E483... Date: Jun-10-2022 | 7:25 AM PDT

Print Name: Alicia Gibbs

Title: Director Shared Services

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

EXECUTIVE SUMMARY

A 2018 Avista brand study found that 65% customers are most likely to see and identify Avista with our trucks. Our vehicles and associated gear are an essential part of our ability to address customer needs and perform work required to be an effective an efficient electric and gas utility. The Fleet Vehicle Refresh Capital Plan is the annual and ongoing plan to replace a portion of Avista's fleet in order to ensure the highest level or reliability and the lowest total cost of ownership. The annual cost of vehicles is split into two types, direct operating and indirect costs. Direct costs include fuel and maintenance, while indirect costs include common ownership expense. Avista's replacement model is based on a proven fleet management concept that there are predictable increasing maintenance costs and decreasing ownership costs as a vehicle ages. The point at which those two lines intersect gives Avista a window of opportunity in which we will achieve the lowest total cost of ownership cost for a given unit. Replacing the unit at that time allows us to ensure a high level of reliability (96% availability currently) at the same time ensuring we have a steady and predictable level of work for the technicians in our garages. Maintaining a high reliability percentage is essential when we experience an EOP event. Over the last several years we have experienced multiple large EOP events. The fleet experienced very few breakdowns even though our units were being used around the clock in some of the most serve conditions. This strategy also gives us the advantage of liquidating units while they still have reasonable amount of after market value. These funds help supplement our planned spend, minimizing the need for additional funds request when market prices fluctuate.

To develop this model Avista has worked with Utilimarc, a utility focused data analytics company who benchmarks and proven record working with utility fleets in the US. The model inputs the initial price, actual maintenance & repair costs, depreciation expense and salvage value to establish each class of vehicle's replacement cycle. The recommended solution will replace 60-90 units per year with an average spend of $6,600,000 per year for a total five year cost of $33,300,000. The investment in Avista's fleet, over the past decade, means that we have a highly reliable fleet that meets the service level expectations of our internal customers. Our equipment must be able to function in the most extreme situations. Our trucks can be in 120+ degree heat in the bottom of Hells Canyon or 0 degree snow storms in Sandpoint. Trucks that are running allow crews to work an outage and reenergize/repressurize the system. By spending a level amount of capital every year, we are able to maintain a constant average fleet age which produces a known quantity of work in our shop and it prevents us from having a bubble of trucks that create budget issues in later years. The investment made has meant that we are a highly reliable and highly functional tool for our crews. We have maximized our value while minimizing our total cost. By failing to fund this program we create a growing cost of repair expense and a decreasing level of reliability/availability. The Fleet Vehicle Capital Refresh Program was reviewed with the Facilities & Fleet Steering Committee in May of 2022.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Greg Loew*	*Initial draft of original business case*	*5/26/2022*	
1.0	*Greg Loew*	*Updated Approval Status*	*9/1/2022*	

GENERAL INFORMATION

Requested Spend Amount	$38,805,600
Requested Spend Time Period	*5 years*
Requesting Organization/Department	Fleet K51
Business Case Owner | Sponsor	Greg Loew | Alicia Gibbs
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Trucks and equipment do not age well. Fleet vehicles experience a duty cycle that most vehicle owners would not imagine for their personal car or truck. Avista's fleet of vehicles operate in environments that are often at the extreme of whatever scale you are looking at, extreme heat, cold, or the dustiest of environments. These vehicles also experience employees constantly entering, and exiting, while the engines experience high idle time or high loads. These factors all contribute to the wear and tear our vehicles and can create substantial demand for repair workorders. This kind of duty cycle over the life of a truck will add up to an increasing amount of repair work and a lower reliability factor as a vehicle ages. By building a replacement program we optimize our vehicle life so that we extract the right amount of useful value from our vehicles before they experience a rapidly growing amount of repair expenses. The program we have built affords us the ability to plan our labor and maximize our internal mechanic resources while having a fleet of vehicles that are available for any job; planned or unplanned operational response.

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 Fleet Equipment Capital Refresh Program is driven by Asset Condition. This program benefits both our internal and external customers.

External customers: Our customers benefit from our Fleet Replacement Program by having a small and predictable annual portion of their bill tied to the acquisition and operation of our fleet. Additionally, new vehicles have the cleanest burning engines and advanced safety features that protect the environment and drivers on the road. A highly reliable fleet ensures that our customers will not experience a delay in getting their energy restored because our crews cannot get there.

Internal customers: Our drivers have the safest most reliable trucks as a result of the investment in our fleet. Our fleet of trucks are ready for work over 96% of the time. In the field our trucks experience fewer breakdowns per 100 hours of operations and are in the 1st quartile when compared to peer utility fleets. Our fleet of vehicles includes advanced safety features, modern efficient engines and operational tools that make many tasks more efficient. We work very hard with input from or customers to make sure we are producing units that give them what they need to serve our external customers safely, efficiently, and reliably.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The investment in vehicles for our Avista's fleet is not an option. Our crews do not get to their jobsites, near or far, in any way but in an Avista owned piece of equipment. Vehicles will break down and reach their end of life. It can be prolonged by making expensive and time-consuming repairs. The availability of the company's fleet and its field reliability will suffer if there is not an invest of capital. Additionally, the company will see a steady rising cost in maintenance both in labor and material dollars. The deferral of investment will also cause bubbles of increased capital needs in out years as the team tries to shore failed assets and work to bring the average fleet age in line with industry best practices. If we do not invest our dollars into the capital replacement plan, we will end up spending those dollars on costly repairs. Repair costs are much more, are unpredictable and make it much more difficult to forecast. In the worst case we would see at 12,000 hour gap between labor available and the labor required to complete necessary repairs experience by the replacement deferral in the coming decade. That difference would likely be met with vendor labor which carries a premium over internal labor. In 2032 that would add an additional $660,000 per year to the clearing account which would be born through significant equipment cost burdens.

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.

Our annual industry benchmarking and year of year analysis of numbers show that we are performing within the industry 50th percentile band. The number of work orders per year and maintenance cost per year have remained steady.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Supplemental information is available from Utilimarc.com

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.

Summary by Class

Class	Average Mileage	Lifetime Mileage	Purchase Price	Lifecycle
Pickup - Class 2a	8,792	105,504	$48,050	12
Pickup - Class 2b	8,807	88,070	$45,922	10
Pickup - Class 3	12,448	124,480	$100,068	10
Dump Truck - Class 7	4,957	64,441	$142,750	13
Dump Truck - Class 8	5,556	88,896	$241,328	16
Service Truck - Class 3	14,255	213,825	$170,000	15
Service Truck - Class 5	8,281	124,215	$175,000	15
Service Truck Class 6+	7,198	107,970	$221,706	15
Stake Truck	6,267	106,539	$110,000	17
Bucket Truck - Class 5	15,253	122,024	$200,000	8
Bucket Truck - Class 7	10,083	100,830	$231,423	10
Bucket Truck - Class 8	5,200	83,200	$349,372	16
Digger Derrick - Class 8	4,809	72,135	$400,000	15

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Fully funded (no adds to complement funded)	*$38.8M*	*01 2023*	*12 2027*
Partial funding	*$19.4M*	*01 2023*	*12 2027*
Lease	*$M*	*01 2023*	*12 2027*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Avistas Vehicle Replacement Model (VRM) uses fleet data to develop company specific replacement criteria for each vehicle class in fleet. This analysis is unique to the behavior and characteristics of the Avista fleet. The inputs for the Utilimarc VRM include:

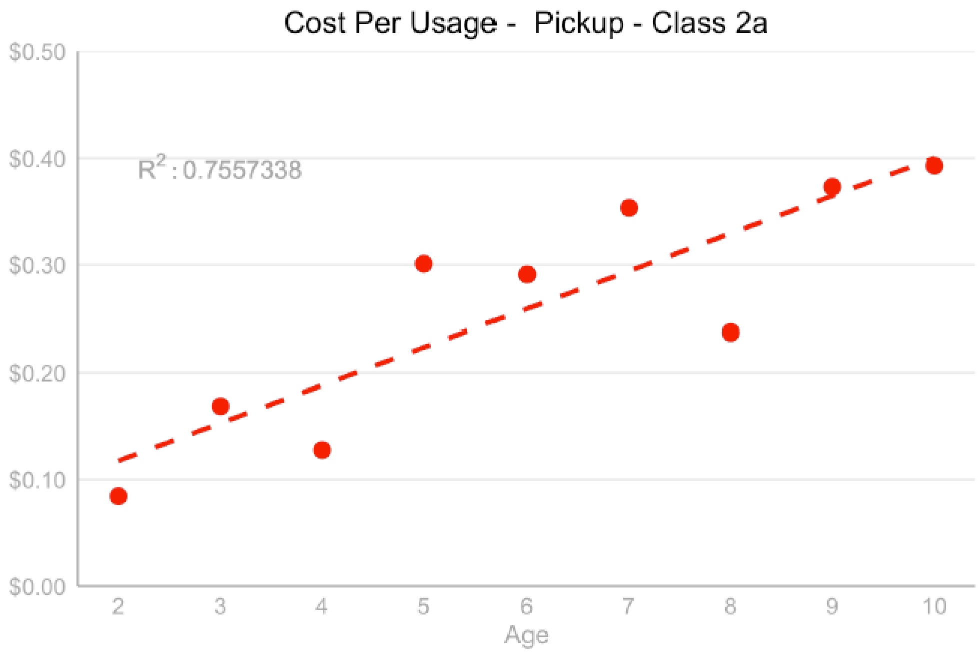
- Company specific trending parts and labor cost for each vehicle class
- Company specific purchase price for each vehicle class
- Company specific annual usage patterns (mileage) for each vehicle class
- Company specific loaded productive labor rate and mechanic productivity
- Vehicles are identified as candidates for replacement when over their recommended replacement age or replacement life to date mileage, whichever occurs first.

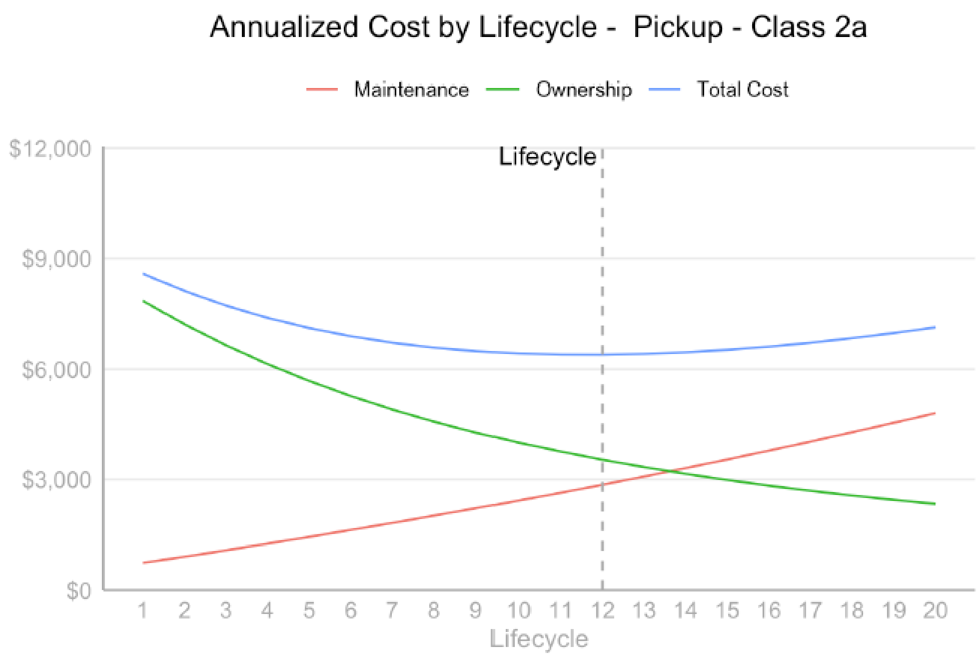
A vehicle is identified as a candidate for replacement when it reaches its replacement range for age or lifetime mileage. Replacing within these ranges ensures operating within 1% of the lowest total ownership cost of the vehicle over its lifetime. A standard regression model is used in this analysis.

Pickup - Class 2a

	Value
Lifecycle	12
Purchase Price	$48,050
Average Salvage at Sale	$4,440
Devaluation Rate	18%
Inflation Rate	2%
Average Annual Miles	8,792

Life	Maint Cost	Own Cost	Total Cost	Percentage
1	$738.74	$7,861.02	$8,599.76	34.58%
2	$907.58	$7,217.99	$8,125.57	27.16%
3	$1,080.82	$6,645.09	$7,725.91	20.91%
4	$1,258.57	$6,133.72	$7,392.29	15.69%
5	$1,440.92	$5,676.40	$7,117.32	11.38%
6	$1,627.97	$5,266.62	$6,894.59	7.9%
7	$1,819.84	$4,898.72	$6,718.56	5.14%
8	$2,016.62	$4,567.76	$6,584.37	3.04%
9	$2,218.42	$4,269.42	$6,487.85	1.53%
10	$2,425.37	$3,999.95	$6,425.32	0.55%
11	$2,637.57	$3,756.06	$6,393.62	0.06%
12	$2,855.13	$3,534.85	$6,389.99	0%
13	$3,078.18	$3,333.82	$6,412.00	0.34%
14	$3,306.85	$3,150.74	$6,457.58	1.06%
15	$3,541.24	$2,983.66	$6,524.90	2.11%
16	$3,781.49	$2,830.88	$6,612.36	3.48%
17	$4,027.73	$2,690.88	$6,718.61	5.14%

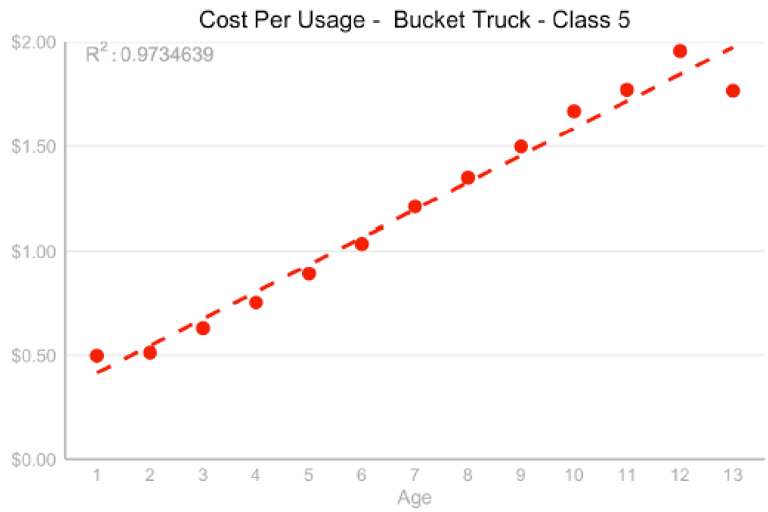

Cost Per Usage - Pickup - Class 2a
$0.50
$0.40
$0.30
$0.20
$0.10
$0.00
R^2 : 0.7557338
2
3
4
5
6
7
8
9
10
Age

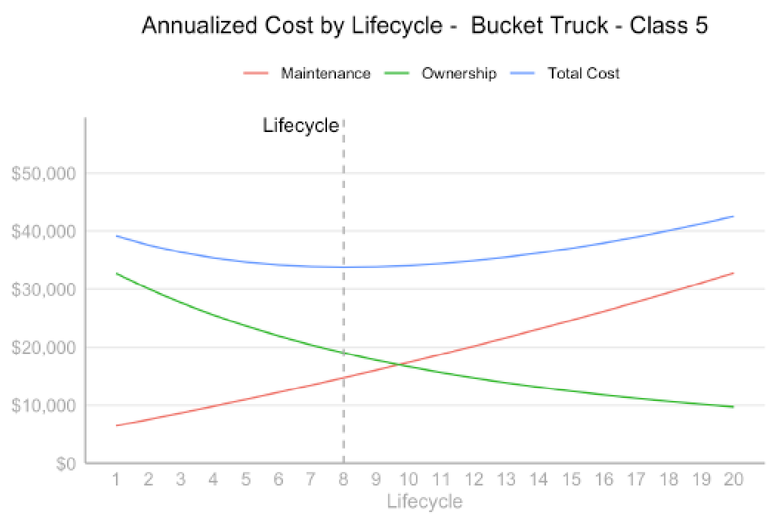

Annualized Cost by Lifecycle - Pickup - Class 2a
Maintenance
Ownership
Total Cost
$12,000
$9,000
$6,000
$3,000
$0
Lifecycle
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Lifecycle

Bucket Truck - Class 5

	Value
Lifecycle	8
Purchase Price	$200,000
Average Salvage at Sale	$40,882
Devaluation Rate	18%
Inflation Rate	2%
Average Annual Miles	15,253

Life	Maint Cost	Own Cost	Total Cost	Percentage
1	$6,459.62	$32,720.00	$39,179.62	16.06%
2	$7,555.17	$30,043.50	$37,598.68	11.37%
3	$8,679.08	$27,658.92	$36,338.01	7.64%
4	$9,831.98	$25,530.44	$35,362.42	4.75%
5	$11,014.50	$23,626.93	$34,641.43	2.61%
6	$12,227.31	$21,921.30	$34,148.61	1.15%
7	$13,471.08	$20,389.98	$33,861.06	0.3%
8	$14,746.50	$19,012.41	$33,758.91	0%
9	$16,054.27	$17,770.65	$33,824.92	0.2%
10	$17,395.11	$16,649.03	$34,044.14	0.84%
11	$18,769.74	$15,633.86	$34,403.60	1.91%
12	$20,178.91	$14,713.15	$34,892.06	3.36%
13	$21,623.39	$13,876.38	$35,499.78	5.16%
14	$23,103.96	$13,114.33	$36,218.29	7.29%
15	$24,621.41	$12,418.91	$37,040.31	9.72%
16	$26,176.55	$11,782.97	$37,959.52	12.44%
17	$27,770.21	$11,200.26	$38,970.47	15.44%
18	$29,403.23	$10,665.24	$40,068.47	18.69%
19	$31,076.49	$10,173.02	$41,249.51	22.19%
20	$32,790.87	$9,719.28	$42,510.15	25.92%


Cost Per Usage - Bucket Truck - Class 5
R^2 : 0.9734639
$2.00
$1.50
$1.00
$0.50
$0.00
1 2 3 4 5 6 7 8 9 10 11 12 13
Age


Annualized Cost by Lifecycle - Bucket Truck - Class 5
Maintenance
Ownership
Total Cost
Lifecycle
$50,000
$40,000
$30,000
$20,000
$10,000
$0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Lifecycle

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 capital in this case will be spent evenly over the 5 year period. The investment of capital in this case will provide a consistent replacement plan which enables a predictable parts and labor cost, vehicle downtime and technician requirements.

Annual labor savings by maintaining the capital plan and having a predictable labor requirement

Value	2023	2024	2025	2026
Annual Capital Full	$5,556,379	$5,794,138	$6,765,327	$8,550,317
Avg Age	11.63	11.45	11.34	11.10
Labor Hours	41,456	42,023	42,191	41,817
Annual Capital-HALF	$2,536,587	$2,816,819	$3,741,889	$3,859,175
Avg Age	12.43	12.73	13.07	13.42
Labor Hours	41,870	43,395	44,689	45,979
Labor Dollars Delta*	35,316	120,693	226,232	388,366
Avoided crew/labor downtime				

Our 2021 analysis showed that demand repair work orders would increase over time when not controlling the total overall average age of fleet. A percentage of demand repair orders has some impact on the users of the trucks. On average for this exercise we assume each work order has a 2 minute impact on the crew.

	2021	2022	2023	2024	2025
Annual Demand Repair Work Orders	6,834	6,880	6,945	6,956	6,990
Crew down time per work order = 2mins	$82,008	$82,560	$83,340	$83,472	$83,880

*2022 hourly 4 person line crew labor rate of $360/hr

Quantified indirect savings:

2022	2023	Lifetime
$82,560	$118,656	$1,232,632***

Allocation:
O&M—$462,025
Capital—$67,021
*assumption $82.89 loaded mechanic rate plus annual 3% increase
**parts demand not included in analysis

***Life-time assumes 1% growth between 2025 and 2026

[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.

Avista's fleet of vehicles is used by nearly every department. By not investing in new assets we increase the potential for equipment failure and unforeseen downtime for our crews and employees in the field. Our industry is amid many changes driven by internal as well as external factors. By not having a replacement plan we limit ourselves on being able to keep up with current standards, as well as new safety requirement. The impact would most be felt when a large EOP or mutual aid event occurs.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The first alternative is to invest approximately 25% less in capital that what our optimum scenario is. By investing at this level, we would be able to continue to address the highest cost per mile vehicle classes (five of which account for 55% of the total annual operating spend) and those vehicles that are critical response units. We will still face increasing costs, downtime and constrained technician hours but the amount is mitigated by the focus on those high cost classes. Additionally, we risk the potential that additional funding is apportioned in one or two of the out years to get "caught up." This creates bubbles of work for the team purchasing vehicles but also in the parts and maintenance costs.

The second scenario would be to fund the program at 50% of what the recommended spend is from our data analytics. This route would create even larger bubbles that will need to be addressed by future capital spending that could exceed the recommended spend by as much as 50%. One of our biggest challenges we will face in this scenario would be the effect it has on our shop workload. As previously stated we this scenario will have a 12,000 hour or a 33% increase in the amount of labor available to what is required to repair all demand driven repairs and maintenance. With a predictable number of units coming in we can better plan our teams schedule. This also allows us to maintain a level staffing needs year over year.

The third scenario is leasing option. Multiple utility fleets lease their vehicles. This on the surface has the potential to free up capital for other uses. The risk in this option is that you are trading a capital cost for an operating cost. The depreciation that had been realized on the P&L statement is now an O&M cost that must be absorbed. Those costs include a leasing company's return on equity. This would require huge change management with help from the operations management team, as our vehicles are highly customized to ensure they can do their work in the most efficient and expedient manner.

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 Fleet Vehicle Refresh is a capital plan. Each vehicle or piece of equipment purchased get a jurisdiction code specific project number and a FERC specific task code. We begin purchasing the next years equipment during the summer of the prior year. Right now, we are taking delivery of equipment that had purchase orders cut last August. Our most expensive mounted hydraulic equipment has a 350 to 450 day lead time. We transfer each individual unit to plant when in becomes used and useful, which is approximately 30 days after receipt and invoicing.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This program enables to Our People to serve Our Customers. When the power is out or gas is not flowing due to an unexpected incident our fleet of trucks gets the people and equipment to where it needs to be and then runs until the issue is resolved.

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 following figure represents the totals of maintenance costs and work orders generated per year. As can be seen on the first and last line we maintain a steady cost and work load year over year. We benchmark and review our results on an annual basis.

Utilimarc Lifecycle Replacement Projections

Value	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Annual Capital	$5,556,379	$5,794,138	$6,765,327	$8,550,317	$8,038,595	$9,425,595	$9,470,600	$10,096,500	$9,378,313	$8,847,861
Units Replaced	69	71	76	88	86	89	90	91	82	85
Annual Maintenance	$8,057,038	$8,330,557	$8,531,107	$8,624,560	$8,757,253	$8,818,198	$8,916,771	$8,928,386	$9,015,413	$9,200,408
Annual Ownership	$5,333,819	$5,350,745	$5,506,508	$5,908,989	$6,174,116	$6,614,670	$6,989,863	$7,406,765	$7,650,302	$7,792,466
Total	$13,390,860	$13,681,300	$14,037,610	$14,533,550	$14,931,370	$15,432,870	$15,906,630	$16,335,150	$16,665,720	$16,992,870
Out of Life	227	223	251	265	251	234	264	243	253	250
Avg Age	11.63	11.45	11.34	11.10	10.93	10.72	10.51	10.29	10.18	10.03
Labor Hours	41,456	42,023	42,191	41,817	41,628	41,095	40,740	39,993	39,591	39,611

Half Utilimarc Lifecycle Replacement Projections

Value	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Annual Capital	$2,536,587	$2,816,819	$3,741,889	$3,859,175	$3,546,683	$3,981,964	$4,467,021	$4,556,362	$4,647,489	$4,740,439
Units Replaced	31	36	40	41	39	40	42	42	42	42
Annual Maintenance	$8,137,428	$8,602,623	$9,036,137	$9,483,095	$9,949,424	$10,410,080	$10,862,510	$11,319,940	$11,772,930	$12,223,390
Annual Ownership	$4,853,715	$4,496,113	$4,341,073	$4,230,449	$4,090,467	$4,043,929	$4,084,629	$4,135,452	$4,196,157	$4,264,716
Total	$12,991,140	$13,098,740	$13,377,210	$13,713,540	$14,039,890	$14,454,010	$14,947,140	$15,455,390	$15,969,090	$16,488,110
Out of Life	265	296	360	421	454	486	564	592	642	686
Avg Age	12.43	12.73	13.07	13.42	13.81	14.18	14.50	14.82	15.12	15.41
Labor Hours	41,870	43,395	44,689	45,979	47,295	48,514	49,630	50,706	51,701	52,626

Avista Budget Replacement Projections

Value	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Annual Capital	$5,180,552	$6,147,232	$6,143,363	$6,189,603	$6,176,617	$6,206,909	$6,212,876	$6,052,722	$6,171,291	$6,203,925
Units Replaced	59	72	72	61	61	54	57	52	50	51
Annual Maintenance	$7,907,314	$8,209,488	$8,555,177	$8,804,992	$9,117,942	$9,451,825	$9,770,447	$10,154,520	$10,537,160	$10,947,320
Annual Ownership	$5,252,313	$5,318,170	$5,381,230	$5,425,657	$5,480,650	$5,529,131	$5,572,587	$5,588,461	$5,622,189	$5,651,153
Total	$13,159,630	$13,527,660	$13,936,410	$14,230,650	$14,598,590	$14,980,960	$15,343,030	$15,742,980	$16,159,350	$16,598,470
Out of Life	237	232	264	305	316	334	397	415	457	498
Avg Age	12.01	11.78	11.74	11.92	12.07	12.34	12.57	12.84	13.13	13.43
Labor Hours	40,686	41,412	42,310	42,692	43,342	44,048	44,640	45,485	46,274	47,132

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Internal Customers:

Distribution Electric Ops	Generation	Engineering
Gas Distribution Ops	Gas Metering	Communication
Sub-station Support	Electric and Gas Metering	IT
Project Management	CPC	Relay Shop
MS Shop	Cathodic	Veg Management

Stakeholder include:

Plant Accounting	Rates
Engineering	Operators

2.8.2 Identify any related Business Cases

None at this time

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The fleet capital plan is driven by statistical analysis that is based on our financial and operating outcomes. The analysis is reviewed by the Fleet Manager, Fleet Specialist and our Fleet Analyst.

3.2 Provide and discuss the governance processes and people that will provide oversight

Each individual vehicle purchase is approved in two parts: 1) The Fleet Manager approves the CPR request and then the director is notified. 2) The requisition process is approved based on value from the Fleet Manager all the way to the CEO if the value is great enough.

Department and district managers are involved in the order process by confirming which vehicles to be replaced and helping to ensure any requests that specific operators or crews may have. Managers, operators/drivers sign off on a VLC form which is maintained for every class and build of vehicle.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Annually, Fleet Spec Committees for our major operating groups come together to review the specifications of their specific core operating vehicles. This helps ensure that vehicles come from the manufacturer ready to work. We track our revisions/change orders on an ECO form and record the dollars in our tracking program by using a change order specific task code. Fleet's goal is to not exceed more than 1% of our total budget in change orders. In 2019 we were less than .8% of our total spend for change orders.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *<Business Case Name>* 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: Greg Loew E32CB80359F242F...	Date:	Sep-09-2022 | 8:44 AM PDT
Print Name:	Greg Loew		
Title:	Fleet Manager		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs 49C42855345E483...	Date:	Sep-08-2022 | 1:14 PM PDT
Print Name:	Alicia Gibbs		
Title:	Alicia Gibbs		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Oil Storage Improvements

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 segregate 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 May 2022). There will be two rate jurisdictions for this project. For the actual oil tanks and dispensing equipment, since they will only be used for Substation Support, the costs will be filed under Electric Only – WA & ID. All other associated site improvements, since they could be used by any business unit at the Mission Campus, will be filed with the rate jurisdiction of 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. The Facilities Capital Steering Committee approved submission of this Business Case.

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	
1.1	Vance Ruppert	BCJN update Capital Planning	7/9/2021	
2.0	Lindsay Miller	Executive Summary Update	5/24/2022	
2.1	Conor Craigen	BCJN update	08/31/2022	

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, Alexis Alexander, and Alicia Gibbs
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 maintenance 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. On June 17, 2020 Avista received a letter from the Washington Department of Ecology's Toxic Cleanup Program stating that "no further action" is required in the cleanup effort.

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 an 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 Underground 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 / Conor Craigen).

Pictures of the oil tank overflow as described in Section 1.1 (B) above are available on request (Facilities /Conor Craigen).

Pictures of the annual water roof leaks as described in Section 1.1 (C) above are available on request (Facilities /Conor Craigen).

Option	Capital Cost	Start	Complete
Recommended Option: Build new above ground tanks, demolish underground vault and tanks	*$1.5M* *(see note 1 below)*	*07/2022*	*11/2023*
Alternate #1: Build a new GPSS Maintenance Shop at Mission or off-site, with a new tank(s) arrangement.	*$15M - $25M (?)*	*2022 (?)*	*2024 (?)*

Notes:

1) See Appendix A for further cost estimate breakdowns of the Recommended Option's $1.5M Capital Cost as shown in the table above.

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 used for tank procurement and construction.

The project will provide the following new equipment and processes:

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 oiland 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 second 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 the Mission Campus ES, and in the field / at any particular substation.

Demolish the existing underground vault. Remove only 6 feet or so top-down, with existing slab and footings to remain. Holes will be bored in to the abandoned slab, and the remaining area filled in with structural fill. The removed underground vault will be replaced with a new asphalt parking lot, approximately the same footprint, for GPSS use.

Siding and slider doors will be added 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 2023. The major milestones and timeline of the project is estimated to be the following:

Complete Design Drawings: Completed

Bidding / permits complete, General Contractor (GC) selection: 2 months

GC procure tanks and long lead items: 6 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 2023, with all of its $1.5M transferring to plant in 2024, 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 strategic vision of environmental stewardship. This Business Case clearly identifies the environmental regulatory issues that could 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

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, with the expectation of meeting scope, schedule, and budget targets.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Major customers/stakeholders:

Environmental Department

Generation Production / Substation Support Department

Facilities

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 August 2022) shall consist of the following: Alicia Gibbs, Jody Morehouse, Alexis Alexander, David Howell, Jim Corder, Adam Munson, Mike Magruder, 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 (Alexis Alexander, Brad McNamara)

Facilities (Dan Johnson, Eric Bowles, Robert Johnson, Dave Schlicht, Nick Lasko, Conor Craigen)

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 Lifetime 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.

Oil Storage Improvements

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:	DocuSigned by: Eric Bowles 4ACC724D18764C2...	Date:	Aug-31-2022 | 2:55 PM PDT
Print Name:	Eric Bowles		
Title:	Corp Facilities Manager		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs 49C42855345E483...	Date:	Aug-31-2022 | 6:14 PM PDT
Print Name:	Alicia Gibbs		
Title:	Director of Shared Services		
Role:	Business Case Sponsor		

Template Version: 05/28/2020

Appendix A – Cost Estimate Breakdown

Presented and approved by Facilities Steering Committee to request additional funds through the Capital Planning Group on June 10, 2021.

YEARLY		2022	
Category		**Planned Spend**	**Scope**
Avista Resources		$ 104,280	Group 1 - 12 hr/month Group 2 - 20 hr/month Group 3 - 48 hr/month
Benefits	95% of Wages	$ 94,895	Matches hours shown above
		$ -	
Contract Project Support		$ 1,145,628	$1.02M + tax for general contractor $21K for special inspections $13K for consultant construction administration
		$ -	
Avista Supplied Equipment and Materials		$ -	
Material Overheads	8% of Mo Total	$ -	
AFUDC		$ 48,620	estimated
Other Expenses		$ -	
Capt OH - Functional and A&G	3.25% of Mo Total	$ 45,286	3.25% of all charges
Contingency	6% of Planned	$ 86,323	If needed for any items as described above
		1,525,031	
		$ 1,500,000	Budget
		$ (25,031)	Variance

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 $12.6M Asset Condition backlog identified using Paragon Asset Condition software. A funding of $4.4M takes into account 7% Inflation in 2023 and 3% Inflation in remaining years. This also includes a $250K one time purchase (2023) for an Asset Management System/ work orders ect. and $100K yearly for outdoor spaces.

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 its 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 Capital Steering Committee approved submission of this Business Case.

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
3.0	Lindsay Miller	Yearly Update	07/30/2021	Updated Graphs
4.0	Lindsay Miller	Executive Summary Only	05/24/2022	

GENERAL INFORMATION

Requested Spend Amount	$4,400,000 + 15% year over year
Requested Spend Time Period	Yearly
Requesting Organization/Department	Facilities
Business Case Owner | Sponsor	Eric Bowles | Alicia Gibbs
Sponsor Organization/Department	Shared Services
Phase	Planning
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

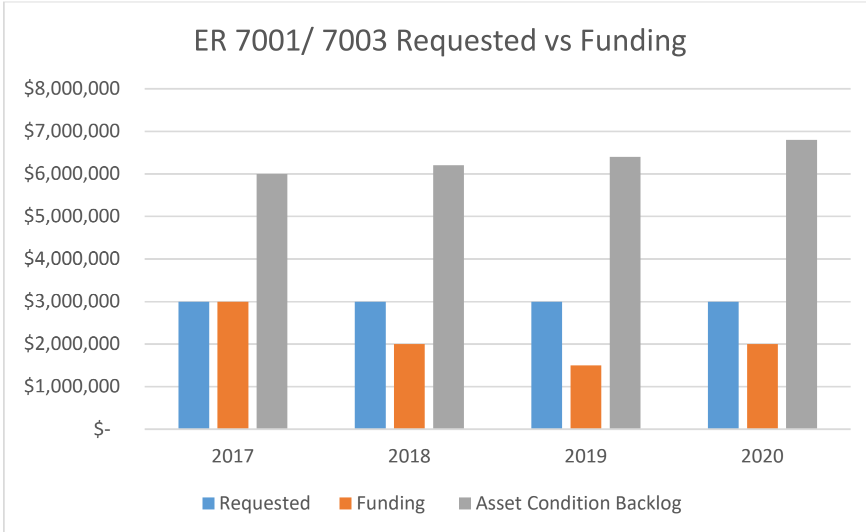
1.1 What is the current or potential problem that is being addressed?

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

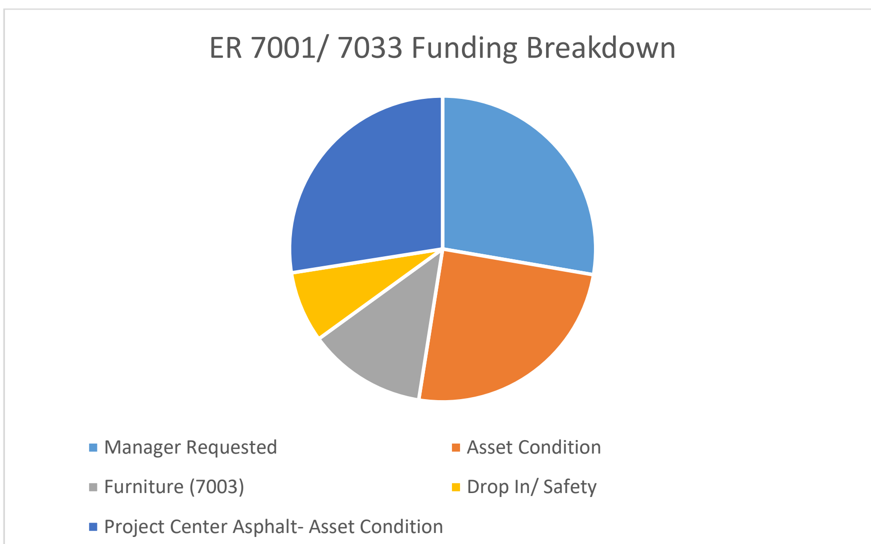
Dollar Road Fleet Shop	2015	2,406 N. Dollar Road	Spokane	WA
Dollar Road Service Center	2019	2406 N. Dollar Road	Spokane	WA
Dollar Road Truck Storage	2014	2406 N. Dollar Road	Spokane	Wa
Dollar Road Wash Bay	2018	2406 N. Dollar Road	Spokane	Wa
Downtown Network Center	2016	1717 W. 4th Ave	Spokane	WA
Downtown 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 $8.2M 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 $8.2M. 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 bow 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.

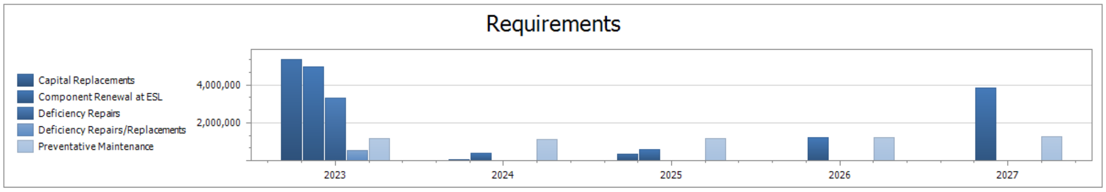
Option	Capital Cost	Start	Complete
Fund Program at Full Amount	$4.4M	01 2023	12 2023
Alternative #1- Partially Fund Program	Less than $4.4M	01 2023	12 2023

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

There is currently an identified backlog and requirements of $8.2M 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.

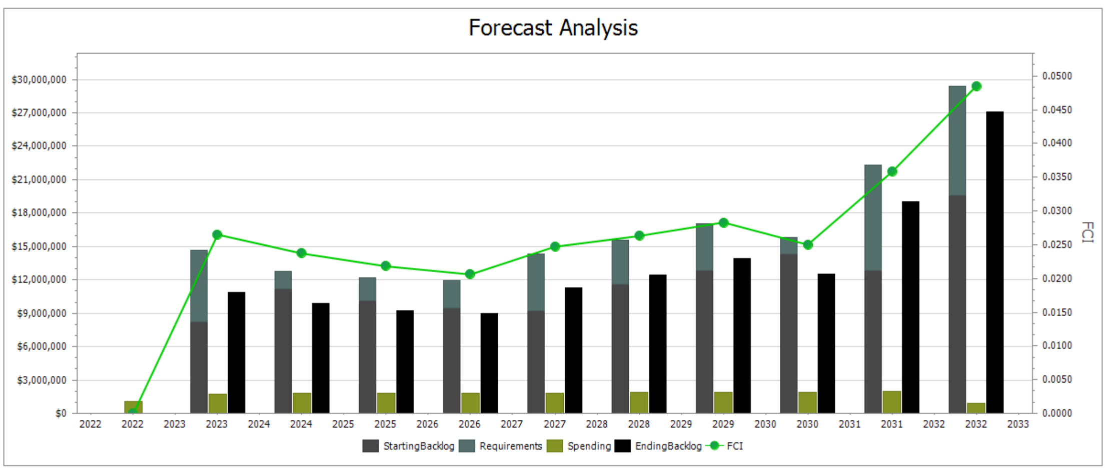
Even funding this program at the $4M level we will never be able to completely reduce the backlog. Providing more than the $4.4M requested would require additional Project Management personnel and possibly FTE's. Facilities can accommodate this request within their current staffing model. It is the goal 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.

Base known projects over the next 5 years- including backlog:



Account	2023	2024	2025	2026	2027	Grand Total
Capital Replacements	$5,340,548	$66,106	$359,299	$0	$0	$5,765,953
Component Renewal at ESL	$4,939,116	$377,479	$595,535	$1,218,186	$3,851,329	$10,981,645
Deficiency Repairs	$3,305,530	$0	$0	$0	$0	$3,305,530
Deficiency Repairs/Replacements	$555,234	$0	$0	$0	$0	$555,234
Preventative Maintenance	$1,144,698	$1,138,305	$1,172,455	$1,207,628	$1,243,857	$5,906,943
Grand Total	$15,285,126	$1,581,891	$2,127,289	$2,425,815	$5,095,186	$26,515,306
Active Assets	121	121	121	121	121	
Total Replacement Value	$437,167,598	$450,282,625	$463,791,104	$477,704,837	$492,035,982	

10-year Forecast- Fully Funded:



Starting Backlog: $8,197,144

ID	Grouping	Category	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Grand Total
1	Backlog (Start of Year)	Capital	$0	$6,147,867	$9,043,926	$7,965,586	$7,261,219	$6,907,128	$9,259,433	$10,360,239	$11,767,494	$10,284,299	$16,905,576	
		O&M	$0	$2,049,277	$2,110,755	$2,174,078	$2,239,300	$2,306,479	$2,375,673	$2,446,944	$2,520,352	$2,595,962	$2,673,841	
	Backlog (Start of Year) Total		$0	$8,197,144	$11,154,681	$10,139,663	$9,500,519	$9,213,607	$11,635,106	$12,807,183	$14,287,846	$12,880,262	$19,579,417	
2	Requirements	Capital	$0	$5,344,333	$456,590	$873,035	$1,259,422	$3,851,329	$2,636,244	$2,933,568	$128,048	$8,065,425	$8,384,840	$33,932,834
		O&M	$0	$1,105,151	$1,138,305	$1,172,455	$1,207,628	$1,243,857	$1,281,173	$1,319,608	$1,359,196	$1,399,972	$1,441,971	$12,669,317
	Requirements Total		$0	$6,449,484	$1,594,895	$2,045,490	$2,467,050	$5,095,186	$3,917,417	$4,253,176	$1,487,244	$9,465,397	$9,826,811	$46,602,151
3	Backlog + Requirements		$0	$14,646,628	$12,749,576	$12,185,153	$11,967,569	$14,308,792	$15,552,523	$17,060,359	$15,775,091	$22,345,659	$29,406,229	
4	Budget	Capital	$1,050,000	$1,750,000	$1,771,000	$1,792,630	$1,814,911	$1,837,857	$1,861,489	$1,885,835	$1,910,909	$1,936,739	$913,339	$18,524,709
5	Spending	Capital	$1,049,784	$1,749,711	$1,770,962	$1,792,495	$1,814,692	$1,837,824	$1,861,392	$1,885,820	$1,910,786	$1,936,698	$913,312	$18,523,476
6	Variance (Budget minus Spending)	Capital	$1,050,000	$289	$38	$135	$219	$33	$97	$15	$123	$41	$27	$1,051,017
7	Backlog (End of Year)	Capital	$0	$8,780,510	$7,733,578	$7,049,727	$6,705,949	$8,989,740	$10,058,485	$11,424,752	$9,984,756	$16,413,181	$24,377,104	
		O&M	$0	$2,049,277	$2,110,755	$2,174,078	$2,239,300	$2,306,479	$2,375,673	$2,446,944	$2,520,352	$2,595,962	$2,673,841	
	Backlog (End of Year) Total		$0	$10,829,787	$9,844,333	$9,223,805	$8,945,249	$11,296,219	$12,434,158	$13,871,696	$12,505,108	$19,009,143	$27,050,945	
8	Unfunded Preventative Maintenance		$0	$1,105,151	$1,138,305	$1,172,455	$1,207,628	$1,243,857	$1,281,173	$1,319,608	$1,359,196	$1,399,972	$1,441,971	$12,669,317
9	FCI		0.0000	0.0265	0.0237	0.0218	0.0206	0.0247	0.0263	0.0283	0.0250	0.0358	0.0485	
10	Total Replacement Value		$0	$450,282,625	$463,791,104	$477,704,837	$492,035,982	$506,797,062	$522,000,974	$537,661,003	$553,790,833	$570,404,558	$587,516,695	
11	Spending as % of TRV		0.00 %	0.39 %	0.38 %	0.38 %	0.37 %	0.36 %	0.36 %	0.35 %	0.35 %	0.34 %	0.16 %	

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 1.1M 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.

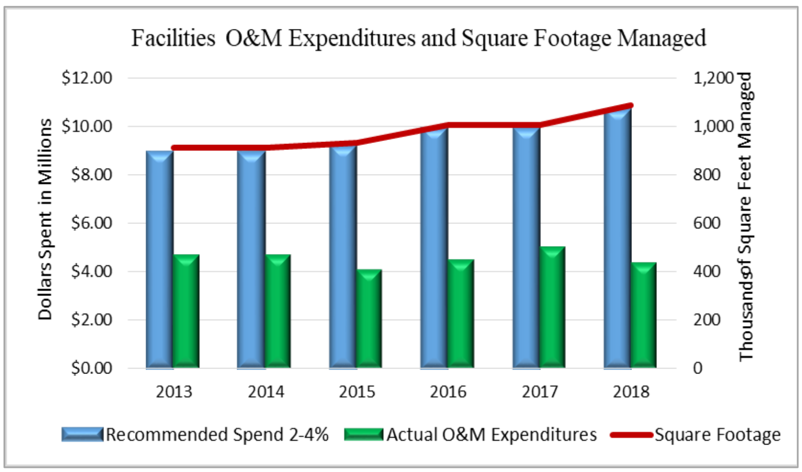
2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

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.
Funding this business case at less then $4M will require a reallocation of the dollars reducing the funding for Manager Requested Projects.

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

This Business Case will interface with the employees that work in the facilities where project work is completed. They will be a partner in the design and execution of these projects. Other teams that may be impacted are: ET, ET Security, Radio Relay, Environmental and Stores/ Warehouse as well as Gas and Electric Operations.

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 and 2022 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 1,186,000 square feet. These facilities were constructed between 1903 and 2019. Terracon estimated the value of this infrastructure at approximately $365 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:	DocuSigned by: Eric Bowles 4ACC724D18764C2...	Date:	Aug-31-2022 | 11:43 AM PDT
Print Name:	Eric Bowles		
Title:	Corporate Facilities Manager		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alicia Gibbs 49C42855345E483...	Date:	Sep-01-2022 | 7:15 AM PDT
Print Name:	Alicia Gibbs		
Title:	Alicia Gibbs		
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 would 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. 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 began this investment in 2021 with the 2022 shutdown of the AT&T 3G network. 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
Draft	Greg Loew	Initial draft of original business case	6/19/2019	
1.0	Greg Loew	Updated business case	7/21/2020	
2.0	Greg Loew	Updated business case	9/1/2022	Includes change to program

GENERAL INFORMATION

Requested Spend Amount	$2,185,250
Requested Spend Time Period	*4 years.*
Requesting Organization/Department	Fleet K51
Business Case Owner | Sponsor	Greg Loew | Alicia Gibbs
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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.

1.1 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.

1.2 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.

1.3 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

By implementing vehicle telemetry as a part of this project and the subsequent data analytics that is part of the program we will experience direct savings in the following areas:

Maintenance—Current maintenance practices are based on time. This practice means we over service a portion of the fleet while at the same time underservicing high use vehicles. The process to manage the underservicing is problem therefore a manual process that currently has no automation and relies on staff knowledge/awareness. By integrating real time usage data into the Fleet Management Information System (FMIS) we can base maintenance on actual use and potential diagnostic codes to perform maintenance only when approaching the threshold or codes indicate an issue.

Vehicle Maintenance Cost Per Mile*	$ 0.85	Miles Driven Per Year*	8344	**Potential Annual Savings**
		Maintenance Reduction	2.0%	$ 106,386.00

Allocation:
O&M—$42,555
Capital—$63,831
Based on current clearing account O&M vs. Capital split

Quantified direct savings:

2022	2023	Lifetime
$0	$106,386	$212,772

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers will gain from this project). For example, deploying this capital investment reduces the future need to hire

X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

Telematics 2025 has the following indirect savings areas

Utilization—Vehicle use each day can be tracked and the validation of equipment needs can be verified. The company's primary focus in the first two years will be pickup trucks. Based on utilization data and subsequent analysis in the first two years, based on peer utility results, it is estimated that Avista can reduce the number of light duty trucks by 7-8 units. That reduction in count results in a two year total of $330,000 (based on 2020 class average spend) is vehicles that will not need to be replaced. Additionally, the company estimates that it can reduce is light and heavy trailers by 1% or 11 total units for an additional $201,000 in capital savings These reductions may not be realized immediately but over the class average life span we will see this reduction. This initiative will begin in 2022 and run through 2024. It will require approximately 6 months of data for validity. This reduction also results in a total life-time operating cost savings on maintenance of $440,310 in 2020 dollars. This is based on the light duty fleet operating cost of $4,516 including major costs such as fuel, maintenance, repairs and licensing over the 13 year life of a pickup truck and finally multiplying that across our estimated reduction.

Light Duty Pickup Reduction Summary Estimate

Average Vehicle Purchase Price*	$ 44,000	Fleet Reduction	0.5%	**Potential Annual Savings**
Realization Period (Years)	2	Vehicle Reduction	3.8	$ 165,000.00

Light and Heavy Trailers Reduction Summary Estimate

Average Non-Vehicle Purchase Price*	$ 18,295	Fleet Reduction	1.00%	**Potential Annual Savings**
Realization Period (Years)	2	Non-Vehicle Reduction	5.5	$ 100,622.50

Allocation*:
O&M—$176,124
Capital—$795,186
Based on current clearing account O&M vs. Capital split

Reduced Total Mileage—Avista's fleet travels more than 7.5 million miles annually. By reducing our total mileage driven .25% we can save $44,000 per year. The focus of this is route optimization, commuter miles and dispatch efficiency.

Vehicle Operating Cost (With Fuel) Per Mile*	$ 2.84	Mileage Reduction	0.25%	**Potential Annual Savings**
		Miles Driven Per Year*	8344	$ 44,431.80

Allocation:
O&M—$17,773
Capital—$26,658
Based on current clearing account O&M vs. Capital split

Customer Service
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.

Calls per year	Average call duration (min)	CSR cost per minute *assuming $52/hr loaded	Potential Annual Savings
55	6.5	$.87	$310

Allocation:
O&M—$310

Safety & Risk Reduction
The use of telematics allows us to identify risky driving behavior.

Average Accident Cost	$ 1,788	Preventable Accident Reduction	1.00%	**Potential Annual Savings**
		Number of Preventable Accidents	30	$ 536.40

2020 Vehicle accident rate per million miles driven	Average annual corporate miles driven	Catastrophic accident settlement / verdict	Catastrophic accident frequency
5.8	7,500,000	$7,500,000	8.5 years
Average recordable accidents per year	Average # of accidents per 8.5yr period	Potential risk exposure	Total annual risk cost
43.5	370	1/370	$20,270

Allocation:
O&M—$20,484
Capital—$321
Based on current clearing account O&M vs. Capital split

Maintenance
Under maintenance, on diesel engines with high idle times, has the potential to cost the company $111,702 annually. By basing maintenance scheduling on real time use age data both hours and miles we have the potential to save engine repair or replacement costs.

2020 engines replaced due to excessive idle and hours exceeding manufactures recommended maintenance interval	Average cost per engine parts & labor	Potential annual savings
5	$18,617	$93,085

Allocation:
O&M—$37,234
Capital—$55,851
Based on current clearing account O&M vs. Capital split

Compliance

DOT inspection administration

Average admin cost per hour loaded	Total number of commercial vehicles	Man hours per vehicle per year	Avoided labor cost
$40	489	1	$19,560

Allocation:
O&M—$19,560
Capital—$0

Quantified indirect savings:

2022	2023	Lifetime
$238,477	$443,815	$1,907,277

Calculation details

	2022	2023
Light Duty Pickup Reduction Summary Estimate	$ 82,500.00	$ 165,000.00
Light and Heavy Trailers Reduction Summary Estimate		$ 100,622.50
Reduced Total Mileage	$ 22,215.90	$ 44,431.80
Customer Service	$ 310.00	$ 310.00
Safety and Risk Reduction	$ 20,806.40	$ 20,806.40
Maintenance	$ 93,085.00	$ 93,085.00
Compliance	$ 19,560.00	$ 19,560.00
Total	**$ 238,477**	**$ 443,815**

1.4 Supplemental Information

1.4.1 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

1.4.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The current network for Zonar will ceased operation in 2022. As noted in section 1.1 several functions were noted as missing for future anticipated business processes.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Full telematics program implementation	$2,185,250M	01 2021	12 2026
Partial funding telematics program	$1,208,250	01 2021	12 2026

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

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 six 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.

[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.

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.

$808K	Q1-2023 Product orders and TTP EOFY 22 work	Q2-2023 Product installs	Q3-2023 Vehicle installs TTPs as districts or orgs completed	Q4-2023 Project planning and remaining TTP
$400K	Q1-2024 Planning and SOW	Q2-2024 Development	Q3-2024 Development	Q4-2024 Development
$200K	Q1-2025 Implementation	Q2-2025 TTP 2024 work	Q3-2025	Q4-2025
$200K	Q1-2026 Planning and SOW	Q2-2026 Integrations, installs and final TTP	Q3-2026	Q4-2026

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
Paul Good	Gas Ops
Alexis Alexander	GPSS
Mike Littrel	Enterprise Technology
Jon Thompson	Enterprise Technology

2.8.2 Identify any related Business Cases

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

This project reports in with the executive advisory committee comprised of:

Heather Rosentrater	Jason Thackston	Jim Kensok

Alicia Gibbs	Jeremy Gall	Kermit Olson
Jim Corder	Liz Fredrickson	

3.2 Provide and discuss the governance processes and people that will provide oversight

Specific project updates will be provided and key decisions will be confirmed by the group from the program owner.

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.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *<Business Case Name>* 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: Greg Loew E32CB80359F242F... Date: Sep-09-2022 | 8:42 AM PDT

Print Name: Greg Loew

Title: Fleet Manager

Role: Business Case Owner

Signature:	DocuSigned by: Alicia Gibbs 49C42855345E483...	Date:	Sep-08-2022 | 1:16 PM PDT
Print Name:	Alicia Gibbs		
Title:	Alicia Gibbs		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		