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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-17-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-17-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	DIRECT TESTIMONY
AND NATURAL GAS CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	HEATHER L. ROSENTRATER
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Heather Rosentrater and I am employed as the Vice President of Energy Delivery for Avista Utilities, at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you briefly describe your educational background and professional experience?

A. Yes. I received a Bachelor of Science degree in electrical engineering from Gonzaga University, and hold a Professional Engineer (PE) credential. I joined Avista in 1996, and worked initially as an electrical engineer at Avista's former subsidiary Avista Labs, where I developed electrical systems for fuel cells. I joined Avista Utilities in 2003, and have broad experience on both the electric and natural gas side of the business, having managed departments and projects in transmission, distribution, SCADA, asset management and supply chain, as well as business process improvement using LEAN and Six Sigma techniques. I was named to my current position in December 2015. In this role, I am responsible for electric and natural gas engineering, operations, and shared services – fleet, facilities and business process improvement.

I currently serve on the board of directors for the Vanessa Behan Crisis Nursery and the West Valley Education Foundation in Spokane. In addition, I am a member of the Washington State University School of Engineering and Computer Science Executive Council.

Q. What is the scope of your testimony?

A. I will provide an overview of the Company's electric and natural gas energy delivery facilities, discuss our electric reliability objectives, types of investments, and system performance, and explain the factors driving our investment in electric distribution infrastructure. My testimony will explain why our planned investments in electric distribution are necessary to maintain the current levels of asset health and performance of our system and will discuss the need for each distribution capital project and program by the "Investment Driver" classification used to categorize our infrastructure investment needs. I will describe how our planned compliance with mandatory federal standards for transmission planning is driving a greater demand for new investment, and why our planned investments in natural gas distribution are necessary in the time frames they are being completed. Finally, I will explain why each capital investment planned for our fleet and facilities areas are necessary to support the efficient delivery of service to our customers, today and into the future. Overall, my testimony will demonstrate that:

1. Avista's recent past, current, and planned investments in electric distribution infrastructure are necessary, and why the failure to make these investments at this time would impair the performance of our system and harm our ability to deliver safe and reliable service to our customers. As such, the Company's investments are necessary in the time frames they are being completed.

2. The investments we make to uphold the current reliability of our electric distribution system, and to comply with required federal standards for transmission reliability, are thoroughly evaluated and cost-effective for our customers.

3. The approaches used by our business units to identify, evaluate, prioritize and recommend capital projects and programs ensure that we are properly identifying and funding the highest priority needs in this planning cycle.

4. Even with our current level of infrastructure investment, the Company has identified needs for investment that are not fully funded in this planning cycle, in an effort to balance investment demand with the planning principles we consider in setting our overall investment limit.

A table of the contents for my testimony is as follows:

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. 8, Schedule 1, which shows the number of customers and customer energy usage for each customer class. Exhibit No. 8, Schedule 2 is the Company's Electric Distribution System 2016 Asset Management Plan. Exhibit No. 8, Schedule 3 is the Company's Electric Substations 2016 System Review performed by Asset Management. Exhibit No. 8, Schedule 4 is the Company's Electric Transmission System 2016 Asset Management Plan. Finally, Exhibit No. 8, Schedule 5 contains the capital business case summary documents for each of the infrastructure investments described in my testimony.

II. OVERVIEW OF AVISTA'S ENERGY DELIVERY SERVICE

Q. Please describe Avista Utilities' electric and natural gas utility operations.

A. Avista Utilities operates a vertically-integrated electric system in Washington and Idaho. In addition to the hydroelectric and thermal generating resources described by Company witness Mr. Kinney, the Company has approximately 18,300 miles of primary and secondary electric distribution lines. Avista has an electric transmission system of 685 miles of 230 kV lines and 1,534 miles of 115 kV lines.

Avista owns and maintains a total of 7,650 miles of natural gas distribution lines, and is served off of the Williams Northwest and Gas Transmission Northwest (GTN) pipelines. A map showing the Company's electric and natural gas service area in Idaho, Washington, and Oregon is provided by Company witness Mr. Morris in Exhibit No. 1, Schedule 4.

As detailed in the Company's 2015 Electric Integrated Resource Plan,[1] Avista expects retail electric sales growth to average 0.6% annually and customer growth is projected to increase approximately 1% for the next twenty years in Avista's

[1] A copy of the Company's 2015 Electric IRP has been provided by Mr. Kinney as Exhibit No. 4, Schedule 1.

service territory, primarily due to increased population and business growth.

Also, based on Avista's 2016 Natural Gas Integrated Resource Plan,[2] the number of natural gas customers in Idaho/Washington is projected to increase at an average annual rate of 1.10%, with demand growing at a compound average annual rate of 0.36% over the next twenty years.

Q. How many customers are served by Avista Utilities in Idaho?

A. Of the Company's 377,285 electric and 240,294 natural gas customers (as of December 31, 2016), 128,560 and 80,033, respectively, were Idaho customers.

Q. Please describe the Company's operation centers that support electric and natural gas customers in Idaho.

A. The Company has construction offices in Coeur d'Alene, Spokane, Colville, Othello, Pullman, Clarkston, Deer Park, and Davenport. Avista's three customer contact centers, located in Spokane, Washington, and Coeur d'Alene and Lewiston, Idaho, are networked, allowing the full pool of regular and part-time employees in each location to respond to customer calls from all jurisdictions.

[2] A copy of the Company's 2016 Natural Gas IRP has been provided by Company witness Ms. Morehouse at Exhibit No. 7, Schedule 1.

Q. Please describe the Company's approach to managing the reliability of its electric distribution system?

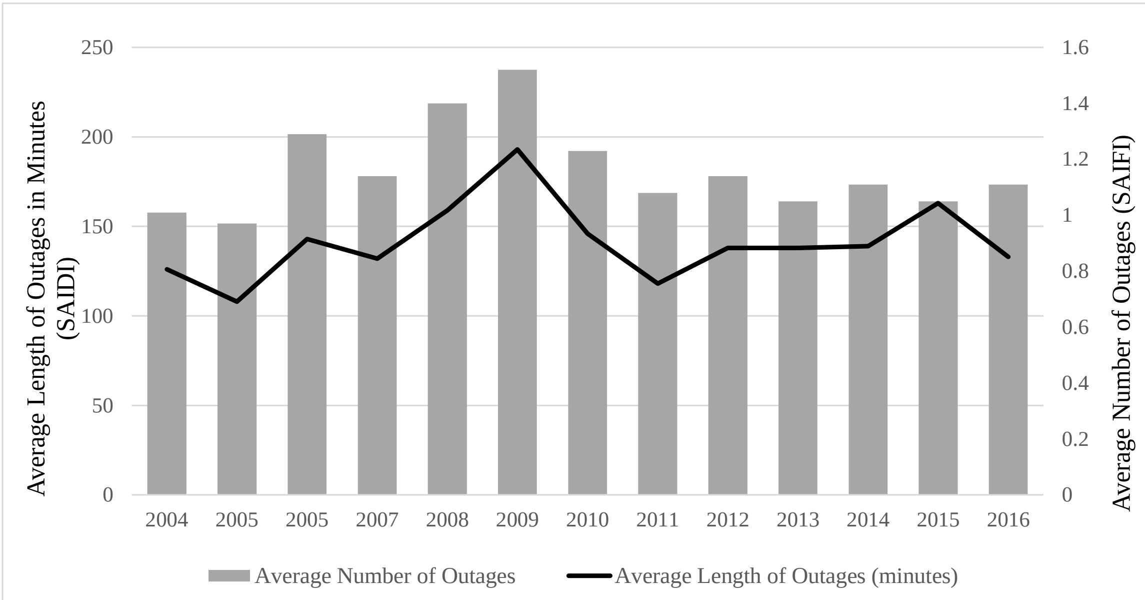
A. Avista is focused on maintaining a high degree of electric reliability as an important aspect of the quality of our service, particularly as our society becomes ever more reliant upon electronic technologies. The Company's objective has been primarily to maintain our current level of reliability.

Q. How does the Company track its reliability performance?

A. For many years Avista has measured, tracked and reported the number of outages and the duration of outages that our customers experience on average each year.[3] Our annual results for the number of electric outages and outage duration on average are provided for the period 2004-2016 in Illustration No. 1 on a system basis.

[3] The number of outages on average is reported as the System Average Interruption Frequency Index (or SAIFI), and the duration of outages on average as the System Average Interruption Duration Index (or SAIDI).

Illustration No. 1 – Duration and Frequency of Outages[4]



Q. What do the results in Illustration No. 1 indicate?

A. Although it is the norm for the number of outages and the average length to vary each year due to factors beyond Avista's control, such as major weather or wind events, our long-term reliability has been stable. In addition to these primary statistics, we report on several other utility-wide measures of reliability, the geographic areas of greatest reliability concern on our electric system, and our plans to improve service performance in those areas of greatest concern.

[4] This illustration excludes major event days. The measuring protocol for SAIDI and SAIFI excludes outages caused by very large outage events such as the windstorm of November 2015. These major events are referred to a "major event days." Even with these major events excluded, however, we can still experience substantial variability caused by, for example, storms that do not qualify as major events.

These plans include investments targeted to: 1) replacing certain sections of overhead feeders with underground lines when cost effective; 2) relocating lines to reduce outages caused by trees and to give our crews better access to speed up outage repairs; 3) implementing special tree trimming and wood pole inspection; 4) improve fuse coordination[5] on the feeder and laterals to reduce the size of an outage; and 5) dividing individual feeders into separate segments, as well as installing operating devices to sectionalize individual feeders, and other means necessary and cost effective to ensure our customers receive a reasonable level of service quality and reliability.

Q. Please describe the overall investments the Company makes to maintain and improve upon its current level of reliability?

A. Avista has in the past referred broadly to individual investments we make as having the purpose of "improving reliability." This reflects the fact that many investments, especially distribution investments made to replace deteriorated assets, are very likely to improve the reliability

[5] Fuse coordination refers to the engineering scheme of ensuring we have the properly-sized fuses for system protection at each juncture of a feeder. Good fuse coordination helps ensure that an outage fault is restricted to that portion of the feeder network where the damage has occurred.

of the specific infrastructure that is being rebuilt or replaced. This is the case because the likelihood of failure of an asset generally increases with age and deterioration over its service life. Avista's many infrastructure investments often include at least a mention of these reliability benefits. In the great majority of cases, however, the *predominant* need for these investments is to replace assets that have reached the end of their useful life, or to a lesser degree to solve capacity and performance issues. This timely replacement of deteriorated assets is crucial to our ability to uphold and maintain our current levels of reliability performance.

III. ELECTRIC DISTRIBUTION INVESTMENTS

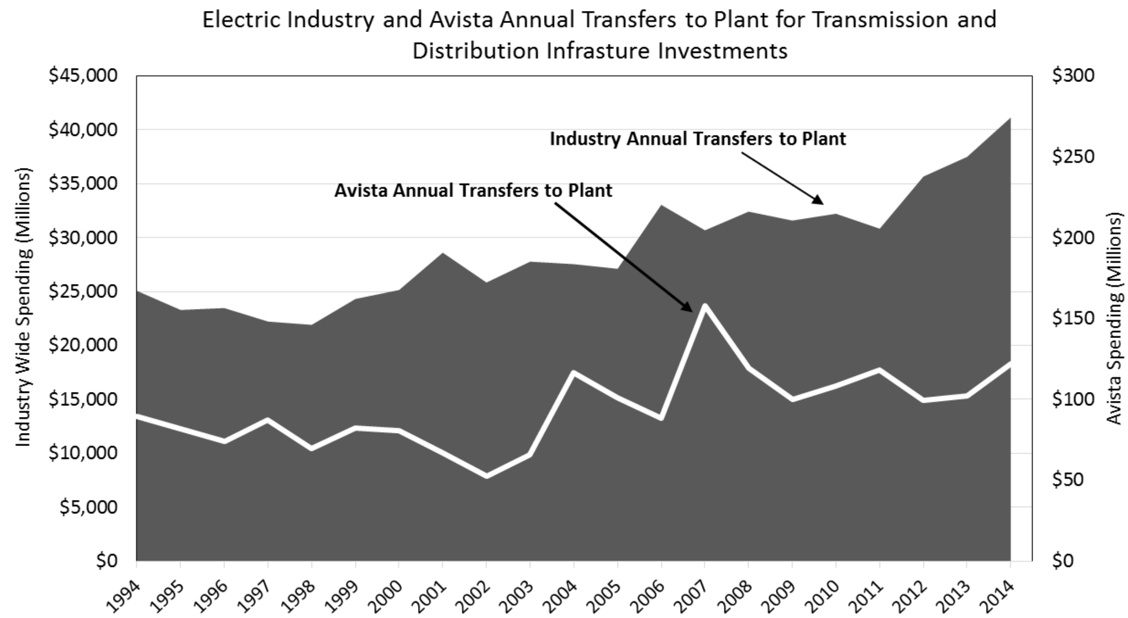
A. Avista's Distribution Investments from 2005 - 2016

Q. How do the electric distribution investments made by Avista over the past several years compare with those made by other similar utilities?

A. Avista, like utilities across the country, has responded to similar needs for increased investment in electric transmission and distribution infrastructure on a system basis as shown in Illustration No. 2.[6]

[6] Results are from the data set gathered and reported by the Energy Institute of the University of Texas, Austin. Fares, L., Robert, King, Carey W.,

Illustration No. 2



Organizations such as the Edison Electric Institute reported total utility investments in electric transmission and distribution facilities doubling between 2009 and 2014, noting that investments in distribution infrastructure alone reached $22.5 billion in 2014, an increase of 8% over 2013.[7] The American Society of Civil Engineers in 2011 conducted an extensive review of then-current trends in electric utility investments, and identified a $37 billion "investment gap" between those current plans and the infrastructure investments

"Trends in Transmission, Distribution, and Administration Costs for U.S. Investor Owned Electric Utilities," 2016.
UTEI/2016-06-1, 2016, available at http://energy.utexas.edu/the-full-cost-of-electricity-fce/.38 electric utilities

[7] 2015 Financial Review: Annual Report of the U.S. Investor-Owned Electric Utility Industry. Edison Electric Institute.

needed by year 2020.[8] Their report on electric infrastructure was updated in 2016, noting the *significant increased investment that had been made by the industry* compared with the 2011 forecast of planned investments, but it still identified an $18 billion investment gap between current spending plans and the investments that will be needed by year 2025.[9] The report noted that 54 percent of the $18 billion gap was attributed to the needs of electric distribution systems alone.

In addition to the similarity in the overall pattern of investment, the Company's annual distribution investments have been similar to those of other electric utilities measured on a cost per customer basis. Illustration No. 3, below, shows the annual electric distribution capital cost per customer for 38 electric utilities similar in size to Avista,[10] as well as the Company's annual capital cost per customer. The illustration shows the maximum and the average annual capital cost per customer for this group. The Company's investments in electric distribution infrastructure on a system basis were depressed

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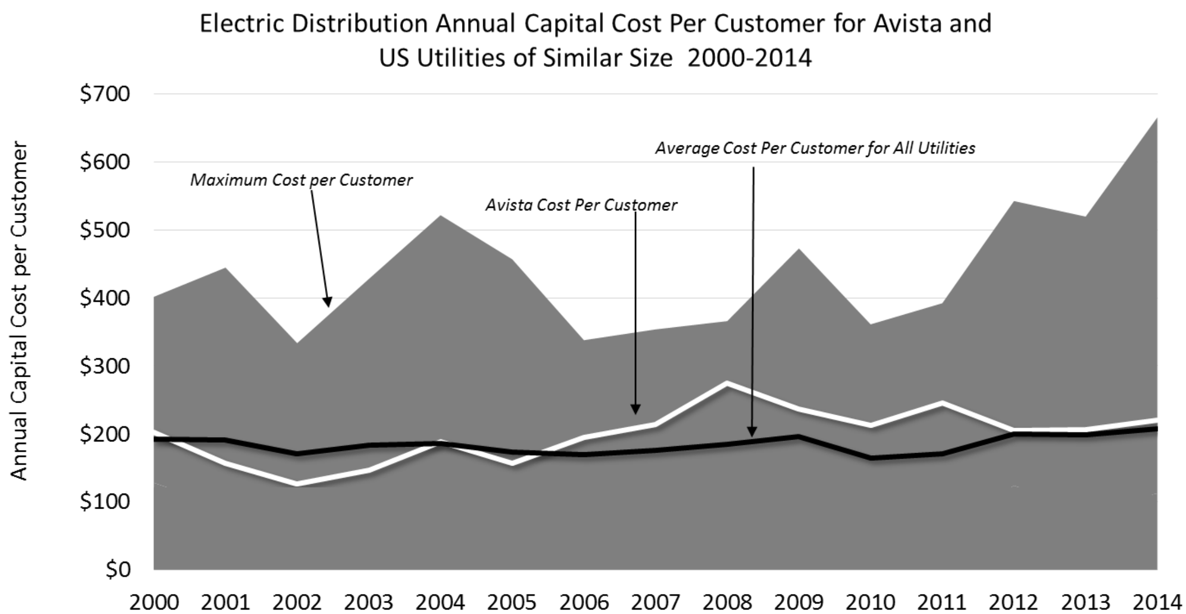
[8] Failure to Act. The Economic Impact of Current Investment Trends in Electricity Infrastructure. American Society of Civil Engineers. 2011.

[9] http://www.infrastructurereportcard.org/wp-content/uploads/2016/10/ASCE-Failure-to-Act-2016-FINAL.pdf pages 16 and 17.

[10] Ibid. Report of the Energy Institute of the University of Texas, Austin. For this figure Avista selected a subset of those utilities similar in the number of electric customers and peak loads from the more than 200 utilities in the data set. A total of 38 utilities were selected based on the parameters of the number of customers between 200,000 and 400,000, and peak loads between 1,000 MW and 3,000 MW.

for several years early in this period, as reflected in our below average cost per customer. Our increasing investments pushed our per customer cost above the national average in 2005, however, our costs have generally converged with the group average since 2012.

Illustration No. 3



Q. What conclusion do you draw from the comparison of Avista's investments in electric distribution infrastructure with those of the broader utility industry since 2000?

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

B. Currently Planned Investments in Distribution Infrastructure

Q. Would you please summarize the distribution investments on a system basis that are planned for years 2017 - 2019?

A. Yes. Planned investments for this period, grouped by investment driver, are shown in Table No. 1 below on a system basis, and the expected transfers-to-plant by "driver" is provided in the following Illustration No. 4. Please see Company witness Mr. Morris' Exhibit No. 1, Schedule 2, consisting of an Infrastructure Investment Plan identifying six "drivers" of infrastructure development. These are:

1. Respond to customer requests for new service or service enhancements;

2. Meet our customers' expectations for quality and reliability of service;

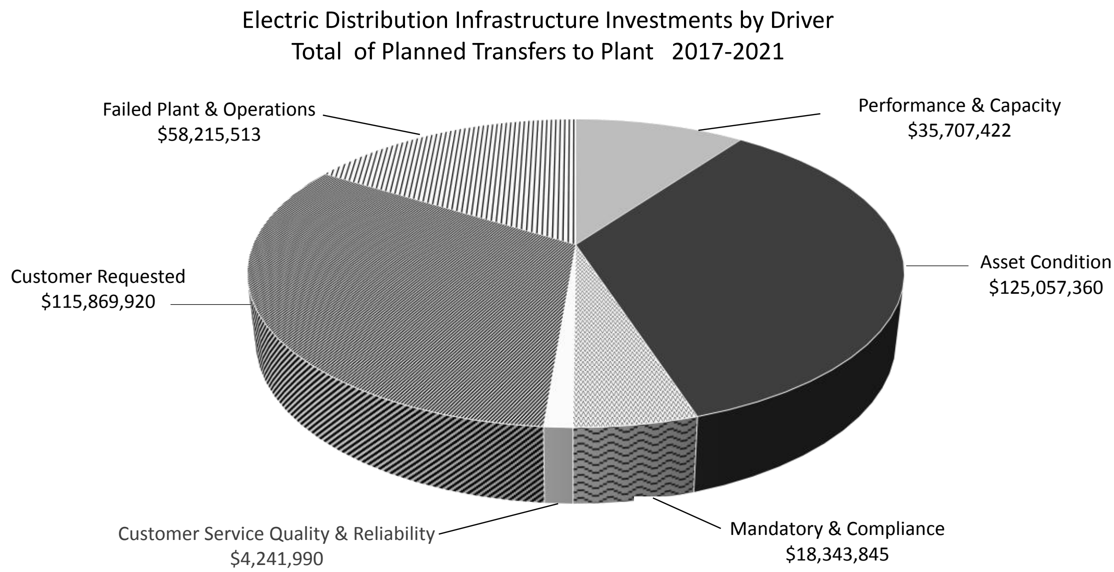
3. Meet regulatory and other mandatory obligations;

4. Address system performance and capacity issues;

5. Replace infrastructure at the end of its useful life based on asset condition, and;

6. Replace equipment that is damaged or fails, and support field operations.

Illustration No. 4



As the illustration shows, the great majority of our planned investment is required to connect new customers who request electric service, to replace assets that have reached the end of their useful life, and to replace failed assets and support operations. In the following sections, I will further explain the need for these investments, by project and program, and by investment driver.[11]

[11] The figures contained within each of the Tables in my testimony reflect "transfers-to-plant" during the respective calendar years; as such, the amounts may differ from the amounts shown for any particular line item in the Infrastructure Investment Plan (Exhibit No. 1, Schedule 2) or in the associated Business Cases (Exhibit No. 8, Schedule 5), which reflect budgeted capital spend numbers. The costs shown in Illustration No. 4 for Customer Service Quality and Reliability are derived from the feeder automation portion of the Grid Modernization Program, which costs are included as part of the overall Grid Modernization investments shown in Table No. 1 on next page."

Table No. 1

Distribution Capital Projects (System) In $(000's)			
Business Case Name	**2017**	**2018**	**2019**
Asset Condition			
Dist Grid Modernization	$ 15,051	$ 13,929	$ 14,333
Distribution Transformer Change-Out Program	3,000	1,200	1,200
Distribution Wood Pole Management	9,000	9,500	9,500
Primary URD Cable Replacement	503	1,000	1,000
Customer Requested			
New Revenue - Growth	23,775	23,249	22,668
Failed Plant and Operations			
Distribution Minor Rebuild	9,105	8,900	8,900
Meter Minor Blanket	505	300	300
Mandatory and Compliance			
Elec Replacement/Relocation	2,600	2,700	2,800
Environmental Compliance	350	350	350
Performance and Capacity			
LED Change Out Program	2,900	2,000	2,320
Segment Reconductor and FDR Tie Program	6,587	4,900	5,001
Subtotal: Electric Distribution Capital Projects	**$ 73,376**	**$ 68,028**	**$ 68,371**
Washington Direct Business Cases[(1)]			
Spokane Electric Network	2,605	2,300	2,300
Franchising for WSDOT	1,594	200	200
	4,199	**2,500**	**2,500**
Total Planned Electric Distribution Capital Projects	**$ 77,575**	**$ 70,528**	**$ 70,871**

(1)Excluded from revenue requirement in this case.

Asset Condition:

Q. Please describe the Asset Condition Investment Driver included and explain why these investments are necessary in the time frame they are being completed.

A. Assets of every type degrade with age, usage and other factors, and must be replaced or substantially rebuilt at some point in order to ensure we continue to deliver reliable and cost effective service. Projects or programs in this driver are defined as: "*investments to replace assets based on established asset management principles and systematic programs adopted by the Company, which are designed to optimize the overall lifecycle value of the investment for our customers*."[12]

The replacement of assets based on condition is essentially the practice of removing them from service and replacing them at the end of their useful life. Across the utility industry, and likewise for Avista, the replacement of assets based on condition often constitutes the largest type of the infrastructure investments required each year.[13] In a survey of 433 U.S. electric utility executives, 47% listed "old infrastructure" as the most challenging issue they face, with the next-closest infrastructure issues reported as "Grid Reliability" (17%) and Smart Grid Deployment (16%).[14] As an industry we face this investment demand today because the sizeable infrastructure built during the period of economic growth and expansion following World War II, and extending generally into the 1970s, has either reached, or is nearing the end of, its useful life and must be replaced.[15] As demonstrated

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[12] Exhibit No. 1, Schedule 2, page 30.
[13] Exhibit No. 1, Schedule 2, page 31.
[14] Why Utilities are Rushing to Replace and Modernize the Aging Grid: State of the Electric Utility 2015.
[15] Exhibit No. 1, Schedule 2, page 31.

earlier in my testimony, our Company like utilities across the nation have stepped up the level of investments needed to accommodate the orderly replacement of these facilities. For our electric distribution system, these investments are required to uphold and maintain the capability of our various feeder equipment, overhead conductor and poles, transformers, and underground cables.

Q. What are the ongoing programs to accomplish this work?

A. These programs include Distribution Wood Pole Management, PCB Transformer Replacement, Underground Cable Replacement, and Distribution Grid modernization. Collectively, the Company relies on these primary programs for making systematic investments in our distribution plant, which allows us to cost-effectively maintain a safe and highly reliable system that meets the expectations of our customers. These programs were developed with support from the Company's asset management group, which has continued to evaluate them as needed through the course of implementation. The most recently completed Electric Distribution System 2016 Asset Management Plan report has been included as Exhibit No. 8, Schedule 2. Below are descriptions of each of these asset programs:

Distribution Grid Modernization – 2017: $15,051,000; 2018: $13,929,000; 2019: $14,333,000

In order to properly select[16] the most appropriate feeders for rebuilding, Grid Modernization uses inventory information from the Wood Pole Management Program and our Avista Facilities Management System, to assess the potential energy efficiency savings, avoided customer outages, and avoided expenses for failure of equipment. This feeder criteria information is used to rank the potential benefits for each compared with all of the other feeders on our system. The top ranked feeders are then balanced among Company operating districts, jurisdictions and urban vs rural service. In the process of evaluating feeders for potential rebuilding, our engineers evaluate reliability results for each feeder, study the actual loadings on each phase of the feeder under a range of seasonal conditions and model the average and peak loadings expected after the phase loads are balanced. They also model the capacity of the overhead conductors, by segments on the trunk and laterals, to identify any limitations as well as potential for energy savings. By integrating all of this information, along with the full range of asset age and condition data, our engineers recommend a comprehensive set of treatments that could be applied and identify the cumulative potential benefits.

This program represents a comprehensive approach to infrastructure management, based on extensive data and engineering-driven analysis and evaluation. It serves as a platform to better integrate a portion of the capital investments we make each year in our electric distribution system. Through grid modernization, we know we are targeting work on the right infrastructure at the right time, and in a priority that allows us to maximize the customer value of every investment made under the program. The failure to fund this program at the planned level for this period will push even more work into the wood pole management program and reduce the value of both programs.

Distribution Transformer Change-Out Program - 2017: $3,000,000; 2018: $1,200,000; 2019: $1,200,000

Between 1929 and 1981, a family of synthetic organic compounds known as Polychlorinated Biphenyls (PCBs) were commonly used in

[16] The objective in selecting candidate feeders for rebuild is to achieve the greatest overall value for customers based on improved reliability (on that feeder), energy efficiency savings, and avoided expenses for equipment failures.

the oil that fills electrical transformers due to their high dielectric strength[17] and resistance to fire. Studies conducted in the 1960s and 70s revealed, however, that these compounds are also toxic, carcinogenic and highly resistant to biodegradation in the environment. Their production was banned in the United States in 1979.[18] As a result of this elevated concern, Avista began to formally analyze alternatives to deal with its distribution transformers containing PCBs.

Under the current plan all transformers with PCB concentrations exceeding 1 ppm should be removed from our system by year 2019. In year 2020 and beyond, the remainder of the pre-1981 transformers in our system will be targeted for removal as part of the wood pole management and grid modernization programs.

Distribution Wood Pole Management – 2017: $9,000,000; 2018: $9,500,000; 2019: $9,500,000

Avista has approximately 340 electric feeders with a total circuit length of approximately 7,700 miles. This system is composed mainly of overhead electric conductors and associated equipment that is supported by approximately 240,000 wood poles and attached equipment that includes crossarms, transformers, cutouts,[19] insulators and pins,[20] wildlife guards, lightning arresters, guy lines,[21] and pole grounding.[22] Poles, equipment and conductors comprise over 70% of the Company's electric distribution infrastructure. In managing these assets, it is the Company's goal to repair or replace aging poles and equipment before they actually fail, but late enough in their expected life span to capture the full value of the initial investment and any follow-up investments. The practical way to accomplish this is to systematically inspect each pole in the

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[17] Dielectric strength refers to the ability of a material to resist carrying an electrical current, which is a measure of its potential to insulate against electric short circuit or fault.

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

[19] Cutouts are fuse devices that protect the feeder and equipment in the event of a fault on the line.

[20] The overhead wire or conductor that carries the electric current is attached to insulators that prevent the conductor from faulting, and each insulator is attached to the pole or crossarm with a wooden pin (though new materials are frequently in use today).

[21] Wire support attached at the upper part of the pole and anchored into the ground diagonally to counteract tension on the line as needed to keep the pole stable, upright and plumb.

[22] To ensure the pole and equipment is electrically grounded to ensure any fault goes safely to ground.

system on a regular cycle and to make the investments needed to replace failed poles or to extend the life of weakened poles so they don't fail before the next inspection. The central question is what time interval to use for the inspection cycle.[23] Generally, more frequent inspections (shorter cycle time) reduce the likelihood that poles and associated components will fail sometime during the interval between inspections, but they also cost more because the annual number of poles inspected is greater than with a longer cycle interval. The optimum interval time can be mathematically determined based on the characteristics of the wood pole population, the associated operating expenses, and the likelihood and cost of customer service outages resulting from poles that fail between inspections. The Company's evaluation of the cycle interval in 2009 pointed to a 20-year cycle as preferable to both a shorter 10-year interval and a much longer interval.

In each 20-year cycle all of the wood poles in our system will have been visually inspected and repaired, reinforced (stubbed), or replaced as needed. The program has been modified to more fully utilize the crews performing inspections, by replacing pre-1960's transformers, identifying inefficiently sized transformers, installing grounds or guy wires where needed, and ensuring equipment meets current safety standards. In 2012 Avista initiated the Grid modernization Program which is dovetailed with the Wood Pole Management Program to make further-optimized use of crews and materials supporting wood pole management. The failure to fund this program at the planned levels for this period will result in more risk of customer outages, and higher expenses and capital costs due to unplanned maintenance and repair. This investment includes associated O&M offsets of $68,400 (System-basis) beginning in 2017. Company witness Ms. Andrews has included Idaho's share of these offsets within the Company's revenue requirement request.

Primary URD Cable Replacement - 2017: $503,000; 2018: $1,000,000; 2019: $1,000,000

Underground residential district cable (underground cable or URD) has been used by the utility industry since the 1930s, though Avista did not begin installing the cable until the late 1960's. During the 1990s it became apparent that the cable manufactured from the 1960s into the 1980s had numerous problems. These included the lack of adequate insulation

[23] The inspection cycle interval is the period of time within which every pole in the system will have been inspected and treated as needed.

resulting in numerous faults, the process of splicing the cable caused weaknesses and premature failure, and excessive corrosion on the neutral strands caused voltage levels to drop unexpectedly or the cable to entirely fail.[24]

In 2009 Avista's asset management group analyzed options for accelerating the replacement schedule from 10 years to a four year program. The analysis, which was based on savings from avoiding unplanned outages, estimated that the four-year program would save customers approximately $7.3 million in capital installation, expenses, and failure consequences.[25] With the majority of the known vintage cable replaced by 2013, the program was ramped down to an annual investment of approximately one million dollars, which provides for the removal and replacement of this vintage cable as we find it on the system (usually through responding to an underground fault). The failure to fund this program at the planned levels for this period will result in more customer outages, and higher expenses and capital costs due to unplanned maintenance and repair.

Q. Does the Company's five-year investment plan fully fund these programs?

A. No. The Company's Distribution Grid Modernization Program is optimized on a 60 year cycle, however, it has not been funded at a level to achieve that cycle time, in order to accommodate other priority investment needs in Avista's electric distribution system. The level of funding for this project that the Company has included in the 2017 – 2021 timeframe provides for an 84 year cycle; longer than the optimized cycle. The effect of the longer than 60-year cycle

[24] Medek, James D. P.E., "Early Underground Residential Distribution (URD) in the Midwest,", 2002, https://www.pesicc.org/iccwebsite/subcommittees/E/E04/2002/fall02 medek.pdf)

[25] Savings are based on the outages forecast to occur without the replacement program, minus the actual outages, multiplied by the average cost of responding to an average cable outage.

interval is that the wood pole management program will have to complete more capital work every year (work that would have been done under grid modernization). Both the grid modernization and wood pole management programs will operate at a lower efficiency, and a portion of the added customer value delivered by the grid modernization program will be lost.

Customer Requested:

Q. Please list and describe the infrastructure programs and projects for electric distribution related to the 'Customer Requested' investment driver?

A. This classification of infrastructure investments is defined as: "*customer requests for new service connections, line extensions, transmission interconnections, or system reinforcements to serve a customer.*"[26] The related capital construction activities are typically limited to the electric distribution system, but may extend to substations and dedicated high voltage transmission lines. The capital investment required to fulfill customer requests for electric service represents 31.4% of the total distribution infrastructure spending planned in the five-year period.

[26] Exhibit No. 1, Schedule 2, page 18.

New Revenue – Growth - 2017: $23,775,000; 2018: $23,249,000; 2019: $22,668,000

These investments include the costs for establishing a new service connection to a customer when requested, and which are provided for in the line extension allowance granted under our tariff. This work can be as simple as setting a new area light or running a new secondary service from an existing transformer, to the more involved instance of extending a primary distribution line to the customer, setting the transformer, running the service line, and setting the new meter. System reinforcements that are required to serve a solitary or a small group of customers, generally involve substation and feeder upgrades that are required to meet new capacity requirements. Because Avista is obligated to provide electric service or service enhancements when requested, we allocate the needed capital to this program based on the number of requests we expect to receive each year, and not through a competitive prioritization process. For this period, Avista expects to connect on average about 6,000 new electric customers each year. Avista is required by its service tariffs to make the investments necessary to connect customers when requested.

<u>Failed Plant and Operations:</u>

Q. Please describe the Failed Plant and Operations Investment Driver?

A. The Failed Plant and Operations investment driver is defined as: "*requirements to replace assets that have failed and which must be replaced in order to provide continuity and adequacy of service to our customers (e.g. capital repair of storm-damaged facilities). Also includes investments in natural gas and electric infrastructure that are performed by Avista's operations staff.*"[27] Avista must respond to various types of equipment failures on our electric distribution system each

[27] Exhibit No. 1, Schedule 2, page 35

year that result from natural forces such as wildfire, third-party damage caused by others, or the unanticipated failure of an asset. In addition to replacing failed plant, investments under this program cover work performed through Avista’s ongoing capital work performed by operations staff.

Distribution Minor Rebuild - 2017: $9,105,000; 2018: $8,900,000; 2019: $8,900,000

A major portion of the investments made under this program are driven by faults or damage to our system that result in service outages for our customers. The vast majority of the outages our customers experience each year occur on our overhead distribution system. In 2016, there were 7,083 outages on the distribution grid compared to only 53 related to substations and 61 associated with transmission lines. The majority of these outages are related to weather (e.g. lightning, wind, rain and snow), downed trees, animals (e.g. squirrels and birds), and equipment failure. In addition to replacing assets that have failed, Avista’s operations staff performs a wide range of limited capital infrastructure work that does not rise to the level of a project or program.[28] This work includes the need to reconfigure, replace, repair, or upgrade distribution facilities that arise for a variety of reasons. Because the Company must promptly replace failed infrastructure in order to ensure the continuity of service to our customers, Avista allocates funding to this program based on the evaluation of historical trends, and not through a competitive prioritization process. If Avista did not make the required investments under this program, we would be unable to repair and/or replace infrastructure that is damaged or fails, and would therefore fail to provide service continuity to our customers.

Meter Minor Blanket - 2017: $505,000; 2018: $300,000; 2019 $300,000

The Company has over 370,000 electric meters in service for measuring the kWh usage for our residential, commercial and

[28] A project is a stand-alone investment activity that upgrades existing assets or installs new assets required for operation of Avista's systems and processes. A program is a systematic or repetitive multi-year investment designed and managed to sustain an expected desired level of system or process performance.

industrial customers. Each year, in response to our customers' requests for a meter check, the Company's detection of billing anomalies, or the identification of failing meters through our annual meter testing program, Avista must promptly replace or repair failed meters to ensure our customers are accurately billed. The investments for meter replacements and repairs are included under this failed plant program.

Mandatory and Compliance:

Q. Please describe the distribution investments related to the Mandatory and Compliance Investment Driver?

A. Avista has defined this driver as: "*investments required to comply with laws, rules, and contracts that are external to the Company (e.g. State and Federal laws, Settlement Agreements, FERC, NERC, and FCC rules, and Commission Orders, and etc.).*"[29]

Electric Replacement/Relocation - 2017: $2,600,000; 2018: $2,700,000; 2019: $2,800,000

Each year Avista is required to respond to the projects of municipalities, counties and state-level agencies to rebuild or realign roads, streets and highways. When these projects impact our distribution facilities located in public rights-of-way, the Company is required to remove and rebuild them in the clear zone of the new roadway, or to place them on a new purchased private easement. This work must be performed at the Company's expense, and while Avista may have some latitude to negotiate the timing of the construction, it has no choice with regard to removing and relocating its infrastructure and paying all of the associated costs.[30] If Avista failed to make these investments we would be in violation of our operating franchises, municipal codes, state laws and regulations, and

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[29] Exhibit No. 1, Schedule 2, page 23.

[30] This requirement is based on Avista's facilities being in the public right-of-way established for this purpose. In cases when the Company's facilities are located in private rights-of-way, while still required to be relocated, the move is at the expense of the governing body responsible for the roadway project.

would be subject to litigation and financial and other penalties.

Environmental Compliance - 2017: $350,000; 2018: $350,000; 2019: $350,000

These required investments include implementation of U.S. Forest Service Special Use Permits, waste oil disposal including PCB transformers, and environmental compliance with storm water management, water quality protection, property cleanup and related issues. If Avista failed to make these investments we would be in violation of mandated environmental compliance regulations, and would be subject to litigation and financial and other penalties.

Q. How are these investments prioritized within the business units?

A. Because Avista is obligated to remove and replace its facilities when requested, and to meet environmental standards, the annual funding level is established based on historical trends and any known specific projects.

Performance and Capacity:

Q. What planned distribution investments are grouped under the Performance & Capacity Investment Driver?

A. When the load-carrying capacity of electric facilities is exceeded for any extended period of time it can stress and damage equipment, cause system instability, and lead to equipment failures that result in customer outages. The investments required to resolve these issues are defined as: *"a range of investments that address the capability of assets to meet defined performance standards, typically developed by* *the Company, or to maintain or enhance the performance level of assets based on need or financial analysis."*[31]

LED Change Out Program - 2017: $2,900,000; 2018: $2,000,000; 2019: $2,320,000

LED lighting technology emerged as a viable alternative to conventional and fluorescent lighting around 2009, and by year 2012 over 14 million units had been installed in the U.S. alone. It is estimated that LEDs will save U.S. consumers and businesses $20 million per year within a decade, and reduce U.S. CO_2 emissions by up to 100 million metric tons per year. LED bulbs cut electricity use by 85% compared with incandescent bulbs, and 40% compared with fluorescent lighting.[32] Avista operates approximately 35,000 street lights we have installed for many of our communities and other jurisdictions across our service territory as well as area lights requested and paid for by individual customers. In 2013, in recognition of the superior safety performance of LED lighting, the energy savings potential, Avista evaluated the benefit of converting all our Schedule 042 street lights from High Pressure Sodium (HPS) to LED fixtures. Also, the State of Washington has established a statewide grant program, which is administered for the state by Avista, which provides small communities an offset to their street lighting costs when their systems are converted to LED lighting. If Avista did not invest in the LED lighting program, we would delay the safety and security benefits to customers, as well as the savings for energy efficiency and reduced operating expenses achieved by the program. This investment includes associated O&M offsets of $1,060,249 (System-basis) beginning in 2017. Ms. Andrews has included Idaho's share of these offsets within the Company's revenue requirement.

Segment Reconductor and FDR Tie Program - 2017: $6,587,000; 2018: $4,900,000; 2019: $5,001,000

The annual investments made under this program represent 7.1% of our planned distribution investments, and remedy the overloading of electric equipment and cable, as well as the conductor sag[33] that results from overheating of the overhead wire. These instances of system overloading result from load

[31] Exhibit No. 1, Schedule 2, page 27.
[32] "PCBs Questions & Answers," United States Environmental Protection Agency, https://www3.epa.gov/region9/pcbs/faq.html.
[33] When the overhead wire (conductor) on a distribution feeder is overloaded, the wire overheats and stretches, and in doing so, sags closer to the ground than designed, which can exceed electric code requirements for safety.

growth and shifts in load demand that occur over time on the distribution system. Resolving these overloading issues involves a combination of two strategies known as "load shifting" and "segment reconductoring." The strategy of load shifting extends existing lines on one feeder to an adjacent feeder that has the available capacity to carry the additional transferred load. Reconductoring involves the removal of the wire or conductor that is too small in diameter for the current loading and replacing it with larger conductor that can easily carry the load. Avista considers a range of options that not only meet the current need to relieve the overloading, but that also provide for the optimization of the overall distribution system.

Q. In conclusion, please summarize Avista's investment plan for its electric distribution system.

A. Our investment plans for our electric distribution system have been thoughtfully developed, thoroughly analyzed and optimized, and adjusted as appropriate to ensure we deliver cost effective value for our customers. The level of our investments has also been conservative as we have balanced distribution needs with our overall infrastructure demands. As an example, we have chosen to fund our grid modernization program at a level that does not achieve the optimized cycle interval in an effort to manage our overall investment needs as a part of being attentive to the price impacts to our customers.

Q. Do you believe that the Company's investment in distribution infrastructure is necessary in the time frame the projects are being completed?

A. Yes, I do.

IV. ELECTRIC TRANSMISSION INVESTMENTS

Q. Please discuss the investment drivers for the Company's transmission projects.

A. Avista must continuously invest in its transmission infrastructure to maintain safe and reliable service for our customers and to meet mandatory federal reliability standards. These investments replace equipment that has reached the end of its useful life, meet customer requests for interconnection or service enhancement, repair or replace infrastructure that fails, meet our regulatory compliance requirements, ensure the availability of critical equipment when needed, and enhance the capacity or performance of the system to meet Company standards or serve additional load. In the following testimony I will provide a description of the transmission investments by investment driver category.

Q. Please discuss the Asset Condition driver as it relates to transmission investment.

A. Investments in transmission infrastructure related to Asset Condition are "*to replace assets based on established asset management principles and strategies adopted by the Company, which are designed to optimize the overall lifecycle value of the investment for our customers.*"[34] The Company's

[34] Exhibit No. 1, Schedule 2, page 30.

Transmission System Asset Management Plan (Exhibit No. 8, Schedule 4) recommends a 30-year replacement period for transmission assets, which requires an investment of $21.1 million per year, split $11.3 million for 115 kV facilities and $9.8 million for 230 kV facilities. Current spending on the replacement of transmission facilities due to asset condition is just under $10 million per year, meaning the Company is currently on a funding level track that will require some transmission assets to operate reliably at an age beyond 60 years.

Q. Please discuss the Customer Requested driver as it relates to transmission investment.

A. These projects are triggered by "*customer requests for new service connections, line extensions, transmission interconnections, or system reinforcements to serve a customer.*"[35] In some cases the Company must construct a distribution substation with an associated transmission line extension in order to meet the requested new load requirements of an industrial or large commercial customer. Other situations may involve a requested transmission interconnection with a neighboring utility or generation project.

[35] Exhibit No. 1, Schedule 2, page 18.

Q. Please discuss the Failed Plant and Operations driver as it relates to transmission investment.

A. Transmission investments in this category are primarily the result of storm damage to the Company's transmission system, including damage caused by major wind events, lightning, fire, and snow and ice.

Q. Please discuss the Mandatory and Compliance Requirements driver as it relates to transmission investment.

A. These investments in transmission infrastructure are primarily driven by North American Electric Reliability Corporation (NERC) standards, which are nationwide requirements for utilities to ensure the reliability of the interconnected transmission grid. Compliance with these standards became mandatory under federal law in 2007, and failure to comply may result in monetary penalties of up to $1 million per day, per infraction. These standards focus mainly on transmission planning, operation, and equipment maintenance. The standards require utilities to plan and operate their systems to avoid customer outages and to prevent adverse impacts to neighboring utility systems arising from the loss of transmission service. Specifically, the transmission system must be designed so that the simultaneous loss of up to two facilities will not impact the interconnected transmission system. Further, the loss of any single facility must not cause any other facility in service to exceed its System Operating Limit (voltage or capacity ratings) [36] or cause the interconnected transmission grid to operate outside specified reliability limits (voltage and stability limits). This includes circumstances where transmission facilities suffer an outage event, or are purposefully removed from service for maintenance and construction work. Finally, the transmission operator must determine in advance whether any single outage will result in a violation of a System Operating Limit, and to mitigate for that occurrence in advance, prior to such contingency occurring. This means the system must be designed to automatically adjust to a reliable state or system operators must take proactive action to mitigate the expected impacts of a potential contingency. Such mitigation efforts may include system configuration changes, generation changes, or the controlled removal of firm load from the transmission system. As a result, Avista must ensure that its system can be operated reliably during a variety of operational, seasonal and other scenarios.

[36] Facilities refer to transmission lines, sections of lines and transmission equipment in substations.

Other federal rules that could require the construction of new transmission facilities include Avista's compliance with its Open Access Transmission Tariff, which can require the Company to construct new facilities at the request of its transmission system customers.

Q. Would you please describe the recent change in the NERC transmission planning standards and explain the possible impact on the Company's investments in transmission and other infrastructure?

A. Yes. In 2013, FERC mandated utility compliance with Requirement R2 of the NERC transmission planning standard TPL-001-4, effective January 1, 2016. This requirement underscores FERC's intent that disconnecting customers <u>not</u> directly connected to a transmission facility that experiences a planned or unplanned outage cannot be generally relied upon to ensure the planned reliability of the transmission system. The Company is now required to make transmission investments to meet this standard or, if it is unable to do so due to circumstances beyond its control, must initiate a broad public stakeholder process explaining how it would rely on the option of disconnecting customers to meet transmission reliability, which plans would be subject to Commission review. The Company believes that relying upon disconnecting customers to meet reliability standards does not meet our customer service or reliability objectives. Consequently, the Company is planning for new transmission investments over the next several years that will allow it to comply with the transmission planning standard. These investments will likely trigger the need to re-prioritize other infrastructure projects during this planning period, resulting in the possible deferral of other priority investment needs.

Q. Please discuss the Performance and Capacity driver as it relates to transmission investment.

A. Just as with distribution facilities, transmission investments driven by Performance and Capacity are "*a range of investments that address the capability of assets to meet defined performance standards, typically developed by the Company, or to maintain or enhance the performance level of assets based on need or financial analysis.*"[37] When the load-carrying capacity of electric facilities is exceeded for any extended period of time it can stress and damage equipment, and lead to equipment failures that result in customer outages. Furthermore, in the case of substation and transmission facilities, the Company must plan for sufficient capacity in the system to accommodate a planned or forced outage to any one

[37] Exhibit No. 1, Schedule 2, page 27.

system component without customers having to experience an extensive outage. For example, to take a substation out of service for necessary maintenance, the Company must plan for sufficient capacity in its neighboring substations so that all lines serving customers from the substation to be taken out of service can be transferred to neighboring substations before the maintenance outage occurs. Other investments, like Supervisory Control and Data Acquisition (SCADA) systems, enable those who operate the Company's transmission system to effectively monitor and control the system to ensure proper system performance.

Q. How do Avista's Transmission Planning, System Operations and Engineering business units evaluate and prioritize proposed transmission projects before they are submitted to the Company's capital planning group?

A. These transmission projects are initiated through planning studies, engineering and asset management analyses, and scheduled upgrades or replacements identified in our operations districts. Projects developed through transmission planning studies undergo internal review by multiple stakeholders who help ensure all system needs and alternatives have been identified and addressed.

In addition to this traditional review, the Company recently implemented a new formal review process referred to as the "Engineering Roundtable." The objective of this process is to provide added structure and increased transparency of the review process for both internal and external stakeholders, for development of *all* proposed transmission projects whether large specific projects or smaller, program-related proposals. Through this review all substation and transmission projects are reviewed, evaluated, returned for additional analysis as needed, and finally prioritized.

Representatives from ten business units participate in this process, which include transmission planning, distribution planning, transmission design, substation design, system protection, distribution design, system operations, asset management, communications engineering, and transmission services groups. Each business unit proposing a project is required to explain the problem that needs to be addressed, the alternatives considered, and to provide the justification for the approach recommended. During the review, the potential benefits of any cross-business unit synergies that could better optimize project benefits and scope are also identified and evaluated.

Q. Please list the transmission infrastructure investments planned by the Company and briefly describe each project by investment driver.

A. The Company's planned transmission investments are listed on a system basis in Table No. 2, below, organized by investment driver. These projects are briefly described following the table.

Table No. 2

Transmission Capital Projects (System) In $(000's)			
Business Case Name	**2017**	**2018**	**2019**
Asset Condition			
SCADA - SOO & BUCC	$ 1,270	$ 920	$ 1,013
Substation - Station Rebuilds	17,524	7,867	15,800
Transmission Minor Rebuild	5,132	1,843	1,908
Transmission Major Rebuild - Asset Condition	9,536	12,025	11,000
Customer Requested			
Growth - Hallet and White	1,458	1,409	
Failed Plant and Operations			
Electric Storms	3,183	3,278	3,377
Mandatory and Compliance			
Colstrip Transmission	325	449	391
Environmental Compliance	72	50	50
Garden Springs 230/115kV Station Integration	56		725
Noxon Switchyard Rebuild	2,504		
S Region Voltage Control	5,733		
Saddle Mountain 230/115kV Station Integration		1,500	14,500
Spokane Valley Transmission Reinforcement	374	7,750	
Transmission - NERC Low Priority Mitigation	2,014	1,500	1,500
Transmission - NERC Medium Priority Mitigation	2,000		
Transmission Construction - Compliance	15,309	13,159	13,000
Tribal Permits and Settlements	621	250	150
Westside 230/115kV Station Rebuild	5,566		
Performance and Capacity			
SCADA Build-Out Program		2,500	6,000
Substation - Capital Spares	4,204	5,065	4,025
Substation - New Distribution Stations	2,424	850	6,375
Total Planned Transmission Capital Projects	**$ 79,303**	**$ 60,416**	**$ 79,814**

Asset Condition

SCADA – SOO & BUCC - 2017: $ 1,270,000; 2018: $920,000; 2019: $1,013,000

This program replaces and/or upgrades existing electric and natural gas control center (System Operations Center and Backup 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. Included are hardware, software, and operating system upgrades, as well as deployment of capabilities to meet new operational standards and requirements. Some system upgrades are initiated by other requirements, including NERC reliability standards, growth, and new projects (e.g. Smart Grid). Examples of upgrades to be completed under this program are Critical Infrastructure Protection version 5 (NERC standards requirement), Gas Control Room Management (PHMSA requirement), PEAK Reliability Coordinator Advanced Applications, and Technology Refresh (network and storage). The failure to make these investments in the timeframe planned will result in the Company losing information connectivity with its transmission system and to be in violation of NERC transmission planning standards, and subject to financial and other penalties.

Substation – Station Rebuilds - 2017: $17,524,000; 2018: $7,867,000; 2019: $15,800,000

This program replaces and/or rebuilds existing substations as they reach the end of their useful lives or where installed equipment that fails or is being replaced for capacity needs cannot be accommodated within the physical constraints of the small, older stations. Included are wood substation rebuilds as well as upgrading stations to current design and construction standards. The failure to timely replace and rebuild end of life equipment in these substations will expose the Company to the risk of more frequent and long duration outages that have a significant impact on our customers. Examples of substation rebuilds to be completed under this program in the next five years are Kamiah (wood substation), Ford (end of service life), 9th & Central, Priest River and Colville. This investment includes associated O&M offsets of $44,884 (System-basis) beginning in 2017. Ms. Andrews has included Idaho’s share of these offsets within the Company’s requested revenue requirement.

Transmission Minor Rebuild - 2017: $5,132,000; 2018: $1,843,000; 2019: $1,908,000

This project covers transmission structure (ER 2057) and air switch (ER 2254) replacements based upon the results of the Company's annual Wood Pole and Aerial Patrol inspection programs, and field operations. Both the Wood Pole and Aerial Patrol inspection programs are undertaken to maintain compliance with NERC Standard FAC-501-WECC-1. Failing to make the necessary replacements identified by the Company's inspection programs increases the risk of transmission system outages and the potential to ignite fires in dry areas. Air switch replacements are made based either on condition, capacity, or functionality issues. Prioritization of installations and replacements are made from information provided by System Operations, Substation Engineering or the Company's regional operations centers. Failing to make the necessary replacements identified by the Company's inspection programs risks placing Avista in violation of NERC standards, and will increase the risk of transmission system outages and the potential to ignite fires in dry areas.

Transmission Major Rebuild - Asset Condition – 2017: $9,536,000; 2018: $12,025,000; 2019: $11,000,000

Projects in this program rebuild existing transmission lines based on overall asset condition (at the end of their useful life). The failure to timely replace aging transmission infrastructure on a planned basis will subject our customers to the increased risk of service outages and increased restoration costs as we become less able to continue providing our current level of reliability. In addition to customer outages, the added risk of failure also impacts the economic dispatch of our Company's generation resources and increases the risk of fire in dry areas. Finally, the failure to properly invest builds a "bow-wave" of needed investments to the future, which makes it more difficult to fund these projects in addition to our already-planned priority infrastructure needs. Projects include: ER 2550 – Burke-Thompson A&B 115kV Transmission Line rebuild; ER 2604 – Lind-Warden 115kV Transmission Line rebuild; ER 2577 – Benewah-Moscow 230kV Transmission Line structure replacement; ER 2597 – Cabinet-Noxon 230kV Transmission Line rebuild; and ER 2596 – Lolo-Oxbow 230kV Transmission Line rebuild.

Customer Requested

Growth - Hallett and White Substation - 2017: $1,458,000; 2018: $1,409,000

An existing large retail customer is expecting to double its load over the next 7-10 years beginning in 2018. Additionally, a wholesale network transmission customer (Inland Power & Light) has requested an interconnection at the Hallett & White Substation. These requests together require an increase in substation transformer capacity and additional feeders. This project will rebuild the Hallett & White 115/13kV Substation with two 30MVA transformers and six feeder bays, with one feeder dedicated to Inland Power & Light, two feeders dedicated to the Company's large retail customer, and the remaining feeders available to provide service to the Company's local distribution system. Failure to construct this project will result in the inability to serve the requested load of the large retail customer, and the failure of the Company to provide the required interconnection and low-voltage wheeling service under FERC jurisdiction for its wholesale transmission customer.

Failed Plant and Operations Projects:

Electric Storms - 2017: $3,183,000; 2018: $3,278,000; 2019: $3,377,000

This ongoing program provides for the timely restoration of the Company's transmission, substation and distribution facilities into serviceable condition during or following major weather-related or other natural events including high winds, heavy ice and snow loads, lightning storms, flooding and wildfires.

Mandatory and Compliance Investments

Colstrip Transmission - 2017: $325,000; 2018: $449,000; 2019: $391,000

As a joint owner of the Colstrip Transmission System, Avista is obligated to pay its commensurate ownership share of all capital improvements. NorthWestern Energy, the designated Transmission Operator of the Colstrip Transmission System under the Colstrip Transmission Agreement, implements the capital program for purposes of maintaining reliable operation and complying with applicable reliability standards for the jointly owned facilities. Avista's failure to pay its share of these investments would place us in violation of the ownership agreement and subject us to the legal recourse provided for in the agreement.

Environmental Compliance - 2017: $ 72,000; 2018: $50,000; 2019: $50,000

This project covers the implementation of required Forest Service Special Use Permits (SUP), Waste Oil Disposal, including polychlorinated biphenyls (PCBs), and Environmental Compliance requirements related to storm water management, water quality protection, property cleanup and related issues. The failure to make these investments would place the Company in violation of mandatory environmental compliance requirements and the federal and tribal permits that grant us authority to use lands for transmission facilities.

Garden Springs 230/115kV Substation - 2017: $56,000; 2019: $725,000

Due to a lack of redundancy and capacity with the existing system, the west Spokane area is unable to meet the applicable NERC transmission planning standards. The project consists of a new 230kV point of interconnection with BPA at a new station to be constructed on the Coulee-Westside 230kV Line and the Garden Springs 230/115kV Substation. The project will mitigate the identified system deficiencies and provide additional transformation capacity in the area. If this project, or a less-than-optimum alternative project that allows us to meet the standard, is not constructed in the timeframe planned, then the Company will be in violation of NERC transmission planning standards and will be subject to the associated penalties. In addition to violating the planning standard, Avista will also risk having to shed load (instantaneous disconnecting of customers from the system) to maintain compliance with NERC transmission operating standards in the long-range planning horizon. The Company's Engineering Roundtable evaluation and prioritization process has deferred the implementation of the 230kV portion of this project, pending completion of the Westside 230/115kV Substation rebuild project, in an effort to balance our overall investment demands, and is considering other possible alternatives to avoid any NERC transmission planning standard violations.

Noxon Switchyard Rebuild - 2017: $2,504,000

Today, Avista's Noxon Rapids 230kV Switching Station is subject to a potential fault current of approximately 14,000 amps, which exceeds the 12,500 amp capability of six 230kV circuit breakers in the station. This potential is not only an immediate safety issue, but it also exposes the Company to a violation of NERC standards. Additionally, the existing station is at the end of its useful life based on age and condition of the equipment in the station. The existing bus has suffered a number of failures and is now configured as a single bus with a bus tie breaker separating the East and West buses. The station is the point of integration for the Noxon Rapids Hydroelectric development as well as a principle point of interconnection between Avista and BPA, providing a key point of integration for the Western Montana Hydro Complex and the Company's interconnection with NorthWestern Energy in Montana. The current bus configuration requires Avista to curtail its own hydro generation for unplanned outages of substation equipment to complete work in the station. The reconstructed Noxon Rapids 230kV Switching Station will have a double-breaker double-bus configuration to facilitate required maintenance activities without impacting local generation levels or transfer loads to or from Montana. The Company's Engineering Roundtable process has resulted in the deferral of the broader station rebuild project and focused on the immediate replacement of the over-dutied circuit breakers. This is not only an immediate safety issue, but our failure to make the investments may result in the Company having to curtail its own hydroelectric generation and further exposes the Company to a violation of mandatory NERC planning standards.

South Region Voltage Control - 2017: $5,733,000

Avista's south region 230kV system, primarily in the Lewiston-Clarkston area, experiences excessively high voltage, where voltage exceeds equipment ratings over 35% of the time. Operation of equipment outside of manufacturer's ratings introduces safety risks to Company operations and employees, and it increases the possibility of equipment failure and associated large scale outages. If the Company does not implement this project in the timeframe planned, then we may be forced to remove our 230kV lines from service (which is not possible to do) in order to maintain compliance with NERC transmission operating standards. This project includes the installation of two 50MVar shunt reactors on the 230kV bus at North Lewiston. With automatic control, overvoltages can be reduced, if not eliminated, on the 230kV buses at Dry Creek, Lolo, North Lewiston, Moscow and Shawnee.

Saddle Mountain 230/115kV Station Integration - 2018: $1,500,000; 2019: $14,500,000

This project is the result of a joint regional transmission planning study team under ColumbiaGrid and resolves a number of NERC transmission planning standard violations in the Grant County PUD transmission system that are exacerbated by the

Company’s load in the Othello area. Apart from the Grant County PUD system, the Company’s Othello area load is supported by only a single 115kV transmission line connection to the Bonneville Power Administration. If Avista does not complete this project in the timeframe planned, then the Company will be subject to possible litigation before the FERC for failing to timely complete a project that has been specified by the sub-regional transmission planning process under the Company’s Open Access Transmission Tariff (OATT). The 230kV portion of the Saddle Mountain 230/115kV Substation is also required to integrate a proposed 126 MW wind generation project in the Othello area.

Spokane Valley Transmission Reinforcement - 2017: $374,000; 2018: $7,750,000

Portions of the Spokane Valley Transmission Reinforcement Project already completed include construction of the Opportunity Substation and Irvin-Millwood 115kV Transmission Line. Currently planned projects include rebuilding the Beacon-Boulder #2 115kV Transmission Line and construction of the Irvin 115kV Switching Station. This project must be completed to mitigate our currently-existing failure to meet NERC transmission planning standards, and to avoid future transmission system reliability issues in the Spokane Valley.

Transmission – NERC Low Priority Mitigation - 2017: $2,014,000; 2018: $1,500,000; 2019: $1,500,000

This program was initiated in response to NERC’s October 7, 2010 NERC Alert Recommendation to the Industry, titled “Consideration of Actual Field Conditions in Determination of Facility Ratings.” It addresses mitigation required on Avista's “Low Risk” 115kV transmission lines, and brings these lines into compliance with National Electric Safety Code (NESC) minimum clearance values. This program reconfigures insulator attachments, rebuilds existing transmission line structures, or removes earth from beneath transmission lines to mitigate ratings/sag discrepancies found between facility designs and actual field conditions. If the Company were to fail to make these investments we would fail to meet the NERC-required facility ratings for the safe and reliable operation of these lines.

Transmission – NERC Medium Priority Mitigation - 2017: $2,000,000

This program was initiated in response to NERC’s October 7, 2010 NERC Alert Recommendation to the Industry, titled

"Consideration of Actual Field Conditions in Determination of Facility Ratings." It addresses mitigation required on Avista's "Medium Risk" 230kV and 115kV transmission lines, and brings these lines into compliance with National Electric Safety Code (NESC) minimum clearance values. This program reconfigures insulator attachments, rebuilds existing transmission line structures, or removes earth from beneath transmission lines to mitigate ratings/sag discrepancies found between facility designs and actual field conditions. If the Company were to fail to make these investments we would fail to meet the NERC-required facility ratings for the safe and reliable operation of these lines.

Transmission Construction – Compliance - 2017: $15,309,000; 2018: $13,159,000; 2019: $13,000,000

This program reconductors and rebuilds existing transmission lines to maintain compliance with NERC transmission planning standards. Investments mitigate NERC transmission planning standard (TPL-001-4) deficiencies that have already been identified for both our current system and for the Near Term transmission planning horizon (1-5 years). Failure to make these planned investments will result in our failure to comply with mandatory NERC standards. Projects include: ER 2557 – 9th & Central-Sunset 115kV Transmission Line reconductor and rebuild; ER 2576 – Addy-Devils Gap 115kV Transmission Line reconductor and rebuild; ER 2457 – Benton-Othello 115kV Transmission Line reconductor and rebuild; ER 2556 – CDA-Pine Creek 115kV Transmission Line reconductor and rebuild; ER 2564 – Devils Gap-Lind 115kV Transmission Line reconductor and rebuild; and ER 2310 West Plains transmission reinforcement. Required construction on ER 2578, the Hatwai-Lolo #2 230kV Transmission Line has been deferred by the Company's Engineering Roundtable to accommodate the other priority investment demands.

Tribal Permits and Settlements - 2017: $621,000; 2018: $250,000; 2019: $150,000

The Company currently owns and operates approximately 82 miles of transmission facilities and a significantly greater amount of distribution facilities on Tribal lands. The failure to complete this work and to attain proper permitting or easement rights on Tribal lands would require the Company to relocate its facilities. This would be cost-prohibitive for its transmission facilities and not viable for distribution facilities considering the Company's obligation to serve its retail customers. Current renewals are being negotiated for terms of from 30 to 50 years. Renewal costs include labor, appraisals, field work, legal review, GIS information, negotiations, survey (as needed), and applicable fees for easements and permits.

Westside 230/115kV Substation Rebuild - 2017: $5,566,000
This project is necessary to mitigate our current noncompliance with mandatory NERC transmission planning standards during heavy summer loading conditions. Failure to make these planned investments will result in our failure to comply with mandatory NERC standards. We will continue to overload the Westside #1 230/115kV transformer during Phase I of this project, which overloading will extend to the existing Westside Substation 115kV and 230kV buses, to allow for installation of a new 250MVA 230/115kV Autotransformer. The additional transformation capacity is necessary to eliminate transformer overload contingencies in the Spokane area. This project has two additional planned phases to complete the entire rebuild of the station. The Company's Engineering Roundtable has deferred the Garden Springs 230/115kV Substation integration due to the timing of the planned completion of this project.

Performance and Capacity Investments

SCADA Build-Out Program - 2018: $2,500,000; 2019: $6,000,000
In order to provide the Company's System Operations group with the necessary Supervisory Control and Data Acquisition (SCADA) capability for reliable system operation, this project will complete the installations of SCADA and EMS/DMS (Energy Management System/Distribution Management System) capability to all Avista substations. This capability will provide full visibility of system conditions and operations, system status indication, and operator control at each substation. The communication infrastructure for SCADA will enable the installation of automation on applicable distribution feeders. Furthermore, SCADA capability to each substation will provide real time and historical system performance data to the Transmission System Planning, Asset Management, Operations and Engineering groups to enable efficient, flexible and safe design and operation the Company's transmission and distribution systems in the future. The failure to make these investments in the timeframe planned will result in the Company losing information connectivity with its transmission system and risk being in violation of NERC transmission planning standards, and subject to financial and other penalties.

Substation – Capital Spares - 2017: $4,204,000; 2018: $5,065,000; 2019: $4,025,000

This program maintains our fleet of power transformers and high voltage circuit breakers, which have very long procurement lead times. Consequently, a sufficient inventory level needs to be maintained to ensure the Company has required equipment for construction projects and can quickly replace failed critical equipment. This critical equipment is capitalized upon receipt and placed in service for both planned and emergency installations as required. Annual program expenditures may vary significantly in years when a 230/115kV autotransformer is purchased.

Substation – New Distribution Stations - 2017: $2,424,000; 2018: $850,000; 2019: $6,375,000

This program adds new distribution substations to the system in order to serve new and growing load as well as to provide increased system reliability and operational flexibility. New substations under this program require planning and operational studies, justifications, and approved project diagrams prior to funding. Planned new projects include substation sites in the Pullman/Moscow stateline area, as well as downtown Spokane, the Spokane west plains area, and north Spokane. The failure to complete these projects in this planning horizon will result in equipment overloading and reliability issues, which are impossible to quickly rectify once they occur.

Q. Please provide some examples of Transmission Capital projects that were not approved, and the risk associated with not completing or deferring these projects.

A. The Hatwai-Lolo #2 230kV Transmission Line construction project, required to comply with NERC transmission planning standards, has been deferred in order to balance the overall demand for investment across the Company. The Company's engineers continue to evaluate short-range operational solutions to mitigate transmission system deficiencies in the southern portion of the Company's transmission system. Until this project can be completed, for certain outages the Company will continue to have to disconnect its transmission interconnection with Idaho Power and reconfigure major portions of its southern system, leaving the majority of the Company's customers in this area exposed to additional outages.

V. NATURAL GAS SYSTEM INVESTMENTS

Q. What needs are driving the Company's planned investments in natural gas distribution infrastructure for the period 2017 - 2019.

A. There are many drivers, including the removal of capacity limitations, we have identified on our natural gas system that could prevent us from meeting our customers' needs during periods of very cold weather. Avista is required to meet a range of mandatory requirements that aim to ensure the integrity of our natural gas system. It is Avista's goal, along with these requirements, to make sure we deliver cost-effective energy services to our customers in a manner that protects their health and safety, as well as that of our employees and the general public. Finally, we face the continuous need to replace materials and equipment that have reached the end of their useful life, based on asset condition; to protect our system from damage by other parties, and respond to the infrastructure plans of municipalities and others that can require us to relocate portions of our natural gas system. The need for our natural gas system investments is organized by investment driver and is briefly explained for each project and program in the following narrative.

Q. How do the business units in Avista's natural gas operations identify the need for and prioritize requests for infrastructure investment?

A. The need for investment is identified in a number of ways, including but not limited to, 1) by our field personnel; 2) from needs identified through our systematic maintenance of the system; 3) by our natural gas engineering group using the SynerGEE® computer-based modeling tool to evaluate current and future customer loads and our system capacity to meet them; 4) from asset management analysis of specific issues; and 5) through our plans to remediate threats to our system identified by Avista's Distribution Integrity Management Planning (DIMP) process. The integrity management plan processes follow a rigorous federal protocol for identifying and ranking any risks or threats that, over time, could impair the integrity of our natural gas system. Avista is then required to develop action plans that reduce or eliminate these threats. Implementation of these plans is mandatory. Our natural gas engineering group serves as the clearing house for evaluating and prioritizing these investment needs, including which projects are forwarded to the Company's Capital Planning Group. Our engineers assess the range of needs to be met by each individual project, the potential consequences of deferring or reducing the amount of the proposed investment, and ranks all proposed projects across the Company's entire natural gas system by overall priority of need, with some deference to the geographical locations of the projects.

Q. Please list the natural gas distribution investments planned for the near-term, and provide a brief description of each project or program?

A. Table No. 3 below lists Avista's planned natural gas distribution projects by investment driver on a system basis for the years 2017-2019. In the narrative that follows I briefly describe each project or program, explaining why we are implementing the project, as well as the likely consequence to Avista of our failure to make these investments in the timeframe proposed.

Table No. 3

Natural Gas Distribution Capital Projects (System) In $(000's)			
Business Case Name	**2017**	**2018**	**2019**
Asset Condition			
Gas Deteriorated Steel Pipe Replacement Program	$ 1,001	$ 1,000	$ 1,000
Gas ERT Replacement Program	240	260	280
Gas Regulator Stn Replacement Program	1,376	800	800
Customer Requested			
New Revenue - Growth	23,099	22,239	22,941
Failed Plant and Operations			
Gas Non-Revenue Program	6,096	6,000	6,000
Mandatory and Compliance			
Gas Cathodic Protection Program	900	700	700
Gas Facilities Replacement Program (Aldyl A)	21,764	20,700	21,160
Gas HP Pipeline Remediation Program	5,275	2,925	3,013
Gas Isolated Steel Replacement Program	2,050	2,000	2,000
Gas Overbuilt Pipe Replacement Program	500	500	500
Gas PMC Program	1,200	1,200	1,200
Gas Replacement Street and Highway Program	3,319	3,000	3,000
Performance and Capacity			
Gas Reinforcement Program	1,000	1,000	1,000
Gas Telemetry Program	209	200	200
Gas Schweitzer Mtn Rd HP Reinforcement		1,500	
Gas Rathdrum Prairie HP Main Reinforcement Project	4,426	4,000	
Subtotal: Natural Gas Distribution Capital Projects	**$ 72,456**	**$ 68,024**	**$ 63,793**
Washington and Oregon Direct Business Cases (1)			
Gas N-S Corridor Greene St HP Main Project	113		
Gas N Spokane Hwy 2 HP Main Reinforcement Project	342		
Gas Pierce Rd La Grande HP Reinforcement	3,901		
Gas Warden HP Reinforcement			6,000
Cheney HP Reinforcement			5,000
	4,356		**11,000**
Total Planned Natural Gas Distribution Capital Projects	**$ 76,811**	**$ 68,024**	**$ 74,793**

(1) Excluded from revenue requirement in this case.

Asset Condition

Gas Deteriorated Steel Pipe Replacement Program - 2017: $1,001,000; 2018: $1,000,000; 2019: $1,000,000

Existing steel natural gas piping in the Company's distribution system is aging and showing signs of deterioration, even when properly maintained, and it presents an increased risk of failure in the event it has been subject to corrosion. Sections of gas main with known corrosion-related issues need to be removed to avoid failure that could impact safety and reliability. Avista's distribution integrity management program has identified this pipe material as a threat that needs to be removed from the Company's natural gas distribution system. If the Company fails to make the investments needed to remove this deteriorated piping we would be exposing our customers and the general public to elevated risk and safety concerns where pipe is located in the vicinity of high risk facilities, in particular, where we have leak potential and corrosion issues.

Gas ERT Replacement Program - 2017: $240,000; 2018: $260,000; 2019: $280,000

The majority of the Company's natural gas meters are equipped with an electronic device that records the amount of natural gas used by the customer and wirelessly transmits that usage to Avista for billing purposes. This device known as an Encoder Receiver Transmitter (ERT) is battery powered, and when these batteries fail, customers' estimated usage must be collected and entered into the billing system manually. Besides the additional cost, this manual process can lead to high rates of customer dissatisfaction because of potential error associated with estimating the customers' bill. Finally, because the Company has so many of these units in service, the replacement of batteries as they failed would quickly become unmanageable as the entire population of batteries reach the end of their useful life. The failure to make these planned investments would eventually have an unsustainable impact on Avista's natural gas billing system and would result in substantially greater costs for replacement compared with the systematic approach.

Gas Regulator Station Replacement Program - 2017: $1,376,000; 2018: $800,000; 2019: $800,000

Investments made under this program replace or upgrade Avista's natural gas regulator stations and industrial meter sets that are at the end of their service life, or are obsolete and no longer supported, based on the Company's performance standards. Avista's regulator stations require federally-mandated annual maintenance, and if the equipment at the stations is obsolete and replacement/maintenance parts are no longer commercially available, then proper maintenance cannot be completed. These investments also enhance the performance of our stations, improving natural gas system safety, reliability and operations. The failure to timely inspect our regulators and industrial meter sets, and to perform required maintenance and replacements, would render them less reliable and unsafe, and would expose the Company to regulatory and other consequences as a result of choosing to not make such investments.

Customer Requested

New Revenue – Growth - 2017: $23,099,000; 2018: $22,239,000; 2019: $22,941,000

This annual program addresses costs to serve new loads for natural gas service. This program includes the cost of new meters, new natural gas piping, the cost of new regulators, the cost of new encoder receiver transmitters (ERTs), and the associated installation cost of these investments. Avista is required by its service tariffs to make the investments necessary to connect customers when requested.

Failed Plant and Operations

Gas Non-Revenue Program - 2017: $6,096,000; 2018: $6,000,000; 2019: $6,000,000

The investments made under this program are responsive to issues identified by the Company in real time, which is why the expected capital spend each year is estimated based on historical trends. Typical activities include increasing the depth of existing gas lines that are identified as not meeting the required depth,[38] performing customer-requested relocates, making leak repairs on mains and service lines, installing meter barricades, eliminating farm taps from the system, and relocating facilities as required (other than street and highway). Our failure to regularly perform these activities would result in a greater likelihood of our shallow pipe being damaged, which could result in increased general public, customer, and/or employee safety risks, and prevent us from prudently managing our natural gas system.

Mandatory and Compliance

Gas Cathodic Protection Program - 2017: $900,000; 2018: $700,000; 2019: $700,000

Cathodic protection involves making in-ground metal structures like steel pipelines part of a DC electrical circuit that prevents them from corroding. Avista is required by federal and state regulations to have effective cathodic protection systems on all steel natural gas piping in its system. Since these

[38] This situation most often occurs because soil above the line has been removed by other activities in the time after the line was installed.

systems have a finite lifespan, and must be replaced when they are nearing the end of their service life. Failing to timely replace them renders the underground steel lines vulnerable to corrosion. This failure would also expose the general public, our customers, and our employees to increased safety risks and would place the Company in violation of mandatory regulations.

Gas Facilities Replacement Program (Aldyl A) - 2017: $21,764,000; 2018: $20,700,000; 2019: $21,160,000

The Company is continuing its 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 Idaho, Washington, and Oregon. Avista's asset management group identified this piping as prone to the increased potential of leaking as it ages, and based on the risks to our customers resulting from these leaks, Avista implemented its Priority Aldyl A Pipe replacement program. In addition to the Company's own analysis, this piping has also been identified as the highest threat to the integrity of Avista's natural gas system. Renamed the Gas Facilities Replacement Program, this effort fulfills the Company's obligation to mitigate such threats on its natural gas system.

Gas High Pressure Pipeline Remediation Program - 2017: $5,275,000; 2018: $2,925,000; 2019: $3,013,000

Current industry practice and pipeline safety codes require natural gas distribution systems to be pressure tested, and the documentation of this testing and the material specifications of the pipelines to be properly maintained. Avista has identified deficiencies in its records resulting from practices generally prior to development of the code and current standards. This is not uncommon in our industry. A new rule in the Federal Pipeline Safety Code, making this testing and documentation mandatory and subject to penalties for non-compliance, will soon become final and effective. This program will perform the work required to develop traceable, verifiable, and complete pressure testing records for all segments of our high pressure pipeline where the records do not currently exist. Failure to make these required investments will expose the Company to penalties for non-compliance with this mandatory requirement.

Gas Isolated Steel Replacement Program - 2017: $2,050,000; 2018: $2,000,000; 2019: $2,000,000

The program identifies and documents areas in our natural gas system where we currently have steel pipe sections, including risers that are “isolated” from steel piping in cathodically-protected zones. The Company is required by Federal code to remediate or replace each cathodically-isolated riser or pipeline section once it has been identified. Avista operates this program in each of its Idaho, Washington, and Oregon service territories. Our failure to make these required investments puts the Company at risk of being in violation of cathodic protection requirements.

Gas Overbuilt Pipe Replacement Program - 2017: $500,000; 2018: $500,000; 2019: $500,000

There are instances where our customers have constructed or placed structures, sheds and decks, etc., directly over sections of our natural gas distribution system. As a result of these “overbuilds” the Company may not have adequate access to operate, repair and safely maintain our system (such as conducting the annual leak survey of our system). Avista is required by Federal code to remediate these overbuilds. This program is focused mainly on identifying and addressing these issues in mobile home parks where we experience the highest incidence rates and risks. Avista’s failure to make these planned investments will expose our customers to risks associated with our inability to access our system, and will place the Company in violation of its mandatory federal requirements, and potential penalties.

Gas Planned Meter Change-Out (PMC) Program - 2017: $1,200,000; 2018: $1,200,000; 2019: $1,200,000

Avista is required by Commission rules and tariffs to test a portion of our meters each year for accuracy to ensure proper metering performance. The costs included under this program include labor and minor materials. Major materials (meters, pressure regulators and encoder receiver transmitters) are charged to the appropriate capital programs. Our failure to make these investments would increase the likelihood that our customers’ billing would be inaccurate and would place the Company in violation of its tariffs, with the attendant consequences of non-compliance.

Gas Replacement Street and Highway Program - 2017: $3,319,000; 2018: $3,000,000; 2019: $3,000,000

Nearly all of Avista’s distribution pipelines are located in public utility easements provided for such service, which are under the control of local jurisdictions administered through the Company’s franchise agreements. Avista is mandated under these agreements to relocate its facilities, at our cost whenever local jurisdictional projects require such a move. While Avista has the opportunity to discuss these requirements and to suggest ways to avoid or minimize the cost to our customers, we have no choice but to move our facilities if required. Our failure to make such required investments would put the Company in violation of its franchise agreements, could subject us to penalties for the delay of a project, legal action, or the revocation of our franchise to provide utility service in that jurisdiction.

Performance and Capacity Investments

Gas Reinforcement Program - 2017: $1,000,000; 2018: $1,000,000; 2019: $1,000,000

This ongoing program supports investments for smaller projects needed to reinforce the capacity of our natural gas distribution system in all our jurisdictions. Our failure to make these investments would expose our customers to the loss of their natural gas service on a design day, and would prevent Avista from meeting future load growth due to inadequate pressure and capacity.

Gas Telemetry Program - 2017: $209,000; 2018: $200,000; 2019: $200,000

Projects under this program install natural gas telemetry throughout our natural gas system. Telemetry is the combination of communications and sensing systems that allow Avista to remotely monitor system pressures, volumes, and flows from areas of special interest such as Gate Stations (supply points into Avista’s system), gas transportation customers, regulator stations (where operating pressure is reduced), certain large industrial customers, and distribution systems that are served by more than one source of natural gas. Having this detailed “visibility” of the gas transmission and distribution systems provides a more rapid response and better decision making by the Company when any abnormal operation or emergency situation occurs. The failure to timely make these investments would reduce the reliability of our system for customers resulting from low or high pressure situations, and the related safety risks, and a higher likelihood of equipment failures that impact our service.

Gas Schweitzer Mtn Rd High Pressure (HP) Reinforcement[39] – 2018: $1,500,000

The Sandpoint Idaho area has exceeded the capacity of the existing gas distribution system. This area has insufficient capacity to serve firm customers on a design day. Therefore, a cold weather action plan has been developed. This plan outlines particular activities that could be implemented such as the manual on-sight monitoring of system pressures, a media blast to request a temporary thermostat turndown, taking extraordinary measures to manually improve the capacity of the system by bypassing regulator stations or manually shedding load (shutting off customers completely), and/or preparing relight lists (to restore service to customers who have lost gas service). Without this reinforcement project, Avista will not have sufficient capacity to serve firm customer load in the Sandpoint area on a design day scenario.

Gas Rathdrum Prairie High Pressure (HP) Main Reinforcement Project – 2017: $4,426,000; 2018: $4,000,000

This multi-year project is composed of a two phase high pressure distribution pipeline reinforcement that will shift gas usage from Williams Northwest Pipeline (NWP) to Gas Transmission Northwest (GTN). This project will also allow Avista to choose a portion of gas nominations from either NWP or GTN, to take advantage of price differentials. This additional capacity will be used to support customer growth in the Post Falls, ID and Coeur d'Alene, ID areas currently served from NWP. Phase one and phase two both consist of installing approximately three miles of 6” high pressure distribution pipeline and two Regulator Stations (pressure reduction stations) within Avista’s system, with phase one scheduled to be constructed in 2017 and phase two constructed in 2018. Load growth on the NWP Coeur d'Alene Lateral pipeline has exceeded both Avista's contractual delivery amounts as well as the physical capacity of the NWP Coeur d’Alene Lateral pipeline. In addition, the distribution system in the Hayden Lake, Idaho area will experience insufficient pressure during periods of peak demand on a design day. Sufficient capacity is defined as pressures at or above 15 pounds per square inch (psig) in the distribution system on a design day analysis. Without a reinforcement project, Avista will not have sufficient capacity to serve Firm

[39] After completion of the Company’s revenue requirement the Company determined that the transfers to plant associated with this project should be excluded from the revenue requirement in this Idaho rate case. The Company will update these transfer to plant amounts during this case.

customer load in the Coeur d'Alene, ID to Kellogg, ID corridor in a design day scenario.

Q. Please provide some examples of Natural Gas Plant Capital projects that were not approved, and the risk associated with not completing or deferring these projects.

A. The Overbuild Pipe Replacement Program was reduced from $900,000 to $500,000 per year. This resulted in an approximately 45% reduction of main and service replacement work. The reduced funding would still allow us to address some of the overbuilt facilities with known risk, but at a pace slower than normal plans to address these safety concerns and maintain compliance. The outcome would result in the continued operation of facilities known to be out of compliance and which are currently operating with higher risk to customers and operations personnel.

VI. GENERAL PLANT AND FLEET INVESTMENTS

Q. Please discuss the drivers for the Company's investments grouped under the category of general plant for the period 2017-2019.

A. The majority of these programs and projects are investments made to maintain, improve or replace the Company's offices, service centers, material storage facilities and their associated properties, based generally on asset condition or to address performance and capacity needs. In addition to having responsibility for maintaining this infrastructure, Avista's facilities management group responds to needs identified by the business and develops responsive projects that support our customer service center; provide ample employee work space; provide for employee and customer safety and efficiency in the flow of pedestrian and vehicle traffic on our central campus; meet the needs of fleet operations; provide space for our field service employees in electric and natural gas operations; ensure adequate space for equipment in our warehouses and storage yards; accommodate the safe and efficient handling of hazardous waste and to manage environmental issues; and provide for safe and adequate employee and customer parking.

Q. How does Avista's facilities group evaluate alternatives to meet identified needs and prioritize capital projects before they are recommended to the Capital Planning Group?

A. The facilities group completed a survey of the structures and appurtenant facilities at each of Avista's operations service centers. Each was rated on asset condition, based on factors including site utilities, interior condition, plumbing and HVAC, and fire safety systems. Using this information the facilities manager and one or more of the group's project managers, met with employees representing electric and natural gas energy delivery, environmental affairs, real estate, and finance, to review the survey results in the context of the business needs identified by each area. Beyond these immediate needs they factored in the needs of our customers, the potential for future expansion, current and expected materials storage needs (including offsite storage yards), environmental concerns, safety and compliance considerations, and site location. This team of employees representing the respective areas of the business then recommended whether each service center should be sold and replaced, replaced on the same site, or should continue to be maintained, repaired, remodeled, and improved with capital upgrades as warranted. Needs were then prioritized based on the condition factors listed above.

Q. Please briefly describe the infrastructure projects under general plant planned for the period 2017 - 2019.

A. These individual projects and programs by year are listed in Table No. 4, and are briefly described in my testimony below.

Table No. 4

General Plant Capital Projects (System) In $(000's)			
Business Case Name	**2017**	**2018**	**2019**
Asset Condition			
COF Long-Term Restructuring Plan	$ 2,064		
Dollar Rd Service Center Addition and Remodel	321	17,710	
Noxon & Clark Fork Living Facilities	1,411	1,563	
Structures and Improvements/Furniture	3,294	3,600	3,600
Customer Service Quality and Reliability			
Meter Data Management System	24,745		
Failed Plant and Operations			
Capital Tools & Stores Equipment	2,712	2,400	2,400
Performance and Capacity			
Apprentice Training	60	60	60
CNG Fleet Conversion	52		
COF Long-Term Restructuring Plan 2 [(1)]	13,695	10,000	
Company Aircraft Capital	296	3,000	
Ergonomic Equipment	616	300	
Airport Hangar	1,500		
Subtotal: General Plant Capital Projects	**50,765**	**38,633**	**6,060**
Washington Direct Business Cases [(2)]			
New Downtown Netwk Bldg	6,559		
New Deer Park Service Center	6	6,247	
	6,565	**6,247**	
Total Planned General Plant Capital Projects	**$ 57,330**	**$ 44,880**	**$ 6,060**

(1) COF = Central Office Facilities
(2) Excluded from revenue requirement in this case.

Asset Condition

COF Long-Term Restructuring Plan - 2017: $2,064,000

The remaining investments under this plan conclude a multiyear effort that began in 2013 and included nine individual projects. These projects completed in their sequence were required for implementation of the Campus Repurposing Phase 2 plan. All of these projects have been completed, with the exception of the expansion of the warehouse storage yard. Without the expansion, the Company will lack adequate and efficient space for its materials storage needs, which today impact crews' efficient access to materials since they are stored at multiple locations at our central office as well as offsite.

Dollar Road Service Center Addition and Remodel[40] - 2017: $321,000; 2018: $17,710,000

This planned investment would replace the existing natural gas operations service center at the existing site. The Dollar Road Service Center is the main natural gas operations center serving approximately 300,000 customers in the greater Spokane area, performed by approximately 70 field crews and administrative support employees. The service center also provides support for local gas crews from the Ritzville, Colville, and Davenport districts, which serve an additional 50,000 customers. The existing Dollar Road Service Center is approximately 22,000 square feet and was constructed in 1956. Our business needs have changed substantially since that time as a result of industry advances and growth in customers. In addition to work flow, many of the main building components, systems, and equipment have deteriorated with age and are past their useful service life. The Dollar Road Service Center scored the second lowest among the Avista facilities rated for asset condition in 2012. If the Company fails to make this investment as planned, we will continue to operate at the level of efficiency currently limited by this facility, we spend increasing amounts of capital and expenses for heavy maintenance, replacement of internal systems, and repair of structures and systems that fail prior to replacement.

Noxon & Clark Fork Living Facilities - 2017: $1,411,000; 2018: $1,563,000

This project includes the rehabilitation of two living facilities at Clark Fork, Idaho and Noxon, Montana, to address deteriorating condition of the facilities and their systems, extend the life of the facilities, and update them to a more modern and energy efficient state. The project combines required repair work with the facility renovation to avoid duplicating efforts and saving costs on contractor mobilization and re-work. The living facilities were constructed in 1983 and 1984 and have been in use for more than 30 years. They are 16-room bunkhouses with a common space containing a kitchen, dining hall and laundry facility. Because of the limited availability of lodging in this rural area, Avista crews and personnel lodge at these facilities when performing work at Noxon Rapids Dam,

[40] After completion of the Company's revenue requirement the Company determined that the transfers to plant associated with this project should be excluded from the revenue requirement in this rate case. The Company will update these transfer to plant amounts during this case.

Cabinet Gorge Dam, or on other Avista equipment in the area. During inspections in 2015, extensive issues were found with the facilities, including structural and water damage to the siding and framing due to water penetration, inadequate and antiquated electric heating systems, HVAC deficiencies and non-compliant electric breaker panels and inadequate insulation. This project would address the structural and water damage, bring the building up to modern code, and extend the life of the facility. The completed facilities would provide years of additional service, increase the efficiency of energy usage, reduce annual O&M costs to maintain the structures, and provide a suitable environment for housing our workforce at these remote sites. Disregarding the continuing water penetration was not an option as this would render portions of, and eventually the entire facility, uninhabitable over time. Maintenance and upgrade work is ongoing at both dams and is planned for the foreseeable future. This work is essential to maintaining the reliability of our power generation and associated infrastructure in the region. Without the continued availability of the living facilities, it's estimated that it would cost more than $300,000 annually to procure lodging at alternate sites for work at the plants, likely in Sandpoint or Thompson Falls, about an hour drive one way from the plant. With a centralized workforce based out of Spokane, the ability to provide lodging near our worksites maximizes available working hours.

Structures and Improvements/Furniture - 2017: $3,294,000; 2018: $3,600,000; 2019: $3,600,000

This ongoing capital program funds lifecycle equipment replacements and needed improvements at more than 40 Avista offices and service facilities (exceeding 900,000 square feet). These needs are compiled, evaluated and prioritized based on need and asset condition and lifecycle standards, designed to address: 1) Lifecycle asset replacements (examples: roofing, asphalt, electrical, plumbing); 2) Lifecycle furniture replacements and new furniture additions (to support growth), and 3) Business additions or site improvements (examples: adding a welding bay, vehicle storage canopy, expanding an asphalt yard, and can sometimes include property purchases to support site expansions). The replacements based on asset condition are intended to achieve a more stable and predictable level of capital requirements, and to avoid peak investments caused by coincident and large-scale failures. The failure to make these timely investments will result in reduced efficiency, safety issues, accelerated deterioration and failure of assets, such as roofing or HVAC systems, which can result in major damage to the facilities, and a bow-wave of needed investments to the future.

Customer Service Quality and Reliability

Meter Data Management System – 2017: $24,745,000

The Meter Data Management System (MDM) will store data from meters for Avista’s Idaho, Washington, and Oregon customers through integrations with the existing metering systems currently collecting consumption data, including the existing AMR system in Idaho. This system will allow consideration of daily meter reads, and enable appointment scheduling and optimized routing through the integration of the MDM’s Service Order Management module with Oracle CC&B. The appointment scheduling and routing optimization capabilities will allow service order management to be centralized on one system, providing consistent work processes and improved operational efficiency. The MDM system will replace the custom functionality that the Company added onto the Oracle’s Customer Care and Billing (CC&B) system as an interim meter data solution until a fully functional MDM system could be implemented, and which was not designed to support meter data with large volumes of data. When the Company is ready to install Advanced Metering Infrastructure (AMI) meters in Idaho, these meter reads will continue to be stored in MDM through similar integrations with the new AMI metering system. If Avista failed to make this investment, it would need to implement two or more separate meter data systems of record in order to accommodate each jurisdiction, which would increase cost and complexity.

Failed Plant and Operations

Capital Tools & Stores Equipment - 2017: $2,712,000; 2018: $2,400,000; 2019: $2,400,000

Avista’s capital tools program provides Company employees with proper tooling and equipment needed to safely and efficiently construct, monitor, manage system integrity, and properly repair and maintain our electric, gas, communications, fleet, facilities, and generation infrastructure. If the Company fails to provide its employees proper tools and equipment when they are needed, we would be unable to provide our customers with adequate, reliable and cost effective services that meet their expectations for quality and value. These tools and equipment also support the safety of our employees.

Performance and Capacity

Apprentice Training - 2017: $60,000; 2018: $60,000; 2019: $60,000

This investment consists of on-going capital facility improvements needed to support required training for apprentice, pre-apprentice, and journey level craft workers, ensuring they are prepared to safely meet the specialized technical needs to build and properly maintain electric and natural gas utility systems. Expenditures include expanding existing or constructing new facilities, purchase of training equipment, and the construction and maintenance of actual utility infrastructure designed specifically for the training of employees.

Compressed Natural Gas (CNG) Fleet Conversion - 2017: $52,000

This program supports the continuing conversion of a portion of Avista's fleet vehicles to run on compressed natural gas (CNG). The use of natural gas by our vehicles helps Avista reduce vehicle emissions and lower our operating costs. Operating our natural gas-powered fleet has also allowed us to provide our customers and others, who have been considering a natural gas powered vehicle, with practical experience on the requirements of owning and operating natural gas fueled vehicles. Importantly, we also use our natural gas compression system to fuel our truck and trailer-mounted natural gas storage tanks that allow us to maintain natural gas service to our customers when the distribution system has been damaged or is being serviced by the Company.

COF Long-Term Restructuring Plan Phase 2 - 2017: $13,695,000; 2018: $10,000,000

Phase 2 of this plan is a continuation of the long-term program to meet our ongoing and future operating needs by renovating, improving and expanding our existing central office and operating facilities. This phase is composed of three major projects that include re-routing a city street adjacent to our campus in 2017, constructing a new building for our fleet operations in 2017 and 2018, and constructing a parking garage in 2018. These three projects are interdependent because of their location, timing of construction and their relationship to the overall design of our central campus. These projects support Avista's objectives of 1) consolidating the footprint of our central facilities, which today consists of several disjointed parcels; 2) modernize and expand our aging fleet facilities to handle today's needs efficiently, meet compressed natural gas fleet compliance, better manage environmental concerns, and provide the space required for efficient queuing of fleet equipment; 3) Provide adequate campus parking for employees, which is currently short by about 400 spaces, and consolidate parking on company-owned land, improving employee and public safety by eliminating our parking sprawl, and 4) separate currently shared traffic routes for our construction vehicles and equipment and pedestrians to improve safety and increase workflow efficiency. Avista selected this plan from several options evaluated by the facilities group for meeting these combined needs. The failure to implement these plans in the timeframe proposed will result in work being terminated mid-stream on work underway, adding significantly to future costs to complete these projects, will require Avista to make alternative investments to mitigate the operational and environmental limitations of our existing fleet operations, and fail to resolve significant issues related to our current employee parking.

Company Aircraft Capital - 2017: $296,000; 2018: $3,000,000
This investment is to purchase the 18-year old Cessna Citation VII aircraft that the Company has leased since 2000. In March 2018, the current lease will expire, which provides for an end-of-term purchase option that applies prior lease payments toward the purchase in a lump-sum amount. In addition to the purchase price of approximately $2.5 million, the planned investment also includes updating the avionics to comply with new FAA mandates at a cost of approximately $500,000, and self-funding the parts plan for the aircraft. The planned purchase option will save approximately $1.1 million in annual expenses. Approximately 50% of flights made each year directly support the Company's utility regulatory activities and the remainder supports travel to Avista's regional offices and other business requirements. A large portion of these destinations are not served by a commercial airline.

Ergonomic Equipment - 2017: $616,000; 2018: $300,000
It is the Company's goal to help our employees be more engaged with maintaining their health, wellness and work productivity. An important step has been the introduction of ergonomic programs, office equipment and education. This effort reduces workplace injuries and other health impacts and helps Avista avoid the associated health costs. This program provides employees with ergonomic equipment and training.

Airport Hanger - 2017: $1,500,000

This project is to build an Avista-owned hangar on leased land at Spokane International Airport. This facility will replace the hangar we currently sublease, which will be demolished after our sublease is withdrawn in July 2018. Avista's facilities group considered four options for securing a hangar for the aircraft, which included building a new hangar, extending use of the current leased hangar, relocating to another airport, and co-use of an existing hangar. The solution to construct a hangar on land leased from the Spokane International Airport was selected for several reasons, including the location, site security, cost, efficiency and cost of aircraft maintenance, and operational safety and efficiency. The failure to make this investment in the timeframe planned will require Avista to adopt an alternative from among those already evaluated and determined to be inferior.

Q. Are there additional infrastructure projects planned for the period 2017 – 2021 that have not been previously addressed in your testimony?

A. Yes. Two additional projects are listed in Table No. 5, and are briefly described in my testimony below.

Table No. 5

Other Capital Projects (System) In $(000's)			
Business Case Name	**2017**	**2018**	**2019**
Asset Condition			
Fleet Capital Replacement Program	$ 7,898	$ 7,850	$ 7,850
Mandatory and Compliance			
Jackson Prairie Storage	1,718	1,562	1,483
	$ 9,616	**$ 9,412**	**$ 9,333**

Asset Condition

Fleet Capital Replacement Program - 2017: $7,898,000; 2018: $7,850,000; 2019: $7,850,000

Avista's replacement of its service vehicles and heavy equipment is based on the analysis of total life cycle costs, optimized to achieve the lowest total cost of ownership. To perform this analysis, the Company relies on the "Vehicle

Replacement Model" provided by Utilimarc. The model uses benchmarking information, purchase and auction sales data, combined with a range of nationwide vehicle statistics, to produce a robust estimate of the optimum timing for replacement of vehicles based on its residual value, the maintenance required to keep the vehicle in service, and the cost of a replacement. Capital project requests are created for each vehicle and piece of equipment to be replaced and the prioritization of projects is based on minimizing our overall business risk and costs of ownership. This approach to replacing assets based on condition, prior to its likely failure, has helped the Company avoid numerous incidents of vehicles failing while in service, resulting in extended vehicle and crew down time, high cost for parts and labor required for emergency repairs, and unplanned replacements. These costly incidents would be the result if the Company were to fail to make the investments in its service vehicles and equipment planned during this timeframe.

<u>Mandatory and Compliance</u>

Jackson Prairie Storage - 2017: $1,718,000; 2018: $1,562,000; 2019: $1,483,000

These projects include various capital improvements that Avista and its partners will complete at the Jackson Prairie facility. The Company is one-third owner in the Jackson Prairie Storage Facility and as such, is a part of the Jackson Prairie Storage Management Committee that meets annually to discuss and approve the capital and O&M projects needed for this facility. The Company's failure to make these investments in the timeframe planned would place us in violation of the joint owners' agreement to make these needed investments.

Q. Please provide some examples of General Plant Capital projects that were <u>not approved</u> at the requested amount, and the risk associated with <u>not</u> completing or deferring these projects.

A. In 2015 and 2016, capital tools and equipment requests exceeded what was funded by approximately $800,000 each year. (see Exhibit No. 8, Schedule 5 under the Capital

Tools Business Case Justification Narrative). Capital tool requests are prioritized by safety and compliance, replacement, and enhanced productivity. When the 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 could lead to reduced efficiency and have safety impacts. All construction, maintenance, and repair work performed at Avista is dependent on the use of capital tools and equipment. Without the necessary equipment, workers cannot perform their duties safely or efficiently, and Avista facilities and equipment could no longer be maintained.

The Facilities Structures and Improvements program funds the capital maintenance, site improvement, and furniture budgets at Avista's offices, storage buildings, and service centers. This program is intended to address the following needs:

- Lifecycle asset replacements (examples: roofing, asphalt, electrical, plumbing);
- Lifecycle furniture replacements and new furniture additions (to support growth); and
- Business additions or site improvements (examples: adding a welding bay, vehicle storage canopy, expanding

an asphalt yard, and can sometimes include property purchases to support site expansions.)

Lifecycle asset replacements are typically funded first, with furniture replacements and business site improvement requests taking a lower priority. Each year, requests for funding through this program far exceed available funds. In 2017 we funded $3.3 million of $7.4 million in requested projects. In 2016, requests totaled $6.3 million and we funded $3.6. In 2015, requests totaled $9.8 million, and we funded $4.6 million.

Sites decline due to normal wear and tear. The failure of certain systems, such as roofing or HVAC, can cause major damage to other areas of the building. Walkways and structural issues not being addressed could have safety impacts to employees, visitors and customers.

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. 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.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.