BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILIITES AND TRANSPORTATION COMMISSION,

Complainant,

v.

AVISTA CORPORATION d/b/a AVISTA UTILITIES,

Respondent.

DOCKET NOS. UE-200900, UG-200901, and UE-200894 (*Consolidated*)

RESPONSE TESTIMONY OF PAUL J. ALVAREZ AND DENNIS STEPHENS
ON BEHALF OF THE
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT PADS-1T

April 21, 2021

DOCKET NOS. UE-200900, UG-200901, and UE-200894 (*Consolidated*)

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EXHIBIT PADS-1T

TABLE OF CONTENTS

DOCKET NOS. UE-200900, UG-200901, and UE-200894 (*Consolidated*)

RESPONSE TESTIMONY OF PAUL J. ALVAREZ AND DENNIS STEPHENS

EXHIBIT PADS-1T

TABLE OF CONTENTS
(Continued)

FIGURES & TABLES

DOCKET NOS. UE-200900, UG-200901, and UE-200894 (*Consolidated*)

RESPONSE TESTIMONY OF PAUL J. ALVAREZ AND DENNIS STEPHENS

EXHIBIT PADS-1T

EXHIBITS LIST

Exhibit PADS-2	Curriculum Vitae of Paul J. Alvarez
Exhibit PADS-3	Curriculum Vitae of Dennis K. Stephens
Exhibit PADS-4	Avista Response to Public Counsel Data Request No. 70
Exhibit PADS-5	Avista Response to Public Counsel Data Request No. 184
Exhibit PADS-6	Avista Revised Response to Public Counsel Data Request No. 256
Exhibit PADS-7	Avista Response to Public Counsel Data Request No. 251
Exhibit PADS-8	Avista Response to Public Counsel Data Request No. 253
Exhibit PADS-9	Avista Response to Public Counsel Data Request No. 254
Exhibit PADS-10	Avista Response to Public Counsel Data Request No. 84
Exhibit PADS-11	Avista Response to Public Counsel Data Request No. 288
Exhibit PADS-12	Avista Response to Public Counsel Data Request No. 307
Exhibit PADS-13	Avista Response to Public Counsel Data Request No. 246
Exhibit PADS-14	Avista Response to Public Counsel Data Request No. 312
Exhibit PADS-15	Avista Supplemental Response to Public Counsel Data Request No. 98, Attachment B
Exhibit PADS-16	Avista Response to Public Counsel Data Request No. 110, Attachments A–N
Exhibit PADS-17	Avista Response to Public Counsel Data Request No. 208, Attachment A

DOCKET NOS. UE-200900, UG-200901, and UE-200894 (*Consolidated*)

RESPONSE TESTIMONY OF PAUL J. ALVAREZ AND DENNIS STEPHENS

EXHIBIT PADS-1T

EXHIBITS LIST
(Continued)

Exhibit PADS-18	Avista Response to Public Counsel Data Request No. 172
Exhibit PADS-19	Presentation to CIGRE by Dan Martin and T. Saha "Power Transformer Failure Survey and Modeling Reliability – Update and Looking Ahead"
Exhibit PADS-20	Avista Response to Public Counsel Data Request No. 215, Attachment A
Exhibit PADS-21	Avista Response to Public Counsel Data Request No. 101, Attachment E
Exhibit PADS-22	Avista Response to Public Counsel Data Request No. 286
Exhibit PADS-23	Avista Response to Public Counsel Data Request No. 241, Attachment A
Exhibit PADS-24	Avista Response to Public Counsel Data Request No. 116
Exhibit PADS-25	Avista Response to Public Counsel Data Request No. 107
Exhibit PADS-26	Avista Response to Public Counsel Data Request No. 106
Exhibit PADS-27	Avista Supplemental Response to Public Counsel Data Request No. 108, Attachment A
Exhibit PADS-28	Avista Response to Public Counsel Data Request No. 105, Attachment A
Exhibit PADS-29	Avista Response to Public Counsel Data Request No. 292
Exhibit PADS-30	Avista Response to Public Counsel Data Request No. 247, Attachment A

I. INTRODUCTION AND PREVIEW

Q. Please state your name and business address (to Alvarez).

A. My name is Paul J. Alvarez. My business address is P.O. Box 620756, Littleton, CO 80162.

Q. Please state your name and business address (to Stephens).

A. My name is Dennis Stephens. My business address is the same as Mr. Alvarez's.

Q. Mr. Alvarez, by whom are you employed and in what capacity?

A. I am the President of the Wired Group, a consulting practice specializing in distribution business planning, investment, and performance. I serve as a consultant to consumer, business, and environmental advocates with an interest in these issues. I also manage the affairs of the business, including associate and subcontractor recruiting and management, project management, business development, and administration.

Q. Mr. Stephens, by whom are you employed and in what capacity?

A. I am an independent consultant, and I frequently serve as the Wired Group's Senior Technical Consultant. I provide advice and counsel on distribution grid planning, operations, asset management, and performance issues.

Q. Mr. Alvarez, on whose behalf are you testifying?

A. I am testifying on behalf of the Public Counsel Unit of the Washington State Attorney General's Office.

Q. Mr. Stephens, on whose behalf are you testifying?

A. I am also testifying on behalf of the Public Counsel Unit of the Washington State Attorney General's office.

Q. Mr. Alvarez, please describe your professional qualifications.

A. My career began in 1984 in a series of finance and marketing roles of progressive responsibility for large corporations, including Motorola's Communications Division (now Android/Google), Baxter Healthcare, Searle Pharmaceuticals (now owned by Pfizer), and Option Care (now owned by Walgreens). My combined aptitude for finance and marketing were well suited for innovation and product development, leading to my first job in the utility industry in 2001 with Xcel Energy, one of the largest investor-owned utilities in the U.S.

At Xcel Energy, I served as product development manager, overseeing the development of new energy efficiency and demand response programs for residential, commercial, and industrial customers, as well as programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance (including distributed solar incentive program design and metering policies). There, I learned the economics of traditional monopoly ratemaking and associated utility incentives, as well as a great deal about utility program benefit quantification (measurement and verification, or "M&V").

In 2012, I started the Wired Group to focus exclusively on distribution utility business optimization. In addition, I serve as an adjunct professor at the University of Colorado's Global Energy Management Program, where I teach an elective graduate course on electric technologies, markets, and policy. I have also taught at Michigan State University's Institute for Public Utilities, where I have educated new regulators and public utilities commission (PUC) staff on grid modernization and distribution utility performance measurement.

In addition, I am the author of Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment, a book that helps laypersons understand smart grid capabilities, optimum designs, and post-deployment performance optimization. I am also the developer of the Utility Evaluator, an Internet-based software program, which benchmarks distribution utility performance against peers with like characteristics using publicly available financial and operational performance data. Finally, I note that my residence is located in a wildland-urban interface in Colorado.

Regarding education, I received an undergraduate degree from Indiana University's Kelley School of Business in 1983, and a master's degree in Management from the Kellogg School at Northwestern University in 1991. Both degrees featured concentrations in Finance and Marketing.

Q. Mr. Alvarez, have you previously appeared before the Washington Utilities and Transportation Commission?

A. Yes. I testified on issues related to smart meters in Puget Sound Energy's recent rate case.[1] In addition, I have testified before 14 other state utility regulatory commissions on distribution planning, investment, and performance issues, and served as a consultant to consumer, business, and environmental advocates in utility regulatory proceedings in six additional states. Please see Exhibit PADS-2 for a complete list of my regulatory appearances.[2]

[1] Response Testimony of Paul Alvarez, Exh. PJA-1T, *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* (2019) Dockets UE-190529 & UG-190530 (Nov. 22, 2019).
[2] Paul Alvarez & Dennis Stephens, Exh. PADS-2 (Curriculum Vitae of Paul Alvarez).

Q. Mr. Stephens, please provide an overview of your professional background and education.

A. After graduating from the University of Missouri with a bachelor's degree in Electrical Engineering, I began work for Xcel Energy (then Public Service Company of Colorado) as an electrical engineer in distribution operations. In a series of electrical engineering and management roles of increasing responsibility, I gained experience in distribution planning, operations, and asset management, and the innovative use of technology to assist with these functions. Positions I have held over the years have included Director, Electric and Gas Operations for the City and County of Denver Colorado; Director, Asset Strategy; and Director, Innovation and Smart Grid Investments. I retired from Xcel Energy in 2011.

I note that some geographies for which I have held operational responsibility are in the wildland-urban interface, and that many of these geographies are commonly on high alert for wildfires. I also note that my residence is located in a wildland-urban interface where high fire risk is common, and that I have helped both my homeowners' association and my community reduce wildfire risk and prepare wildfire response plans. I also developed Wildfire Alert™, a non-profit smart phone app designed as an early wildfire warning system for wildland residents. .

Q. Mr. Stephens, have you testified previously before the Washington Utilities and Telecommunications Commission?

A. No. However, I have testified before state utility regulatory commissions in California, Indiana, North Carolina, and Maryland on distribution grid planning, investment, asset management, and performance measurement issues. I have also served as a technical consultant to parties participating in state utility regulatory proceedings in Kentucky, Florida, Michigan, New Hampshire, Oklahoma, South Carolina, and Virginia. My Curriculum Vitae is attached as Exhibit PADS-3 to this testimony.[3]

Q. What is the purpose of your Panel Testimony in this proceeding?

A. (Alvarez) In this testimony Mr. Stephens and I address Avista Corporation's ("Avista" or "the Company") historical and proposed Wildfire Plan spending and cost recovery and Electric Distribution Plan spending and cost recovery.

Q. Please summarize your Panel Testimony on Avista's Wildfire Plan.

A. (Alvarez) Our testimony is organized as follows:

- Context for Wildfire Risk Management (Alvarez)
- A critique of Avista's Wildfire Management Plan (Stephens)
- Review and Recommendations for Avista's Wildfire Plan

Q. Please summarize your Panel Testimony on Avista's Electric Distribution Plan.

A. (Alvarez) Our testimony is organized as follows:

- Preview of Recurring Themes in Avista's Electric Distribution Plan (Alvarez)
- Critique of Avista's Substation Rebuild Program (Stephens)
- Critique of Avista's Grid Modernization ("Feeder Review") Program (Stephens)
- Review and Recommendations for Avista's Electric Distribution Plan

[3] Alvarez & Stephens, Exh. PADS-3 (Curriculum Vitae of Dennis Stephens).

II. AVISTA'S WILDFIRE PLAN

A. Context for Wildfire Risk Management (Alvarez)

Q. Please preview this section of your Panel Testimony on Avista's Wildfire Plan.

A. In this section of Panel Testimony, I will provide some context for wildfire risk management. The context will explore how people feel about wildfires, and how those feelings can influence decisions regarding wildfire risk management. I will also provide some guidelines for enterprise risk management in general, drawing upon the experiences of government agencies and businesses in competitive industries. This information will be valuable for understanding risk management methods for wildfires as well as other risks utilities face, such as the risk of service outages, or of an inability to serve growing loads or distributed generation. Finally, I will apply enterprise risk management guidelines to Avista's Wildfire Plan, thereby illustrating important concepts for the Commission before it reads Mr. Stephens's critique of Avista's Plan.

Q. How do people's feelings about wildfires influence associated risk management choices?

A. Many people are understandably terrified by wildfires. As someone who lives in a wildland-urban interface myself, I am certainly concerned about wildfires. Wildfires can be destructive and deadly. In the worst cases, human efforts to control wildfires can be futile for days on end, and such futility can be almost unbearable for those whose homes, belongings, and way of life are being threatened by an out-of-control wildfire. In short, fear is a strong motivator for most people, and can drive them to make different decisions than they would have made had actual historical data been available. Indeed, many psychological scientists now assume that emotions are, for better or worse, the dominant driver of most meaningful decisions.[4] For example, one may feel afraid to fly and decide to drive instead, even though base rates for death by driving are much higher than base rates for death by flying the equivalent mileage.[5] Thus, it is generally preferable to make decisions based on data, not fear.

When it comes to wildfires, fear may drive some to spend "whatever it costs" to reduce wildfire risk. But this is clearly not the wisest choice, as it is possible to spend unlimited amounts of money to reduce wildfire risk. Regardless of the amounts spent to reduce wildfire risk, wildfires will still happen. Avista claims that electric distribution causes 4–6 percent of all wildfires in Washington (without data from its own service area), and that its 10-year, $326.7 million wildfire plan will reduce this risk by 89 percent.[6] While Mr. Stephens will note later in this testimony that the 89 percent risk reduction estimate is based on absolutely no relevant historical actual data whatsoever, I note that even if the 4–6 percent wildfire causation and 89 percent risk reduction estimates are accurate, about 0.5 percent of the wildfires in Avista's service territory will still be caused by Avista's electric distribution services. Further, if one assumes that $326.7 million is an appropriate price to pay to reduce wildfire risk by about 5 percent, then by extension, the appropriate price to pay to reduce wildfire risk by 50 percent (all causes) would be $3.267 billion, or about $13,000 per household in Avista's electric

[4] Jennifer S. Lerner, et al. *Emotion and Decision Making.* Ann. Rev. of Psychol. 2015, Vol. 66, 799, at 801, https://scholar.harvard.edu/files/jenniferlerner/files/emotion-and-decision-making.pdf?m=1450899163
[5] *Id*., at 803.
[6] David R. Howell, Exh. DRH-2 at 13.

service territory ($3.267 billion divided by 250,000 households). Not only is this a lot of money, but I also note that wildfires will still happen, and some of these may be as devastating as those experienced in the Pacific Northwest last summer. The questions for stakeholders are therefore: 1) Which types of wildfire efforts deliver the biggest risk reductions per dollar; and 2) Which types of wildfire efforts deliver risk reductions so small, or sufficiently unknown, relative to costs, that they should not be pursued? Clearly, spending decisions regarding wildfire risk reduction should be based on data. These spending decisions must be based to some extent on an understanding of the actual amount of wildfire risk reduction Avista customers will get for their money.

Q. But doesn't Avista bear some responsibility for reducing wildfire risk?

A. Of course it does. Avista must, and already does, comply with industry standard practices regarding vegetation management, equipment inspections, equipment maintenance, and so on. The question of how much more Avista should do above and beyond industry standard practices to reduce wildfire risk should be informed by the amount of actual risk reduction Avista customers will receive for the amount of money customers will pay.

Avista's interest in reducing wildfire risk is not entirely altruistic. First, Avista customers are paying for these risk reductions, though Avista shareholders will benefit from positive financial market impacts associated with these wildfire risk reductions. Avista customers should not be expected to pay for exceptional risk reductions that stand to benefit Avista shareholders more than customers. Second, Avista shareholder earnings grow with every capital dollar Avista spends to reduce wildfire risk. This creates the incentive to focus heavily on solutions that require capital investment as opposed to options, which do not rely on new capital spending. As I discuss later in this testimony, 80 percent of the spending in Avista's wildfire plan consists of capital investment, despite the fact that capital-intensive wildfire programs, such as grid hardening, deliver the smallest wildfire risk reductions per dollar.

Q. You mentioned that government agencies and businesses in competitive industries offer experience from which the utility industry can learn. How do these organizations manage risk?

A. Modern risk management practices were first developed at NASA (to maximize risk reductions per dollar) and honed by the Army Corp of Engineers (in dam evaluations), and are now being adopted by large corporations globally.[7] Though a gross oversimplification, I synthesize some of the best practices I have researched, below:

- Identify risks (adverse events);
- Assess/prioritize risks in dollars (likelihood of event x consequence of event);
- Identify the drivers of high-priority risks;
- Create a portfolio of potential solutions to mitigate drivers;
- Evaluate potential solutions based on ability to reduce risk per dollar;
- Select/implement solutions which collectively optimize risk reductions per dollar;
- Establish plans to manage identified adverse events if they should occur; and
- Repeat the process on a periodic basis.

[7] Nurtis Ismail & Reid Paquin, OPERATIONAL RISK MANAGEMENT: HOW BEST-IN-CLASS MANUFACTURERS IMPROVE OPERATING PERFORMANCE WITH PROACTIVE RISK REDUCTION, Automation.com, (Mar. 1, 2013), https://www.automation.com/en-us/articles/2013-1/operational-risk-management-managing-change-to-imp.

Q. This seems reasonable. What are the benefits to such an approach?

A. In my estimation the biggest benefit of this approach is that, properly implemented, it maximizes risk reduction per dollar. It also makes clear the trade-offs associated with various investment strategies. I appreciate how all risks are translated into dollars for comparison across risk types. In the utility industry, this provides a method to compare, and prioritize, among different types of risk – service outage risk, load accommodation risk (including electrification), wildfire risk, distributed energy resource accommodation risk, environmental risk, etc. These same principles may all also be applied beyond the prioritization of risks to be managed. For example, they can be applied in the evaluation and selection of risk drivers to manage, or in the evaluation and selection of potential risk driver mitigation solutions. The concept of making investment decisions based on quantified risk reduction is known as risk-informed decision support.

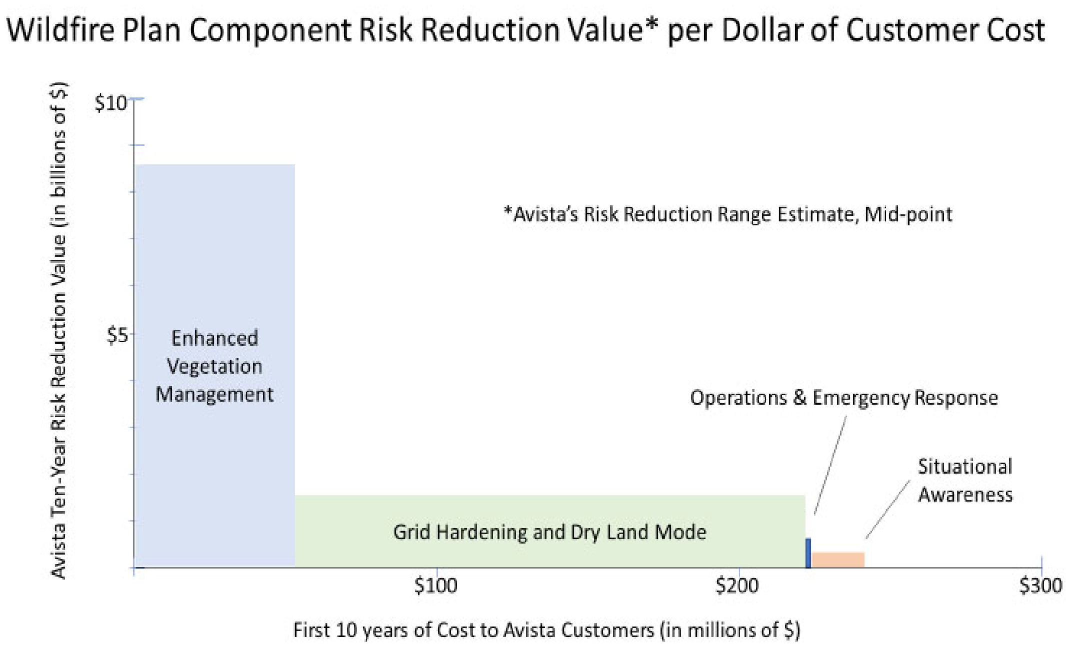
Q. Can these principles be applied to a single type of risk, for example, to the risk that electric distribution will start a wildfire?

A. Yes. In fact, I have evaluated the risk reduction value of Avista's Wildfire Plan components, as Avista has estimated them, relative to costs. Some proposed Plan components, such as the Operations and Emergency Response program, offer excellent risk reduction value per dollar ($229.51 in risk reduction value for every $1 spent).[8] Others, like the Grid Hardening and Dry Land Mode ("Grid Hardening") program, offer

[8] Calculated from benefit and cost amounts provided in Howell, Exh. DRH-2.

extremely poor risk reduction value ($5.86 for every $1 spent using Avista's own estimates, which Mr. Stephens will testify later are suspect).[9] Risk reductions per dollar of Wildfire Plan components are presented in Figure 1 below. Rectangles represent each major Wildfire Plan component, and the shape of each rectangle indicates the relationship between risk and cost. Rectangles which are taller than they are wide present much better value (risk reduction per dollar) than programs which are wider than they are tall. As the chart below indicates, the Operations and Emergency Response program, though offering almost half the risk reduction value of Grid Hardening, can be implemented for about one percent of the cost of Grid Hardening program.

Figure 1: Risk Reduction Value per Dollar, Avista Wildfire Plan Components



[9] Calculated from benefit and cost amounts provided in Howell, Exh. DRH 2 or Exh. PADS-4 (Avista Response to Public Counsel Data Request No. 70).

The question for stakeholders becomes "At what point is the level of risk reduction no longer sufficient to justify the costs?" The concept of picking and choosing from among a portfolio of potential risks to manage, risk drivers to mitigate, and potential solutions, as presented in Figure 1, is at the heart of all distribution utility investments, and at the heart of the stakeholder question I pose. This stakeholder question will be the subject of the next section of testimony.

B. Critique of Avista's Wildfire Plan (Stephens)

Q. Provide a preview of this section of testimony.

A. In this section of testimony, I will critique Avista's Wildfire Plan. First, I will discuss my observation that Avista did not develop its Wildfire Plan based on historical data. Second, I will discuss the fact that Avista did not take cost effectiveness into account when selecting risk driver mitigation solutions, consistent with the previous section of testimony. Finally, I will tie my observations together through the use of a hypothetical illustration of how a typical customer would assess risk reduction per dollar offered by the grid-hardening component of Avista's Wildfire Plan.

Q. Describe how Avista developed its Wildfire Plan.

A. Avista conducted a series of six workshops to inform its Wildfire Plan in May and June of 2019. The workshops involved a working group of employees and experts in distribution operations, asset management, safety, arboriculture, risk management, and from outside agencies (unspecified).[10] These workshops were employed to complete

[10] Alvarez & Stephens, Exh. PADS-4 (Avista Response to Public Counsel Data Request No. 70(b)) and Exh. PADS-5 (Avista Response to Public Counsel Data Request No.184(a)).

many of the risk management process steps identified in the previous section of testimony, including risk identification, risk assessment and prioritization, risk driver identification, identification of potential solutions, and solution evaluation. Exhibit DRH-3 captures the working group's recommendations. While these efforts are admirable, when asked for the data which informed these process steps, Avista referred me to historical data on outage causes,[11] but provided no data on ground fires whatsoever.[12] Instead, it appears that Avista made the enormous assumption that outage-cause data could be used as a proxy for ground fire data,[13] and relied on informed guesses to estimate the probabilities and consequences (i.e., risk level) of existing conditions, as well as the level of risk reductions provided by potential solutions.[14] It does not appear that any part of Avista's Wildfire Plan was informed by any historical ground fire data whatsoever. In my experience, any plan recommending almost $330 million in spending which incorporates essentially no historical data cannot be considered cost effective or prudent.

Q. How would you recommend developing a wildfire risk reduction plan?

A. I would have started by assembling historical data on the causes of ground fires related to Avista's electric distribution services. For missing data, I would begin a tracking program (which Avista has done). I would then proceed with the workshops with as much data as I

[11] Howell, Exh. DRH-2 at 28 and 31.
[12] Alvarez & Stephens, Exh. PADS-5 (Avista Response to Public Counsel Data Request No. 184(a)).
[13] Howell, Exh. DRH-2 at 31 (table of outage data associated with equipment Avista proposes to replace or install as part of its Grid Hardening program).
[14] Alvarez & Stephens, Exh. PADS-4 (Avista Response to Public Counsel Data Request No. 70(b), which asks for support regarding inherent risk levels and estimated risk reductions: "The example of 'pole fires' as noted in the Exhibit DRH-2, Page 22 (Avista 2020 Wildfire Resiliency Plan) was included for illustration purposes only.")

could assemble. In the workshops, I would follow the risk management process steps, making the best of available data. Avista's workshops appear to have done this. Then, at the "evaluate potential solutions" steps, I would identify solutions which I considered "no regrets" activities due to their low cost and/or because they are based on standard industry practices. Avista's workshops appear to have done this too, labeling these "no regrets" solutions as "Base Level Actions" and "Primary Actions" recommended in its workshop summary report.[15] I would then place a hold on all other potential solutions not identified as "no regrets", either due to a lack of data, high cost, or a lack of standard industry practices. I would reserve these potential solutions for future consideration while awaiting the results of my data-tracking program. Avista's working group also did this, identifying potential solutions not identified as "no regrets" as potential next steps (prioritized as "Secondary Actions", and "Future Actions"). But unfortunately, this is the point in the risk management process where Avista's Wildfire Plan development departs from what a rational business participating in a competitive industry would have done.

Q. How does Avista's Wildfire Plan depart from what a rational business participating in a competitive industry would have done?

A. Appropriately, all "no regrets" solutions the working group recommended as "Base Actions" and "Primary Actions" carry through to Avista's Wildfire Plan. But unfortunately, the most capital-intensive solutions from among the "Secondary Actions" identified by the workgroups, and some capital-intensive solutions not identified at all by the workgroups, were added to the Wildfire Plan with no data to justify those additions.

[15] *See* Howell, Exh. DRH-3.

For example, the distribution-hardening component of Grid Hardening ($193 million in capital) was moved from “Secondary Actions” in the working group to full implementation in the Wildfire Plan with no supporting data. Capital-intensive actions not recommended at all by the working group that were added to the Wildfire Plan with no supporting data include an expansion of the Dry Land Mode and transmission hardening components of Grid Hardening ($49.4 million in capital).

These unsupported additions to the Wildfire Plan are highly consequential for Wildfire Plan costs. Though none of these programs were recommended by the working group, total Grid Hardening added $245.4 million to the working group’s recommendations. These decisions increased the cost of the Wildfire Plan from $82.9 million for the working group recommendations to $328.3 million, an increase of almost 300 percent, primarily in capital spending. Given Avista’s capital bias, request for deferred cost recovery, and poor risk reduction to cost ratio, this causes us concern. Absent Grid Hardening, capital spending recommended by the working group represented just 28.1 percent of Wildfire Plan spending, at just $23.3 million. With the addition of Grid Hardening, capital spending constitutes 81.9 percent of Wildfire Plan spending and more than 10 times the capital spending recommended by the working group, at $245.4 million. The extremely capital-intensive nature of the final Wildfire Plan, the differences between working group recommendations and the final Wildfire Plan, and the lack of supporting data for capital-intensive components all lead me to believe that Grid Hardening is more focused on capital spending than ensuring cost-effective reductions to wildfire risk.

Q. What is this "missing data"?

A. As indicated above, I am specifically interested in data to support those parts of the Wildfire Plan not identified as "Base Actions" or "Primary Actions" by the working group, namely Grid Hardening. In support of this program, Avista provides service outage causation data.[16] I note that there is a big difference between service outages and ground fires. Before spending $245.4 million in capital on the Grid Hardening and Dry Land Mode plan component, I recommend Avista collect actual data on the causes of ground fires related to Avista's electric service delivery. Only then will we be able to judge the magnitude of the actual wildfire risks posed by Avista equipment relative to other risks (such as vegetation contact), let alone to accurately identify the equipment-related drivers of wildfire risk. If Avista cannot accurately identify the drivers of equipment-related wildfires, it cannot possibly identify potential solutions to those drivers, nor can it accurately evaluate the risk-reduction levels associated with various potential solutions. If Avista cannot accurately evaluate the risk reduction levels associated with various potential solutions, it is impossible to determine the cost effectiveness of those solutions, and therefore impossible to select the most cost-effective solutions for implementation. For all these reasons, Avista's Grid Hardening proposal is highly deficient.

I would like to specifically discuss the risk reduction levels Avista estimates for various potential wildfire prevention solutions, as the absence of supporting data for these

[16] Howell, Exh. DRH-2 at 31 (table of outage data associated with equipment Avista proposes to replace or install as part of its Grid Hardening program).

critical estimates is particularly conspicuous. Avista's Wildfire Plan estimates that distribution Grid Hardening will reduce the risk of wildfire from five sources – pole fires, primary conductor failure, secondary conductor failure, primary connector failure, and animal contact – by an astounding 98 percent. Avista provides absolutely no data to support this estimate,[17] which essentially means the estimate represents an informed guess. Further, Avista has absolutely no data on the frequency with which these five sources create ground fires.[18] Given that Avista's Wildfire Plan proposes to spend $193 million on grid hardening, and given that Avista does not even know the frequency with which these five sources of service outages result in ground fires, this is simply and unequivocally unacceptable.

Avista's Wildfire Plan also proposes to spend $44 million to replace some wood transmission poles with steel ones (transmission hardening). Avista provides no data to support existing risk levels from wood transmission poles or data on the reduction in risk levels from replacing some wood transmission poles with steel. In addition, Avista does not even attempt to estimate the existing or reduced risk levels associated with its $44 million the wood transmission pole replacement proposal.[19]

Avista claims that its wood transmission pole replacement proposal is more about resilience to wildfire impacts than it is about wildfire risk reduction, as steel poles do not burn. If this is the case, I would categorize the program as a reliability program, not a

[17] *Id*.
[18] Alvarez & Stephens, Exh. PADS-6 (Avista Revised Response to Public Counsel Data Request No. 256).
[19] Howell, Exh.DRH-2 at 35; Alvarez & Stephens, Exh. PADS-4 (Avista Response to Public Counsel Data Request No. 70).

wildfire program, and recommend the program be evaluated on its potential to improve reliability. Indeed, all capital components of Avista's Grid Hardening and Dry Land Mode program, amounting to $245.4 million, incorporate a reliability improvement aspect. Due to the extremely low wildfire risk reduction represented by Grid Hardening, I contend that the entire program is more about improving reliability than reducing wildfire risk. However, even then, based on my experience, the program would not deliver reliability improvements sufficient to justify costs to customers.

Q. How do you know Avista's Grid Hardening represents an extremely low level of wildfire risk reduction? Have you attempted to develop your own assessments of wildfire risks posed by Avista equipment?

A. While I have developed my own assessments of wildfire risks posed by several types of Avista equipment, and found all of them to be exceptionally low, I would like to focus on one equipment type as an example. Avista claims (without data on its own system experience)[20] that fires occur on poles with wood crossarms more frequently than on poles with fiberglass crossarms, and that wood crossarms therefore present an unacceptable risk. I choose to focus on wood crossarms because the prospect of actual flames on a pole in the middle of a remote, arid area during a high fire alert period prompts a particularly high level of fear and concern among wildland-urban interface residents and Commissioners. But I also choose to focus on wood crossarms to illustrate the inordinately small level of risk Avista claims to be unacceptable, for which Avista is

[20] Alvarez & Stephens, Exh. PADS-7 (Avista Response to Public Counsel Data Request No. 251) and Exh. PADS-6 (Avista Revised Response to Public Counsel Data Request No. 256).

prepared to spend hundreds of millions of dollars that customers must repay, including Avista shareholder profits, to rectify.

Q. Before you begin, can you explain how pole fires start?

A. Dust and road salt can accumulate on the insulators (attached to the conductors) and crossarms mounted on the pole. With a bit of light rain, the contaminants and moisture combine to create a conductive path electricity can follow over the crossarm to the pole. Once the electricity hits the pole, it gets hot and can start a fire. Despite this possibility, it is a rare condition.

Q. How rare?

A. Avista reports it has 117,667 wood distribution poles[21] and 23,088 wood transmission poles[22] on its system as of March 17, 2021, for a total of 140,755 wood poles. Avista also reports that it experiences an average of 92 distribution pole fires per year,[23] and an average of 12 transmission pole fires per year,[24] for an average of 104 total pole fires per year. Given these statistics, the likelihood that a fire will occur on any given pole in any given year on Avista's system is just 7.4 in 10,000.[25]

Q. How often do pole fires result in ground fires?

A. Unfortunately, Avista has not tracked that data.[26] I find it suspect that Avista could

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[21] Alvarez & Stephens, Exh. PADS-8 (Avista Response to Public Counsel Data Request No. 253(a)).
[22] Alvarez & Stephens, Exh. PADS-9 (Avista Response to Public Counsel Data Request No. 254(b)).
[23] Howell, Exh. DRH-2 at 31.
[24] Alvarez & Stephens, Exh. PADS-9 (Avista Response to Public Counsel Data Request No. 254(a)).
[25] 104 pole fires divided by 140,755 poles.
[26] Alvarez & Stephens, Exh. PADS-10 (Avista Response to Public Counsel Data Request No. 84(c)).

propose a $193 million Grid Hardening program, and a $44 million transmission hardening program, without an answer to such a basic question. However, giving Avista the benefit of the doubt, and based on my own experience, let us assume that one out of the 104 pole fires that occur annually results in a ground fire. This would mean that the likelihood that a fire will occur on any given pole in any given year, and that such a pole fire will result in a ground fire, is just 7.1 in a million.[27]

Q. Then, presumably, one would like to know how many ground fires become wildfires?

A. Correct. Again, Avista does not track this data. However, given that only 26.4 percent of Avista's wood distribution poles, and less than 20 percent of its wood transmission poles,[28] are located in Tier 2 or Tier 3 Wildland-Urban Interface areas (highest risk),[29] the likelihood that a pole fire will result in a ground fire which will become a wildfire in any one year is even smaller, perhaps as small as 1.8 in a million.[30] Yet Avista deems this almost imperceptible risk to be substantial enough to propose a multi-hundred-million-dollar program to reduce (but not eliminate) it, ultimately producing little value or increased security for customers. It makes no sense to me at all.

Q. Is this what you were alluding to when you said that Avista did not take program cost effectiveness into account when designing its Wildfire Plan?

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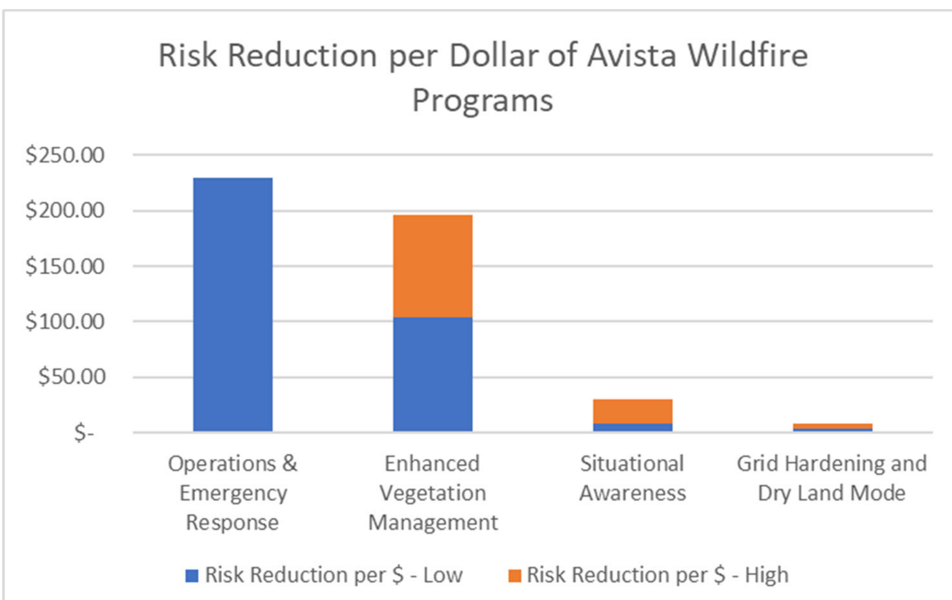
[27] 1 divided by 140,755 poles.
[28] Alvarez & Stephens, Exh. PADS-9 (Avista Response to Public Counsel Data Request No. 254 (b)).
[29] Wildland Urban Interface Tiers (1 through 3, with 3 representing highest risk) are geographies defined by Avista based on a combination of fuel concentration and housing density. It is described in more detail in Howell, Exh DRH-2 at 11–12.
[30] 7.1 in a million multiplied by 25 percent.

A. Yes. Figure 1 in the previous section of testimony makes this point well, though I provide the same data, presented in a different manner to clarify the point, in Figure 2 below. Figure 2 presents the risk reduction per dollar of each program in the Avista Wildfire Plan, using Avista's own estimates of risk reduction. As the pole fire example illustrates, the Commission should be skeptical of Avista's risk reduction estimates, as these estimates are not based on any historical data. Nor could Avista provide data or research from any other utilities in support of its risk reduction estimates.[31] However, even if Avista's risk reduction estimates are somehow reflective of reality, the message of Figure 2 is clear: The Grid Hardening spending Avista proposes is inappropriate, at least until more relevant data can be collected.

Figure 2: Risk Reduction per Dollar of Avista Wildfire Programs



[31] Alvarez & Stephens, Exh. PADS-4 (Avista Response to Public Counsel Data Request No. 70(b), which asks for support regarding inherent risk levels and estimated risk reductions: "The example of 'pole fires' as noted in the Exhibit DRH-2, Page 22 (Avista 2020 Wildfire Resiliency Plan) was included for illustration purposes only.")

Q. So, the Grid Hardening program is both the most costly and the least effective component of Avista's Wildfire Plan?

A. Precisely. This observation, combined with the fact that the risk reduction value is not based on any historical data, form the basis of my recommendations regarding Avista's Wildfire Plan. These recommendations include: 1) the Commission should reject recovery of and on $10.05 million Grid Hardening capital Avista requests in this rate case due to a lack of prudence;[32] 2) the Commission should instruct Avista to immediately place the capital components of the Grid Hardening program on hold pending relevant data collection and subsequent re-evaluation; and 3) the Commission should approve all other aspects of Avista's Wildfire Plan and cost recovery requests in this rate case, including Avista's request for deferred cost recovery of Wildfire Plan O&M spending. We specifically recommend that Avista's request for deferred cost recovery be limited to O&M spending, and to specifically exclude deferred cost recovery for capital spending. Excluding capital spending from deferred cost recovery ensures Avista's customers are shielded from bearing the expense of measures that are unlikely to yield significant risk reductions. Furthermore, it prevents Avista from unduly earning a rate of return on capital spending for programs offering such small and unsupported risk reductions relative to costs, as Grid Hardening does.

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[32] The impact of this disallowance on Avista's proposed revenue requirement is calculated in the Response Testimony of Public Counsel witness Ms. Andrea Crane, Exhibit ACC-1T.

Q. What "relevant data" do you recommend Avista collect?

A. First, if the Commission is considering an order, which requires Avista to collect data, I recommend the Commission be highly specific. Among the Wildfire Plan components I recommend the Commission approve, is a proposal to develop a Fire Ignition Tracking System.[33] Between that system and/or Avista's existing outage management system, I recommend Avista track the grid hardening data points presented in Table 1 below.

Table 1: Recommended data collection for Grid Hardening component of Avista's Wildfire Plan

Grid Hardening Component	Total in Service	Pole Fires per Year/Failures per Year	Ground Fires per pole fire or per failure
Fiberglass crossarms	Count		
Wood crossarms	Count		
Wood transmission poles	Count		
Primary conductor	Miles		
Small copper wire conductor	Miles		
Failure from animal contact	n/a		
Primary Connectors	Count		
Secondary conductor	Miles		

[33] Howell, Exh. DRH-2 at 63.

Armed with this data, stakeholders would be able to accurately assess the current fire risk associated with various pieces of Avista equipment, as well as the risk reduction value (risk reduction per dollar) associated with various solutions.

Q. Please provide the hypothetical illustration of how a typical customer would assess risk reduction per dollar offered by the grid-hardening component of Avista's Wildfire Plan.

A. I appreciate that Avista's Wildfire Plan puts the Commission in a difficult position. If the Commission follows my recommendations, and a destructive wildfire is caused by some piece of Avista equipment, the Commission could face public scrutiny. *It is important for the Commission to understand that, even if it approves Avista's $245 million Grid Hardening proposal, fires due to Avista's equipment can and probably will still occur*. However, under my recommendations, a destructive wildfire resulting from Avista equipment is extremely unlikely. And, even if such a wildfire occurs, the Commission can be confident that all reasonable measures were exercised to severely reduce the likelihood of a utility-ignited fire. Such a wildfire may have occurred even if the Grid Hardening and Dry Land Mode program had been implemented.

To illustrate how an average Avista customer might evaluate the risk reductions per dollar of Grid Hardening spending, I developed the following hypothetical example. All values included, below, are calculated from data from the American Red Cross, Avista's Grid Hardening proposal, or Avista's rate case.

The hypothetical example involves a door-to-door salesman whose job is to sell an amazing new technology, the Home Electric Fire Eliminator. After making acquaintances, the salesman provides the following data:

- The risk that your home will experience a house fire is one in 3,000 annually;[34]
- If you experience a house fire, there is a 4%–6% chance it was caused by electrical wiring in your home.[35]

At this point, the homeowner appears to lose interest, as she calculates the likelihood that her home's electrical wiring will cause a house fire is only 1.67 in 100,000 per year (1/3,000th multiplied by 5%). Undaunted, the Home Electric Fire Eliminator salesman continues. He exclaims, "The Home Electric Fire Eliminator will reduce the risk of a house fire from electrical wiring by 98%!" The homeowner asks for the source of the claim. The salesman replies that the risk reduction is not based on the experiences of others who have purchased the Home Electric Fire Eliminator, but is instead an estimate developed by experts in home electrical wiring safety and related building codes. The homeowner is now growing impatient, and prefers to cut to the chase to bring the sales call to a speedy end. When she asks the price of the Electric Fire Eliminator, the salesman replies "The price is only $1,963,[36] but if you buy today, you can pay this balance off over 30 years." The homeowner abruptly declines the offer, thanks the salesman for his time, and escorts the salesman out the door.

I provide this example to illustrate a few points. The first point is that few

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[34] American Red Cross, *You're More Likely to Experience a Home Fire Than These 5 Things* (Jan. 11, 2019), https://redcrosschat.org/2019/01/11/youre-more-likely-to-experience-a-home-fire-than-these-5-things/.
[35] This is the rate at which Avista claims wildfires in its service area can be traced to electric service delivery.
[36] This is the utility revenue co-panel witness, Mr. Alvarez estimates a $245.4 million Grid Hardening program investment will require ($490.9 million), assuming a 30-year equipment life and other determinants (rate of return, weighted average cost of debt, debt-to-equity ratio, federal income tax, Washington electric utility tax, and MACRS depreciation) in this Avista rate case, divided by 250,000 residential households in Avista's electric service territory.

customers would voluntarily pay $1,963 to protect against so small a risk with absolutely no evidence that the level of risk reduction claimed would actually be delivered. Second, if the Commission approves the Grid Hardening part of Avista's Wildfire Plan, it essentially forces Avista customers to buy such a product. While the example illustrates how difficult it would be to sell the Grid Hardening part of the Plan to a single customer, *imagine how difficult it would be to sell Grid Hardening to every one of Avista's customers*. Finally, the story is intended to illustrate the risk the Commission will take if it approves the Grid Hardening part of Avista's Wildfire Plan: the risk that customers will be burdened with almost $2,000 in cost over 30 years for a product, which is unlikely to deliver on the promises advertised.

C. Review and Recommendations for Avista's Wildfire Plan

Q. Please review your Panel Testimony on Avista's Wildfire Plan.

A. Our testimony began with some context on wildfire risk management. Points addressed included the role of fear in decision-making; guidelines for risk management processes in general; and the application of risk-informed decision-making principles to Avista's Wildfire Plan. Along the way, we make the point that Avista's Wildfire Plan, in addition to growing rate base and earnings for shareholders, reduces shareholder risk.

In the next section of this testimony we critiqued Avista's Wildfire Plan. These critiques included: 1) that Avista did not develop its Wildfire Plan, or determine risk levels or risk reductions, through the use of relevant, historical data; and 2) that Avista did not take cost effectiveness into account when developing its Wildfire Plan. Along the way, we pointed out that while the working group Avista used to inform its Wildfire Plan recommended only "no regrets" programs that were either low-cost or comported with existing industry practices, Avista's Wildfire Plan ultimately included a capital intensive program (Grid Hardening) costing $250 million. This program not only tripled the cost of the Wildfire Plan, and increased the capital required for the Plan more than 10-fold, it was not recommended by the working group, nor was it supported by any historical data regarding equipment-related causes of ground fires. Further, using Avista's own risk reduction estimates, not backed by historical data, the Grid Hardening program offered the worst risk reduction per dollar of any program in its Wildfire Plan. We provided logic, which indicated the likelihood that a pole fire will result in a wildfire could be as low as 1.8 in a million, and concluded with a story to illustrate how a consumer would perceive a pitch from a salesman using the cost and effectiveness characteristics of the Grid Hardening program.

Q. Based on this testimony, what are your recommendations to the Commission regarding Avista's Wildfire Plan?

A. We recommend the Commission:

- Reject recovery of and on $10.05 million in Grid Hardening capital Avista requests in this rate case due to a lack of prudence, as incorporated in the revenue requirement adjustments of Public Counsel witness Ms. Andrea Crane;
- Instruct Avista to immediately place the capital components of the Grid Hardening program on hold pending relevant data collection and subsequent re-evaluation; and
- Approve all other aspects of Avista's Wildfire Plan and cost recovery requests in this rate case. However, we are careful to specify that Avista's request for

deferred cost recovery should apply only to Wildfire Plan O&M spending. The Commission should deny deferred cost recovery for Wildfire Plan capital spending so as not to encourage spending on Grid Hardening, which delivers small, or unknown, wildfire risk reductions per dollar.

III. AVISTA'S ELECTRIC DISTRIBUTION PLAN

A. Preview of Recurring Themes in Avista's Electric Distribution Plan (Alvarez)

Q. Please preview this section of your Panel Testimony on Avista's Electric Distribution Plan.

A. In this section of Panel Testimony, I will provide a preview of two recurring themes identified in our review of Avista's Electric Distribution Plans. First, Avista makes significant use of what we call "standing budgets." We believe the standing budget approach leads to investments over and above those necessary for safe and reliable service. Second, I note that the programs for which Avista uses standing budgets — its Substation Rebuild and Grid Modernization programs — feature prospective replacement of distribution equipment. Prospective replacement is not a standard industry practice, and there is no research that indicates the incremental benefits of prospective replacement exceed the incremental costs of prospective replacement.

1. Avista's Use of Standing Budgets Leads to Excess Grid Investment

Q. What are "standing budgets"?

A. Mr. Stephens and I have reviewed dozens of electric distribution plans from investor-owned utilities in recent years. In each and every case, a utility develops new capital budgets from scratch (called "Zero-based Budgeting"). That is, they make no preconceived assumptions about the level of capital and O&M spending necessary to deliver safe and reliable service. Instead, they first begin with a distribution plan created by developing load forecasts by circuit, and comparing these forecasts to feeder-specific (and substation-specific) equipment capacity ratings. Any projected exceedances of equipment capacity ratings are then addressed. There are several ways to address insufficient capacity. Some are almost no cost, such as re-balancing feeder loads by reconfiguring which piece of substation equipment supplies which feeder. Some solutions require significant capital expenditures, such as increasing the capacity of a feeder or a substation. Construction plans to accommodate load growth are the foundation of distribution plan capital budgets.

Other known capital expenditures are then added to capital budgets. For example, routine substation equipment testing may have identified equipment in need of replacement; the projected costs of these replacements are added to the capital budget. Finally, budget provisions for expenditures that are difficult to estimate with certainty are added. For example, utilities know that some equipment will fail in service, some equipment will be damaged by storms or accidents, some capital will be required for new customer connections, and some capital will be needed for ongoing reliability improvement programs, such as worst performing feeder programs, which will be explained later in this testimony. For these programs, in which the amount of capital required is not knowable with certainty, historical averages are typically employed to establish future capital budgets. Some such budgets will turn out to be inadequate, but others will turn out to be excessive, so that overall the averages will prevail. To summarize, standard industry practice is to first determine grid needs, and then to build capital budgets designed to satisfy grid needs.

While Avista appears to follow most of this process in most cases, Avista also appears to determine the budgets for some programs in advance. Rather than determine what the needs are, or to use historical averages to estimate what the capital requirement is likely to be, Avista establishes the capital budgets for its Substation Rebuild and Grid Modernization programs in advance of any determination of grid needs. These are what we call "standing budgets," as they are simply established, and "stand," without regard to specific needs or historical precedent. We have not seen such an approach employed in any electric distribution plans we have reviewed in other proceedings.

Q. Is there a difference between a standing infrastructure program and a standing budget?

A. Yes. It is possible to have a standing infrastructure program without a standing budget. In this testimony we will describe a common infrastructure program typically called a "worst performing feeder" program. While budgets for such programs are typically established based on historical averages, there is no amount of budget presumed "necessary" in advance.

Q. Is there any documented, standardized approach to electric distribution planning and capital budgeting?

A. Until very recently, this testimony would have had to rely on our extensive experience to ascertain standard practices regarding distribution planning and capital budgeting. But in February, a joint NARUC-NASEO (National Association of Regulatory Utility Commissioners-National Association of State Energy Offices) Task Force ("Task Force") released the result of a two-year effort by 15 states to provide guidance on electricity planning processes.[37] The portion of the Task Force's recommendation related specifically to distribution planning, which the Task Force labeled the "Jade Cohort," is presented in Figure 3, below. The recommended process comports with the standard industry practices in distribution planning I just described. However, having said that, we do not recommend a distinct process for 'grid modernization' as depicted in Figure 3. Instead, we believe new distribution technologies should simply be considered as potential solutions to grid needs as part of routine planning processes. We have found that separate processes for grid modernization result in technology investment in excess of the amount that would have been identified through the routine application of a distribution planning process.

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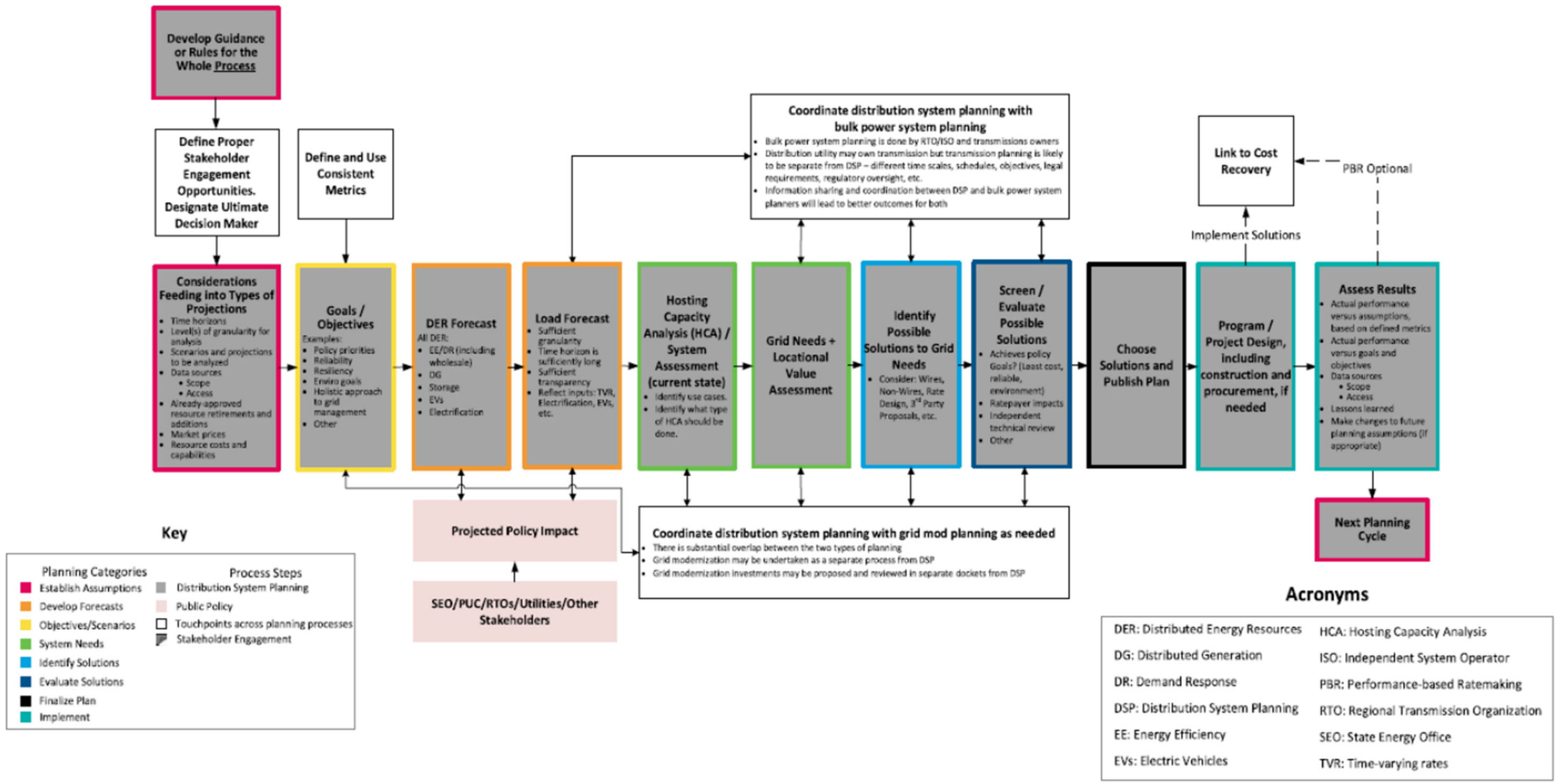
[37] BLUEPRINT FOR STATE ACTION: NARUC-NASEO TASK FORCE ON COMPREHENSIVE ELECTRICITY PLANNING, NARUC and NASEO (Feb. 2021) (and other materials available at www.naruc.org/taskforce).

Figure 3: "Jade Cohort" process guideline from the NARUC-NASEO Task Force on Comprehensive Electric Planning



Q. Does Avista follow the Task Force's recommended process for distribution planning?

A. Mr. Stephens and I believe Avista follows the process recommended by the Task Force for most of their distribution plan. However, Avista's Substation Rebuild and Grid Modernization programs stand out as exceptions because the Company uses a standing budget approach for these programs instead of zero-based budgeting. Neither standing budgets, nor the prospective equipment replacement practices encouraged by the use of standing budgets, are standard in the industry.

Q. You have explained the concept of "standing" budgets; what do you mean by "prospective equipment replacement"?

A. By prospective, we mean that equipment is being replaced in advance of need.

Mr. Stephens and I believe that a piece of equipment "needs" to be replaced when: 1) it fails an objective test or formal inspection; or 2) a benefit-cost analysis indicates that the customer benefits of replacement exceed the cost to customers of replacement; or 3) the asset fails in service. These are standard industry practices.

Q. How does Avista respond to your claims that standing budgets and prospective equipment replacement are not standard practices?

A. Regarding standing budgets, Avista claims that its standing budgets "are intended to have the integrated long-term impact of generally maintaining and upholding the overall reliability performance of our electric infrastructure."[38] Regarding prospective replacement, Avista claims that it does not replace equipment prospectively, but "when it should be replaced — at the end of its useful service life — defined typically as the "Economic End of Life."[39] I will address these two claims in turn.

Q. Why do you oppose the use of standing budgets?

A. Mr. Stephens and I believe the use of standing budgets leads to investment over and above the amount necessary for safe and reliable electric service delivery. Prospective equipment replacement is the primary example of this type of spending. As Mr. Stephens will describe in detail in the next sections of this testimony, Avista's Substation Rebuild and Grid Modernization programs consist of copious amounts of prospective equipment replacement.

Prospective replacement can also mean upgrading equipment too far in advance of that required to accommodate growing loads. We are unaware of any industry research that indicates that the incremental customer benefits of prospective replacement exceed the incremental costs to customers of prospective replacement, and Avista could not prove to us that its "Economic End-of-Life" approach to equipment replacement — which Mr. Stephens and I consider prospective replacement — delivers incremental benefits to customers in excess of incremental costs to customers. We consider prospective replacement to be one indication that standing budgets lead to excess investment.

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[38] Stephens & Alvarez, Exh. PADS-11, (Avista Response to Public Counsel Data Request No. 288(b)).
[39] Stephens & Alvarez, Exh. PADS-12 (Avista Response to Public Counsel Data Request No. 307(b)).

Q. Are there other indications that standing budgets lead to excess investment?

A. Yes. We can point to simple human nature. Managers in electric distribution are instructed to deliver safe and reliable electric distribution service. It is natural for such managers to ask for more budget than might be needed, as any excess budget can be spent to make doubly sure the stated objective is met. Once given a budget, that manager is likely to spend it all, to help ensure he or she gets at least as big a budget in the next planning cycle. This dynamic leads such managers to search for solutions to apply, rather than an optimal approach to identifying, assessing, and prioritizing grid needs, and risks to be reduced, in accordance with standard industry practice. Mr. Stephens and I have observed this phenomenon first-hand as employees of a multi-state utility. Jurisdictions with higher authorized returns on equity always secured budgets with more "fat" in them than jurisdictions with lower authorized returns. In the former jurisdictions, managers sought solutions to apply. In the latter jurisdictions, where capital was constrained, managers were required to justify capital-spending requests with rigorous benefit-cost analyses and extensive service outage risk reduction quantifications. This latter approach — determining how best to spend limited available capital in a manner which reduces the greatest amount of operational risk — is how operations managers in unregulated businesses are forced to work. It makes sense that a capital budgeting approach that begins with grid needs, not standing budgets that encourage managers to seek solutions on which to spend available funds, should be the standard for utilities.

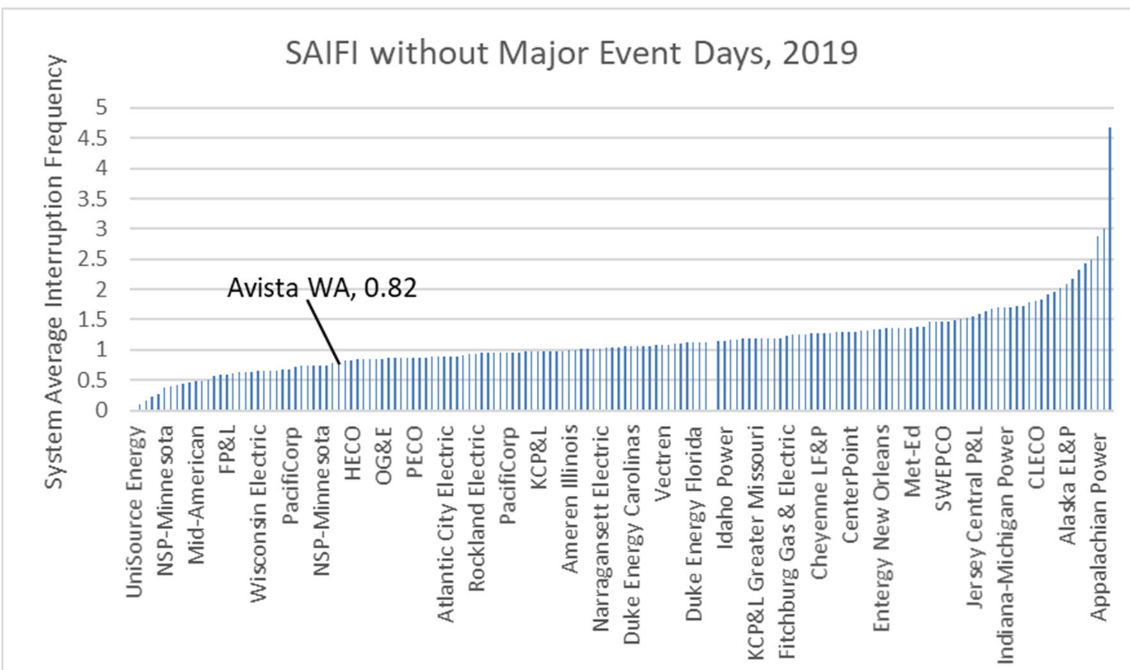
Additionally, evidence from Avista's actual capital spending history shows how standing budgets result in greater capital investment than necessary. One example is the contrast in capital budget size between Avista's former worst performing feeder program, focused on reliability, and the "grid modernization" program, which absorbed the worst performing feeder program capital budget when that program was terminated in 2017.[40] The budget for the worst performing feeder program was approximately $1.6 million annually on average from 2013 to 2016.[41] By contrast, capital spent on the Grid Modernization program averaged $13.25 million annually from 2015 to 2019.[42] Avista counters that the programs are not comparable, as the Grid Modernization program is designed to accomplish more than the worst performing feeder program, including O&M spending reductions and energy efficiency improvements. However, upon review of the 14 feeder "modernization" plans Avista provided in discovery, not a single one estimated costs, or reliability benefits, or O&M benefits, or energy-efficiency benefits.[43] It is therefore impossible to determine whether the Grid Modernization program is the most cost-effective way to improve reliability. Further, with no quantification of costs, benefits, or risk reductions in a feeder's modernization plan, a manager is free to spend what he or she wants without regard to benefits or risk reductions delivered per dollar spent. These are all indications that standing budgets encourage excess investment.

I observe other indications that standing budgets and prospective replacement lead to excess investment in Avista's System Average Interruption Frequency Index

[40] Alvarez & Stephens, Exh. PADS-13 (Avista Response to Public Counsel Data Request No. 246(a) and (b).
[41] Alvarez & Stephens, Exh. PADS-14 (Avista Response to Public Counsel Data Request No. 312).
[42] Alvarez & Stephens, Exh. PADS-15 (Avista Supplemental Response to Public Counsel Data Request No. 98, Attachment B).
[43] Alvarez & Stephens, Exh. PADS-16 (Avista Response to Public Counsel Data Request No. 110, Attachments A–N).

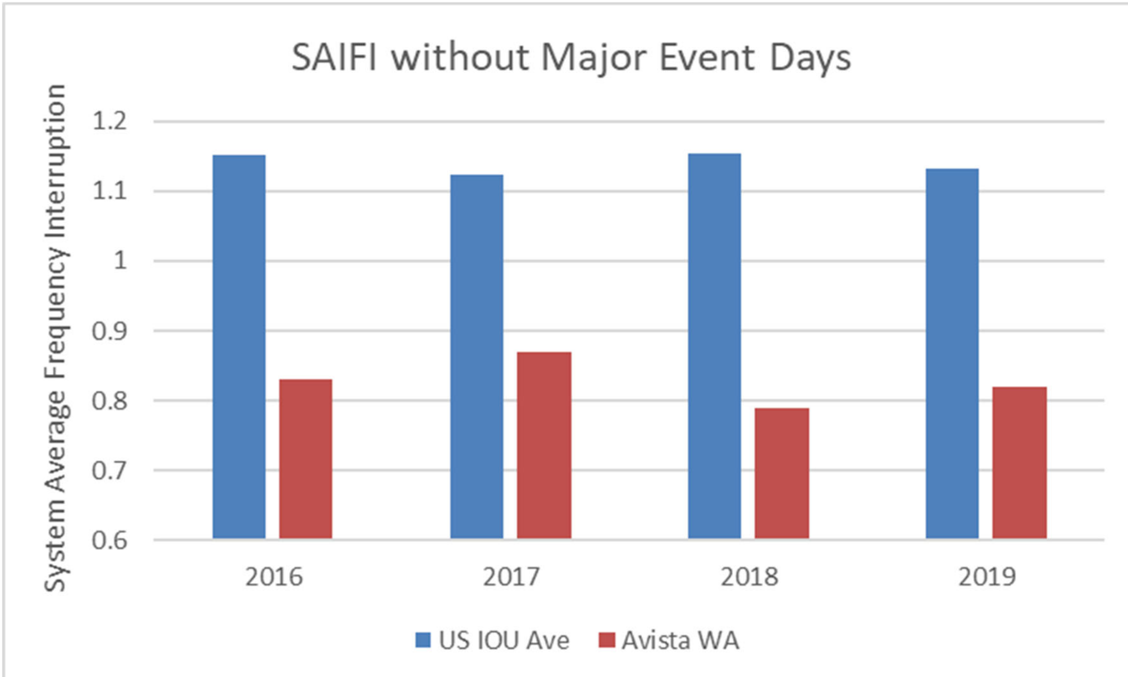
performance, or SAIFI. Prospective replacement is intended to avoid outages, thereby improving SAIFI. However, Avista's SAIFI performance is already excellent. Avista-Washington's SAIFI performance was in the top quartile of investor-owned utilities nationwide in 2019 (Figure 4),[44] and the Company's SAIFI performance has been consistently strong for years (Figure 5).[45] There appears to be no SAIFI crisis that would imply that Avista must prospectively replace equipment to improve poor SAIFI performance.

Figure 4: SAIFI without Major Event Days, 2019, US investor-owned utilities by state.



[44] Data submitted by U.S. investor-owned utilities on Energy Information Administration Form 861, Part B, 2019. This data is available for download at https://www.eia.gov/electricity/data/eia861/.
[45] *Id.* (years 2016–2019).

Figure 5: SAIFI without Major Event Days, Avista Washington vs. US investor-owned utilities, 2016-2019

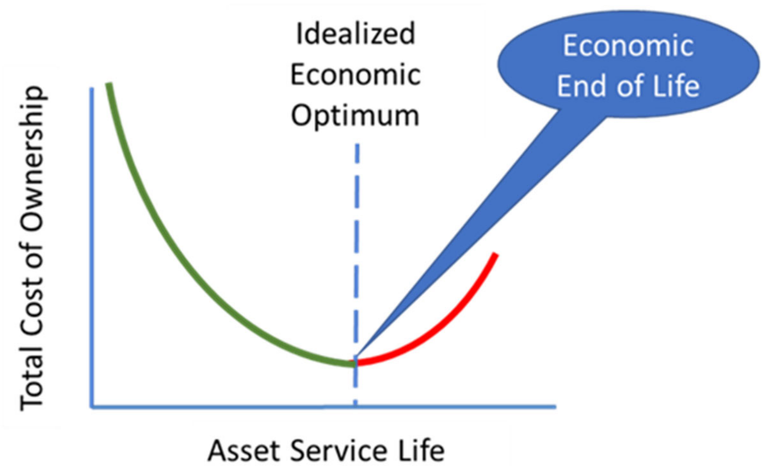


2. Avista Programs Featuring Standing Budgets Replace Equipment Prospectively, Leading to Excess Investment.

Q. Please turn now to "prospective" equipment replacement. You claim Avista is replacing equipment prospectively, while Avista claims its Economic End-of-Life approach does not constitute prospective equipment replacement. Can you explain Avista's Economic End-of-Life approach?

A. Avista's Economic End-of-Life approach is based on a "total cost of ownership" model. The total cost of ownership model takes into account all costs of asset ownership, from installation and financing to operations and maintenance costs and availability risk (the risk that an asset will not be working when needed). According to Avista, an asset reaches the economic end-of-life once an asset's total cost of ownership begins to increase. At that point, more or less, Avista replaces the asset.[46] This is depicted by Figure 6 below, provided by Avista in discovery.[47]

Figure 6: Avista's "Economic End-of-Life" Approach to Asset Replacement



Q. What is wrong with the Economic End of Life approach?

A. The problem with the Economic End of Life approach is that it is typically applied by unregulated businesses in competitive industries, not regulated utilities. From the perspective of a competitive business, as assets age, they typically become less productive, as indicated by falling revenues generated by the asset. Asset-related revenues, when added to Avista's chart in Figure 7 below, indicate that a competitive business can still get profits out of an asset once its total cost of ownership begins to climb. The augmented chart also indicates that such businesses will wait until the total cost of asset ownership exceeds the revenues from the aging asset before it replaces the asset.

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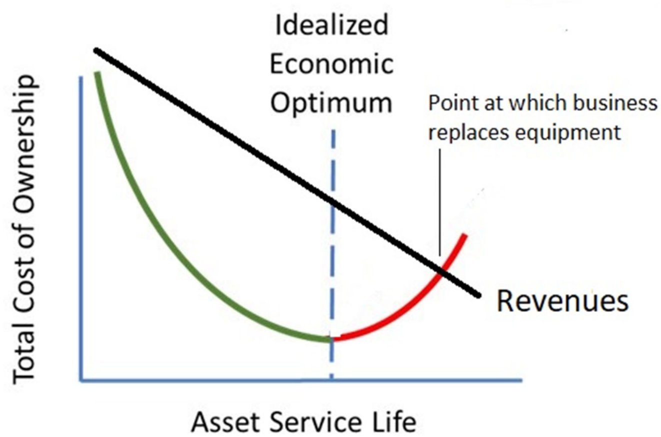
[46] Alvarez & Stephens, Exh. PADS-12 (Avista Response to Public Counsel Data Request No. 307(b)).
.[47] *Id*. (Avista Response to Public Counsel Data Request No. 307(a)).

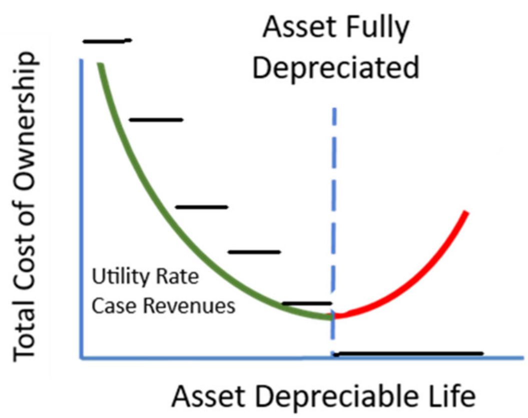
Figure 7: The Economic End-of-Life Approach to Asset Replacement from the Perspective of a Competitive Business



Note that Avista's "Idealized Economic Optimum" for asset replacement does not apply to a competitive business. The competitive business only invests in replacement assets when its existing assets become economically unviable (i.e., costs exceed revenues). The economic end-of-life approach requires significant adaptations to be appropriately applied in the context of a regulated utility. First, the risks are different. Competitive businesses rarely have duplicate assets to take the place of any asset, which becomes unavailable. All utilities design substations with full redundancy, called "N-1" design. In an N-1 design, each substation is designed to accommodate the loads of adjacent substations should one of those adjacent substations fail. Thus, the failure of a piece of equipment, and hence its availability risk, does not necessarily result in a service outage for customers. However, while service outage risk is much lower than availability risk for regulated utilities, and for substation equipment, Avista does not appear to have made that adjustment to its economic end-of-life modeling. Second, and perhaps even more importantly, the revenue dependency is dramatically different. Unlike a competitive business, regulated utility revenues are not dependent on substation asset availability.

Instead, regulated utility revenues are based on the value of the asset in the rate base, net of accumulated depreciation. This situation is depicted in Figure 8.

Figure 8: The Role of Rate Case Revenues in Regulated Utility Asset Replacement

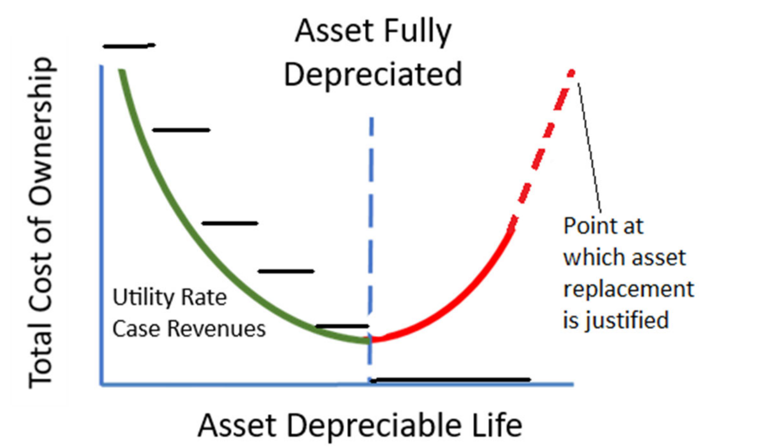


As Figure 8 indicates, once an asset is fully depreciated, a regulated utility earns no return on equity from it. In fact, fully depreciated assets not only result in zero earnings, any O&M costs incurred represent a reduction in earnings. This explains why regulated utilities are motivated to replace assets as soon as possible once fully depreciated.

Q. However, simply because a regulated utility is motivated to replace assets as soon as possible once fully depreciated does not mean Avista is replacing assets before it is necessary to do so, correct?

A. No, it does not. But consider the fact that Avista's own stated policy – to replace assets at their economic end-of-life, as Avista defines it, is deeply flawed. If the total cost of ownership curve reflects all costs and risks, as Avista claims it does, then assets should only be replaced when the total cost of ownership of an existing asset *exceeds* the total cost of ownership of a new asset, as depicted in Figure 9.[48]

Figure 9: Point at which "total cost of ownership", if used, should indicate asset replacement



Further, I note that Avista's total cost of ownership curves assume that substation equipment should be replaced based on the likelihood of asset failure, which Avista determines almost exclusively by asset age. These "likelihood of failure" risks (represented by yet another type of curve, called "Weibull" curves) appear to be a key input into Avista's total cost of ownership estimates, which Avista then uses to identify assets in need of replacement. The use of failure likelihoods to identify assets in need of replacement might be acceptable if there were no better way to do so. Fortunately, much better, and much more objective, means to identify substation assets in need of replacement are available. In fact, all utilities, including Avista, maintain substation asset

[48] The dotted part of the red line represents the additional O&M costs that can be incurred before it becomes cheaper to replace an asset than it does to maintain it. This happens when the peak of the red line (dotted) reaches the peak of the green line.

testing programs to identify critical substation assets, which are likely to fail and therefore need to be replaced. These programs objectively test substation transformers, circuit breakers, and relays on a routine, periodic basis. Given these testing programs, there is no need to prospectively replace substation assets based on likelihood of failure. Instead, substation assets should be identified for replacement based on the results of these objective tests. In the next section of testimony, Mr. Stephens will describe these standard practices and their application, providing examples to illustrate how Avista's prospective replacement results in electric distribution investment in excess of that required for safe and reliable service.

B. Critique of Avista's Substation Rebuild Program (Stephens)

Q. Provide a preview of this section of testimony.

A. In this section of testimony, I will critique Avista's Substation Rebuild program. First, I will describe standard industry practices for identifying substation equipment in need of replacement, and for upgrading substation capacity as dictated by load forecasts. Second, I will describe Avista's Substation Rebuild program, which consists largely of prospective replacement, identifying instances in which the substation rebuild program departs from standard industry practices. Finally, I will discuss recommendations for the Commission regarding Avista's Substation Rebuild program, including both recent and planned spending, and implications for distribution planning at Avista in general.

1. Standard Industry Practice for Identifying Substation Equipment in Need of Replacement

Q. What are standard industry practices for replacing substation equipment?

A. Substation equipment, when it fails, typically impacts large numbers of customers. A single substation transformer might serve three or four circuits, each of which might serve one thousand or more customers. As a result, standard industry practices regarding objective testing of substation equipment have arisen over time. Key types of substation equipment, including power transformers, circuit breakers, and relays, are the subject of routine, periodic testing processes applied every three to five years.

In the case of transformers, transformer oil is tested through dissolved gas analysis. Increases in dissolved gasses indicate an increased risk of failure, and power transformers that fail a dissolved gas analysis test are scheduled for replacement. In the case of circuit breakers and relays, physical testing (for example, by purposely introducing a fault) is performed to determine if the equipment will operate as designed when called upon.[49] As with power transformers, circuit breakers and relays that fail the physical tests are scheduled for replacement.

2. How Avista Identifies Substation Assets for Replacement

Q. Does Avista follow these routine, periodic substation equipment-testing practices?

A. Yes, of course. All utilities do. However, Avista uses a number of other factors that are not industry standard practices to justify substation equipment replacement. These

[49] For physical tests, circuits are temporarily re-configured so as not to inconvenience customers with outages while tests are conducted.

include: 1) compliance with NERC and FERC transmission substation standards and current Avista construction standards; 2) requirement to install communications equipment and relays, which make equipment remotely controllable; 3) equipment subjectively evaluated as end-of-life, in poor condition, and/or obsolete; and 4) to accommodate load growth by replacing existing equipment with equipment of higher capacity. (Note that while this last item is of course standard practice, Avista accommodates growing loads in a manner which is not, as I will describe.)

Q. Please explain why these practices are problematic.

A. These practices appear reasonable out of context, but none of these practices, in and of themselves, justify substation equipment replacement in the manner Avista applies them. Following these non-standard practices, Avista replaces substation equipment without the objective test results or cost-benefit analyses that indicate the benefits to customers from equipment replacements exceed the costs to customers. Avista also applies subjective criteria to determine the timing of equipment replacement and upgrades substation capacity significantly earlier than necessary. By using non-standard practices to justify substation equipment replacements and capacity upgrades, Avista significantly inflates its substation equipment rate base. I will describe each of these practices in turn and explain why they do not justify the level of substation equipment replacement Avista has spent recently, or proposes to spend in the future.

3. Example of Non-standard Equipment Replacement: Compliance with Inapplicable Standards

Q. Please explain why it is not reasonable for Avista to use NERC and FERC transmission substation standards or its own construction standards to justify its proposed level of spending on distribution substation equipment replacement.

A. First, Avista often cites NERC and FERC transmission substation standards as rationale for distribution substation equipment replacement. However, NERC and FERC *transmission* substation standards are stricter than standards for *distribution* substations, and for good reason. While a distribution substation may serve a few thousand customers, transmission substations can serve tens of thousands of customers. Standards that may be cost effective for a transmission substation serving tens of thousands of customers may not be cost effective for a distribution substation serving thousands, and may therefore be an inappropriate factor to determine the level of spending for distribution substations. Further, even in cases in which a transmission substation standard might make sense for a distribution substation, Mr. Alvarez and I have observed utilities taking liberties with how standards are interpreted in a manner resulting in excess capital investment. For example, NERC and FERC transmission standards rarely prescribe capital investments. Instead, these standards typically require that an asset owner have certain operating capabilities or periodic review processes in place. The manner in which an asset owner fulfills those requirements is typically left up to the asset owner. While one asset owner (for example, a regulated, for-profit utility) might choose to fulfill a specific requirement through a capital investment, another asset owner (for example, a non-profit co-operative or government agency) might choose to fulfill the same requirement without a capital investment. Increased inspection, maintenance, or monitoring can often serve to meet NERC and FERC-type standards without large capital investments.

Avista also justifies substation equipment replacement by citing compliance with its own construction standards. In my experience, construction standards are applied to new construction, not retroactively applied to existing equipment already in operation. As an engineer, I can appreciate Avista's interest in harmonizing its grid; it could be useful to engineers if the same equipment, design, spacing, and other characteristics were in place at substations throughout Avista's system. Nevertheless, harmonization will never be achieved, as the grid is always changing, and new technologies and practices are always being introduced. By the time a piece of substation equipment, characteristic, or design practice is applied across Avista's system, a new technology or practice will come along which will make the newly achieved consistency obsolete. Even if harmonization could be achieved, the benefits of doing so would never exceed harmonization's astronomical costs. This is a very slippery slope. If the Commission permits this type of activity to continue, every update to Avista construction standards will result in tens or hundreds of millions of dollars in capital to continually retrofit Avista's system.

4. Example of Non-standard Equipment Replacement: Lack of Favorable Cost-Benefit Analysis

Q. What about remote communications and control capabilities? Please explain why Avista's practice of installing remote communications and control capabilities is unreasonably increasing substation equipment replacement costs.

A. I do not mean to imply that remote communications and control capabilities are always a bad investment. Certainly, there are instances in which remote communications and control capabilities are cost-justified. My concern is that Avista cites the lack of remote communications and control capabilities as a reason to replace an asset. Instead, the decision to add remote communications and control capabilities should be based on a cost-benefit analysis. For example, if a certain piece of equipment is only visited once or twice a year to flip a switch or change a setting, the savings in labor just does not justify paying $50,000 to $100,000 or more to change it out with a remotely communicating and controllable version. I also note that retrofit kits are available to add communications and control capabilities to the devices most-commonly installed in substations, thereby avoiding the capital required to replace the device itself.

5. Example of Non-standard Equipment Replacement: Premature "End of Life" Determination

Q. How about equipment that is approaching end-of-life, and/or is in poor condition, and/or has become obsolete? Please explain why Avista's approach to replacing old equipment does not comport with industry standard practices.

A. As explained by Mr. Alvarez in the previous section of testimony, Avista's approach to identifying assets in need of replacement, defined as the point at which total cost of ownership starts to increase, is flawed. Equipment age, which is a significant input in Avista's total cost of ownership calculations, is actually a fairly poor predictor of equipment failure. This is why the objective substation equipment testing programs I described earlier have become standard practice: they are excellent predictors of equipment failure.

Further, I note that Avista adds subjective assessments of asset condition to justify substation equipment replacement. All engineers prefer new equipment to old equipment.

Certainly, engineers look for reasons to replace old equipment with new equipment, using words like "old" and "obsolete", and phrases like "in poor condition." But subjective assessments do not stand up to empirical data. A bit of rust or oil on the outside of a device does not mean it is in such poor condition that it cannot operate reliably. In discovery, in example after example, I found such claims did not stand up to empirical data.

Q. Please provide examples of instances in which Avista claims did not stand up to empirical data.

A. One example is air switch replacement. In 2018, Avista prospectively replaced 91 air switches with an age range of 19 to 53 years, and an average age of 41.2 years.[50] Only two of these were replaced due to overloading (a valid justification); almost all the others were replaced due to "obsolescence," with a few citations of high maintenance costs. Avista also reports that it has a 90-year-old air switch currently operating safely and reliably on its system.[51] Not only is it clear that air switches can operate safely and reliably until at least 90 years of age, Avista provided no rate of failure-in-service data which indicates air switches should be replaced at the average age of 41.2 years. When asked to provide evidence that air switches were obsolete, and could not be obtained from any manufacturer, Avista replied: "The fact that an apparatus may be available for

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[50] Alvarez & Stephens, Exh. PADS-17 (Avista Response to Public Counsel Data Request No. 208, Attachment A, tab "2018").
[51] *Id*., (Avista Response to Public Counsel Data Request No. 208, Attachment A, tab "PC-208 Part h Equip Type Data").

purchase does not obviate the practical need to make asset decisions in the aggregate that allow us to run an efficient, reliable, and cost-effective operation."[52] I take this response to mean that air switches are not obsolete. Further, I guarantee that tens of thousands of air switches older than 60 years of age are operating safely and reliably on electric distribution grids across the U.S. at this very moment.

Another example is Avista's decision to replace Transformer #2 in its Colville substation at an age of 67 years. This may sound old, but the oldest substation transformer operating safely and reliably on Avista's system today is 75 years old. Substation transformers in the industry are known to last over 100 years, with an average age of failure at approximately 79 years of age.[53] This industry data indicates that a 67-year-old transformer has 12 years of life remaining on average, and possibly as much as 24 more years of life remaining. The 67-year-old Colville Transformer #2 passed all its most recent tests.[54] Avista justified this $680,000 replacement with just a few sentences: "Oil leaks abound on this unit. Relaying on the unit does not have differential protection. Associated circuit switcher is under-rated for the fault duty."[55] I note that the presence of oil does not necessarily indicate a leak, that oil leaks are repairable, and that neither the presence of oil nor a leak justify transformer replacement. When questioned,

[52] Alvarez & Stephens, Exh. PADS-18 (Avista Response to Public Counsel Data Request No. 172 (d)).
[53] Alvarez & Stephens, Exh. PADS-19 (Dan Martin and T. Saha. POWER TRANSFORMER FAILURE SURVEY AND MODELING RELIABILITY – UPDATE AND LOOKING AHEAD, Univ. of Queensl. Austl. (Aug. 22, 2017.)
[54] Alvarez & Stephens, Exh. PADS-20 (Avista Response to Public Counsel Data Request No. 215(i), Attachment A.)
[55] Alvarez & Stephens, Exh. PADS-21 (Avista Response to Public Counsel Data Request No. 101, Attachment E).

Avista estimated that oil is present on about 15 percent of its transformers.[56] Yet, Avista is clearly not replacing all transformers with oil present, nor should it; Avista only uses this as part of a transformer replacement justification. Relays with differential protection are certainly available for installation, and Avista admits that an under-rated circuit switcher does not justify transformer replacement either.[57]

6. Example of Non-standard Equipment Replacement: Premature Capacity Increases

Q. To summarize, your point is that prospective equipment replacement, when based on premature end-of-life determinations, and/or subjective assessments, is not cost effective. But certainly Avista must increase substation capacity as dictated by load growth, correct?

A. Of course, Avista must upgrade substation equipment capacity when no alternative exists. However, even here, I find that Avista does not upgrade substation equipment capacity in accordance with standard industry practices. Instead, Avista replaces substation equipment many years in advance of need.

Q. What is the standard industry practice for upgrading substation capacity based on load growth?

A. Standard practice is to forecast peak load growth by circuit, in megawatts, and to compare those forecasts to equipment capacity ratings in megawatts.[58] When the

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[56] Alvarez & Stephens, Exh. PADS-20 (Avista Response to Public Counsel Data Request No. 215(d)).
[57] *Id*. (Avista Response to Public Counsel Data Request No. 215 (h)).
[58] Note that "load forecasts" include not just loads of the feeders a substation is normally configured to support, but also the loads of nearby substations should a line supplying one of those nearby substations fail for any reason. With this redundant design, also known as "N-1" design, a substation will continue to operate even if one of its two supply lines is lost. Redundant, "N-1" design of sub transmission (substation) networks is standard industry practice.

forecasts threaten to exceed capacity, utilities begin planning to replace existing equipment with equipment of greater capacity. Standard industry practice is to begin planning these upgrades when loads are first forecasted to exceed 100 percent of equipment capacity ratings.

Q. How does Avista upgrade substation capacity based on load growth?

A. Avista follows this process pretty much exactly, but with one very significant exception. Instead of planning to upgrade a substation when load forecasts first indicate that loads will soon exceed 100 percent of equipment capacity, Avista begins the equipment replacement process as soon as actual loads exceed 80 percent of equipment capacity.[59] In all the electric distribution plans I have reviewed, I have never observed such an approach. It can take decades — if ever — for load growth on a substation or piece of equipment serving at 80 percent of rated capacity to reach 100 percent of capacity. Even then, substation equipment is designed to operate for several hours at a time well beyond 100 percent of capacity; this is called the net overload limit.

Q. How does Avista's practice result in excess distribution investment?

A. By using 80 percent actual loading instead of 100 percent forecasted loading to trigger substation capacity expansion, Avista is dramatically accelerating and increasing investment over and above the amount needed to provide safe and reliable service. At 80 percent load, the risk that a piece of equipment will fail due to overloading is essentially

[59] Alvarez & Stephens, Exh. PADS-21 (Avista Response to Public Counsel Data Request No. 101(d)).

zero,[60] yet Avista is making substantial investments to reduce an overload risk, which is unlikely to materialize in the near term, if at all.

Q. How should Avista identify the need to upgrade substation equipment capacity?

A. Avista should adopt standard industry practices regarding substation equipment capacity upgrades, and upgrade equipment when load forecasts first indicate 100 percent loading of rated equipment capacities is expected. There is no need to replace equipment substantially in advance of such an indicator. Doing so will result in costs to customers in excess of benefits to customers.

Q. What are your recommendations to the Commission regarding Avista's Substation Rebuild Program?

A. Due to excess capital investment resulting from prospective equipment replacement, which is not standard industry practice, I recommend the Commission reject recovery of $11.84 million[61] in Substation Rebuild capital cost Avista requests in this rate case as well as the associated return on investment. The revenue impact of this recommendation is addressed in the testimony of Public Counsel witness, Ms. Andrea Crane. In addition, I recommend the Commission order Avista to make several changes to its substation rebuild program, with the result being a substation planning and capital budgeting process that comports with standard industry practices, as well as a reduction in excessive grid investments. These changes include:

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[60] Alvarez & Stephens, Exh. PADS-22 (Avista Response to Public Counsel Data Request No. 286(a)).
[61] Alvarez & Stephens, Exh. PADS-23 (Avista Response to Public Counsel Data Request No. 241, Attachment A).

1. Avista should use zero-based budgeting, not standing budgets, for its substation rebuild program;
2. Avista's zero-based budgets for the substation rebuild program should be developed from a distribution planning process which follows the Jade Cohort recommendation of the NARUC-NASEO Task Force, with the exception that there is no need for a separate grid modernization process;
3. Prospective equipment replacement in the absence of objective test result failure, or without cost-benefit analyses which indicate benefits to customers exceed costs to customers, should be prohibited. Specifically, distribution substation equipment replacements should not be justified through: a) transmission substation standards/Avista construction standards; b) a "requirement" for communications capabilities absent a benefit-cost analysis; and/or c) premature determinations of "end-of-life" based on flawed definitions or subjective assessments.
4. Planning for substation capacity increases should begin when the load forecasts for the substation first indicate that 100 percent of rated capacity is likely to be reached in the next 4–5 years. Avista's practice of planning and implementing capacity increases once actual loads reach 80 percent of rated capacity should be prohibited.

Further, given the significant departure of Avista's planning and budgeting practices from industry standards, I recommend the Commission consider ordering greater transparency and stakeholder participation in Avista's distribution planning and capital budgeting processes. In fact, the Commission may wish to consider this for all regulated distribution utilities in Washington, be they electric, gas, or water. We will return to this subject in the summary and recommendations section of this testimony.

C. Critique of Avista's Grid Modernization ("Feeder Review") Program (Stephens)

Q. Please provide a preview of this section of testimony.

A. In this section of testimony, I will critique Avista's Grid Modernization program. First, I will describe standard industry practices for replacing distribution equipment. Second, I will describe Avista's Grid Modernization program, which consists largely of prospective equipment replacement, and will identify instances in which the program departs from standard industry practices. Finally, I will discuss recommendations for the Commission regarding Avista's Grid Modernization program, including both recent and planned spending, and implications for distribution planning at Avista in general.

Q. Please describe standard industry practices for replacing distribution equipment.

A. As I testified in the previous section, objective tests are available for various types of substation equipment. Because the reliability of large numbers of customers depends on substation equipment, routine, periodic testing of critical types of substation equipment is a standard industry practice. This is because the cost of such testing, and the cost to replace equipment which fails objective tests, has proven to be cost effective over time. By "cost effective," I mean that the benefits to customers of equipment testing and replacement exceed the costs of these activities.

However, distribution equipment is fundamentally different from substation equipment. Most utilities count the number of various types of distribution equipment in the thousands or tens of thousands; each piece of distribution equipment therefore serves a very small number of customers. For example, at most utilities, distribution transformers serve three to five customers each. At Avista, the average number of customers served per distribution transformer is higher, due to the "open secondary" design Avista employed on older parts of its system, but is still probably no more than 10 or so customers. A mile of Avista distribution line serves only 20 customers on average; a cut-out (fuse) probably serves an average of just 30–50 customers. The implication is that a failure of any one piece of distribution equipment causes an outage for relatively few customers. This fact, combined with the fact that distribution equipment typically lasts for many decades before failing, has resulted in a standard industry practice for replacing distribution equipment, which is much different than that for substation equipment. Though the name of the practice may sound negative, "run-to-failure" has become an industry standard because, when it comes to distribution equipment, no other approach has proven to be as cost effective.

Q. So, "Run-to-Failure" is what it seems? You run equipment until it fails?

A. Yes, and such failures do cause outages. Since so few customers are impacted by the failure of any one distribution device, and such equipment failures are rare, prospective equipment replacement is simply not a cost effective option. Utilities must make decisions that balance the cost of an adverse event, such as a transformer failure, against the cost of prospective equipment replacement. It is in all customers' interests for utilities to do so.

For example, assume that the average service life of a distribution transformer is 60 years. Thus, once every 60 years, somewhere between three and 10 customers served by a specific transformer will experience an outage because that transformer fails. A utility could reduce the once-in-60-year outage risk by replacing transformers more frequently, say every 10 years or so. But it is not worth replacing the same transformer six times over to avoid a single outage in 60 years, impacting just 3–10 customers. Multiply the cost of a once-a-decade transformer replacement by the tens of thousands of distribution transformers Avista has on its system, and one can readily see the enormous rate impact prospective equipment replacement can have. The reality is that reliability is subject to the law of diminishing returns. We could have perfectly reliable electricity service if we really wanted it, but the cost would be so high that no one could afford their electric bill. Conscious decisions about the appropriate balance between reliability and cost should be made. Because different customers (and customer classes) place different values on reliability, it can be argued that decisions regarding the reliability versus cost balance should be made by stakeholders, not utilities.

Q. Are there other standard distribution grid practices of which the Commission should be aware?

A. Another distribution grid practice most utilities maintain is a "worst performing feeder" program. In such a program, the distribution feeders exhibiting the poorest reliability performance over a defined period (generally three years) are given special attention. Utility engineers examine worst performing feeders to identify frequently-occurring outage causes (root cause analysis), and take the steps necessary to rectify root causes. Utilities have adopted such programs because they focus spending where that spending will deliver the greatest customer benefits: on the feeders with the worst reliability. In fact, Avista reports that it has maintained a worst performing feeder program at times in the past, with the most recent program iteration terminated in 2017 in favor of the Grid Modernization program.[62]

Q. Please summarize Avista's Grid Modernization program.

A. To begin, Avista's Grid Modernization program is inappropriately named. In all the electric distribution plans I have evaluated, "modernization" refers to the installation of devices that can monitor grid conditions, communicate data, and be controlled remotely. While Avista's Grid Modernization program does some of this, it is a relatively small component of program spending. Of the 14 Avista feeder review reports I examined,[63] which typically run 30 to 70 pages each, only a few pages (generally 2–3) are dedicated to the installation of a handful of such devices (generally 4–6). A few feeder reviews incorporate no such installations. Instead, actions and investments recommended in feeder review reports are dominated by prospective replacement of mundane grid equipment — conductors, transformers, poles, cut-outs (fuses), etc. — with like equipment. I would more appropriately describe the program as a feeder review program rather than a true grid modernization program. For the sake of conformity with Avista's testimony, however, I will refer to the program as Avista's Grid Modernization program.

To summarize, Avista's Grid Modernization program is designed to conduct a complete review of every feeder in Avista's system once every 60 years. With 347 feeders (circuits) on Avista's system, this would amount to completing about six feeder

[62] Alvarez & Stephens, Exh. PADS-13 (Avista Response to Public Counsel Data Request No. 246(a) and (b)).
[63] Alvarez & Stephens, Exh. PADS-16 (Avista Response to Public Counsel Data Request No. 110, Attachments A–N).

reviews a year. Feeders are prioritized for review by feeder health, performance, and "criticality" using 13 related metrics. I note that only two of these 13 metrics involve reliability performance.[64] Reviews generally follow a pre-defined format which examines specific feeder characteristics, including performance (reliability, voltage, power factor, and energy efficiency); equipment condition (subjectively determined); design (including ties to nearby feeders and automated device inventory); and load balance (between phases). I note that vegetation is not inspected as part of the feeder review process, an omission to which I will return later in this section of testimony. The output of a feeder review is a recommendations report. This report is directed to grid engineers and prescribes actions to take and capital investments to design. I get the impression the report authorizes grid engineers to charge costs of prescribed actions to the Grid Modernization capital budget.

Q. What are your concerns about Avista's grid modernization program?

A. My concerns are significant. First, poor reliability does not appear to be the primary driver of feeder selection for review. Of the 14 feeder review reports Avista provided for my examination, six did not review prior reliability performance at all; four feeders featured outage frequency, which was average or better; and only four featured below average outage frequency. Only one of the 14 feeders reviewed performed very poorly on outage frequency.[65] To me, this implies a poor focus of time, effort, and capital.

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[64] Alvarez & Stephens, Exh. PADS-24 (Avista Response to Public Counsel Data Request No. 116(a)).
[65] Alvarez & Stephens, Exh. PADS-16 (Avista Response to Public Counsel Data Request No. 110, Attachments A–N).

My second concern is that none of the feeder review report recommendations are cost-justified. The projected value of recommended projects, in terms of improved reliability, reduced O&M spending, or improved energy efficiency, is never quantified in these reports. The cost of the recommended projects is not even estimated in these reports. As mentioned above, the recommendations consist largely of prospective replacement of equipment that appears to be working safely and reliably. I do not understand how a utility can proceed to implement the recommendations in a particular feeder review report without an understanding of the costs or benefits of the recommendations. Further, if none of the feeder review recommendations are cost-justified, I fail to see how the Grid Modernization program as a whole is cost-justified.

Q. Please describe Avista's rationale for its grid modernization program.

A. Avista reported that the program delivers value overall, stating the program, like the substation rebuild program, is "intended to have the integrated long-term impact of generally maintaining and upholding the overall reliability performance of our electric infrastructure."[66] Avista also claims its grid modernization program provides energy efficiency and operations and maintenance (O&M) cost reductions. However, as I will testify next, I believe reliability can be maintained for much lower costs, and there is evidence the energy efficiency and O&M cost reductions are negligible.

[66] Alvarez & Stephens, Exh. PADS-11 (Avista Response to Public Counsel Data Request No. 288(b)).

Q. Does Avista provide evidence of reliability improvements from its Grid Modernization program?

A. Yes, it does, but what we do not know from Avista's feeder review reports, and cannot know due to a lack of information on cost effectiveness, is whether or not the same results could have been secured in a less costly manner. Any utility can spend millions of capital dollars on a feeder, and the feeder's reliability performance will improve. The question is whether that utility could have secured the same reliability improvements at a lower cost by focusing its efforts on worst performing feeders and targeting capital spending on the results of associated root cause analyses of recurring outages on those feeders. These are questions Avista cannot answer regarding its Grid Modernization/feeder review program, which could mean that Avista's customers are significantly overpaying for these reliability improvements.

Q. Please explain the problems with the Avista's claims regarding the energy efficiency and O&M savings benefits of its Grid Modernization program.

A. Avista's claims are not backed by data. For example, Avista estimates that the energy savings from Washington feeders on which Grid Modernization capital was spent from 2018 through 2020 amounted to just 1,674 MWh annually.[67] At an energy cost of $15.37 per MWh,[68] this amounts to just $25,729 annually. Over a 30-year average life of these equipment replacements, assuming a two percent inflation rate, and discounting by

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[67] Alvarez & Stephens, Exh. PADS-16 (Avista Response to Public Counsel Data Request No. 110(f)).
[68] Clint G. Kalich, Exh. CGK-6.

Avista's weighted average cost of capital (7.4325 percent), this works out to a present value of just $375,800 for customers. For a program on which Avista spent an average of $13.25 million annually between 2015 and 2019,[69] energy efficiency value is essentially the size of a rounding error. (Note that the $375,800 present value from energy efficiency is from *three* years of feeder review program spending, not just one year.) Regarding O&M spending reductions, Avista admitted in discovery that it could not specifically attribute a single headcount reduction to feeder review program.[70] Make no mistake; the feeder review program is justified primarily through reliability improvements. I contend a worst performing feeder program, complete with associated root cause analyses, could secure the same reliability benefits as the feeder review program at dramatically less cost, as efforts and spending are more focused in worst performing feeder programs.

Q. Do you have other concerns with Avista's Grid Modernization program?

A. Yes. Avista's Grid Modernization program appears to be an attempt to shift activities, which would be classified as O&M spending to activities, which can be classified as capital spending. Again, we do not know if the reliability improvements could have been secured through less costly means, as neither the program nor the actions prompted by the feeder reviews are subject to a cost-benefit analysis.

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[69] Alvarez & Stephens, Exh. PADS-15 (Avista Supplemental Response to Public Counsel Data Request No. 98, Attachment B).
[70] Alvarez & Stephens, Exh. PADS-25 (Avista Response to Public Counsel Data Request No. 107(a)).

Q. Can you provide examples where Avista focuses spending on capital-intensive programs rather than O&M programs?

A. One example is certainly vegetation management, an O&M expense. Though trees account for almost 10 percent of Avista outages,[71] tree trimming is not a focus of the grid modernization feeder reviews. Of the 14 feeder review reports I examined, which again consist typically of between 30–70 pages filled with capital spending recommendations, a single tree-trimming paragraph is repeated by rote in every single report, starting with "Vegetation management shall be employed on (feeder xyz) where applicable." That a function so critical to maintaining and improving feeder reliability is not even part of the grid modernization feeder review process is an indication that the program is not designed to identify and prioritize reliability risks to be addressed based on historical outage causes.

Avista's treatment of vegetation management contrasts with its replacement of cutouts, which is a capital-intensive program. Cutouts are essentially fuses that are installed at the point at which a lateral line, or "tap," taps into a feeder. These laterals and cutouts serve 30–50 homes each at most utilities. Taps are also used to provide protection and a disconnect point for distribution transformers, which may serve as few as 3–5 customers. Avista's feeder review program guide[72] encourages grid engineers to prospectively replace cutouts for many reasons, including: 1) replacement at the discretion of the engineer; 2) replacement when an associated transformer is being replaced; and 3) replacement of all the cutouts on a crossarm if any one cutout on a

[71] Alvarez & Stephens, Exh. PADS-26 (Avista Response to Public Counsel Data Request No. 106(a)).
[72] Alvarez & Stephens, Exh. PADS-27 (Avista Supplemental Response to Public Counsel Data Request No. 108, Attachment A at 11–12).

crossarm requires replacement. None of these reasons is consistent with standard industry practice (run-to-failure) for cutouts, resulting in excess capital investment not based on current risk levels. Indeed, Avista reports that about 100 of its cutouts fail in an average year.[73] However, this figure must be placed into context, as Avista currently operates tens of thousands of cutouts, perhaps as many as 30,000 or more. In addition, the guide encourages grid engineers to replace seven different cutout models. Just one of these models (porcelain cutouts manufactured by A.B. Chance Company) is responsible for 97.6 percent of the cutout failures Avista has experienced in recent decades.[74] Thus, Avista's guidance to prospectively replace cutouts for a variety of reasons not based on quantified risks should instead consist simply of replacing all porcelain cutouts manufactured by A.B. Chance. While Avista certainly is replacing all A.B. Chance porcelain cutouts, an effort that is almost 100 percent complete, Avista also appears to be generalizing its experience with one type of cutout to encourage and justify unnecessary, prospective replacement of all cutouts. This example illustrates two recurring themes in this testimony: 1) standing budgets encourage a search of solutions to apply, rather than an identification and prioritization of risks to address based on data; and 2) prospective replacement is not a cost-effective approach to improving distribution reliability.

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[73] Alvarez & Stephens, Exh. PADS-28 (Avista Response to Public Counsel Data Request No. 105, Attachment A at 45, Figure 23).
[74] Alvarez & Stephens, Exh. PADS-29 (Avista Response to Public Counsel Data Request No. 292(b)).

Q. What are your recommendations to the Commission regarding Avista's Grid Modernization Program?

A. Due to excess capital investment resulting from prospective equipment replacement, which is not standard industry practice, I recommend the Commission reject recovery of $11.27 million in Grid Modernization capital cost Avista requests in this rate case as well as the associated return on the investment.[75] The revenue impact of this recommendation is addressed in the testimony of Public Counsel witness, Ms. Andrea Crane. In addition, I recommend the Commission order Avista to eliminate its Grid Modernization (feeder review) program, and return instead to a more focused, and lower-cost, approach to improving grid reliability in the form of a worst performing feeder program. The worst performing feeder program should consist of the following characteristics:

1. Avista should select the reliability metrics, minimum performance levels, and performance periods used to identify feeders for special attention. Each year, the Avista feeders that have consistently violated these minimums during the defined performance period (for example, 3–5 years) should be selected for special review.
2. The reviews should focus on the root causes of poor reliability on selected feeders. Root cause analysis should be data-driven, using the causes of outages as a starting point. Reliability risks to be addressed should be prioritized in dollar values as calculated on an event probability x event consequence basis.

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[75] Alvarez & Stephens, Exh. PADS-30 (Avista Response to Public Counsel Data Request No. 247(a), Attachment A).

3. Potential solutions to high-priority risks should be evaluated and selected based on risk reduction per dollar of cost, and without regard to spending type (capital vs. O&M). It should be recognized that some reliability risks, if no reasonably cost--effective solution is available, are appropriate to accept. It is likely these will be lower-priority risks quantified through the dollar valuation approach described above.
4. Regarding budgets, I recommend that no specific budgets should be established for the program at this time. Instead, once several years of experience regarding the capital and O&M spending required to mitigate the reliability risks of worst performing feeders annually is established, appropriate capital and O&M budgets for the worst performing feeder program based on historical actual spending can be set.
5. Avista should begin considering the feeder (and substation) upgrades needed to accommodate growing loads, growing capacity of distributed energy resources, and similar concerns as identified in the Jade Cohort distribution planning process recommended by the NARUC-NASEO Task Force. In addition, as recommended by the Task Force, non-wires alternatives to meet these needs should be considered. These issues and efforts should not be limited by the worst performing feeder program, nor limited to the feeders reviewed in the worst performing feeder program.
6. Avista should adopt "run-to-failure" as the default policy for distribution equipment.

7. Regarding the fact that Avista's Grid Modernization program consists only minimally of distribution automation, Avista should proceed with a proposed installation of grid state-sensing, communicating, remotely-controllable devices only for those installations which pass a rigorous benefit-cost analysis. It is anticipated these will be devices that isolate outages and/or re-route power for reliability, or which advance Avista's conservation voltage reduction program. These actions need not be limited to worst performing feeders.

Further, given the significant departure of Avista's feeder review program practices from industry standards, I reiterate my recommendation that the Commission consider ordering greater transparency and stakeholder participation in Avista's distribution planning and capital budgeting processes. In fact, the Commission may wish to consider this for all regulated distribution utilities in Washington, be they electric, gas, or water. Mr. Alvarez and I provide more information on this recommendation in the final section of this testimony, next.

D. Review and Recommendations for Avista's Electric Distribution Plan

Q. Please summarize your Panel Testimony on Avista's Electric Distribution Plan.

A. Our testimony began with a preview of recurring themes found in our critiques of Avista's historical and planned electric distribution spending. Specifically, we challenged the use of standing budgets and prospective equipment replacement employed in Avista's substation rebuild and feeder review programs. We presented information in support of our contentions that standing budgets and prospective equipment replacement differ from standard industry practices, and likely resulted in capital spending greater than necessary for safe and reliable electric service delivery. We introduced a distribution planning process recommended by a NARUC-sponsored task force as an illustration of standard industry practices and zero-based budgeting (as opposed to standing budgets). We pointed out that Avista's outage frequency performance is already in the top quartile of investor-owned utilities in the U.S. nationwide, leading us to question the need or urgency for any departure from standard industry practices. We also described how Avista's approach to determining assets' economic end-of-life is inappropriate for regulated utilities, and constitutes prospective replacement of equipment.

Our testimony then turned to a critique of Avista's Substation Rebuild and Grid Modernization programs, the latter of which we more appropriately labeled as a feeder review program. In these critiques, we compared Avista's approaches to standard industry practices. These comparisons identified departures from standard practices, provided examples to illustrate the deficiencies of such departures, and offered recommendations for Commission consideration.

Q. Based on this testimony, what are your recommendations to the Commission?

A. We recommend the Commission reject cost recovery of $11.84 million in substation rebuild program capital and $11.27 million in Grid Modernization program capital, and the associated return on investment, due to a lack of prudence, as incorporated into the revenue requirement adjustments of Public Counsel witness, Ms. Andrea Crane. In addition, we recommend the Commission order significant modifications to Avista's Substation Rebuild program, and order that the Grid modernization ("feeder review") program be eliminated in favor of a worst-performing feeder program.

Our primary critique of Avista's Substation Rebuild program is that the program features prospective equipment replacement that is neither cost effective, nor standard industry practice, nor justified by the rationale Avista employs. These rationales, in and of themselves, do not justify prospective replacement, which we believe is encouraged by Avista's use of "standing" budgets. These insufficient rationale include: 1) compliance with transmission substation standards, which do not apply to distribution substations, and with Avista construction standards, which do not apply to existing installations; 2) installation of communications equipment and relays that make equipment remotely-controllable without benefit-cost justification; 3) premature determination of end-of-life, and/or subjective assessments of equipment condition; and 4) increasing substation capacity once 80 percent of rated capacity is reached (100 percent is standard) to accommodate load growth by replacing existing equipment with equipment of higher capacity.

We therefore recommend the following modifications to Avista's substation rebuild program: 1) Replace the use of "standing" budgets with zero-based budgets; 2) Develop budgets using the distribution planning process recommended by the NARUC-NASEO Task Force (without a separate grid modernization process, however); 3) Prohibit prospective equipment replacement; and 4) Plan and implement capacity increases only when load forecasts indicate 100 percent capacity will be reached in the next 4–5 years.

Our primary critiques of Avista's Grid Modernization ("feeder review") program include: 1) Neither reviews nor spending are focused on the feeders with poorest reliability, or on the root causes of poor reliability performance; and 2) Neither the costs nor the benefits of feeder-specific recommendations are estimated. We note that the Grid Modernization program employs standing budgets, consists primarily of prospective replacement of mundane grid equipment, does not comply with standard industry practice, and is designed largely around capital-intensive programs that will grow rate base. We therefore recommend the Commission order Avista to eliminate its Grid Modernization program, and return instead to a more focused, and lower-cost, approach to improving grid reliability in the form of a worst performing feeder program. Our recommendation that the program's reliability benefits could be delivered at much lower cost is based on the more focused spending available from a worst performing feeder program.

Concerning the recommended worst performing feeder program, we made multiple suggestions for the design and operation of such a program, addressing issues such as feeder prioritization, root cause analysis, risk assessment, the approaching proliferation of distributed energy resources, and the role of non-wires alternatives in the testimony, above.

Q. You also recommended the Commission consider ordering greater transparency and stakeholder participation in utility distribution planning and capital budgeting. Please describe that recommendation and rationale in greater detail.

A. We recognize that it is difficult for the Commission to reject capital spending a utility claims is in the interest of improving or maintaining reliability. Information and expertise asymmetry lie at the heart of this difficulty. We believe a transparent distribution planning process featuring increased stakeholder participation in investment decisions offers an opportunity to address difficult decisions in advance of capital spending. These will also lead to less biased investment decisions as well as less cost disallowance risk for utilities.

We propose that the highly litigious rate case process is not the appropriate venue for developing distribution plans and capital budgets with stakeholder participation in a transparent manner. Despite hundreds of data requests submitted in discovery, we still have much to learn about Avista's distribution grid, distribution business, and distribution plans, and await responses to outstanding data requests even as we submit this testimony. We believe a collaborative process between stakeholders and utilities, over many months, related to the rate case process but not part of that process, hold great promise for delivering value to customers and shareholders while advancing Washington energy and environmental policy objectives at the least cost.

Q. Does this conclude your testimony on Avista's wildfire plan and electric distribution plan?

A. (Alvarez) Yes, it does, though I would appreciate the opportunity to revise this testimony if necessary based on responses received on outstanding data requests.

A. (Stephens) Yes, it does, though I would appreciate the opportunity to revise this testimony if necessary based on responses received on outstanding data requests.