BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-20____

DIRECT TESTIMONY OF

JASON R. THACKSTON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Jason R. Thackston. I am employed as the Senior Vice President of Energy Resources and Environmental Compliance Officer at Avista Corporation, located at 1411 East Mission Avenue, Spokane, Washington.

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

A. Yes. I graduated from Whitworth University in 1992 with a Bachelor of Arts in International Studies and an emphasis in Business Management and a Master of Business Administration from Gonzaga University in 2000. I joined the Company in 1996 as a Corporate Treasury Analyst. I have held several different positions at Avista, including roles in Finance and Accounting, Internal Audit, Risk Management, Power Supply, and Gas Supply. I was appointed Vice President of Finance in June 2009 and have since held the roles of Vice President of Energy Delivery and Vice President of Customer Solutions before assuming my current role in January 2013. The Energy Resources group is primarily responsible for producing or procuring the electricity and natural gas to serve our customers' needs, including the construction, operation, and maintenance of our generation facilities and the optimization of those electric and natural gas facilities for the benefit of our customers. The Energy Resources group also includes environmental affairs, including compliance with, and management of, the licenses issued by the Federal Energy Regulatory Commission authorizing the Company to operate its hydroelectric facilities.

Q. What is the scope of your testimony in this proceeding?

A. My testimony provides an overview of the Company's 100% Clean Electricity goal by 2045, carbon neutral electricity supply by the end of 2027, and why it is important to our Company. I will also provide an overview of Avista's resource planning and power supply operations. This overview includes summaries of the Company's current and future resource plans, as well as an overview of the Company's Energy Resources Risk Policy. I will address the generation-related capital projects included in this case, including capital additions associated with the Company's investment in Colstrip Unit Nos. 3 and 4 for the periods 2018-2022, as well as the prudency of its SmartBurn investments in 2016 and 2017. My testimony will conclude with a discussion of the Rattlesnake Flat Wind Power Purchase Agreement.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. Exh. JRT-2 is Avista's 2020 Electric Integrated Resource Plan and Appendices. Confidential Exh. JRT-3C is Avista's Energy Resources Risk Policy. Exh. JRT-4 includes a listing of all the generation capital projects that have transferred to plant during 2018-2019. Exh. JRT-5 contains Avista Utilities Generation Infrastructure Plan. Exh. JRT-6 includes the capital business cases for the historical major projects in 2018 and 2019, as well as the 2020 pro forma projects, all of which are discussed later in my testimony. Confidential Exh. JRT-7C contains the 2018 Renewable RFP Report and Documentation. Confidential

Exh. JRT-8C includes the Rattlesnake Wind Power Purchase Agreement and Confidential Exh. JRT-9C includes the Board documentation concerning the Rattlesnake Flat Wind Power Purchase Agreement. Exh. JRT-10 includes supporting documentation concerning the decision to install SmartBurn on Colstrip Units 3 and 4. Finally, Exh. JRT-11 provides additional documentation about the capital projects at Colstrip.

II. CLEAN ELECTRICITY AND NATURAL GAS GOALS

Q. Would you provide an update to the Company's 100% clean electricity goal by 2045, and carbon neutral electricity supply by the end of 2027?

A. Yes, the announcement made by Avista in April 2019 bolsters our long-standing history of, and well-established approach to, providing clean, reliable and affordable energy to the customers and communities we serve. We believe that the 100 percent clean electricity goal is an important step forward in caring for our environment while continuing to meet the energy needs of our customers and communities today and well into the future. Since Avista's founding on clean, renewable hydro power in 1889, we've served our customers with an electric generation resource mix that is more than half renewable, allowing us to keep our carbon emissions among the lowest in the nation.

Further, the Company has always been committed to balancing reliability and affordability while maintaining responsibility for our environmental footprint, and our actions demonstrate these values. Just in the last five years, we've implemented three renewable energy projects on behalf of our customers. Our Community Solar project in Spokane Valley, Solar Select project in Lind, and the Rattlesnake Flat Wind project in Adams County, discussed later in my testimony, together have allowed us to add to the clean electricity we already provide, meet the energy needs of our customers without increasing their bills and drive economic vitality in these communities.

Q. Why did Avista declare an electric carbon neutral goal when CETA already requires 100% clean electricity?

A. The Washington Clean Energy Transformation Act, or CETA, requires carbon neutral electricity by 2030 and carbon free by 2045 to serve Washington customers. We have seen a growing focus on clean electricity generation at the national, regional, and local levels. Our customers, communities and governments of all levels increasingly express an interest in knowing how Avista is positioned on this topic. While we have a strong and long track record related to clean electric generation, we felt it was time to be clear about our path forward for all of our customers, not just those we serve in Washington. Reaching this goal, of course, will require further improvements in technology and a reduction in their associated cost of clean electric generation and energy storage, as well as regulatory support. Going forward, we will track progress through our Integrated Resource Plan.

Q. What does carbon neutral mean and what percent of Avista's load is actually served with renewables?

A. Carbon neutral means achieving an overall net-carbon footprint by meeting our customers' annual electric needs through either utilizing non-carbon emitting resources, or investing in or acquiring carbon offsets to net-out emissions created from carbon emitting resources. An example of a carbon offset is acquiring renewable energy credits from a renewable energy resource. Currently, over 60 percent of Avista's customers' annual electric need is served from clean non-carbon emitting resources.

Q. What is the impact of this clean energy goal on Colstrip?

A. Colstrip has been an important source of generation in the region and for Avista's customers for over 30 years. It is available to serve our customers when the wind isn't blowing, the sun isn't shining, or there isn't enough water flowing down our rivers to generate enough electricity to meet our customers' energy needs. Colstrip will no longer be used to serve Washington customers after 2025 to comply with CETA. As described below in the IRP section of my testimony, modeling for the 2020 IRP indicated that Colstrip will also no longer be economically beneficial to serve Idaho customers after 2025 as well. However, it is important to note that the Company will continue to have a contractual obligation to pay for past, ongoing, and future costs associated with the generation of this output based on the joint ownership agreement. We continue to work with our five co-owners related to the future operation of Colstrip Units 3 and 4.

Q. How does natural gas fit with the Company's clean energy goal?

A. Natural gas has been a key energy choice for Avista's customers for nearly 70 years. It is an affordable and less expensive heating option for customers, especially for many large commercial and industrial customers who rely on it to run their business, provide jobs for their employees and serve their communities. Natural gas is one of the cleanest burning fuels and is an essential part of reducing carbon emissions, particularly when used directly by customers in their homes rather than used to generate electricity to meet the same need. Compared to wood, heating oil and other fuels, natural gas improves air quality. Additionally, the use of compressed natural gas (CNG) to fuel vehicles reduces carbon emissions in the transportation sector, which is a leading contributor of emissions. Avista consistently engages customers to educate about natural gas efficiency, and offers natural gas energy efficiency programs that also support lower emissions. In short, direct use of natural gas is efficient, creates less environmental impact than other fuels, and is an affordable option for customers.

Even though natural gas creates less environmental impact than other fuels, the Company recognizes the opportunity to implement strategies that will further improve the environmental impact by reducing the carbon emissions associated with the direct use of natural gas. Examples of carbon emissions reduction strategies include the following:

- Diversify or transition from fossil fuel-based natural gas to renewable natural gas;
- Reduce natural gas consumption via conservation, energy efficiency and new technologies; and
- Purchase carbon offsets as necessary.

Achieving the carbon emission reductions for the natural gas system will involve various pathways. The initial primary pathways include renewable natural gas (RNG), energy efficiency, customer voluntary RNG and carbon offset programs.

Q. How does energy efficiency play a role in this plan?

A. Energy efficiency has been an important piece of our energy resource puzzle for over 40 years, and we will continue to partner with our customers to use electricity more efficiently through our own customer education, outreach and economic incentive programs, as well as regionally through participation in the Northwest Energy Efficiency Alliance. Energy efficiency continues to be an effective option to lower customers' energy use, reduce our need to build additional generation, and further reduce the carbon intensity of our local economy.

III. RESOURCE PLANNING AND POWER OPERATIONS

Q. Would you please provide a summary of Avista's power supply operations and acquisition of new resources?

A. Yes. Avista uses a combination of owned and contracted-for resources to serve its load requirements. The Power Supply Department (Power Supply) is responsible for dispatch decisions related to those resources for which the Company has dispatch rights. Power Supply monitors and routinely studies capacity and energy resource needs. Short-and medium-term wholesale transactions are used to economically balance resources with load requirements. The Integrated Resource Plan (IRP) generally guides longer-term resource decisions such as the acquisition of new generation resources, upgrades to existing resources, demand-side management (DSM), demand response, energy storage, and long-term contract purchases. Resource acquisitions typically include a Request for Proposals (RFP) and/or other market due diligence processes.

Q. Please summarize Avista's load and resource position.

A. Avista's 2020 IRP shows forecasted annual energy and capacity deficits beginning in 2026. The deficits are a result of the expiration of the Lancaster power purchase agreement and the elimination of Colstrip from the Company's resource portfolio. The capacity and energy load/resource positions are shown on pages 7-4 and 7-5 of Exh. JRT-2.

The 2021 Electric IRP is currently being developed and is scheduled to be filed with the Commission on April 1, 2021, consistent with the Commission's Order 02 in Docket UE-180738 where it approved a delayed filing from the original August 31, 2019 filing date to provide time for required rulemakings under CETA.

Q. How does Avista plan to meet future energy and capacity needs?

A. The Preferred Resource Strategy (PRS) in the 2020 Electric IRP guides the Company's resource acquisitions, subject to any additional legislative requirements. The IRP provides details about future resource needs, specific resource costs, resource-operating characteristics, and the scenarios used for evaluating the mix of resources for the PRS. The IRP represents the preferred plan at a point in time; however, Avista continuously evaluates different resource options to meet current and future load obligations, especially in light of new legislation and market opportunities. Avista's 2020 IRP included as Exh. JRT-2, was filed with the Commission on February 28, 2020 as a progress report per Commission guidance.

Avista's 2020 PRS includes 1,133 MW of net supply-side resources which includes the addition of 1,667 MWs of new wind, pumped hydro, battery storage, solar and plant upgrades as well as the loss of 534 MWs of coal and gas-fired resources from the Company's resource portfolio. The PRS also includes 112 MW of demand response and 187 aMW of new energy efficiency through 2045. The timing and type of these resources included in the PRS for the 2020 IRP are provided in Table No. 1 below.

Table No. 1: 2020 Electric IRP Preferred Resource Strategy

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022-2023	200
Kettle Falls upgrade	2026	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	175
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
Montana wind	2027	200
Mid-Columbia hydro	2031	75
Northeast CTs retires	2035	-55
Long Lake 2nd powerhouse	2035	68
Liquid-air storage (16 hours)	2036-2041	100
Wind (including PPA renewals)	2041-2043	300
Lithium-ion storage (4 hour)	2042-2045	300
Solar w/ storage (4 hours)	2044	55
4-hr Storage for Solar	2044	50
Supply-side resource net total (MW)		1,133
Supply-side additions through 2045 (MW)		1,667
Demand Response through 2045 (MW)		112
Energy Efficiency through 2045 (aMW)		187

Q. Would you please provide a high-level summary of Avista's risk management program for energy resources?

A. Yes. Avista Utilities uses several techniques to manage the risks associated with serving customers and managing Company-owned and controlled resources. The Energy Resources Risk Policy, which is attached as Confidential Exh. JRT-3C, provides general guidance to manage the Company's energy risk exposure relating to electric power and natural gas resources over the long-term (more than 41 months), the short-term (monthly and quarterly periods up to approximately 41 months), and the immediate term (present month).

The Energy Resources Risk Policy is not a specific procurement plan for buying or selling power or natural gas at any particular time, but is a guideline used by management when making procurement decisions for electric power and natural gas as fuel for electric generation. The policy considers several factors, including the variability associated with loads, hydroelectric generation, planned and forced outages, and electric power and natural gas prices in the decision-making process.

Avista aims to develop or acquire long-term energy resources based on the current Integrated Resource Plan's Preferred Resource Strategy, while taking advantage of competitive opportunities to satisfy electric resource supply needs in the long-term period. Electric power and natural gas fuel transactions in the immediate term are driven by a combination of factors that incorporate both economics and operations, including near-term market conditions (price and liquidity), generation economics, project license requirements, load and generation variability and availability, reliability considerations, and other near-term operational factors.

For the short-term timeframe, the Company's Energy Resources Risk Policy guides its approach to hedging financially-open forward positions. A financially-open forward period position may be the result of either a short position situation, for which the Company has not yet purchased the fixed-price fuel to generate, or alternatively has not purchased fixed-price electric power from the market, to meet projected average load for the forward period. Or it may be a long position, for which Avista has generation above its expected average load needs, and has not yet made a fixed-price sale of that surplus to the market in order to balance resources and loads.

The Company employs an Electric Hedging Plan to guide power supply position management in the short-term period. The Risk Policy Electric Hedging Plan is essentially a price diversification approach employing a layering strategy for forward purchases and sales of either natural gas fuel for generation or electric power in order to approach a generally balanced financial position against expected load as forward periods draw nearer.

Q. Would you please provide an update concerning Avista's involvement with the Western Energy Imbalance Market?

A. Yes, as previously discussed with the Commission, Avista has chosen to participate in the CAISO Western Energy Imbalance Market (EIM) beginning in March 2022. Company witness Mr. Kinney provides details about Avista's participation in the EIM and the expenses required for joining and participating in the EIM.

IV. OVERVIEW OF MAJOR 2018/2019 NON-COLSTRIP GENERATION CAPITAL PROJECTS

Q. Are there any specific 2018 or 2019 investments you sponsor that you would like to elaborate on?

A. Yes. As discussed by Company witness Ms. Schultz, for projects included since our last general rate case and through the 2019 test year, Avista's capital witnesses, including myself, describe certain major projects completed in 2018 and 2019. For the generation major projects, my testimony and exhibits provide an overview of the need for the investments made and detail how those projects benefit our customers. The selection of major projects was based on any project, <u>on a Washington-allocated basis</u>, that was greater than $5 million for electric operations and greater than $2 million for natural gas operations. We believe this designation is consistent with the information provided in the Company's prior general rate cases to include within testimony. In addition, provided as Exh. JRT-4 is a listing, including project/program name, description and amount transferred to plant, <u>for every</u> project or program completed in 2018 and 2019 that I sponsor. Additionally, many of the pro forma 2020 projects discussed later in my testimony are similar to projects and programs which occurred in 2018 and 2019. The information that supports those 2020 pro forma projects and programs also helps to support several projects and programs that transferred in 2018 and 2019.

Q. The Company included specific pro forma 2020 capital additions within its request for rate relief. Would you please explain how the capital additions for 2020 were decided on?

A. Yes. As discussed by Company witness Ms. Andrews, the Company typically has approximately 120 projects (business cases) completed on an annual basis which represent the approximate $405 million of capital spending for any given year. In order to minimize the projects pro formed in this case for calendar 2020, the Company used the Commission's recent Used and Useful Policy Statement[1], as well as the recent PSE Order 08 in Dockets UE-190529 and UG-190530 ("PSE Order")[2], for guidance in selecting projects for inclusion in this proceeding as follows:

- First, the Company looked for a balance between the burden on parties to review and the Company's need to recover 2020 capital additions that were already largely in-service serving customers at the time of filing the Company's case (or would, within two months of filing, be in-service through December 31, 2020), ensuring these projects meet the Commission's requirement that each project is "used and useful" and "known and measurable."

- Second, the Company grouped its projects to fit into the Commission defined categories: 1) specific, identifiable and distinct[3]; 2) programmatic (on-going programs or scheduled investments), and 3) short-lived assets. The Company created a 4th category – reflecting projects that are mainly "programmatic," and required to meet regulatory and other mandatory obligations, titled: 4) Mandatory and Compliance. The Company excluded all non-material projects generally less than $500,000 electric and $200,000 natural gas.

Q. Please describe the capital planning process that Generation Production and Substation Support conducts before generation capital projects are submitted to the Capital Planning Group (described by Company witness Mr. Thies).

A. The capital planning process in Generation Production and Substation Support (GPSS) consists of a long-range forecast, a five-year forecast, and an execution plan. Descriptions of each phase of the planning process follow. The Company's long-range forecasting uses the Maximo enterprise asset management software as the central repository

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[1] In the Commissions' "Policy Statement on Property That Becomes Used and Useful After Rate Effective Date" ("Policy Statement"), Docket No. U-190531, at para. 11, p. 5, it define three broad types of investments it would consider for inclusion in rates: 1) specific - clearly defined, identifiable or discrete; 2) programmatic - made according to a schedule, plan or method; and 3) projected: i.e., the use of a k-factor, an attrition adjustment, or a growth analysis.

[2] PSE Order 08, para. 558, p. 163, the Commission explained its plan to address on a case-by-case basis the impact of short-lived assets on regulatory lag.

[3] The Company's pro forma 2020 additions "Customer at the Center" fits into category 1) specific, identifiable and distinct.

for projects and their associated elements. Projects can be added to the long-range forecast database in several ways:

- Informal project requests;
- Input from asset life cycle, condition, needs assessment;
- Periodic reports from Maximo of open corrective maintenance work orders;
- Periodic reports from Maximo of scheduled preventive maintenance work orders;
- Annual maintenance requirements;
- Regulatory mandates;
- Project change requests, drop ins, budget changes, etc.;
- Formal project request applications; and
- Efficiency and IRP-related upgrades.

The GPSS management team meets twice every year to review the long-range forecast, confirm that it is up-to-date and to close completed projects. New projects are highlighted and noted. The impact of each additional project is reviewed. Any disagreement in the priority of projects is discussed until a solution is found.

The GPSS management team participates in an annual workshop in preparation for the budget cycle to prioritize the projects included in the five-year horizon. The team utilizes a formal ranking matrix to ensure that the projects are prioritized consistently.

As projects for the next year are assigned, any capacity or budget constraints are identified and project schedules are adjusted accordingly by the GPSS Management Team. GPSS management and key stakeholders meet monthly at the Generation Coordination Meeting, the GPSS coordinated-team meeting, and specific Program or Project Steering Committee Meetings to discuss the progress of projects and any proposed changes to the execution plan. Adjustments and consensus take place at these meetings.

Q. Company witness Mr. Thies identifies and briefly explains the six "Investment Drivers" or classifications of Avista's infrastructure projects and

programs. How then do these “drivers” translate to the capital expenditures that are occurring in the Company’s generation area?

A. The Company’s six Investment Drivers are briefly described as follows:

1. **Customer Requested** - Respond to customer requests for new service or service enhancements required for connecting new distribution customers or large transmission-direct customers. This driver is generally not applicable to Generation.

2. **Mandatory and Compliance** – These investment drivers are compelled by regulation or contract and are generally beyond the Company’s control as they are a direct result of compliance with laws, regulations and agreements, including projects related to dam safety upgrades, public safety, air and water quality, and equipment essential to legally operating within the interconnected grid among others.

3. **Failed Plant and Operations** – This investment driver includes the replacement of equipment that is damaged or fails due to an accident, or normal wearing out requiring periodic replacement. The large, massive rotating equipment and associated support machinery used for electric generation can experience sudden mechanical failures or electrical insulation breakdowns even with the benefit of ongoing maintenance and preventive maintenance programs.

4. **Asset Condition** – Replace infrastructure assets or portions of assets at the end of their functional service life based on asset condition due to age, obsolescence and parts availability, and degradation of the asset. This category includes replacement of critical parts requiring replacement prior to failure, as well as replacing or overhauling older equipment to bring it up to meet current codes and standards.

5. **Customer Service Quality and Reliability** – Meet our customers’ expectations for quality and reliability of service, as well as increasing the reliability of operating assets.

6. **Performance and Capacity** – Programs and projects to address system performance and capacity issues so Company assets can continue to satisfy business needs and meet performance standards to support the interconnected grid and to ensure the ability to participate in the regional wholesale energy market.

The primary investment drivers for generation projects include Mandatory and

Compliance, Failed Plant and Operation, Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity. Please refer to Exh. JRT-5 – Avista Utilities Generation Infrastructure Plan which contains additional details, more thorough discussions and specific examples concerning each of the six investment drivers, as well as overviews of the planned capital and maintenance investments from 2020 through 2024. The main drivers for each of the major generation-related capital investments in my testimony are discussed below for each project.

Q. For capital additions in 2018 and 2019, for which you are responsible, is the Company seeking to include all of those investments in general rates in this case?

A. Yes. The Company is providing more detailed information in testimony and exhibits related to the major projects completed in 2018 and 2019 and certain pro forma projects for 2020. Exh. JRT-4 provides a summary listing of all program and project investments in my area of responsibility for 2018 and 2019. Details about the generation-related capital projects over the period included in this case are discussed below, and business cases supporting each of these projects are provided in Exh. JRT-6. See Table No. 2 for the total cost of the major generation capital projects completed in 2018 and 2019, and Table No. 3 for the 2020 generation capital projects included in this case. The generation capital projects associated with Colstrip Units 3 and 4 are covered in a later section of my testimony.

Table No. 2: 2018 and 2019 Non-Colstrip Major Generation Capital Projects

Project #	Business Case	2018 TTP (System)	2019 TTP (System)	Exh. JRT-6 Page #
Generation				
1	Little Falls Plant Upgrade	$ 7,892,001	$ 8,953,839	2
2	Nine Mile Rehabilitation	8,556,852	322,027	9
Total Generation		**$ 16,448,853**	**$ 9,275,866**	
Exh. JRT-1T Total Major Investments for 2018 & 2019		**$ 16,448,853**	**$ 9,275,866**	

Table No. 3: 2020 Non-Colstrip Generation Capital Projects

WA GRC Plant Group	Project #	Business Case	2020 TTP (System)	Exh. JRT-6 Page #
Large Distinct Projects	3	Cabinet Gorge 15 kV Bus Replacement	1,400,000	14
	4	Cabinet Gorge Automation	4,083,318	18
	5	CS2 Single Phase Transformer	3,114,004	25
Total Large Distinct Projects			**8,597,322**	
Mandatory & Compliance	6	Clark Fork Settlement Agreement	1,962,038	35
	7	Spokane River License Implementation	1,193,332	41
Total Mandatory & Compliance			**3,155,370**	
Programs	8	Base Load Thermal Program	2,303,670	48
	9	Regulating Hydro	1,646,370	56
Total Programs			**3,950,040**	
Exh. JRT-1T Total 2020 Pro Forma Capital Additions			**15,702,732**	

2018-2019 Major Projects

Q. Could you please describe the Little Falls Modernization Powerhouse Redevelopment Project?

A. Yes. The Little Falls Modernization Program was initiated in 2010 to replace generation equipment at the end of its useful life. From 2006 to 2010, the number and duration of forced outages at Little Falls increased due to equipment failure. This program was initiated to first replace the equipment responsible for the majority of the outages, followed by preparing the plant for the large generation unit upgrades, and concluding with projects structured to replace the majority of the generator's components.

The preparation work for the unit upgrade involved overhauling the crane to make it usable and safe again, constructing a warehouse for storage and staging of equipment, and upgrading the AC and DC electrical distribution system in the plant to handle the new equipment. The unit upgrades began in 2014 with four units being upgraded, one at a time. The last unit upgrade was completed in the Fall of 2019. Each unit upgrade includes the replacement of the generator stators, generator cables, turbine shaft assembly, governor system, unit control and protection systems, re-babbiting of the bearings, reinsulating the field poles, and upgrades to the unit water, oil and air systems. Additional plant work was also included in this program that either directly or indirectly affected the generator units, such as lighting, backup generator, control room upgrades, and other subsystem upgrades. The Little Falls Spillway System is not included in this program. The investment drivers for this project includes Failed Plant and Operation, Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Did Avista consider alternatives to the Little Falls Modernization Program/Powerhouse Redevelopment?

A. Yes, multiple alternatives were considered including: leaving the plant as-is by replacing only the switchgear and exciter (Alternative 1); replacing the four generating units with larger, vertical units with more output and install new ancillary equipment and systems (Alternative 2); and the Selected Alternative - replacing four generating units with the same generating capacity and installing new ancillary equipment and systems. Table No. 4 shows the estimated capital and O&M costs for each of the alternatives.

Table No. 4: Little Falls Modernization Alternatives Considered

	Capital Cost	Annual O&M Cost
Status Quo	$0	$150,000
Alternative 1	$5,000,000	$20,000
Alternative 2	$83,000,000	$0
Selected Alternative	$56,100,000	$0

Alternative 1, although the lowest cost, was not considered a viable solution based on the recent operating history of the generating units. The units had become unreliable and there was no guarantee they would be fully operational at any time of the year. Alternative 2 would have provided additional plant output, but the increase in generation for the extra cost was not as economical as just replacing all four generators in kind. The selected alternative was originally estimated to be approximately $56,100,000.

Q. What was the timeline for the completion of the Little Falls Modernization Program/Powerhouse Redevelopment project?

A. Table No. 5 below provides the Little Falls Modernization Project Schedule shows the date, project description and project cost.

Table No. 5: Little Falls Modernization Project Schedule[4]

Line No.	Date	Project Description	Project Cost
1	January 2010	Program Begins	
2	March 2012TTP	Exciter and Generator Breaker Replacement Complete	$ 3,440,000
3	January 2014TTP	Warehouse Construction Complete	$ 1,443,000
4	January 2014TTP	Bridge Crane Overhaul Complete	$ 836,000
5	February 2015TTP	Station Service Replacement Complete	$ 3,757,000
6	February 2016TTP	Unit 3 Modernization Complete	$ 15,676,000
7	October 2016TTP	Control Room Modernization Complete	$ 723,000
8	April 2017TTP	Unit 1 Modernization Complete	$ 9,730,755
9	Remainder of 2017	Smaller projects transferred to plant	$ 527,513
10	June 2018TTP	Unit 2 Modernization Complete	$ 7,121,062
11	November 2018TTP	Backup Generator Install Complete	$ 770,940
12	Fall 2019	Unit 4 Modernization Complete[5]	$ 9,029,212
13	June 2021	Plant Sewer Sump Upgrades/Misc. Complete[6]	$ 650,000≈
14	March 2021	Panel Room Roof/Enclosure	$ 495,000≈
15		Total	$ 54,199,482

[4] Only major projects under the LFMP Program are listed in this table, small projects are not shown. TTP shows the month and year of Transfer-to-Plant/In-Service. Project costs marked with ≈ are estimates.
[5] Unit 4 Modernization TTP was $9,029,212 plus about $200,000 remaining for as-builts and removal of Bailey controls cabinets which cannot be removed until the sump work is completed and the power is restored.
[6] Septic work is scheduled for completion in November 2020 and Sump work in June 2021.

Q. What specific Little Falls Modernization Program/Powerhouse ("LFMP") Projects are discussed in this testimony?

A. In April 2017, the Unit 1 Modernization/Generator Upgrade was completed and transferred to plant for $9,730,755 (see Line 8 of Table No. 5). There were additional trailing costs for work, invoices, materials, redlines, as-builts, and project closeout that transferred to service. Unit 1 was the second generator completed of the four units planned to be upgraded under the LFMP.[7]

Turning now to costs included in this case, in June 2018, the Unit 2 Modernization/Generator Upgrade was completed and transferred to plant for $7,121,062 (see Line 10 of Table No. 5). There were additional trailing costs for work, invoices, materials, redlines, as-builts, and project closeout. Unit 2 was the third generator completed of the four units planned to be upgraded under the LFMP.

In November 2018, the Back-up Generator installation and commissioning was completed and transferred to plant at a cost of $770,940 (see Line 11 of Table No. 5). There were additional trailing costs for work, invoices, materials, redlines, as-builts, and project closeout. This is a new generator, as no previous back-up generator existed at Little Falls for the plant.

The Unit 4 Modernization/Generator Upgrade was completed in Fall 2019 (see Line 12 of Table No. 5). The final cost of this project was $9,029,212 including additional trailing costs for invoices, materials, redlines, as-builts, and project closeout. Unit 4 was the final generator upgrade that is part of LFMP. This 2019 "major" project is included in the

[7] The 2017 project costs were reviewed by the Commission in Docket UE-170485.

Company's test period.

The last project to be completed under the LFMP is the Plant Sewer Sump replacement with an estimate of approximately $650,000 (Line 13 of Table No. 5). The septic work will be completed in November 2020 and the Sump work in June 2021. There may be some additional miscellaneous work and costs that will also be completed in 2020. The miscellaneous 2020 projects, however, have not been pro formed into the Company's case although they will be completed during the pendency of this case. Please see Exh. JRT-6, pp. 2-8 for additional information about this project.

Q. Please describe the <u>Nine Mile Redevelopment</u> Project.

A. The Nine Mile Redevelopment capital project was required to rehabilitate and modernize the Nine Mile Hydroelectric Dam.[8] Previous projects include the complete upgrades of Units 1 and 2 completed in 2016 and replacement of the Intake Deck and Debris System completed in 2017. Two major projects were placed into service in 2018 under the umbrella of this rehabilitation program at a cost of $8,556,852. The largest project was the successful completion of the Sediment Bypass Enhancement, which included improvements to an existing passage for increased sediment diversion. The second project, for $322,027 in 2019, was the final work to improve the filtration of the Cooling Water System to prevent forced outages caused by excessive debris during runoff. The investment drivers for these projects include: Mandatory and Compliance, Performance and Capacity, Asset Condition and Failed Plant and Operations.

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[8]A private developer built the Nine Mile development in 1908 near Nine Mile Falls, Washington. Avista purchased the project in 1925 from the Spokane & Inland Empire Railroad Company. Nine Mile has undergone recent substantial upgrades. The development has two new 8-MW units and two 10-MW units for a total nameplate capacity of 36 MW.

Q. Did Avista consider alternatives to the Nine Mile Redevelopment Projects completed in 2018?

A. Yes, the Sediment Bypass Enhancement project was one of four alternatives that were considered for this project. The alternatives evaluated for this project included:

1. leaving the system nonfunctional;
2. returning the system to service at the existing capacity;
3. increasing the system to the maximum capacity of the existing tunnel; and
4. replacing the current tunnel to increase capacity further.

A study determined that the best value was to increase the capacity of the existing tunnel, given the improved impact of higher bypass flows, while avoiding the cost of a new tunnel for little additional improvement.

Leading to the need for the Cooling Water Project, Nine Mile Units 1 and 2 experienced several outages in 2017 due to clogged cooling water equipment. Investigations identified river debris bypassing existing filtration as the cause of the clogging and Avista evaluated several alternatives to solve this problem. Due to the need to adhere to regulatory requirements and determine lowest operational costs, a new multistage filtration system was selected and added to the existing system.

Q. What was the timeline for the completion of the Nine Mile Redevelopment Project?

A. The overall rehabilitation project was scheduled to be completed in phases beginning in 2016 and ending in 2018 at the conclusion of the Sediment Bypass Enhancement project activities, and these timelines have been met. This included the procurement and installation of a Debris Management System, new Intake Deck to support the Debris

Management System, and improvements to the Sediment Bypass System.

Q. Describe the system need for the Sediment Bypass and Cooling Water portion of the Redevelopment Project.

A. The original Sediment Bypass System was only partially functional and would have continued to allow significant amounts of sediment into the operating units without modifications and improvements. This decreased functionality caused damage to the runners, resulting in forced outages, increased operating cost, and continued maintenance issues. In addition to the improved flow and passage of sediment, it is necessary to maintain the operation of the bypass system throughout the year by removing any blockages from the intake area. As a result, a debris system removal and subsequent intake deck modification were required to ensure full functionality of the bypass system.

Failing to address the Cooling Water System outages on Units 1 and 2 would cause reoccurring outages each runoff season when debris is swept into the river and eventually plugs the existing filter system. In addition, significant maintenance efforts are required to return the units to service after the original filter system is plugged. Please see Exh. JRT-6, pp. 9-13 for additional information about this project.

<u>2020 Pro Forma Projects</u>

Q. Before describing the 2020 capital projects that you sponsor in your testimony, in general, has the Company applied offsets against the projects you discuss below?

A. Yes, although not directly. Most projects do not have direct identifiable offsets that can be applied on an individual project basis. However, as discussed by Ms. Schultz, in each of her 2020 Pro Forma Capital Adjustments (non-Colstrip) in which the projects I sponsor are captured, she reduces depreciation expense for all 2019 retirements. The inclusion of 2019 retirements act as an offset to the 2020 projects pro formed into this case, effectively reducing 2020 pro formed depreciation expense approximately 21% for electric and 16% for natural gas.

Q. Turning now to the 2020 Pro Forma projects listed in Table No. 3, please describe the <u>Cabinet Gorge 15 kV Bus Replacement Project</u>.

A. The scope of this project includes the replacement of the existing 15 kV bus with a new 4000 Amp segregated bus at Cabinet Gorge. The new configuration will have an increased load rating and the horizontal sections will be raised five feet to allow for acceptable access to the bus room equipment. The current 15kV bus is underrated by approximately 10 percent based on the load requirements between the generators and the Generation Step-up (GSU) transformers. In addition, the current configuration and location of the bus is preventing access for the installation of new station service equipment in the bus rooms. This access requires the horizontal portion of the bus to be raised five feet.

Q. Did Avista consider alternatives to this project or program?

A. Yes. The first alternative considered raising the existing bus section. This alternative was unfavorable because it would extend the plant outage to approximately eight weeks. New transition sections would still be required and there was a signification risk to damaging the old existing hardware, insulators and bus sections. This alternative also did not address the marginal rating of the existing equipment. This would be the highest cost alternative.

The second alternative considered was the replacement of the existing 15kV bus with a new 4000 Amp segregated bus. This was the least cost alternative. This alternative upgraded the bus rating to be more in line with the generators and GSU transformers, and required only a two week outage per bus section. The new bus will be seismically certified as a packaged system and would include all the appropriate vertical and horizontal bus sections, hangers and support systems required to raise and install the bus.

Q. How does this project benefit Avista's customers?

A. Avista's Safe and Reliable Infrastructure strategic initiative seeks to leverage technology and innovative products and services offered to existing and new customers. The work proposed for Cabinet Gorge 15 kV Bus Replacement will include equipment and component replacement geared toward increasing reliability and plant capacity. Customers benefit in that it will allow Avista to economically optimize an existing asset to provide energy and other energy related products.

Q. What is the project completion (or target) date or timeline?

A. The B section of the bus is expected to be placed into service by November 1, 2020. The A Section of the bus is expected to be completed by November 1, 2021. Design was completed in June 2020 and the ordering and receipt of material was completed in August of 2020. The bus outage for the B section is expected to begin in October of 2020. Transfer to plant of approximately $997,000 is expected in November of 2020. The bus outage for the A section is expected to take place in September and October of 2021 and transfer to plant of approximately $434,000 is expected in November of 2021. The A section project in 2021 was not pro formed into the Company's case.

This project is managed by a formal Project Manager and governed by a Steering Committee. Changes in cost, scope and schedule are vetted by the Project Team, facilitated and proposed by the Project Manager, and then reviewed by the Steering Committee. The Steering Committee receives monthly project status updates, but also meets in the event that guidance or a decision is needed. The project/stakeholder team met on a more regular basis (at least monthly) to work on the project's scope and planning. The project/stakeholder team is comprised of representatives from the various engineering groups (electrical, controls, mechanical) and plant operations. Please see Exh. JRT-6, pp. 14-17 for additional information about this project.

Q. Are there any offsetting costs associated with this project/program (i.e. reductions in O&M)?

A. There are no specific offsetting costs for this project. If an alternative was selected, the majority of the work would have been O&M since it would have been a modification to the bus and not a replacement.

Q. Would you please describe the Company's <u>Cabinet Gorge Automation Project</u>?

A. The Automation Project includes the replacement of speed controllers (governors), voltage controls (automatic voltage regulator or AVR), primary unit control system (i.e. PLC), and the protective relay system. The control systems and associated equipment at Cabinet Gorge are at the end of their intended life and there is an increased likelihood of forced outages and subsequent loss of revenue and reliability.

Today, Cabinet Gorge is called on to not only provide load, but to quickly change output in response to the variability of wind and solar generation, to adjust to changing customer loads, and other regulating services needed to balance the system load requirements and assure transmission reliability. The control upgrade is necessary to respond to these new demands. In addition to reducing unplanned outages, these systems will provide Avista the ability to maximize these services from within the pool of its own assets on behalf of its customers rather than having to procure them from other providers. The automation project will also provide additional value when Avista joins the EIM in 2022. The new controls will help the unit follow market dispatch signals. The investment drivers for this project includes Asset Condition, and Performance and Capacity.

Q. Did Avista consider alternatives to this project?

A. Yes. One option was to continue to operate the unit with the current controls and maintain them as long as possible. While the generator is capable of producing energy with existing systems, the present equipment does not provide the system support abilities needed to meet today's requirements described above. This solution would require maintenance of old systems that are no longer supported by the original manufacturer and there is some question about the availability of parts. Additionally, trained personnel available to work on these older systems are becoming scarce and formal training on these systems is no longer available to train new personnel. The option to continue operating the unit is not the preferred option because of system obsolescence, inadequate system performance, and increasing maintenance demands due to the age and condition of the equipment.

Q. How does this project benefit Avista's customers?

A. Avista's Safe & Reliable Infrastructure strategic initiative seeks to leverage technology and innovative products and services offered to existing and new customers. The work proposed for Cabinet Gorge will include equipment and component replacement geared at increasing reliability and unit control/monitoring. Customers benefit in that it will allow Avista to economically optimize an existing asset to provide energy and other energy related products. Please see Exh. JRT-6, pp. 18-24 for additional information about this project.

Q. What was the project timeline and completion date?

A. Design was completed in September 2019, followed by construction in September of 2019 and was completed in March 2020. This project was managed by a formal Project Manager and governed by a Steering Committee. Changes in cost, scope and schedule were vetted by the Project Team, facilitated and proposed by the Project Manager and then reviewed by the Steering Committee. The Steering Committee for this project included: the Director of Power Supply, the Director of GPSS, the Manager Hydro Operations and Manager Project Delivery. This team received monthly project status updates, but only met in the event a decision was needed. The project/stakeholder team met on a more regular basis (at least monthly) to work on the project's scope and planning. The project/stakeholder team was comprised of representatives from the various engineering groups (electrical, controls, mechanical) and plant operations.

Q. Are there any offsetting costs associated with this project (i.e. reductions in O&M)?

A. There are no specific O&M offsetting costs for this capital project. The maintenance demand on the unit controls would have increased as equipment continued to age causing increased maintenance costs. There was also a risk to forced outages which would have an adverse impact on power supply costs.

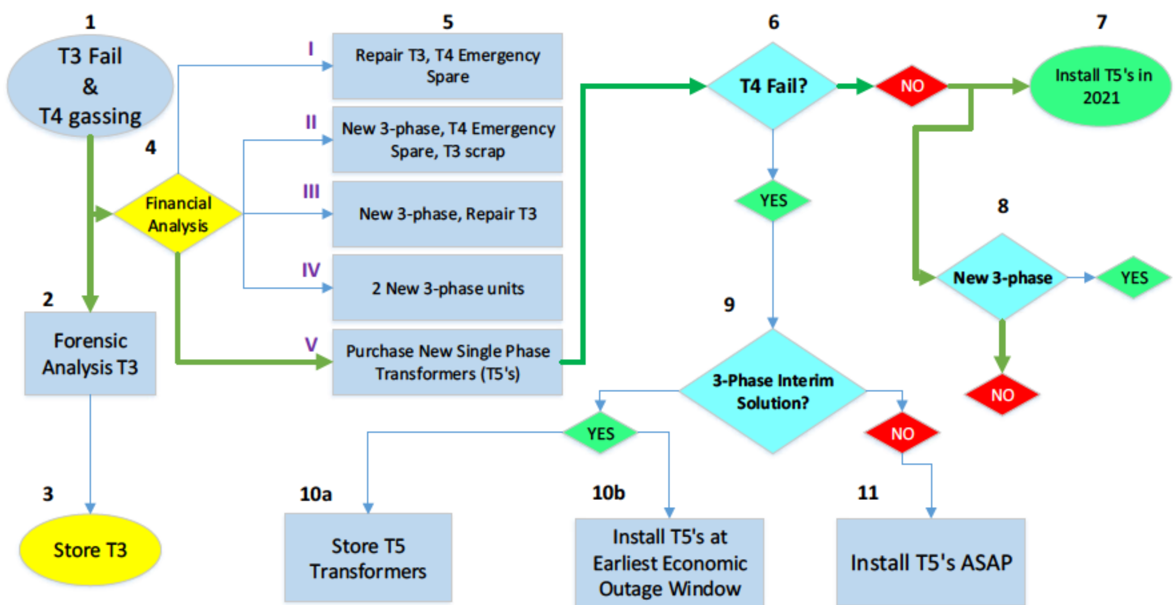
Q. Would you please describe the Company's <u>Coyote Springs 2 Single Phase Transformer Project</u>?

A. Avista has experienced multiple failures of its generator step-up (GSU) transformers at Coyote Springs 2 over its 17 years of operation. Four GSU's have been placed into service since 2003: two Alstom/Areva units (T1 & T2), which were manufactured in Turkey; and two Siemens units (T3 & T4), which were manufactured in Brazil. All four units were dual low voltage wound (13.8/18 kV) to 500 kV transformers. Most recently, in 2018, after nine years of service, T3 failed in service. The spare transformer, T4, was placed into service later the same year, but after several months of operation it also began exhibiting signs of internal deterioration that would eventually lead to failure. The Coyote Springs 2 generator facility is currently operating without a spare transformer and the in-service transformer, although able to function at near full capacity, is gassing internally and could fail in the same manner as T3. To reduce risk of failure the maximum plant generation output was reduced to keep heating in the windings down per recommendations from a consultant, until such time as the transformer can be replaced.

When Avista purchased T3 and T4, we specifically excluded Areva Turkey (original manufacturer of T1 and T2) as a potential supplier so as to get a different design and to have the unit manufactured in a different factory to avoid a factory-related systemic deficiency. This was successful in one aspect as the initial forensic analysis of the T3 failure shows a failure in an entirely different location from the failures that were observed in T1 and T2. Nevertheless, given that we have encountered multiple failures of this three-phase configuration over the operating lifetime, Avista chose to conduct a detailed financial analysis of multiple options that included an alternate single-phase configuration and also considered a risk element for options that would just continue using the three-phase dual wound configuration.

The decision tree below in Illustration 1 provides a high-level summary of where we are now regarding the transformer decision at Coyote Springs 2. Element 4 represents a financial analysis we performed to determine the best path forward. Options evaluated included various T3/T4 repair combinations, purchasing of two new dual wound three-phase units, and purchasing new single-phase dual wound units. The financial analysis determined the purchase of single phase dual wound transformers to be the most cost-effective solution for customers. Because of the extraordinarily long lead time associated with acquiring transformers of this size, Avista has had to keep other options open. In the decision tree below, the bolded green lines represent the chosen path to date. You may note that Element 6 presented a choice that could have taken us down a path of repairing T3 or T4 and placing it back into service even though new transformers of a completely different design had been ordered. The reason for maintaining this optionality is the long lead time required for these types of transformers to be built and shipped, and the potential for extremely long outages that expose the Company to market volatility and higher power supply expense. We are now at a point in time where construction of the new single-phase units is far enough along that we would be able to install them faster than any potential repair and reinstallation of T3/T4.

<u>Illustration 1: Coyote Springs 2 Transformer Decision Tree</u>



This project has two sub-projects. The portion of the overall project that transferred to plant in 2020 included the civil and structural modifications that needed to be made to accommodate the installation of the new transformers, oil containment, and firewall systems. This portion of the work will be completed in 2020 to allow the transformers to be installed during the spring of 2021 before summer peak load conditions. The 2020 capital portion of this project has been pro formed into this case. The installation of the new transformers to be completed in 2021, however, has not been included in this case. Please see the attached document in Exh. JRT-6 (pp. 25-34) which includes the Business Case as well as other documents explaining the need for this project. The investment drivers for this project includes Failed Plant and Operation, Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Did Avista consider alternatives to this project?

A. Avista considered multiple alternatives to this project as indicated in the decision tree in Illustration 1 above and detailed in the attached documentation in Exh. JRT-6. The Company selected what is considered by our expert consultants to be the premier transformer factory in the world, Siemens' facility in Austria, to manufacture four (4) single-phase dual wound transformers. These transformers are of a dramatically different design than the previous transformers at Coyote Springs 2. Each single-phase transformer is much lighter (thus much less costly to transport and handle) than the previous three phase transformers because the duty is divided between three units, yet the combined MVA capacity of these single-phase transformers is significantly higher than T1-T4, which provides for significant additional operating margin and reliability. Had we chosen to replace T4 with a similar upgraded capacity three-phase unit, it likely would not have fit on the existing transformer pad.

Q. How does this project benefit Avista's customers?

A. This project replaces Transformer 3, which has failed, and Transformer 4 that is currently in service but began exhibiting a troubling gassing pattern after only a three-month in-service run. A reliable GSU and spare is required to keep Coyote Springs 2 in service and minimize exposure to market volatility. Coyote Springs 2 alone typically provides about 20 percent of Avista's annual energy needs. The financial analysis considered all of the options and selected the optimal cost option for customers.

Q. What is the project target completion date?

A. The transformer installation is on schedule to be complete by June 30, 2021.

Q. Are there any offsetting costs associated with this project/program (i.e. reductions in O&M)?

A. Avista believes that the new configuration using individual single-phase transformers will provide long term dependable reliability and reduce the Power Supply expense associated with replacement power for the outages that we have observed over the life of the plant because of the first four transformer failures. Additionally, the new transformers have increased capacity to afford a larger operational margin and will accommodate increased output from the facility if future plant upgrades are made.

Q. Would you please describe the Company's <u>Clark Fork License Project</u>?

A. Yes. This capital program helps ensure the ongoing operation of the Clark Fork Project (Noxon Rapids and Cabinet Gorge dams), which is subject to the Clark Fork Settlement Agreement (CFSA) and FERC License No. 2058. Under this FERC License, Avista must develop and carry out Protection, Mitigation and

Enhancement (PM&E) measures each year. These License measures consist of the completion of numerous specific projects each year for habitat, fisheries, recreation, land management, wildlife and other natural resources related to our Clark Fork hydro operations. Implementation of these measures also addresses ongoing compliance with Montana and Idaho Clean Water Act Section 401 Certification requirements, the Endangered Species Act, National Historic Preservation Act, Clean Water Act, and additional state, federal and tribal laws and regulations. Some projects are multi-year while other projects are one-time, but the entire capital program continues to evolve over the 45-year License term.

If the PM&Es and license articles were not implemented and/or funded, Avista would be in breach of an agreement and in violation of our FERC License. There would be high risk for penalties and fines, new license requirements, higher mitigation costs, and potential loss of operational flexibility of the Cabinet Gorge and Noxon Rapids Hydroelectric Facilities. Loss of operational flexibility, or of these generation assets, would create substantial new costs, which would be detrimental of all of our electric customers and to the Company. Funding of the Clark Fork License Implementation is essential to remain in compliance with the FERC license and CFSA, which provides Avista the operational flexibility to own and operate the hydroelectric facilities. The investment drivers for this project are predominantly Mandatory and Compliance in nature.

Q. Did Avista consider alternatives to this program?

A. Funding of the Clark Fork License Implementation is essential to remain in compliance with the FERC License and CFSA for permission to continue to own and operate the Clark Fork hydroelectric facilities. Avista evaluated alternatives to a negotiated license through the Licensing process in the late 1990s as reflected in the consultation record submitted with the license application. Forgoing a collaborative relicensing process (and ultimately, an agreement) was determined to create significant risk to the operational flexibility of the dams, as well as risks for increased costs related to the process as well as a litigated license. This commitment was finalized by the issuance of a new 45-year License by FERC in 2001 and is ongoing. The CFSA was the result of collaborative negotiations between numerous federal and state agencies, several Native American tribes, local governments, a number of non-governmental organizations, and Avista on behalf of our customers. Subsequently, FERC incorporated the CFSA in a License Order, along with other conditions. FERC continues to oversee License implementation through annual review and frequent orders. Each year, Avista and CFSA signatories, through a Management Committee and technical subcommittees, evaluate project proposals and alternatives before approving an annual work plan that is submitted to FERC for final approval.

Q. How does this program benefit Avista's customers?

A. As stated above, this program represents Avista meeting its regulatory and legal requirements under the FERC Clark Fork License. If we didn't do so, we would risk legal action, penalties, reputational loss and potential loss of operational flexibility. Loss of operational flexibility, or of these generation assets, would create substantial new costs, which would be detrimental of all our electric customers and the Company.

Q. Does the program have a target completion date?

A. This is an ongoing commitment running with the Clark Fork FERC License

#2058 and will continue at least until the License expires in 2046.

Q. Can you demonstrate historical spending trends of this program?

A. Yes, we have a 20-year record of implementing the Clark Fork Settlement Agreement. Annual capital spending varies depending on the specific projects selected, as well the ability to secure permits and other approvals to complete projects each year. Please see Exh. JRT-6, pp. 35-40 for additional information about this project.

Q. Are there cost controls for this program? If so, please describe.

A. The CFSA and Clark Fork License outline specific financial commitments that act as potential spending caps for resource issues. Avista is required to develop, in consultation with the CFSA Management Committee, an annual implementation plan and report, addressing all PM&E measures of the License, which includes estimated budgets. All projects within the capital program are subject to either spending limits or management controls for overseeing project costs.

Q. What capital additions for this program did Avista make in 2018, 2019 and 2020?

A. As part of a 2017 agreement to reduce the minimum flow below Cabinet Gorge Dam from 5,000 cfs to 3,000 cfs, Avista agreed to provide up to $1 million for PM&E of the aquatic resources during the remainder of the Clark Fork Project FERC License. These funds were first available for use starting in 2018. The reduction in minimum flow resulted in increased operational flexibility of Cabinet Gorge Dam, which directly benefits our customers.

Q. Are there any offsetting costs associated with this /program (i.e. reductions in O&M)?

A. These projects are required based on our FERC license. Because Avista is subject to specific financial commitments to address the impacts of our hydro facilities on resources, if we were unable to implement the capital program, we would have to account for these activities as O&M costs.

Q. Would you please describe the Company's <u>Spokane River License Project</u>?

A. The Spokane River License Project, or Spokane River Implementation, is a capital program that helps ensure the ongoing operation of the Spokane River Project which includes the Post Falls, Upper Falls, Monroe Street, Nine Mile and Long Lake dams. The Spokane River Project is subject to FERC License No. 2545 and several other settlement agreements. This license, issued in 2009 following almost seven years of consultation, negotiations, and litigation, defines how Avista operates the Spokane River Project and includes several hundred requirements, expressed as license conditions.

The FERC license was issued pursuant to the Federal Power Act (FPA) and embodies the requirements of a wide range of other laws such as The Clean Water Act, The Endangered Species Act, and The National Historic Preservation Act, among others. These requirements are expressed through specific license articles relating to fish, terrestrial issues, water quality, recreation, land use, education, cultural and aesthetic resources. Avista also entered into additional two-party agreements with local, state, and federal agencies, and the Coeur d'Alene and Spokane Tribes. Most of these agreements are embodied in the License. Avista's FERC License also includes mandatory conditions issued by the Idaho Department of Environmental Quality (401 Water Quality Certification, issued June 5, 2008), the Washington Department of Ecology (401 Water Quality Certification, issued May 8, 2009), the U.S. Forest Service

(Federal Power Act 4(e), issued May 4, 2007), and the U.S. Department of Interior on behalf of the Coeur d'Alene Tribe (Federal Power Act 4(e), filed January 27, 2009). The FERC license ensures Avista's ability to operate the Spokane River Project on behalf of our electric customers within our service territory over the 50-year license term. This capital program consists of numerous projects each year, and the total cost of implementing these projects varies each year, depending on specific license requirements and opportunities.

Complying with our FERC license is mandatory for continued permission to operate the Spokane River Project and funding the implementation activities is essential to remain in compliance with the License. Ultimately, FERC has the authority to issue orders and penalties, or in the extreme, revoke our license, if we do not comply with the terms and conditions required by it. We would also be subject to additional legal sanctions from other agencies and settlement partners if we do not meet the conditions of the License and subsequent agreements. Loss of operational flexibility, or in the extreme, loss of our generation assets, would create substantial new costs to our customers and provide no benefits in return. In addition, Avista would suffer reputational costs for not meeting our commitments. The investment driver for this project is Mandatory and Compliance.

Q. Did Avista consider alternatives to this program?

A. The capital projects included in the Company's Spokane River Implementation Project are mandatory obligations after agreements are reached with the various participants in the licensing process. If the license conditions and settlement agreements are not implemented and/or funded, we would be out of compliance and/or in violation of our License. This could lead to penalties and fines, new license requirements, court costs, higher mitigation costs, and loss of operational flexibility. Ultimately, FERC has the authority to revoke

Avista's Spokane River License if it does not comply with the required terms and conditions. Loss of operational flexibility, or in the extreme, loss of our generation assets, would create substantial new costs to our customers, damage the company's reputation, make it more difficult to pursue other hydro projects, and ultimately provide no benefits to the Company or its customers.

Q. How does this program benefit Avista's customers?

A. As stated above, this program represents Avista meeting its regulatory and legal requirements under its Spokane River Project FERC License. If the Company failed to meet these legal obligations and commitments, there would be high risk of legal action, financial penalties, reputational loss and potential loss of operational flexibility for the Spokane Hydroelectric Project. Loss of operational flexibility, or of these generation assets, would create substantial new costs by requiring the acquisition of new renewable resources which may not possess the same level of cost, reliability or operationally flexibility. This would be detrimental to all of our electric customers and to the Company.

Implementing the required Spokane River License conditions during 2020 is required by the FERC License in order to operate the Spokane River Hydroelectric Project. This ensures a reliable energy supply for our customers from the Spokane River Project resources. The License is the result of seven years of community-based collaboration, and implementation also reflects ongoing collaboration with key stakeholders, most of whom are also customers. Additionally, these implementation measures demonstrate Avista's ongoing commitment to environmental stewardship which benefits our customers, the Company and the communities we serve.

Q. Does the program have a target completion date?

A. No, the Spokane River Implementation Project is an ongoing commitment with the Spokane River FERC License No. 2545. This project will continue at least until the License expires in 2059. We would expect the same, modified or additional license conditions after that time depending on the results of future License requirements. Please see Exh. JRT-6, pp. 41-47 for additional information about this project.

Q. Can you demonstrate historical spending trends of this program?

A. Yes, we have an 11-year record of implementing the current Spokane River FERC License. Annual capital spending varies depending on the specific projects selected, as well the ability to secure permits and other approvals to complete projects each year.

Q. Are there cost controls for this program? If so, please describe.

A. The Spokane River License outlines several specific financial commitments that act as potential spending caps for recourse concerning License implementation activities. The requested capital costs are implemented in accordance with the schedules, milestones and benchmarks identified in the annual planning process as identified and committed to within annual, five-year and ten-year work plans. The work is completed in collaboration with internal and external stakeholders, subject to review and approval by FERC. At every opportunity during project planning, cost sharing options and opportunities are fully explored to ensure Avista's fiduciary duty to its customers is upheld. Project costs are reviewed monthly, if not weekly, and managed tightly by each Spokane River resource lead, budget analyst and the Spokane River License Manager. All projects within the capital program are subject to either spending limits or management controls for overseeing project costs.

Q. What capital additions for this program did Avista make in 2018, 2019 and 2020?

A. The Spokane River License program had $415,863 of capital projects in 2018, $435,911 in 2019, and $1,193,332 in capital spending in 2020.

Q. Are there any offsetting costs associated with this program (i.e. reductions in O&M)?

A. These projects are required based on our FERC license. Because Avista is subject to specific financial commitments to address the impacts of our hydro facilities on resources, if we were unable to implement the capital program, we would have to account for these activities as O&M costs.

Q. Would you please describe the Company's <u>Base Load Thermal Program</u>?

A. The purpose of the Base Load Thermal Program is for Kettle Falls GS and Coyote Springs 2 to keep their operating expenses as low as possible by providing funding for many individual projects under this program. These projects are typically to replace things that are broken or are at their end of useful life. The investment drivers for this project includes Asset Condition, and Performance and Capacity. Please see Exh. JRT-6, pp. 48-55 for additional information about this program.

Q. Did Avista consider alternatives to this program?

A. The individual projects within the Base Load Thermal Program are evaluated by committees that are respective to Kettle Falls and Coyote Springs 2. One of the purposes of this evaluation is to ensure appropriateness of the project and analysis of any alternatives, if applicable.

Q. How does this program benefit Avista's customers?

A. This program is designed to ensure continued safe, low cost, reliable, and compliant electrical generation for the use and benefit of Avista's electrical customers at the

Kettle Falls Generating Station and at the Coyote Springs 2 natural gas-fired plant.

Q. Does the program have a target completion date?

A. No. This is a recurring program required for ongoing operations so there is no anticipated completion date. The project is reviewed and renewed on a five-year cycle.

Q. Can you demonstrate historical spending trends of this program?

A. Yes. Five-year historical spending trends were submitted with this business case when it was renewed and will continue to be reviewed with the ongoing nature of this program.

Q. Are there cost controls for this program? If so, please describe.

A. Yes. As these are typically smaller projects that are reviewed and justified by the need to continue reliable and efficient operation at the facilities. The cost controls come from the respective plant management and committees providing oversight of the plants and these projects as well as review and approval of the annual business case funding by the Capital Planning Committee (CPG).

Q. What capital additions for this program did Avista make in 2018, 2019 and 2020?

A. There were 69 individual projects under Base Load Thermal program between 2018, 2019 and 2020 at the two plants. Examples of capital additions include the main reclaim chain at the Kettle Falls Generating Station and the steam turbine gearbox bearing replacement at Coyote Springs 2. Please refer to Exh. JRT-6 pp. 48-55 for more details about the specific projects included in this program.

Q. Are there any offsetting costs associated with this program (i.e. reductions in O&M)?

A. The purpose of this program is to minimize operating expenses by providing funding for small capital projects needed for continued safe and reliable plant operation.

Q. Would you please describe the Company's <u>Regulating Hydro Program</u>?

A. Yes. The purpose of this program is to fund smaller capital expenditures and upgrades that are required to maintain safe and reliable operation of Avista's regulating hydro plants. Maintaining these plants safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

Avista's regulating hydro plants are the four largest hydro plants on Avista's system representing more than 950 MW of power and include Noxon Rapids and Cabinet Gorge on the Clark Fork River in Montana and Idaho, and Long Lake and Little Falls on the Spokane River in Washington. Avista's regulating hydro plants are unique in that they have storage available in their reservoirs. This enables these plants to have operational flexibility and are operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match the changing system loads, and other types of ancillary services necessary to provide a stable electric grid and to maximize value to Avista and its customers. The investment drivers for this project includes Asset Condition, and Performance and Capacity.

Q. Did Avista consider alternatives to this program?

A. Yes. One alternative would be to create business cases using the business case template and process for each of these small projects. There are typically 40 to 50 projects a year funded by this program. This would overload the Capital Budget Process with small to medium sized projects whose governance can be effectively handled by the hydro organization. These projects are specific to these plants and the leadership in hydro operations best understands the nature and context of these projects. These projects are somewhat unpredictable from year-to-year. It would be difficult, if not impossible, to accurately forecast the timing of certain events such as equipment failures and to identify critical asset condition that could effectively be put in the annual capital plan.

Another alternative would be to attempt to repair this equipment instead of replacing critical assets at the end of their lifecycle. This alternative would be more expensive and older equipment will become increasingly unreliable until it becomes obsolete. Operating in a run-to-failure mode is proven to be an unsuccessful approach and subjects Avista and its customers to an unacceptable level of risk.

Q. How does this program benefit Avista's customers?

A. The hydroelectric plants covered under this project are unique in that they have energy storage available in their reservoirs. This enables these plants to have operational flexibility and are operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match changing system loads, other types of ancillary services necessary to provide a stable electric grid and to maximize value to Avista and its customers. Maintaining these plants and their ability to safely and reliably provide our customers with low cost, reliable and clean power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

Q. What is the program completion timeline?

A. This is an ongoing program with no set end date. It will continue as long as the hydroelectric plants it supports are still in service. This program is funded annually. Projects selected for the program are typically completed within the calendar year. Please see

Exh. JRT-6, pp. 56-63 for additional information about this project.

Q. Can you demonstrate historical spending trends of this program?

A. Yes. The annual budget program, based on review of the past six years of data, is approximately $3.5 million. The projects in this program typically take place during the outages scheduled in late summer and fall of each year. Most of the capital is deployed in the third and fourth quarter of each year.

Q. Are there cost controls for this program? If so, please describe.

A. Yes. The Advisory Group for this program, consisting of the four regional Hydro Managers and the Senior Manager of Hydro Operations and Maintenance, is tasked with oversight of this program. These projects vary in size and support needed based on the requests from the department and from key stakeholders. The larger projects require formal project management with a broader stakeholder team. Medium to small projects can often be implemented by a project engineer or project coordinator and many cases can be handled by contractors managed by the regional personnel. All these projects are prioritized and coordinated by the broader support team and reviewed by the Advisory Group. The overall budget for the business case is reviewed and approved by the CPG

Q. What capital additions for this program did Avista make in 2018, 2019 and 2020?

A. Approximately forty-eight projects were completed in 2018 under this program with capital transfer to plant of approximately $4.3 million (system). Thirty-two projects were completed under this program in 2019 with a transfer to plant of approximately $2.3 million (system). Approximately 30 projects are currently funded from the program in 2020 and the expected transfer to plant is $1.6 million (system). In order to support the budget constraints of the department, the budget target amount was reduced in 2019 and 2020 by delaying certain projects with lower risk through this period.

Q. Are there any offsetting costs associated with this program (i.e. reductions in O&M)?

A. There are no specific cost offsets for this program. Operating in a run-to-failure mode is proven to be an unsuccessful approach and subjects Avista and its customers to unacceptable risk.

V. <u>COLSTRIP GENERATION CAPITAL PROJECTS</u>

<u>A. Introduction and Summary of Capital Additions</u>

Q. Before discussing the operation of and capital additions for Colstrip Units 3 and 4, please discuss the purpose of this section of your testimony.

A. In Order No. 7 of Docket UE-170485, the Commission requested that "Avista must provide a more detailed examination of its justification for its investments at Colstrip in its next GRC".[9] Furthermore, Final Order 09 of Docket No. UE-190334 states:

> "As part of the Settlement, Avista agrees not to support capital expenditures beyond routine capital maintenance costs at Colstrip that will extend the plant's operational life beyond December 31, 2025. The Parties agree that all Colstrip capital expenditures after December 31, 2017, will be subject to a prudence determination in future rate proceedings and Avista will provide detailed information, including a complete record of the decision making and a full accounting of the costs related to those project expenditures on an annual basis." (Final Order No. 9, pgs. 19-20)

My testimony will discuss the updated analysis of the economics and environmental

[9] UE-170485, Order 07, Page 69, paragraph 205.

liability and risks of Colstrip Units 3 and 4 over the expected life of the plant, which is now expected to be through the end of 2025 based on the 2020 IRP analysis and for compliance with coal-fired generation requirements in the CETA for Washington customers. This section of my testimony will also discuss the prudency of Colstrip capital additions for ongoing routine maintenance and environmental compliance projects already completed during 2018 and 2019 that were not included as part of the Settlement in the prior general rate case (see Table No. 6), as well as a discussion about the capital additions from 2020 through 2022 (see Table No. 7). None of the Colstrip capital projects discussed below were or are being done to extend the life of the plant beyond the end of 2025 as agreed to in` the Settlement for the last general rate case and in compliance with CETA. Ms. Andrews will discuss the recovery treatment of these assets.

Table No. 6: 2018 and 2019 Colstrip Capital Additions

Project	2018	2019	Grand Total
Colstrip 3 & 4 Capital Projects	$5,125,260	$2,868,628	$7,993,888

Table No. 7: 2020 – 2022 Colstrip Capital Additions

Project	2020	2021	2022
Unit 4 Overhaul	$872,875		
Plant per Colstrip Spreadsheet	$6,586,200	$4,276,902	$403,372
Plant for Environmental	$2,554,200	$3,829,500	$3,006,600
Total Colstrip Capital	$10,013,275	$8,106,402	$3,409,972
Washington Share	65.64%	65.64%	65.64%
WA Pro Forma Capital for Colstrip	$6,572,714	$5,321,042	$2,238,306

Q. Can you provide some background about how Colstrip capital decisions are made and managed by the Company?

A. Yes. Talen, the plant operator, makes ongoing assessments regarding the conditions of the equipment at the plant during operations, outages and overhauls. Talen uses the information obtained in these assessments to determine when particular components need to be repaired or replaced. This assessment process also includes the solicitation of advice from original equipment manufacturers, equipment vendors, internal and external plant engineers, as well as the plant Owners. Talen produces a budget after consideration of different options and timing for capital projects and presents them to the Project Committee for discussion, additional analysis if necessary, and for voting as directed by the ownership agreement. The approval of capital budgets requires at least 55 percent of the ownership and three members of the Project Committee including the Plant Operator.

Avista actively participates in the capital decision-making process at Colstrip and fully exercises its ownership interest in Units 3 and 4. Each year Talen, the plant operator, proposes a set of capital projects for Units 3 and 4, as well as for the plant-in-common. These projects are reviewed by one or more Avista representatives on an individual basis and also as an ownership group. Additionally, Avista and other Company representatives meet with Talen at least every other month to review plant operations including capital projects. Projects may be added or subtracted throughout the year as appropriate based on the operational, environmental and safety requirements of the project. While it is true that the ownership structure and operating agreement for Colstrip do not provide a line item veto of individual capital projects, and Avista only has a small ownership interest preventing it from unilaterally stopping capital projects on its own, the Company nevertheless actively exercises its ownership rights while projects are being discussed. The compensation structure for the plant operator is cost-based and does not include any rate of return based on the capital spending at the plant. There is no economic incentive or justification for the plant operator to spend foolishly or "gold plate" the facility while maintaining and operating the plant. In fact, quite the opposite is true. The plant operator is an independent power producer whose business model requires low plant costs to ensure the plant is competitive in the market, so there is no financial incentive for them to spend needless capital on any projects. The plant operator's financial interests to minimize costs while meeting all regulations, are the same as all of the Colstrip owners and in turn their customers.

Q. What is the overall reason for the on-going capital projects at Colstrip if the plant is not going to continue to serve Washington customers beyond 2025?

A. Continued capital projects at Colstrip are necessary to maintain present operational plant output expectations required by owners to meet their anticipated load demands. The Colstrip Generating Station consists of Units 1 and 2 – 333 (MW) that operated from 1975 until their retirement in January 2020, and Units 3 and 4 – 805 MW each operating since 1983 and 1986, currently assumed to operate until 2025 to serve Washington customers. An actual retirement date for Units 3 and 4 had not been determined by the collective owners at this time. Despite the ongoing discussion about retirement, Colstrip will continue to meet past, current and future regulatory obligations and environmental compliance requirements while maintaining a reliable, operational facility. This requires a strategic approach to planning and completing certain capital projects in order to meet current and future regulatory goals. Specifically, the entire facility will manage water and waste well beyond the operating life of the units according to the following requirements:

- The Site Certificate originally issued including the amended 12(d) stipulation under the Major Facility Siting Act in Montana, Nov. 1975.

- Federal Coal Combustion Residual (CCR) Rule, 40 Code of Federal Regulations (CFR), April 2015.

- Administrative Order on Consent (AOC) Regarding Impacts Related to Wastewater Facilities, MDEQ (July 2012), Settlement agreement entered (2016).

Q. How do the owners of Colstrip address regulatory obligations and environmental compliance requirements?

A. The Colstrip owner's group does not approach its regulatory obligations and environmental compliance requirements through a narrow perspective. The owners' group, and specifically Avista, must always strategically manage the risk to both our customers and shareholders for the known and possible regulatory obligations at both the federal and state levels, while managing reliability and cost of all of our generating resources. The owners do not take this responsibility lightly and they exercise careful diligence in gathering information at the point in time when strategic decisions must be made.

Q. Will projects still need to be completed regardless of when the Plant is shut down?

A. Yes. The AOC has required an extensive evaluation process that included site characterization, clean-up criteria, risk assessment that resulted in the MDEQ selection of a remedy and remedial action work plans. The draft and finalized documents can be found on the Montana Department of Environmental Quality (MDEQ) website specific to the Plant groundwater clean-up.[10] In addition, the AOC actions must also meet Federal CCR requirements and deadlines in the interim while maintaining reliable plant operation. The AOC remedial action work plans and Federal CCR are both regulatory obligations and environmental compliance requirements that must be met regardless of the Plant operational

[10] http://deq mt.gov/DEQAdmin/mfs/ColstripSteamElectricStation

status. Below, I briefly discuss the capital projects completed in the 2018-2019 timeframe, as well as expected projects for 2020 through 2022.

Q. In Footnote 314 of Order 07, Docket No. UE-170485 the Commission required the Company to provide a "comprehensive, up-to-date analysis of the economics and environmental liabilities" associated with Colstrip. Will you please briefly discuss how the Company is meeting this requirement?

A. Yes. As noted above, the Company takes the economic and associated customer impacts of operating, and meeting regulatory and environmental requirements very seriously. In addition to daily/monthly/yearly decisions about resource maintenance and capital decisions, the Company also looks to the forward planning timeframe to determine best practices. This forward looking, ongoing economic analysis of Colstrip, as well as the Company's other generation resources, is undertaken through the Integrated Resource Plan (IRP). The currently-acknowledged IRP was submitted on August 31, 2017 and acknowledged by the Commission on May 5, 2018 in Docket No. UE-161036. However, as discussed earlier in my testimony in the resource planning section, the Company produced another IRP in February 2020 which provides a more up-to-date economic analysis of Colstrip Units 3 and 4. This IRP was submitted to the Commission in final as well as in a progress update form.

> The 2020 IRP "… assumes Colstrip will not be available for purposes of this IRP and is no longer available to serve Washington customers due to Washington state law excluding the plant from customer rates. … Avista's analysis of Colstrip in this IRP (Chapter 12) indicates retiring the plant for Idaho customers in 2025 rather than 2035 is the economic choice1. (Footnote 1 states: "1 Avista did not model any alternative shut down dates in this plan." (pp. 12-2, 2020 IRP).

The economic analysis used to develop the Expected Case for the 2020 IRP Colstrip analysis used the following assumptions:

1. Closure of Units 1 and 2 in January 2020 and transfer of shared common costs to Units 3 and 4;

2. Colstrip Units 3 and 4 no longer serve Washington or Idaho customers after 2025;

3. Selected Catalytic Reduction (SCR) are not expected to be added to Units 3 and 4 because the plant is expected to not continue serving Avista customers after 2025[11];

4. Expected Coal Combustion Residual capital requirements and water management issues required regardless of the length of continued service of the plant; and

5. Coal prices for Units 3 and 4 using the contract signed in December 2019 which extends through the end of 2025.

Besides the ongoing current and expected expenses modeled in the 2020 IRP, several scenarios concerning Colstrip were also completed to determine any changes to the Preferred Resource Strategy ("PRS") under different portfolio assumptions. The 2020 IRP ran 14 additional portfolios to compare cost, risk and emissions against the PRS. Three of these portfolios, shown in Table No. 8 below, included changes to the expected case Colstrip Unit 3 and 4 assumptions:

1. Portfolio 7: Extended Colstrip to 2035 without CETA;
2. Portfolio 8: Extended Colstrip to 2035 with CETA; and
3. Portfolio 15: Assumed Unit 3 closes in 2026 and Unit 4 in 2035.

Table No. 8 highlights the 14 different portfolio costs for the 2021 – 2045 and 2021 – 2030 periods, as well as the expected rates for the different portfolios in 2030 and 2045 modeled for the 2020 IRP.

[11] This is a planning assumption for modeling purposes in the IRP. If the plant continued to operate further into the future than expected, it may still be required to install SCR. This analysis assumes closure of the plant prior to the requirement of SCR.

A high cost Colstrip case was not included in the 2020 IRP, as had been included in the 2017 IRP, because the plant is expected to no longer serve Avista customers by the end of 2025 to meet CETA requirements as well as for economic considerations for both Washington and Idaho customers. Final disposition of Colstrip Units 3 and 4 will still need to be determined by the Owners whose legal, economic and operational considerations may not perfectly meet the same end dates expected for Avista's customers.

2020 IRP Portfolio Scenarios 7 and 8, which modeled the extension of Colstrip Units 3 and 4 through 2035 to better understand the economics of continued operation of the plant, had similar results in 2030 as the PRS, but slightly lower energy rates in 2045. However, the total modeled cost was $2 million higher each year in the scenario that kept Colstrip in the portfolio through 2035 (pg. 12-21, 2020 IRP). Even without CETA requirements, the modeled total expected portfolio cost was higher to keep Colstrip running through 2035 as shown in the change in cost between Portfolio #7 and Portfolio #2. The PRS, with Colstrip no longer serving Avista customers after 2025, is also lower cost compared to the portfolio with only Colstrip Unit 4 continuing operations until 2035.

Table No. 8: 2020 IRP Table 12-17: Portfolio Costs and Rates

Portfolio Number	Portfolio name	PVRR (2021-45) Millions	PVRR (2021-30) Millions	2030 Rate (c/kWh)	2045 Rate (c/kWh)
1	Preferred Resource Strategy	11,832	6,329	10.4	14.1
2	Least Cost Plan- w/o CETA	11,670	6,222	10.1	13.5
3	Clean Resource Plan - 100% net clean by 2027	12,439	6,505	11.1	15.6
4	Rely on energy markets only (no capacity or renewable additions)	11,185	6,000	9.4	12.7
5	Clean Resource Plan - 100% net clean by 2027 and no CTs by 2045	12,563	6,511	11.1	18.2
6	Least Cost Plan w/o pumped hydro or Long Lake upgrade	11,826	6,270	10.2	14.5
7	Colstrip extended to 2035 w/o CETA	11,740	6,252	10.3	13.5
8	Colstrip extended to 2035 w/ CETA	11,852	6,346	10.4	14.0
9	Least Cost Plan w/ higher pumped hydro costs (+35%)	11,873	6,329	10.4	14.3
10	Least Cost Plan w/ federal tax credits extended	11,510	6,210	10.0	13.3
11	Clean Resource Plan w/ federal tax credits extended	12,004	6,344	10.6	14.4
12	Least Cost Plan w/ low economic growth	11,521	6,216	10.4	14.5
13	Least Cost Plan w/ high economic growth	12,106	6,391	10.3	13.9
14	Colstrip 4 extended to 2035	11,855	6,343	10.5	14.0

The 2020 IRP's analysis determined the best date for Colstrip to economically shut down is at the end of 2025 when compared to alternative scenarios, such as a 2035 Colstrip closure or to continue operating a single Colstrip unit through 2035. As discussed in Chapter 12 – Portfolio Scenarios of the 2020 IRP, the inclusion or exclusion of the social cost of carbon regarding Colstrip also did not change the answer to the Colstrip closure date question. Avista will continue evaluating this analysis and work with the other owners for the best course of action to meet state objectives under CETA and to meet the economic needs of Avista's customers (pp. 13-5, 2020 IRP).

Avista's 2021 IRP is currently in development and the due date was extended to April 1, 2021 to provide time for CETA rulemaking by several state agencies as discussed above.

An exact future shutdown date for Colstrip Units 3 and 4 for all other purposes is unknown at this time. The 2021 IRP is analyzing the following assumptions regarding Colstrip:

1. Current coal contract costs through 2025.

2. Mercury controls will assume continued operations to meet Montana and Federal MATS regulations as long as the plant continues operation.

3. The installation of a SCR is no longer being modeled because the plant is expected to cease operations before the need for that equipment is necessary to meet the goals of the Regional Haze glide path[12].

4. Inclusion of CCR costs and projects that are required no matter how long the plant continues to operate.

5. Units 3 and 4 being fully depreciated by the end of 2025 to satisfy the requirements of CETA and Avista's last General Rate Case.

In addition, the IRP that will be filed in April 2021 will also include the results of any additional CETA rulemakings that will impact Colstrip. As discussed below, the capital projects included in this filing are only for environmental and operational requirements, and are not meant to extend the life of the plant beyond the end of 2025.

Q. Will CETA requirement for the elimination of energy from Colstrip 3 and 4 serving Washington customers by the end of 2025 impact any of the capital projects in this case?

A. No. As discussed elsewhere in my testimony, the Company is required to meet several regulatory obligations and environmental compliance requirements, in addition to maintaining Colstrip as a reliable, operational facility while it is still being used and relied upon to serve customers. This requires a strategic approach to planning and completing

[12] This is a planning assumption for modeling purposes in the IRP. If the plant continued to operate further into the future than expected, it may still be required to install SCR. This analysis assumes closure of the plant prior to the requirement of SCR.

certain capital projects in order to meet required deadlines. As such, the owners will continue to make the capital investments necessary to meet these requirements some of which extend beyond the operation of the plant. Put another way, the projects the Owners have undertaken are necessary, irrespective of existing laws or additional legislation.

Q. Can you provide additional details concerning the "environmental liabilities" associated with Colstrip as discussed in Footnote 314 of Order 07, Docket No. UE-170485?

A. Yes. The environmental liabilities are managed and considered through Avista's active management of its ownership share in conjunction with the plant operator. This occurs with the input of Avista employees from GPSS and Environmental Affairs, as Avista actively manages its shares of Colstrip Units 3 and 4, as described above, to ensure that the plant operator is complying with all relevant state and federal environmental regulations. The projects and costs needed for current and expected future compliance then feed into the economic models used for the IRP. The environmental liability areas covered for Colstrip include the following areas:

1. Coal supply: Coal mine reclamation is ongoing and Avista's share of reclamation costs are paid for as the coal is purchased. The Company has no additional costs or legal requirements beyond this cost which has already occurred. The mine owners are responsible for the actual reclamation.

2. Mercury controls: The current mercury abatement controls will continue to be used as long as the plant is in operation. There are no additional mercury controls expected to meet new requirements from the federal or state levels at this time.

3. Regional Haze: As discussed in the SmartBurn section of my testimony, the combination of SmartBurn and regional plant closures place Colstrip Units 3 and 4 within the glide path and SCR is not expected to be required, but could still be made a requirement under the Regional Haze Program if the plant were to run longer than currently anticipated.

4. <u>CCR and water management</u>: Please refer to this section later in my testimony describing the need for required ongoing capital spending on CCR and water management.

<u>B. Installation of SmartBurn</u>

Q. In regard to the Regional Haze Program, can you please describe the SmartBurn Project for Colstrip Units 3 and 4?

A. Yes. SmartBurn was originally developed as the part of Alliant Energy's Combustion Initiative Program focused on the reduction of nitrogen oxides ("NOx") by optimizing the combustion process in coal-fired generation plants.[13] NOx is a haze-inducing pollutant produced during the combustion of coal that is regulated under the Regional Haze Rule. SmartBurn uses air staging technology to reduce the amount of NOx that is formed by reducing flame temperatures and improving the efficiency of the combustion of coal. SmartBurn reduces the amount of NOx being formed, so there is less of it to be removed from the emissions stream as additional NOx emissions reductions are required. The NOx emissions data received from Colstrip Units 3 and 4 after SmartBurn was installed would be used to determine the appropriate size of the technology needed to address the next expected step in NOx reduction - Selective Catalytic Reduction, which is described below.

Q. What is Selective Catalytic Reduction?

A. Selective Catalytic Reduction ("SCR") is a post-combustion control technology based on the chemical reduction of NOx into molecular nitrogen (N_2) and water vapor (H_2O). SCR typically combines a catalyst with ammonia injection to increase the NOx removal efficiency. The size, scope and amount of ammonia used by the SCR is directly

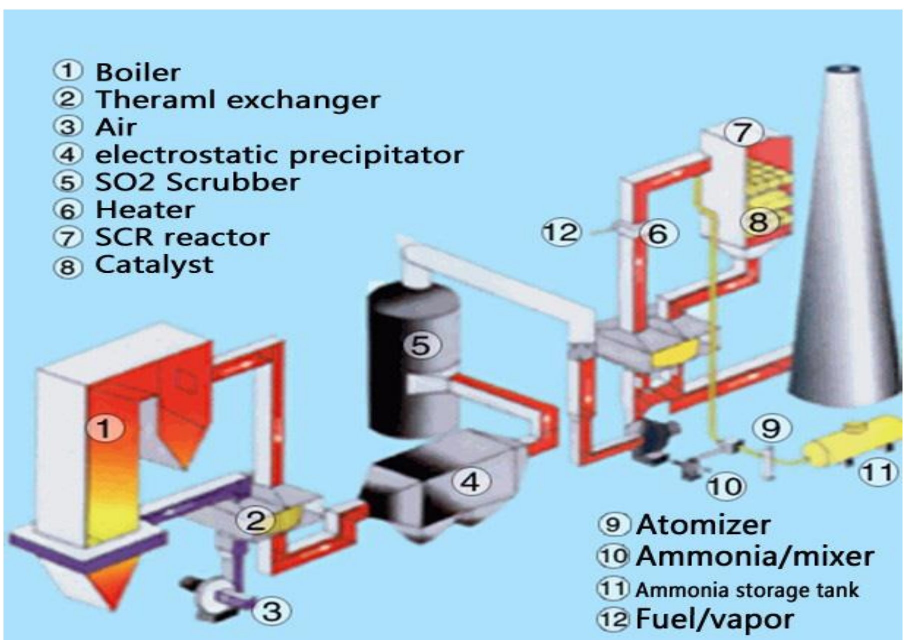
[13] http://www.smartburn.com/background.php

related to the amount of NOx created during the earlier combustion process. Less NOx produced during the combustion phase results in the need for a smaller, and less costly SCR, and a smaller amount of chemicals are needed to operate a smaller SCR.

Q. Can you provide a schematic showing where SmartBurn and SCR would be located in the coal combustion process?

A. Yes. Illustration No. 2 is a schematic showing where SCR (Item No. 7) would be located in the combustion stream, as opposed to the SmartBurn Technology which is deployed earlier in the boiler (Item No. 1).[14] This schematic, however, differs somewhat from the current configuration at Colstrip, which does not have SCR (Item No. 7) or an electrostatic precipitator (Item No. 4), but it serves to illustrate the point of where these technologies are in the coal combustion process.

<u>Illustration 2: Plant Schematic</u>



[14] https://www.tilemachinery.com/production-technology/coal-fired-power-plant-scrselective-catalytic-reduction-honeycomb-denitrification-catalyst/

The SmartBurn technology is applied to the boiler (#1 in above illustration) in order to improve combustion, while the SCR (#7 in above illustration) is employed at the end of the combustion process to remove additional NOx emissions.

Q. Is SCR currently required on Colstrip Units 3 and 4?

A. No, SCR is not currently required. However, there has been a long expectation of SCR being required on Colstrip Units 3 and 4 when the plant was still expected to continue operations well into the future. The expectation of SCR being needed at the plant to meet the Regional Haze Program was an expectation that was modeled in the Company's IRP since at least the 2011 IRP. In fact, as discussed later, members of the IRPs Technical Advisory Committee requested the inclusion of SCR for Colstrip modeling and often requested earlier dates for the installation, which were modeled through different scenarios (See Exh. JRT-10, Part 1, pgs. 1 – 29).

Q. Would you please provide additional background about when and why SmartBurn technology was installed on Colstrip Units 3 and 4?

A. Yes. In the 2012 decision timeframe, SCRs were being ordered in many surrounding states and previous litigation against Colstrip demanded a <u>requirement of</u> SCR for alleged "New Source Review" violations.[15] The owners, therefore, proactively decided to install SmartBurn in an effort to manage a future expected regulatory obligation, doing so in a strategic and cost-effective manner. Furthermore, SmartBurn was the last available, low cost, NOx pollution prevention emission control prior to the expected installation of a very expensive emission control (e.g., SCR).

[15] State of Montana Regional Haze Progress Report, August 2017, Montana Department of Environmental Quality, page 2-8 to 2-10.

Q. What was the timeline for completion of the Smart Burn projects and how much capital cost was included through 2017?

A. The SmartBurn projects began in 2015. SmartBurn on Unit 4 was completed in 2016 and the installation on Unit 3 was completed in 2017. Avista's share of the final cost for both units was $4.2 million (Avista), or $2.74 million for Washington.

Q. What was known about NOx emissions requirements for Colstrip Units 3 and 4 when the Company's decision to install SmartBurn was made in 2012?

A. There was a continuing expectation that future additional NOx reductions would be required for Colstrip Units 3 and 4. Avista's 2013 Electric IRP estimated SCR installation on Colstrip Units 3 and 4 could be required in 2027, and the Company ran scenarios to understand the implications of the SCR investment at that time. This was based on the Federal Implementation Plan for the State of Montana, finalized on September 18, 2012, and the expectation of a Reasonable Progress Report in September 2017.

Q. Were there other benefits for the timing of installing SmartBurn?

A. Yes. The SmartBurn technology was installed on Units 3 and 4 during previously scheduled outages thereby reducing implementation costs. If the SmartBurn needed to be added at a later date for more near-term compliance needs, a separate outage might be required in consecutive years – the first outage to install the SmartBurn technology, and a second outage to install additional plant controls. Depending on market conditions at the time of the outage, the additional cost of an extra week-long outage could be approximately one half the cost of installing SmartBurn itself. Finally, the operational effectiveness of SmartBurn may allow for a different and more cost-effective technology to be installed in place of SCR, because a lower amount of NOx is being produced by the plant.

SmartBurn does not otherwise improve reliability or extend the life of the plant, so it has no bearing on the useful life of the plant or the Colstrip owner's decision to operate the plant. SmartBurn provides immediate environmental benefits through NOx reduction now and would help mitigate the cost of later SCR additions which were anticipated at the time that the SmartBurn installation was approved.

Q. Would you provide some context concerning the timeline for the Regional Haze Program and where SmartBurn and SCR fit in regard to the program for Colstrip and the State of Montana?

A. Yes. The installation of SmartBurn on Units 3 and 4 was a strategic decision to meet expected and ongoing economic and regulatory purposes that are not well-defined and subject to change. The decision to install SmartBurn occurred in 2012, so the information and expectations <u>at that time</u> need to be considered when evaluating this capital spending decision. Anticipating that Colstrip Units 3 and 4 could be ordered to install SCR during the 2017 review period, the Colstrip Owners' proactively installed the SmartBurn technology to reduce the formation of Nitrous Oxides (NOx) in the combustion zone for two major benefits:

1. Make proactive and verifiable NOx reduction and
2. Optimize the size, scope and ammonia use of any future SCR installation.

The Regional Haze Program is a unique regulation approach in comparison to the typical "command and control" environmental regulation where the emission limitations and timelines are established at issuance. Regional Haze sets a goal of zero in 2064 and uses a "glide path" and reasonable progress goals to define the compliance trajectory. Combining this approach with the program volatility created in changing administrations and policy, Federal oversight with State implementation, various litigation decisions, State budgets, etc.

The result in Montana has been anything but a clear regulatory obligation as seen in the brief timeline of Montana's Regional Haze program that follows:

- Regional Haze Program is established by Federal EPA in 1999.
- Several years of emission data collection and evaluation to establish baseline years (2001-2003) for glide path.
- Regional Haze Program amended in 2005. State plans are required to be submitted in 2007, but Montana did not submit a plan.
- In 2009, Court ordered 37 States to submit plans by 2011, but Montana still did not submit a plan.
- Federal EPA requested and Talen submitted emission control evaluations for Colstrip Units 3 & 4.
- Spring 2012, Talen met with Federal EPA Region 8 in Denver to convey that emission controls were not needed at Colstrip, Avista attended.
- Federal EPA issues Montana Federal Implementation Plan (FIP) in September 2012, requiring additional emission controls on Colstrip Units 1 and 2. EPA defers emission controls on Units 3 and 4 until the next review period.
- Sierra Club and others petition to the Ninth Circuit regarding the Montana FIP.
- Sierra Club files Clean Air Act lawsuit against Colstrip Owners for alleged violations.
- Several lawsuit settlements occur in surrounding States requiring combinations of unit shutdown and/or the installation of SCR on coal-fired units.
- Colstrip Owners decide to proceed with SmartBurn installation in conjunction with existing outage schedules on Unit 4 in Spring 2016 and Unit 3 in Spring 2017.
- Montana FIP was remanded in May 2015 back to EPA Region 8 by the Ninth Circuit court.
- Colstrip Owners settle lawsuit with Sierra Club resulting in the shutdown of Units 1 and 2 by 2022 with dry ash storage requirement for Units 3 and 4.
- SmartBurn installation completed on Unit 4, Colstrip owners evaluate data and decide to proceed with Unit 3 installation during upcoming outage.
- Governor Bullock ordered Montana DEQ to take the Regional Haze program back from the EPA.
- Montana completes five-year review and report for Regional Haze Program (See MDEQ program link).
- Talen submitted the required four factor analysis in September 2019 confirming that no emission controls should be required since emissions remain below the glide path (See Exh. JRT-10, Part 2, pgs. 30 – 75).
- EPA is expected to issue an order to confirm that emission controls have deferred to the next review period.

The Colstrip Owners' proactively installed SmartBurn as the last available, low cost, pollution prevention emission control prior to the expected installation of a very expensive SCR. As will be discussed below, Avista's share of SmartBurn capital costs was approximately $4.2M (Avista), compared with Avista's estimated share of $105 million for SCR. In the decision timeframe, SCRs were being ordered in many surrounding states (see Exh. JRT-10, Part 2, pgs. 66 – 70) and the Sierra Club was litigating against Colstrip to require SCR for alleged NSR violations. The Owners installed SmartBurn in an effort to manage an expected future regulatory obligation in a strategic and cost-effective manner.

Q. In its recent Order in Puget Sound Energy's 2019 Rate Case, didn't the Commissions reject the capital costs associates with their share of SmartBurn?

A. Yes, it did, finding that Puget Sound Energy (PSE) failed to demonstrate that it was necessary in order to comply with any law, State or Federal, and that PSE failed to document <u>its</u> decision to support SmartBurn.

Q. Why does Avista believe that case, and those findings are not conclusive?

A. Firstly, each case must be decided on the record before it, and the Company is providing substantial evidence pertaining to prudency of its investment. In reviewing the record in the PSE case, Avista believes that the record was not sufficiently developed. Avista respectfully asks the Commissions to issue its decision in this case based on the record now before it.

Secondly, Avista does not believe that the test of prudency in this instance should be whether the investment in SmartBurn, per se, is specifically required by law or regulation. If that is the test, much of the prudent investment of capital in its system would fail such a narrow test. Prudent investments are made for any number of reasons – not just to satisfy some legal mandate;[16] so surely the test of prudency cannot be confined to a question of whether or not the investment is required by law. Indeed, Avista has categorized its capital investments into one of "six drivers" – only one of which is investment required for legal compliance.

Q. So what other evidence suggests that investment in SmartBurn was prudent when the decision was made in 2012?

A. The decision to invest in SmartBurn was the first step in mitigating the cost of any future requirement to install SCR. The reasonable plant operator at the time (2012) of course could not predict whether SCR would be required under any Regional Haze rules – but it could prepare for that eventuality, by investing in a technology that would mitigate any future costs associated with SCR. Indeed, it was assumed that SmartBurn would reduce the operational cost of future SCR compliance through the reduction of ammonia needed to operate a smaller, optimal sized unit. As shown in Exh. JRT-10, Part 1, pg. 4, Avista's share of any future SCR capital costs were estimated to be $105 million and $565,000 annually. Compare this to Avista's share of SmartBurn capital costs of approximately $4.2 million (Avista).

Utilities often prudently invest in efforts to mitigate future risks and costs (even if unknown): Examples include purchase of insurance, investment in fire protection, and even routine maintenance.

Q. At the time of the decision in 2012 to install SmartBurn, was it reasonable to assume that additional NOx reductions would be required in the future?

A. Yes. At the time, the Owners of Colstrip anticipated a need to install SCR

[16] It is true, however, in a broader sense that all prudent utility investment is required to satisfy a general legal obligation to provide safe and reliable service.

technology to meet the need for future NOx reductions. This speculation was founded on the Federal Implementation Plan for the State of Montana, finalized on September 18, 2012. Orders requiring SCR were also being issued in other states (See Exh. JRT-10, Part 2, pgs. 66 – 70). And, of course, there was no reason not to believe at the time that Colstrip would not be in service for decades to come. SmartBurn controls were the last available, low cost, NOx pollution prevention controls (and far less expensive than SCR).

Q. Did the Owners believe SmartBurn would satisfy all future NOx emissions reduction requirements at Colstrip?

A. No, and that was never the intent. Rather the Owners wanted to mitigate the very substantial cost of future SCR investments in the future – and at less cost.

Q. Did SmartBurn also provide immediate benefits?

A. Yes. It provided a tool to control NOx emissions within current operating requirements by preventing the formation of some of the NOx during the combustion process. Indeed, following its installation, it increased plant efficiency from 80 to 86 percent (i.e., removal of NOx emissions).

Q. At the end of the day, did Owners believe SmartBurn would, in and of itself, fully address NOx emissions requirements?

A. No, and that was never the expectation. It was but a step in the process that envisioned additional investments in SCR.

Q. How reasonable was it to prepare for the possibility of later SCR?

A. Very, and the eventuality of SCR was seemingly well understood by the parties. The need for SCR was discussed openly in the TAC meetings for the 2013, 2015, 2017, and 2019 Avista Electric IRPs attended by Staff and other interested parties, and was a planning assumption in the Company's Electric IRPs filed with and acknowledged by the Commission. Indeed, the Commission even directed the Company to include an SCR assumption in its 2017 IRP (See Exh. JRT-10, Part 1, pg. 19). At no time did Staff, interested parties, or the Commission challenge the planning assumptions around the inclusion of SCR in the base or expected case. Exh. JRT-10, Part 1, pgs. 1 – 29 contains experts from the 2013, 2015 and 2017 Electric IRPs plainly disclosing the need for the installation of SCR as a planning assumption.

There are a number of known facts that seem to be in contention about Colstrip and specifically how the Company should have known that the plant would not require additional NOx reductions. For example, the following pieces of information and data were known and knowable at the time:

- Colstrip was expected to continue operating throughout the 20-year resource plans in all of the Avista IRPs until the 2020 IRP – well after the time the SmartBurn decision was made and implemented.

- The 2017 IRP specifically included and modeled the cost of Selective Catalytic Reduction (SCR) beginning service in 2028 (2017 IRP, p. 12-2) and this was even noted in footnote 13 on page 5 of Staff Comments concerning that IRP. There were requests from the Technical Advisory Committee (TAC), which included Commission Staff and the Sierra Club, supporting the inclusion of SCR costs in the Expected Case. Staff and the other TAC members could not point to a specific law requiring specific technology and timing of the installation of that technology, but they saw the value in modeling the costs of SCR as a future expectation for the plant.

- Higher costs and more environmental requirements on Colstrip was also modeled. Footnote 8, Page 12-6 of Avista's 2017 IRP: Including the pricing in the market analysis, the total carbon price of $23.88 per metric ton. The High Colstrip Cost Scenario includes: requirements for SCR by the end of 2023, Units 1 & 2 close in 2018, which shifts common facility costs earlier than expected, adding a baghouse system by the end of 2023, and assumes the State of Montana will reduce carbon emissions following the Clean Power Plan's "mass-based with new sources levels," but delayed until 2024.

- Avista had no knowledge of any early planned shutdown dates for Colstrip Units 1 and 2 when the SmartBurn decision was made in 2012 because it has never been an owner or operator of those units. Only Talen and Puget Sound Energy possessed that economic and operational information. Even with that additional information, Puget Sound Energy also decided to invest in the SmartBurn technology.

Q. Did Avista/Talen consider alternatives to the Smart Burn Unit projects?

A. Talen reviewed a wide variety of NOx control solutions over the years, including selective non-catalytic reduction (SNCR), SCR, SmartBurn and others in expectation of future NOx reductions requirements under the Regional Haze Rule.

Q. How might SmartBurn impact the later addition of SCR?

A. SmartBurn is not a replacement for SCR, but as described above, it prevents some of the NOx from even being produced. The combination of SmartBurn, and associated measured data, results in the need for a smaller and less expensive SCR to limit the amount of NOx produced and to ensure compliance with the Regional Haze Rule. A smaller SCR requires less chemicals to operate, so a smaller amount of injected ammonia is needed, resulting in lower future operating costs.

The SmartBurn technology saves future capital expenditures, reduces future O&M expenditures, and provides an earlier environmental benefit by reducing the production of NOx. Using the SmartBurn technology before the installation of SCR is analogous to making a home as energy efficient as possible before adding solar panels, thereby reducing the overall size of the solar array and lowering subsequent cost. The energy efficiency investments do not eliminate the need for the energy produced by solar panels, but it reduces that need and results in a smaller number of panels needed to be purchased, installed and maintained. Put differently, energy efficiency should not be ignored altogether simply because it does not meet 100 percent of needs.

Q. Did the Idaho Public Utilities Commission (IPUC) already address the prudency of SmartBurn?

A. Yes. In Order No 33953 Case No. AVU-E-1701 the Commission concluded that Avista's investment in the SmartBurn projects were prudent when made. They stated:

> "We find that the SmartBurn equipment, while not required, was a cost-effective way to incrementally reduce NOx emissions now, thereby likely reducing the size and cost of emission controls."[17]

Q. Did the CETA legislation which established 2025 as an end-date for ceasing to use Colstrip as a Washington-resource make this investment imprudent?

A. No. The decision to install SmartBurn was made in 2012 well before the enactment, or even the legislative concept of CETA was known. The prudence of the SmartBurn decision needs to be based on what was known about the Regional Haze Program and the expectations about the future need for additional NOx reduction on Units 3 and 4 at the time the decision was made, the life expectancy of Avista's Colstrip ownership interests in Units 3 and 4 at the time the decision was made, and the other applicable laws and regulations in place at the time the decision was made. The Company could not predict and should not be held to a standard of perfect foresight about how a law that was not passed until 2019 would impact an investment decision made to reduce plant NOx emissions and minimize future expected investments to further reduce emissions as required to meet the Regional Haze Rule. At the time the decision to install SmartBurn was made in 2012, the Company knew the following:

- Colstrip was a cost-effective resource at the time and was expected to continue to be a cost-effective resource;

[17] Order No. 33953, Case No. AVU-E-1701 page 13, ¶ 3

- Colstrip was expected to remain a cost-effective resource based on what was known and modeled in the 20-year forecast of the IRP at the time, and in which Staff and other parties participated in developing the assumptions for that IRP;

- The expected glide path of the Regional Haze program was projected to require additional measures to reduce NOx emissions from Units 3 and 4 in the mid to late 2020s; and

- There were no laws or regulations in place in either Washington or Montana requiring the closure of Colstrip by a certain date – CETA did not exist when the decision to install SmartBurn was made.

Q. Would you conclude, by explaining why Avista supported the use of SmartBurn?

A. There are a number of important reasons Avista supported approval of the SmartBurn project. SmartBurn was expected to provide a compliance margin for the plant to be able to consistently remain in NOx emissions compliance. Although the plant was in compliance before the addition of SmartBurn, this project provided additional margin in the event unknown conditions were/are encountered. In order to comply with the "Glide Path" that is associated with the federal Regional Haze rules, it was expected that a SCR would eventually be required. <u>At the time of the SmartBurn installations</u>, Talen and Avista believed that a SCR would be required around the 2027 timeframe. Talen as plant operator analyzed Regional Haze requirements and determined that a final NOx Regional Haze solution would have required both Smart Burn and a SCR to meet expected NOx requirements. The reason for this was that SmartBurn provided the first and easiest reduction of NOx by eliminating its up-front formation. By installing SmartBurn first and obtaining the necessary operating data, it would be possible to size a SCR appropriately and an SCR was expected at the time the decision to install SmartBurn was made. Furthermore, future chemical use in a SCR (ammonia) would be reduced, and the incoming NOx would be lower thus reducing O&M expense.

C. Other Colstrip Capital Projects

Q. What other capital projects for Colstrip are included in the Company's case beyond SmartBurn?

A. Table No. 9 provides an overview of the Colstrip capital projects and costs completed in 2018 and 2019, and pro forma projects from 2020 through September 2022 included in this case beyond the SmartBurn project discussed earlier in my testimony. Additional documentation concerning capital projects at Colstrip is available in Exh. JRT-11.

Table No. 9: Colstrip Capital Projects

Colstrip Untit 3 and 4 Capital Project Name*	Unit(s)	Total Costs	Avista Share
Separate Overfire Air Bucket Replacements - 2020	4	$414,000	$62,100
New Break/Shear/Electric Shop/CaBr2 System Building - 2020	3 & 4	$2,050,000	$307,500
Capture Well Treatment System - Total 2019 -2021	1 – 4	$13,200,000	$1,980,000
Capture Well Treatment System - 2020 Costs		$6,600,000	$990,000
Unit 3 Aux Transformer - Total 2020 - 2021	3	$1,950,000	$293,000
Unit 3 Aux Transformer - 2020 Costs		$250,000	$37,500
Unit 3 Turbine Generator Base Overhaul - Total 2020 - 2021	3	$3,727,000	$559,000
Unit 3 Turbine Generator Base Overhaul - 2020 Costs		$150,000	$22,500
Unit 4 Intermediate Pressure Turbine Overhaul - Total 2018-2020	4	$8,250,000	$1,238,000
Unit 4 Intermediate Pressure Turbine Overhaul - 2020 Costs		$2,719,000	$408,000
Unit 4 Low Pressure Turbine Overhaul - 2020	4	$1,814,000	$196,650
Unit 4 Turbine Generator Base Overhaul - 2020	4	$4,762,000	$714,000
Unit 4 Boiler Bucket Burner and Auxiliary Air Replacement - 2020	3 & 4	$1,575,000	$236,000
Unit 4 Auxiliary Transformer-4 - 2020	4	$2,033,704	$305,056
Unit 4 Air Preheater Basket Replacement - 2020	4	$2,345,000	$351,750
Unit 4 Cooling Tower Fill - 2020	4	$3,000,000	$450,000
Install New Capture Wells at EHP - 2020	3 & 4	$3,596,000	$539,400
Design and Install in situ Flushing System EHP - Total 2020 - 2021	3 & 4	$5,965,000	$894,750
Design and Install in situ Flushing System EHP - 2020 Costs		$1,786,000	$539,400
Design/Build Dry Waste System – ARO - Total 2020 - 2022	3 & 4	$16,000,000	$2,400,000
Design/Build Dry Waste System – ARO - 2020 Costs		$3,000,000	$450,000
*See also Exh. JRT-11 for Project information.			

Q. Describe Avista/Talen's project management process that was used to manage the Colstrip capital projects.

A. Avista does not manage the projects at Colstrip directly. Talen as contract operator, manages all of the projects. They use Primavera as a software solution to keep projects on budget and on schedule. Talen employs a number of Project Management Professionals and engineers who may be assigned to manage projects depending on complexity.

Q. Describe how Talen kept Avista management informed during the Colstrip capital projects.

A. Budget to Actual reports are issued to Avista by Talen on a monthly basis. The cost status of each individual project in Table No. 9 above, prepared by Avista, are included in the summary reports contained in Exh. JRT-11.

Q. Please describe the <u>Separate Overfire Air Bucket Replacements Project</u>.

A. Separated overfire air (SOFA) buckets are essential to meeting environmental compliance by helping control the combustion process. To maintain equipment function and help provide for NOx emission and opacity control, the separated overfire buckets (and the top overfire buckets (TOFA)) need to be replaced every four years during a unit overhaul.

Overfire buckets warp with heat exposure over an extended time, which causes buckets to bind up in the boiler and restrict movement during unit operation. Through inspection during overhaul, the buckets on Unit 4 were found to be at the end of their life. The SOFA buckets are scheduled to be replaced during the 2020 overhaul. Part of the work included in the 2020 overhaul is the erecting of scaffolding in the boiler. The process of replacing buckets is most economical with a scaffold in place as this allows for an effective and cohesive removal of buckets, easier access to make repairs to support material, testing of movement, and alignment of all emission control components associated with the boiler corners at the same time. Complete failure of the buckets is <u>highly probable</u> if not replaced during the U4 2020 outage. SOFA buckets are a portion of the NOX control system and need to be in good working order for combustion optimization and PM, opacity, & NOX control. The investment drivers for this project include Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. Yes. The only other option is to "Do Nothing" and replace SOFA buckets during the next planned outage in four years in 2024. Not performing this work would result in a high risk that environmental compliance (NOx, PM, Opacity) would not be met. This could also result in fines from the MDEQ for violating emissions standards. In addition to consequences from the resulting non-compliance situation, the Unit would need to be run at reduced load or be placed offline until new buckets were purchased and installed. The lead time to obtain SOFA buckets is three to four months.

Q. What was the timeline for completion?

A. The new Overfire Buckets were purchased in early 2020 so they would be available for planners to incorporate into the 2020 Unit 4 Overhaul work. Due to concerns with COVID-19, the Unit 4 Overhaul effort was rescheduled to mid-September 2020 and includes the installation of the Overfire Buckets.

Q. What was the final cost of the project and when did it go into service?

A. The total cost is estimated to be $414,000, of which Avista's portion is $62,100. This includes $160,000 in materials and the balance of $254,000 is associated with labor to remove the old Overfire Air buckets, make any necessary repairs to supporting materials, and install the new ones. Work was expected to begin in September 2020 and be placed in service this year during the scheduled Unit 4 maintenance outage.

Q. Describe the system need for these projects.

A. The injection of air into the boiler fire at various levels allows the combustion to be lengthened, resulting in less air being combusted to create the same heat for production purposes. By this process, lower NOx levels are achieved while the fuel is still fully consumed to manage other constituents of the combustion process.

The overfire air system is a critical component used to manage the coal combustion process by providing a means to control the combustion by lengthening the combustion as described above. The ability to control the combustion in the boiler is essential to managing the NOx emissions from the unit. In addition, proper combustion management is required to also manage opacity, PM emissions, and other elements and properties that result when coal is burned. Collectively, there are several components needed to allow the coal to combust as clean as possible and achieve low NOx and still provide the energy needed to produce the power from the unit. The SOFA elements are one of these components.

Q. Describe the alternatives and how this solution was chosen?

A. The SOFA buckets are in poor condition. Replacing these buckets during the 2020 overhaul is the only viable alternative if the unit is to continue to meet its permitted emissions levels and avoid non-compliance.

Q. Provide up-to-date environmental liabilities and risks over its expected life.

A. Not performing this work would result in a high risk that environmental compliance (NOX, PM, Opacity) would not be met. This could also result in fines from the MDEQ for violating emissions standards.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, these buckets are crucial to the combustion process and are therefore right in the combustion chain. As a result, they are subject to extreme heat and will warp and get out of alignment in a relatively short time. These buckets need to be replaced every three to four years due to the warping from the normal amount of heat in the combustion process.

Q. Please describe the New Brake/Shear/Electric Shop/CaBr2 System Building Project.

A. With the shutdown of Units 1 and 2 in January 2020, a number of items have been identified that will need to be addressed that affect the near term continued operation of Units 3 and 4. One of these items is the bulk storage and transfer system for the Calcium Bromide (CaBr2) used for mercury abatement in Units 3 and 4. The existing bulk storage and transfer system is housed alongside the Condensate system in Units 1 and 2. With the demolition and removal of Units 1 and 2, that location will no longer be a serviceable location.

A new building will be erected on the East side of Unit 4, just south of the existing Hydrazine building. It will share a common wall with Unit 4. The new building will house the Calcium Bromide Bulk tank and transfer pumps in one end of the building in an enclosed space with tank containment built into the foundation. The other end of the new building will house the electric shop work area and an area where the existing brake and shear will be placed. The electric shop and the brake and shear area will be serviced by an electric overhead crane. These work areas are also currently within the Unit 1 and 2 footprint and are required for near term continued operation of Units 3 and 4. The investment drivers for this project include Asset Condition, Regulatory and Mandatory, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. Talen considered other alternatives including erecting different buildings to house the brake and shear equipment, a separate building to house the electric shop, and the CaBr2 building. Conceptually, each building would be smaller than the single building being proposed. The alternatives turned out to be an estimated three times more expensive to construct the individual buildings rather than the single larger building. In addition, no alternate space was found where the Brake and Shear Equipment nor the Electric shop could be reasonably located. The CaBr2 system must be moved so that it can continue to function because of the environmental permit requirements for the mercury abatement, which is a mandatory condition.

Finally, there was consideration of not erecting the building to include the Brake and Shear equipment and the Electric Shop. Without this space, the work performed there would need to be contracted out, likely to the Billings area, which could cause delays in maintenance and corrective actions for Units 3 and 4 as well as increase expenses. Additionally, work areas for the electrical work would be required to be set up throughout the plant on an ad hoc basis that would reduce efficiencies provided by a central electrical work location as well as increase access hazards throughout the plant.

Q. Describe the system need for these projects.

A. This project is required to support the mercury abatement system. The Calcium Bromide (CaBR2) solution is injected into the scrubber slurry. This reacts with the mercury and oxidizes the mercury in the flue gas which can then be captured by the plants existing scrubber equipment. This system is required to meet EPA Mercury and Air Toxic Standards, commonly referred to as MATS.

Q. Describe the alternatives and how this solution was chosen?

A. The alternatives are described above. As discussed, this project was the lowest cost solution to address the three concerns of the combination CaBr2 bulk storage and transfer system, Brake and Sheer Equipment and Electric Shop. All of these concerns are necessary for the cost-effective maintenance and operational compliance of Units 3 and 4 in the near term and until the final disposition of Units 3 and 4.

Q. Please provide up-to-date environmental liabilities and risks over its expected life.

A. This project provides for the bulk storage and transfer system required containment to store the Calcium Bromide (CaBr2) used for mercury abatement in Units 3 and 4.

Q. What is the timeline for completion?

A. The anticipated completion and "In-Service" date is scheduled for November 2020. Foundation work was done in 2019, but building erection and transfer of equipment is still ongoing.

Q. What is the expected cost of this project?

A. This project is expected to cost $2.05 million, with Avista's share approximately $307,500.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, as explained earlier, this project is required to continue operation of Units 3 and 4 up to the shutdown date of the plant, whenever that date occurs.

Q. Please describe the <u>Capture Well Treatment System Project</u>.

A. By way of background, the Water Management System and Coal Combustion Residual are essentially a building block set of projects that support the same strategic goal of meeting our regulatory obligations and environmental compliance requirements under the Agreement of Consent (AOC) with the Montana Department of Environmental Quality

(MDEQ) and Environmental Protection Agency (EPA) rules on Coal Combustion Residuals (CCR). These requirements result in several multi-year capital projects that will likely extend out through 2024 to address groundwater quality at the Colstrip site totaling $13.2 million, or $2.0 million Avista share.

A simple process description begins with raw water being piped from the Yellowstone River to Castle Rock Lake and ultimately to holding tanks at the plant site. This water is used in boilers, cooling towers and scrubber systems. Fly ash from the scrubber system is transported to the plants which then removes the excess water and deposits paste into disposal cells. Once the water is clear, it is ultimately recirculated back to the plant for reuse. All water is reused or lost through evaporation because Colstrip is a zero-discharge facility. Throughout the years, some water has been lost through seepage from the ponds that has contaminated the groundwater on the Colstrip site. The AOC is the primary Montana regulatory mechanism to address the groundwater contamination. This is a multi-year project due to the complexity and inter-related nature of the ponds.

Due to the significant amount of work required to meet these environmental regulations, this project has and will continue to have Capital Projects in each year from 2020 through the close of the Plant. The overall handling of the closed loop water system at Colstrip is subject to these two Environmental Must Do requirements.

The Colstrip Wastewater Administrative Order on Consent (AOC) requires specific actions by the plant to remediate impacted groundwater at the Plant Site. MDEQ approved actions requires treatment of the capture well water as part of the cleanup of impacted groundwater at the Plant Site. This project provides funding for a two-year design/construction schedule to implement a groundwater capture treatment system in accordance with the requirements identified in the Colstrip Wastewater AOC Plant Site Remedy as approved by MDEQ. The construction schedule meets the requirements of the approved MDEQ remediation for the plant site groundwater capture wells.

The MDEQ approved remedy for remediation also includes fresh-water injection into the plant water system. To implement this remedy, fresh-water injection wells will be installed and additional capture wells developed this year as required by this approved remedy. Once the remediation injection wells are operating at full capacity, we expect the total capture rate to be approximately 500 gpm. At this full capacity rate, we will fill the Groundwater Capture Storage Pond in about two years. The two-year design and construction schedule proposed with this project will meet the remediation requirements as approved by MDEQ.

This project will also include the design and construction of a new Brine Concentrator, steam supply, and a Crystallizer. The steam supply unit will provide capacity for this groundwater capture treatment system and the other groundwater capture treatment systems (currently in service) when all four units cease operation. In addition, this steam supply unit is capable of supplying steam heating to Units 3 and 4 if both Units are off during winter months. The investment drivers for this project includes Mandatory and Compliance, Asset Condition, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. As part of the effort, there were alternatives considered. These included upgrading some ponds and implementing more rigid institutional controls (i.e. more strict procedures, but at a higher cost with those more strict procedures), changing existing pumping performance requirements for the site and adding a treatments system, or continuing with the present operation. MDEQ ultimately determined that these options were not as effective as the selected option. Therefore the selected option was written into the AOC with the MDEQ to remedy the water issues at Colstrip.

Q. What is the timeline for completion?

A. Project engineering started in late 2019, with design in January 2020 and construction installation completion in 2021.

Q. What is the final cost of the project?

A. Total project costs is expected at $13.2 million, with $6.6 million completed in 2020. Avista's share totals $2.0 million, with $990,000 in 2020.

Q. Describe the system need for these projects.

A. This system is required for the overall water handling requirements for the Colstrip site as directed by MDEQ under the AOC. Costs have been adjudicated between the Unit 1 and 2 Owners and the Unit 3 and 4 Owners.

Q. Would you provide up-to-date environmental liabilities and risks over its expected life?

A. Currently, water from existing containment ponds has leaked into the ground water system on or near the site. This contamination is required to be remediated under the AOC. It is anticipated that this remediation will continue on past the operating life of the units.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No. This project is required to be continued by the AOC even after the Plant may be shut down and dismantled. This is an ongoing environmental commitment.

Q. Please describe the <u>Unit 3 Auxiliary Transformer Project</u>.

A. Unit 3's auxiliary transformer is original equipment and has been in service over 36 years. This unit has been subject to several through faults due to in-plant electrical failures. The load tap changers (LTCs) on Unit 3's Auxiliary transformer have experienced internal arcing failure, oil leakage and controls failures in the last five years. The furanic compound testing of the in-service transformer oil shows insulation aging concerns. Recently the 13.8 kV load tap changer failed. The troubleshooting indicated failed components on a control board. The failure was repaired by removing a control board from the failed Unit 4 auxiliary transformer and installing it in the Unit 3 auxiliary transformer. The auxiliary transformer for Unit 4 had failed in service previously (a year earlier). The new transformer was ordered early and delivered so that it is on site if the old auxiliary transfer fails. The investment drivers for this project includes Failed Plant and Operation, Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. Yes. The Unit 4 Auxiliary Transformer had previously failed in service. As a stop gap measure, a configuration was made with the transmission lines, the unit starting transformers, and station service bus to back feed the auxiliary load (normally served by the auxiliary transformer) through this arrangement. The resulting configuration results in substantial system losses. In addition, it would require a significant de-rate on the operating unit in order to start the other unit if it had been shut down for any reason. This placed the entire plant at risk of losing this key startup transformer. The startup transformers were not designed for this heavy continual loading condition. There was discussion to serve Unit 3 continuously with this configuration. Also, attempts were made to locate a used or rebuilt transformer, but the unique configuration of the 1,000 MVA rating at the 26kV/13.8kV/4160 winding with load tap changer on both lower voltage windings is very rare. No other suitable units were located.

Q. What was the timeline for completion?

A. The order was placed for the transformer in 2019. Installation of the transformer will coincide with the four-year outage plan for Unit 3. This outage is currently planned for a window of 56 days starting in early May of 2021, with in-service date in June 2021.

Q. What is the expected cost of this project?

A. The total expected cost for this project is $1.95 million, with $250,000 spent in 2020. Avista's share of these totals are $293,000 for the project, with $37,500 related to 2020.

Q. Describe the system need for these projects.

A. The auxiliary transformer provides the necessary power to run the mills, ID and FD fans, and other critical loads necessary to support the generation of steam to power the turbines. These are very large loads – enough load to serve a small town in many cases. In addition, other miscellaneous loads needed to run the unit are provided by this source. An auxiliary transformer is used rather than using the grid as a source in that it can be tapped directly from the output of the generator, saving considerable system losses if the power is sourced through the transmission system. If the grid was used to source this load, it exposes the plant and these critical loads to a variety of possible failures due to line faults, storms, "driver hits pole", and other risks.

Q. Describe the alternatives and how this solution was chosen?

A. The alternatives were described above. For reasons of reduced exposure to possible grid faults or problems, using equipment (i.e. startup transformers) in a manner for which they were not designed, reduction in system losses, unit reliability, and the wear on the LTC's a new auxiliary transformer was the best solution.

Q. Did Avista/Talen re-evaluate the alternatives?

A. Yes. Prior to placing the order, the alternatives were again discussed with the plant and the Owners. No change in the decision resulted from those discussions about alternatives.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, this project replaces failed equipment to restore expected operations. It does not extend the plant life beyond the anticipated shut down date.

Q. Please describe the <u>Unit 3 Turbine Generator Base Overhaul Project</u>.

A. This project has planned work in two years. The first year (2020 commitment) is to rebuild the turbine control valves that are removed from Unit 4 in 2020. This work is associated with shipping the removed valves to have them completely refurbished and prepared so they can be installed as part of the overhaul for Unit 3 scheduled in 2021. This rebuild is to assure the control valves will perform as they are crucial for turbine control and over speed protection.

The work to be performed in 2021 includes the mobilization of labor, the high velocity oil flush, bearing work as required, general open and close on the generator, throttle valve pinned seat installation, governor valves, turbine control valves, reheat stop valve routine rebuilds, contractor overhead (site support staff, project management, contract engineering support, office/clerical help, etc.), scaffolding, insulation, tool use, general steam chest maintenance, NDE testing and maintenance of the bolts and studs on the valves and steam chest and other assigned duties. This maintenance is performed every overhaul to ensure proper operation and reliability of the turbine/generator. The investment drivers for this project includes Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. The other option here is to do nothing. This is routine work necessary to provide a level of assurance that the unit will function as expected until the next overhaul outage in four years.

Q. What is the timeline for completion?

A. This work would coincide with the four-year outage plan for Unit 3. This is currently planned for a window of 56 days starting in early May of 2021, with in-service date in June 2021.

Q. What is the expected cost of this project?

A. The total expected cost for this project is $3.73 million, with $150,000 spent in 2020. Avista's share of these totals are $559,000 for the project, with $22,500 related to 2020.

Q. Describe the system need for these projects.

A. This project entails a series of refurbishments and replacements of parts of the turbine controls to assure they will function properly to provide the output control for a variety of items including indirectly managing emissions levels (by managing the output of the turbine, it provides means to make adjustments to the combustion process that can affect emissions), controlling the turbine output and response to system conditions, and as a safety system to prevent turbine over speed.

Q. Describe the alternatives and how this solution was chosen?

A. This work is either a "do" or a "don't" project. Failure to perform this routine work can increase the risk of an equipment failure or a system failure that could lead to personnel hazards. This work is intended to be scoped to provide adequate margins for safe and reliable operations between major outages. While this project does not guarantee that systems will not fail between major outages, this is commonly accepted practice to minimize an unplanned event.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, this project does not extend the plant life beyond the anticipated shut down date.

Q. Please describe the <u>Unit 4 Intermediate Pressure Turbine Overhaul Project</u>.

A. This project was originally approved as part of the 2018 budget as a three-year project with completion planned for 2020. As proposed, this project was planned for $4.0 million in 2018, $1.63 million in 2019, and $2.62 million in 2020. 2020 is the last year of this project.

This project entails disassembling the Intermediate Pressure (IP) Turbine and replacing the turbine rotor, stationary blades (blade rings), and the inner cylinder with new equipment. The current outer cylinder will be re-used. Blade rows 1-3 and blade rings on both sides of the existing IP Turbine have moderate to severe trailing edge erosion and some blunt leading edges. The inlet flow guide is out of round due to thermal distortion and the inner cylinder bolting hardware is starting to bottom out. The initial rows of the turbine have had shroud repairs to mitigate shroud lifting. This turbine has been ordered, manufactured, and is currently in storage, ready to be shipped to the plant for installation. The investment drivers for this project include Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. Yes. There was consideration given to ordering replacement turbine blades and rings to replace the damaged ones on the first three stages. Because of the extent of the damage observed in the inspection, it was determined to proceed with the replacement of the complete turbine blades, rings, and inner cylinder.

Q. What is the timeline for completion?

A. This work coincides with the four-year outage plan for Unit 4. This outage started in mid-September 2020 with the decision to shift the outage from spring to fall due to the COVID-19 issues and will be completed in November 2020.

Q. What is the expected final cost of the project?

A. Final costs are anticipated to be within the original budget for this project of $8.25 million, or Avista's share of $1.24 million. Remaining capital cost in 2020 is for the replacement of the IP rotor at $2.719 million, which includes $131,000 for remaining storage cost, $2.1 million for labor to install and complete performance testing, and about 10 percent contingency costs. Avista's share of these 2020 costs is $408,000. It is expected to go into service in November 2020.

Q. Describe the system need for these projects.

A. This project was previously approved in 2018. The basis for the approval was to address reliability concerns associated with the condition of the IP turbine blades and rings. Some photos in Illustrations 3 and 4 below show the current condition that is causing the concerns with this equipment and the need for its replacement.

Illustration 3:

RS Generator Blower Stationary Blade Casting Gouges

Illustration 4:

Governor UH Blade Ring 1 Row 1 Typical FOD to Blades

Q. Describe the alternatives and how this solution was chosen?

A. As briefly discussed above, some consideration was given to only replacing the damaged components. In addition, doing nothing was also discussed and considered. At the time the decision was made, it was determined that replacing the entire turbine blade, ring and rotor sections would best address plant reliability and would be less expensive to replace rather than repair due to the extensive field work necessary to repair in contrast to the shop work to replace the components.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, this project does not extend the plant life beyond the anticipated shut down date.

Q. Please describe the <u>Unit 4 Low Pressure Turbine Overhaul Project</u>.

A. The scope of this capital project is to perform base maintenance on the Low Pressure (LP) Turbine associated with the overhaul on Colstrip Unit 4. The work to be performed includes General Non-Destructive Evaluation (NDE), cleaning, blade and seal inspections and repairs as needed. This work is done during an overhaul to ensure proper operation and reliability of the LP Turbine. The investment drivers for this project includes Asset Condition, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. No. The LP Turbine Overhaul Project is planned work that is driven by manufacturer's recommendations, the results of ongoing inspections, and needed work discovered when the unit is opened up for its planned overhaul.

Q. What is the timeline for completion?

A. This work coincides with the four-year outage plan for Unit 4. Due to concerns from COVID-19, the spring outage was delayed until fall 2020. This work began in mid-September 2020 and will be completed in November 2020.

Q. What are the expected final cost of the project?

A. Final costs are anticipated to be within the original budget of $1.8 million. Inspection, cleaning, and non-destructive testing for the two Low Pressure turbines are expected to cost $769,000. The balance of the costs address worn and damaged turbine seals that were discovered during the previous inspection four years ago. Avista's share of these project costs are approximately $196,650 in 2020.

Q. Describe the system need for these projects.

A. In previous Unit 4 inspections, modest damage to the low-pressure turbine were found. The damage was due to several influences including some debris strike damage, erosion on the blade due to normal operation, and some minor cracking due to age and wear. If this damage is not addressed in a routine way, it could cause a major failure and extended unplanned outage in the future.

Q. Describe the alternatives and how this solution was chosen?

A. Long established industry practices have demonstrated the prudence of performing this type of work during a planned maintenance event to avoid the risk of a major unplanned failure in the future.

Q. Please describe any material changes that impacted the project scope, schedule or budget?

A. During the maintenance inspection, cracking was found on a low-pressure blade that will require replacement.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, this project does not extend the plant life beyond the anticipated shut down.

Q. Please describe the <u>Unit 4 Turbine Generator Base Overhaul Project</u>.

A. The work to be performed on the Unit 4 Generator Base Overhaul Project includes the mobilization of labor; high velocity oil flush; bearing work as required; general open and close on the generator; throttle valve pinned seat installation; governor valves, turbine valves, and reheat stop valve routine rebuilds; contractor overhead (site support staff, project management, contract engineering support, office/clerical help, etc.); scaffolding; insulation; tool use; general steam chest maintenance; NDE testing and maintenance of the bolts and studs on the valves and steam chest; and other assigned duties. This maintenance project is performed every overhaul to ensure proper operation and reliability of the turbine/generator. This work will install a rebuilt turbine valve system that had been previously removed from the last time Unit 3 was overhauled in 2017. The investment drivers for this project includes Asset Condition, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. The only other option here is to do nothing. This is routine work necessary to provide a level of assurance that the unit will continue to function through the outage interval.

Q. What is the timeline for completion?

A. This project work coincides with the four-year outage plan for Unit 4. With the decision to shift the outage from spring to fall due to the COVID-19 issues, this work began in mid-September 2020 and is currently planned to be completed in November 2020.

Q. What is the expected cost of this project?

A. The expected project costs for this project is $4.76 million, or $714,000 Avista share.

Q. Describe the system need for these projects.

A. This is a series of refurbishments and replacements of parts of the turbine controls to assure they will function properly to provide the output control for a variety of items including indirectly managing emissions levels (by managing the output of the turbine, it provides a means to make adjustments to the combustion process that can affect emissions), controlling the turbine output and response to system conditions, and as a safety system to prevent turbine over speed.

Q. Describe the alternatives and how this solution was chosen?

A. This work is either a "do" or a "don't" type of project. Failure to perform this routine work can increase the risk of an equipment failure or a system failure that could lead to personnel hazards. This work is intended to be scoped to provide adequate margins for safe and reliable operations between major outages. While this work does not guarantee that systems will not fail between major outages, this project is part of commonly accepted practice to minimize an unplanned event from occurring.

Q. Please describe any material changes that impacted the project scope, schedule or budget?

A. The schedule shifted from spring to fall due to the decision to delay the outage due to COVID-19 concerns. No other issues have come up that would materially change the project scope or budget.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, this project does not extend the plant life beyond the anticipated shut down.

Q. Please describe the <u>Unit 4 Boiler Bucket Burner and Auxiliary Air Replacement Project</u>.

A. A critical component of the NOx control system are the Burner buckets and Auxiliary Air Tips. In order to meet environmental emission targets, these elements must perform at a certain level. To maintain equipment function and to provide for NOx emission and opacity control, buckets (separated overfire air (SOFA), top overfire air (TOFA), and Burner) need to be replaced every four years during the unit overhaul. Buckets warp with heat exposure over an extended time, which causes the buckets to bind up in the boiler and restrict movement during unit operation. Through inspection during overhaul, the buckets are generally found to be at the end of their useful life within three to four years.

<u>Illustration 5: Separated Overfire Buckets</u>

Burner buckets/Aux Air tips are scheduled to be replaced on a four-year plan during an overhaul. Scheduling replacement of these components during an overhaul allows physical access to all buckets (SOFA, TOFA, and Burner) while a scaffold is installed in the boiler. The preventative maintenance process of replacing buckets is most economical with the use of a scaffold as this allows for an effective and cohesive removal of buckets, repairs to support material, testing of movement, and alignment of all emission components associated with the boiler corners at the same time. Burner buckets/Aux Air Tips are a portion of the SmartBurn NOx control system and need to be in good repair for combustion optimization, and particulate matter and NOx control. The investment drivers for this project includes Mandatory and Compliance, Failed Plant and Operation, Asset Condition, Reliability, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. No. The work being performed in this capital project is the replacement of worn out equipment that has been used to end of life. This is an "in-kind" replacement project and is part of the ongoing work on the unit to keep its combustion performance optimal for emission management purposes.

Q. What is the timeline for completion?

A. The work for this project is expected to be completed during the Unit 4 major planned outage that began in mid-September 2020 and will be completed in November 2020. The schedule had shifted from spring to fall due to the decision to delay the outage due to COVID-19 concerns.

Q. What is the expected cost for this project?

A. Final costs for this project are expected to be $1.58 million, or $236,000 Avista share.

Q. Describe the system need for these projects.

A. The elements being replaced here are part of the combustion system. An optimal performing system will compliment other emission controls to minimize all emissions from the plant. This project allows the plant to continue to operate within its permitted levels of emissions.

Q. Provide up-to-date environmental liabilities and risks over its expected life.

A. This project creates no new environmental liabilities. As indicated above, this is only an issue while the unit is operating.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, this project does not extend the plant life beyond the anticipated shut down.

Q. Please describe the Unit 4 Auxiliary Transformer Project.

A. In 2018, the Unit 4 Auxiliary transformer developed high levels of gassing in routine oil sampling indicating internal problems. Specifically, high levels of acetylene. When the transformer was opened for inspection, damage to the tap changer and into the transformer winding was discovered. The damage was unrepairable, so it was determined that the most cost-effective solution was to place an order for a new transformer and replace the out of service unit. The failed auxiliary transformer was original plant equipment and had 36 years of service. The investment drivers for this project includes Failed Plant and Operation, Asset Condition, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. Yes. As a stop gap measure, a configuration was made with the transmission lines, the unit starting transformers, and station service bus to back feed the auxiliary load (normally served by the auxiliary transformer) through this arrangement. The resulting configuration results in significant system losses. In addition, it would require a significant de-rate on the operating unit in order to start the other unit if it had been shut down for any reason. This configuration placed the entire plant at some risk of losing these key start up transformers as well. The startup transformers were not designed for this heavy continual loading condition. There was discussion to serve Unit 3 with this configuration.

Attempts were made to locate a used or rebuilt transformer, but the unique configuration of the 1000 MVA rating at the 26kV/13.8kV/4160 winding with load tap changer on both lower voltage windings is very rare. No other units were located. Inquiries were also made to assess if repair of the failed transformer was an option, but vendor quotes indicated it was far more expensive to attempt to repair the unit than to just replace with a new one. The chosen alternative was determined to mitigate risk as a reliability must do project.

Q. What is the timeline for completion?

A. The order was placed for the transformer in 2019. The Unit 4 Auxiliary transformer arrived on site in April 2020. Because of concerns with the COVID-19 Pandemic, a small outage of three weeks was taken in May 2020 to inspect Unit 4 in advance of the major overhaul outage rescheduled to September 2020. During this three-week outage, the Unit 4 Auxiliary transformer was installed and was placed into service.

Q. What was the final cost of the project?

A. The final costs for this project were $2.03 million, or $305,056 Avista share.

Q. Describe the system need for these projects.

A. The auxiliary transformer provides the necessary power to run the mills, induced draft (ID) and forced draft (FD) fans, and other critical loads necessary to support the generation of steam to power the turbines. These are very large loads, large enough load to serve a small town in many cases. In addition, other miscellaneous loads needed to run the unit are also provided by this source. An auxiliary transformer is used rather than using the grid as a source in that it can be tapped directly from the output of the generator, saving considerable system losses if the power is sourced through the transmission system. If the grid was used as a source of power for this load, it would expose the plant and these critical loads to a variety of possible failures due to line faults, storms, "driver hits pole" scenario, and other risks.

Q. Describe the alternatives and how this solution was chosen?

A. The alternatives for this project were described above. A new auxiliary transformer was the best solution because it reduced exposure to possible grid faults or problems, prevented the use of equipment (i.e. startup transformers) in a manner for which they were not designed, reduced in system losses, increases unit reliability, and reduces wear on the LTC's.

Q. Did Avista/Talen re-evaluate the alternatives?

A. Yes, prior to placing the order for the new Unit 4 Auxiliary Transformer, the alternatives were again discussed with the plant and the Owners. No change in the decision resulted from those discussions.

Q. Please describe any material changes that impacted the project scope, schedule or budget?

A. While there were some logistical challenges in getting the new transformer to the site, the installation went off as planned and the unit was successfully placed in service.

Q. Provide up-to-date environmental liabilities and risks over its expected life.

A. This project does not directly impact environmental liabilities. The exposure to an oil release is the same as the old unit as tank volumes are comparable.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, this project does not extend the plant life beyond the anticipated shut down.

Q. Please describe the <u>Unit 4 Air Preheater Basket Replacement Project</u>.

A. The Unit 4 Air Preheater Basket Replacement project is to replace major sections of the air heat transfer baskets on the B Air Preheater (APH). Because of the arrangement of the baskets, they wear on the inner rows and some have caused damaged to the intermediate baskets. The wear on the baskets has caused the hot end baskets to fall apart and drop onto the top of the hot intermediate baskets. This has resulted in plugging with the APH that cannot be mitigated with a high-pressure wash. The only way to restore full function of the APH is to replace the damaged APH baskets. Illustrations No. 6 and No. 7 show the current condition of the baskets.

Illustration No. 6: Unit 4 Air Preheater Basket Condition

Illustration No. 7: Unit 4 Air Preheater Basket Condition

This is a reliability must do project. These baskets need to be replaced in order to maintain equipment operation, reliability and efficiency. The investment drivers for this project includes Failed Plant and Operation, Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. As this is a replacement of elements of an existing system required for the efficient and reliable operation of the unit, there are few options. Choosing to continue to run in their current condition would result in a continual failure of the system and the degradation of the ability to preheat air for the combustion process. This would result in a significant decrease in unit performance. Removing the Air Preheater is not a viable option as this is a critical element in the heat cycle process and unit performance would significantly change, thereby increasing the operating expense of the plant and subsequently increasing cost to customers.

The replacement option was chosen as it will restore a normal operating condition to the unit without penalty or significant risk of failure after the overhaul work is completed. Removal and installation of baskets and seals is most effective while done during an overhaul. An overhaul of an air preheater is a systematic process which involves repair of numerous sections of the air preheater as a whole, removal and replacement of baskets, repair of supports as well as removal of ash and other debris. If forced to replace baskets after the overhaul, cost would include about 24 days of lost generation, additional material required to move new and old baskets, cleaning prior to installation and removal, additional staffing, and equipment rental.

Q. Describe the system need for these projects.

A. The air pre-heater system is a key to overall boiler efficiency. This system extracts heat from the flue gas and transfers it to the boiler make up air before the fire. It takes less heat using hot air to reach operating temperatures within the boiler than colder air. This process improves the cost effectiveness of the overall system. The condition of the baskets is poor, they are falling apart and clogging the APH causing high differential pressure through the APH which causes more work load on the ID fans. The current design has shown to cause erosion and damage to additional baskets. The recommended replacement is with redesigned baskets.

Q. Describe the alternatives and how this solution was chosen?

A. The expense to replace the system rather than replacing parts of the system would be much more expensive and would not improve performance. Removing the system would deprive the overall boiler of a significant efficiency improvement and cost more in fuel and likely reduce output to the detriment of the energy expense.

Q. What is the timeline for completion?

A. This work is planned to be performed during the 2020 Unit 4 overhaul outage that began in mid-September 2020 and will be completed in November 2020. The schedule had shifted from spring to fall due to the decision to delay the outage due to COVID-19 concerns.

Q. What is the expected cost for this project?

A. Project costs planned in 2020 total $1.26 million (Avista share $189,000), with final costs for this project expected to be $2.35 million, or $351,750 Avista share. This project was approved as a two-year project, with material ordered in 2019.

Q. What is the expected final cost of the project?

A. Final costs are anticipated to be within the original budget and will be available after completion of the project.

Q. Provide up-to-date environmental liabilities and risks over its expected life.

A. This project does not directly impact environmental liabilities.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, this project does not extend the plant life beyond the anticipated shut down.

Q. Please describe the <u>Unit 4 Cooling Tower Fill Project</u>.

A. The Cooling Tower Fill has been in place for over ten years and is over its recommended life span. Cooling Tower Fill ("Fill") is typically replaced every 10 years, per the manufacturer's recommendations. The Fill is becoming brittle, as expected with increasing age; and additionally, has been subjected to additional breakage due to structural failures in the Cooling Tower structure. As these structural members fail due to normal age and wear, it causes those parts of the Fill material that those members supported to also fail and the brittle remnants of the failed cooling tower cause the circulating water system to plug up.

This project will replace 90 percent of the Fill and 50 percent of the piping and nozzles, in conjunction with the structural maintenance to replace those failed members during the 2020 overhaul. New Fill material will be installed over these new members that will help restore the Cooling Tower function. This is a partial retrofit intended to allow reasonable operation until a similar project will be done at the next overhaul outage in four years. Additionally, the Fill will need to be removed to replace the structural beams which will cause further degradation and breakage, resulting in reliability issues. The investment drivers for this project includes Asset Condition, Customer Service Quality and Reliability, and Performance and Capacity.

Q. Did Avista/Talen consider alternatives to the project?

A. Yes, the original recommendation was to remove and replace all of the weak structural members and associated Fill. The team also considered an option that would only replace those members that had either failed as well as the most at risk structural members based upon a pre-outage inspection. This would not correct the Cooling Tower for the long run, but would provide an expectation to get through to the next overhaul outage. Additionally, discussions were also made concerning if the work needed to be done at all. It was concluded that this work would be needed to avoid possible intermittent shutdowns. If the Fill is not replaced, there will likely be failures in the Cooling Tower, resulting in unplanned outages. As the brittle Cooling Tower breaks away, it collects in the circulating water channels, ultimately ending up against the screens. This causes plugging at the screens and throughout the system. This results in very high condenser back pressure which can lead to unit outages.

Q. What is the timeline for completion?

A. The Unit 4 Cooling Tower Fill is being replaced during in the 2020 scheduled overhaul outage. This should be completed in November 2020.

Q. What is the expected final cost of the project?

A. Total project costs are expected at $3.0 million, or $450,000 Avista share.

Q. Describe the system need for these projects.

A. The Cooling Tower Fill has been in place for more than ten years, which is over its recommended life span. Cooling Tower Fill is typically replaced every 10 years, per the manufacturer's recommendations. It has become brittle and the situation is further complicated by structural failures within the Cooling Tower structure. As these structural members fail due to normal age and wear, it causes those parts of the Fill material that they supported to fail and the brittle remnants of the failed Cooling Tower then cause the circulating water system to plug up. Additionally, the Fill will need to be removed to replace the structural beams which will cause further degradation and breakage, resulting in reliability issues.

Q. Describe the alternatives and how this solution was chosen?

A. After discussion of the alternatives described above, it was believed the choice to address only the most critical items at this time would be the appropriate course of action at this time. Doing nothing was thought to be a higher outage risk choice that would not meet operational expectations.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, this project does not extend the plant life beyond the anticipated shut down.

Q. Please describe the <u>Install New Capture Wells at Effluent Holding Pond Project</u>.

A. This project provides for additional capture wells to be installed at the Unit 3 and 4 Effluent Holding Pond (EHP) to capture water that seeps from the ponds into the ground. These wells collect this water to keep it from moving off the site. As required by the Colstrip Wastewater AOC, this project provides for additional capture wells to be installed at the Units 3 and 4 EHP to meet the remedy evaluation activities identified in Alternative 4 of the Units

3 and 4 Remedy Evaluation Report. Remedial activities are required under the AOC to mitigate impacted groundwater related to the Units 3 and 4 EHP. The Remedy Evaluation Report was approved by MDEQ and the Remedial Design/Remedial Action Report for Units 3 and 4 is currently under review. Alternative 4 identifies the installation of 23 new vertical wells and 2 new horizontal wells in 2020 to meet the cleanup criteria in the time frame identified by MDEQ under the AOC. This project is considered an Environmental Must Do as required by the AOC. The investment driver for this project is Mandatory and Compliance.

Q. Did Avista/Talen consider alternatives to the project?

A. This work is required from the Colstrip AOC that dictates how water on the site is to be remediated. Any discussion of options is provided through the process of negotiations and process of settlement for the AOC with the MDEQ. Any non-AOC approved alternative would result in a violation of the Colstrip Wastewater AOC and a high risk of a Notice of Violation (NOV) with subsequent litigation, fines and penalties.

Q. What is the timeline for completion?

A. The work on this item is to be completed by the end 2020.

Q. What is the expected final cost of this project?

A. This expected total project cost of this project is $3.6 million, or $539,400 Avista share.

Q. Describe the alternatives and how this solution was chosen?

A. This project is a requirement under the AOC that is determined through a process conducted by the MDEQ. The first and chosen alternative is to implement the additional capture wells as identified in alternative 4 of the Colstrip Units 3 and 4 EHP Remedy Evaluation Report. The only other alternative is the Do Nothing alternative, which would result in a violation of the Colstrip Wastewater AOC, a Notice of Violation (NOV), probable litigation, fines and penalties.

Q. Did Avista/Talen re-evaluate the alternatives?

A. No, Avista/Talen did not reevaluate the alternatives since the evaluation of alternatives was done in the AOC process, which become requirements after the MDEQ approves the various components of the AOC.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, this project does not extend the plant life beyond the anticipated shut down of the plant whenever that event occurs.

Q. Please describe the <u>Design and Install in situ Flushing System EHP Project</u>.

A. This project provides for installation of 46 freshwater injection wells to be installed at the Unit 3&4 EHP to promote capture of water that seeps from the ponds into the ground. These wells inject fresh water into the ground to promote flows into the capture wells at the edge of the property near the EHP. This project is another part of this groundwater capture system. As required by the Colstrip Wastewater AOC, this project provides for design and installation of in-situ flushing wells to be installed at the Unit 3 and 4 EHP to meet the remedy evaluation activities identified in Alternative 4 of the Units 3 and 4 Remedy Evaluation Report. Remedial activities are required under the AOC to mitigate impacted groundwater related to the Unit 3 and 4 EHP. The Remedy Evaluation Report has been approved by the MDEQ and the Remedial Design/Remedial Action Report for Units 3 and 4 is currently under review. Alternative 4 identified the installation of 46 vertical injection wells in 2020 to provide clean flushing water to meet the cleanup criteria in the time frame identified by MDEQ under the AOC. This project is budgeted over two years; $1,786,000 in 2020 for the design and initial installation of wells, then $4,179,000 for final installation of the in-situ flushing system, for a total project cost of $5,965,000. This project is considered an Environmental Must Do as required by the AOC.

Q. Did Avista/Talen consider alternatives to the project?

A. This work is required from the Colstrip AOC that dictates how water on the site is to be remediated. Any discussion of options is provided through the process of negotiations and process of settlement for the AOC with the MDEQ. Not fulfilling requirements would result in a violation of the Colstrip Wastewater AOC, a Notice of Violation (NOV) and a high expectation of litigation, and fines or penalties.

Q. What was the timeline for completion?

A. The work on the In-Situ Flushing Well System item consists of design efforts in 2020 and installation in 2021.

Q. What was the final cost of the project and when did it go into service?

A. As noted above, this project is expected to cost $1,786,000 in 2020 for the design and initial installation of wells, then $4,179,000 for final installation of the in-situ flushing system in 2021, for a total project cost of $5,965,000. Avista's share of the total project cost is $894,750.

Q. Describe the system need for these projects.

A. This is an environmental must do project for AOC compliance. As required by the Colstrip AOC, this project provides for design and installation of in-situ flushing wells to be installed at the Units 3 and 4 EHP to meet the remedy evaluation activities identified in

Alternative 4 of the Units 3 and 4 Remedy Evaluation Report. Remedial activities are required under the AOC to mitigate impacted groundwater related to the Unit 3 and 4 EHP.

Q. Describe the alternatives and how this solution was chosen?

A. This is included in the AOC that is determined through a process conducted by MDEQ.

Q. Did Avista/Talen re-evaluate the alternatives?

A. No, Avista/Talen did not reevaluate the alternatives since the evaluation of alternatives was done in the AOC process, which become requirements after the MDEQ approves the various components of the AOC.

Q. Does this project extend the plant life beyond the anticipated shut down date?

A. No, this project does not extend the plant life as this is a portion of what is ultimately required to shut down the plant, whenever that event occurs.

Q. Please describe the <u>Design/Build Dry Waste Disposal System Project</u>.

A. This project provides for installation of a “non-liquid” disposal system for Coal Combustion Residue (CCR) material created by the operation of Units 3 and 4. This capital project is required as part of the AOC. The Colstrip Wastewater AOC requires pond closure and remediation activities to address impacted groundwater at the Units 3 and 4 Effluent Holding Pond (EHP) area. Litigation on the AOC resulted in a Settlement that requires a "non-liquid" disposal system for CCR material generated by Units 3 and 4 at the EHP no later than July 1, 2022. This project designs and builds that "non-liquid" disposal system. This project is considered an Environmental Must Do project because of the AOC and AOC Settlement requirements. The investment driver for this project is Mandatory and

Compliance.

Q. Did Avista/Talen consider alternatives to the project?

A. Yes. This work is required from the Colstrip AOC that dictates how water on the site is to be remediated. Any discussion of options is provided through the process of negotiations and process of settlement for the AOC with the MDEQ. Not completing this project would result in a violation of the Colstrip Wastewater AOC and AOC Settlement. This alternative would result in a Notice of Violation (NOV) and a high risk of litigation along with fines and penalties.

Q. What is the timeline for completion?

A. The work on this item consists of design efforts in 2020 and construction starting in 2021 with estimated completion in mid-2022.

Q. What is the expected final cost of the project?

A. The total project cost is expected to be approximately $16.0 million, with 2020 costs totaling $3.0 million. Avista's share of the 2020 project costs are $450,000, with total project cost at $2.4 million (Avista).

Q. Describe the system need for these projects.

A. This is an environmental must do project for AOC compliance. The Colstrip Wastewater AOC requires pond closure and remediation activities to address impacted groundwater at the Units 3 and 4 EHP area as described above.

Q. Describe the alternatives and how this solution was chosen?

A. The consideration of alternatives is included in the AOC that is determined through a process conducted and the results of which are approved by MDEQ.

Q. Does this project extend the plant life beyond the anticipated shut down

date?

A. No, this project does not extend the plant life beyond the anticipated shut down. This project is a portion of what will ultimately be required to shut down the plant, whenever that date actually occurs.

<u>VI. RATTLESNAKE FLAT WIND POWER PURCHASE AGREEMENT</u>

Q. Please explain the Rattlesnake Flat Wind Power Purchase Agreement and what was the need for that resource?

A. The Rattlesnake Flat Wind Power Purchase Agreement (Rattlesnake Wind PPA) is a 20-year agreement to purchase all of the generation output and all environmental benefits associated with the 144 MW Rattlesnake Flat Wind project. Avista's acquisition of the 144 MW Rattlesnake Flat Wind project began with the goal of acquiring renewable energy at a price less than Avista's 2017 Integrated Resource Plan (IRP) avoided cost as filed with the UTC and the IPUC on August 31, 2017, and acknowledged by the UTC in Docket UE-161036 on May 7, 2018. Any long-term resource acquisition below these avoided costs is in the best interest of customers for two reasons. First, the expected cost is less than the forecast price of power at the time of the acquisition. Second, the price is fixed (known) as compared to the electric market that could change due to many factors.

Avista decided to issue a renewable RFP in June 2018 to attempt to secure low cost renewable generation based on expiring tax breaks and indicative developer pricing, and potential clean energy legislation expected at that time and since manifested in the CETA. A full summary of the RFP process and justifications for signing the Rattlesnake PPA is provided as Confidential Exh. JRT-7C – 2018 Renewable RFP Report which contains the following supplemental documentation in addition to the main summary report:

- Exhibit A – Evaluation Methodology
- Exhibit B – Avista 2018 Renewables RFP Instructions
- Exhibit C – Avista 2018 Renewables RFP Document
- Exhibit D.1 – Evaluation Matrix 6/26/18
- Exhibit D.2 – Financial Analysis 6/23/18
- Exhibit E.1 – Short List Bid Scoring Summary 8/7/18
- Exhibit E.2 – Financial Analysis 8/18/18
- Exhibit F – Commission Staffs and Public Counsel Update 7/9/18
- Exhibit G.1 – Evaluation Matrix Short List Bids 9/5/18
- Exhibit G.2 – Financial Analysis 9/6/18
- Exhibit H – Black and Veatch Independent Evaluation Final Report
- Exhibit I – Management Approvals
- Exhibit J – WUTC Staff Presentation 4/2/19

Q. Please briefly describe the Rattlesnake Flat Wind Project.

A. The Rattlesnake Flat Wind Project consists of 50 Siemens S-129 2.9 MW wind turbines that are located on 20,000 acres about 12 miles southeast of Lind, Washington with a total capacity 160.45 MWs nameplate capacity "clipped" to 144 MWs of maximum delivery based on the interconnection contract with Avista. The project is directly connected to the Avista electric system and is expected to begin commercial operation before the end of 2020.

Q. Can you provide a simplified timeline of events leading up to the execution of the Rattlesnake Flat Wind PPA?

A. Yes. The following list is a timeline of the major events leading up to the execution of the Rattlesnake Flat Wind PPA:

- **2014 to 2017:** Company received unsolicited indicative bids for wind projects with increasingly attractive pricing.
- **First Quarter 2018:** Lower indicative bid pricing received from potential developers.
- **March 2018 –** Initiated renewable RFP process internally.
- **March 2018:** Retained Black & Veatch as an Independent Evaluator for the RFP.
- **May 2018:** Outreach with Commission staffs, Public Counsel and intervenors.

- **June 6, 2018:** Phase I - RFP released.
- **June 21, 2018:** RFP Phase I bid opening and conference call with Commission Staff and Public Counsel.
- **June 29, 2020:** Phase II – Shortlist identified, eight bidders.
- **July 9, 2018:** Conference Call – RFP short list update and presentation to Commission Staffs and Public Counsel.
- **July 23, 2018 to August 15, 2018:** Questions and clarifications with Phase II bidders.
- **August 16, 2018:** Phase 2 – Requested price refresh from Phase II bidders.
- **August 24, 2018:** Received price refresh.
- **September 12, 2018:** Selected Rattlesnake Flat Wind Project as the preferred project.
- **September 19, 2018:** Notified Commission and Public Counsel Staffs of the winning RFP selection.
- **September 2018 – February 2019:** Contract negotiations.
- **March 7, 2019:** Signed contract with Clearway Energy for the Rattlesnake Flat 144 MW wind project - ***See Confidential Exh. JRT-8C***

Q. Can you provide some background regarding why the Company initiated an RFP for renewable resources in 2018.

A. Yes. Avista began the 2018 RFP process with the goal of acquiring renewable energy below the avoided cost identified in the 2017 IRP ($31.87 per MWh for wind and $29.90 per MWh for solar, page 11-19 of the 2017 IRP). Obtaining this new, long-term renewable resources would be in the best interests of customers because the cost would be below the forecast price of power at the time of the acquisition and it would be at a known price thereby eliminating the variations inherent in shorter term market purchases.

The spring of 2018 was seen as an opportune time for the Company to request and evaluate renewable market options. Indicators for the timing of this RFP included the expiration of the Production Tax Credit (PTC) in 2020, indicative pricing and developer activity, competition for preferred projects and locations, technology advancements and competition for least cost resources. The PTC was lowering prices as compared to price quotes after 2020. The $23/MWh PTC was scheduled to be reduced or expire in 2020, as well as the investment tax credit (ITC) in 2022[18]. The $23/MWh PTC value is significant as it represents approximately 44% of the cost of the selected project for the first 10 years. Pricing was expected to increase after tax credits expired. Developer activity along with industry market insights provided Avista opportunities to observe and analyze changes in renewable energy technology and pricing. Indicative and actual pricing for renewables in the west at that time suggested renewable resources were competitive in the wholesale market. In fact pricing provided to Avista during 2017 and early 2018 showed falling renewable prices. With advances of machine technologies and the sun-setting of tax credits, pricing for renewables had never been lower. Indications were pricing could increase if tax credit opportunities were not fully captured. A more detailed discussion of the background for initiating the 2018 Renewables RFP is available in Confidential Exh. JRT-7C – 2018 Renewable RFP Report.

Q. What are the prudence standards applied by this Commission related to the acquisition of a resource?

A. The Commission articulated in PacifiCorp's rate proceeding (Docket No. UE-090205) the four main questions that must be answered in order to support the acquisition of a generation resource as "prudent and used and useful in providing service to customers in Washington" (see Order No. 09, p. 23):

> When examining the acquisition of new facilities, we consider whether: (1) the new resources are necessary; (2) the Company evaluated and considered alternatives; (3) the acquisition decision involved the Board of Directors; and (4) whether the Company's analysis and decision-making process is adequately documented. In addition, new power resources must comply with all state laws including the RCW 80.80 Greenhouse Gas Emissions

[18] The Investment Tax Credit (ITC) was modified by the IRS to include certain projects completed by 2024 on June 22, 2018, subsequent to the issuance of the RFP.

Performance Standard.

The four main considerations regarding prudence are discussed in order below.

1. Resource Necessity

Q. At the time of the 2018 Renewables RFP, please explain how the Company determined that a new resource was necessary.

A. The 2018 RFP for renewables was issued in June 2018 to leverage beneficial pricing (including tax breaks going away and developer pricing) and to prepare for the expected outcome of clean energy legislation which came to pass in the Clean Energy Transformation Act on May 7, 2019. Although this RFP was held prior to the Company's announcement of its clean energy goals, the RFP provided an opportunity for the Company to evaluate a transition to a cleaner resource portfolio at a lower cost. The Preferred Resource Strategy identified in the 2017 Integrated Resource Planning process only included the Solar Select renewable resource. The other new resources identified in that IRP included natural gas peakers, upgrades to existing facilities, energy efficiency, demand response and some distribution efficiencies. As discussed in the 2017 IRP, Avista relies on market purchases to meet a small portion of its energy and capacity needs. If Avista could replace these market purchases with a known lower cost resource, then it is in the best interest of its customers to do so.

2. Evaluation and Consideration of Alternatives

Q. How did Avista evaluate and consider alternatives to the Rattlesnake Flat Wind PPA?

A. The Company issued an RFP on June 6, 2018 for 50 aMW of Washington RPS qualified renewable energy to be online by the end of 2020 and to secure the output through a Power Purchase Agreement (PPA) and/or an option to purchase the project from renewable generation resources, including electricity, capacity and associated environmental attributes. (See Confidential Exh. JRT-7C). Bidders could submit one or more proposals including wind, solar, geothermal, biomass, hydroelectric, and other renewable resources with or without storage with a minimum net annual output of 5 aMW AC up to 50 aMW. The RFP was open to parties who owned, proposed to develop, or held rights to new renewable resource generating facilities. Avista engaged an independent evaluator, Black & Veatch, for this RFP to review the selection criteria and provide an independent review of the received bids. The Company did not accept proposals for renewable energy certificates only and did not consider a self-build option. The RFP process was also not required under WAC 480-107.

Avista produced an evaluation criteria and methodology for scoring bids in consultation with the independent evaluator. The RFP evaluation methodology was shared and discussed with the Staffs of the UTC and IPUC on June 21, 2018. The methodology is provided in <u>Exhibit A of the 2018 Renewable RFP Report contained in</u> Confidential Exh. JRT-7C. The general qualifications for each proposal were evaluated on the five characteristics shown in Table 10 below. The weightings for each characteristic were determined based on their importance in helping the Company meet its resource development goals stated in the 2017 IRP. Within each characteristic, <u>points can be subtracted or added to the initial 100 points</u> based on responses to the RFP and Avista's interpretation of the data. Avista reserved the right to modify the scoring criteria in consultation with Black & Veatch and the Commission Staffs in Washington and Idaho if proposals were received that contained circumstances not considered in the original methodology. However, this was unnecessary, as the situation did not occur.

Table 10: 2018 Renewables RFP Evaluation Criteria and Weightings

Characteristic	Weighting (%)
Risk Management	25
Net Price	40
Price Risk	5
Electric Factors	20
Environmental	10
Total	100

Avista utilized a two-step bid process. Avista first evaluated and ranked projects based on preliminary information by allowing developers to submit a condensed initial bid utilizing a template provided in the RFP. The evaluation and ranking of the preliminary information focused on conformance of each bidder's submittal with the RFP requirements and the proposed net price, among other factors. Evaluation and ranking, performed in a fair and consistent manner, produced a short list of bids confirmed by Black & Veatch. Once the short list was compiled, short-listed bidders were asked to submit detailed proposals. Each short-listed bidder's detailed proposal was evaluated against the other proposals. In the end, 28 developers submitted over 40 responses to the RFP with projects in excess of 3,000 MW proposed. Potential projects were evaluated both quantitatively and qualitatively based on predetermined criteria shared with the staffs of the Washington and Idaho Commissions, as well as the Public Counsel Unit of the Washington Attorney General's Office. Eight projects were selected for a short list and were asked to provide detailed responses to the proposal.

The first screening began on June 20, 2018. This screen focused on removing proposals that did not meet the minimum RFP requirements. Preliminary information was reviewed for all projects and an initial break point was established based on site control and other issues. Most projects had either executed a binding option to lease the project site or executed lease agreement(s) with landowner(s). Bids that had not discussed the project with the landowner or executed any agreements were removed from further consideration. Projects that did not provide a bid price were also removed. Sixteen project proposals were eliminated through this initial review process.

Further evaluation of Preliminary Information resulted in rankings with clear break in the rankings after the top seven proposals. As we investigated one project further, it was confirmed this was a repowering of an existing wind farm at the same capacity so the project did not meet the RFP requirement for a new resource. Out of the top six ranked projects, five were wind projects. To provide some projects for comparison to the top ranked solar project, two additional solar projects were short-listed based on their next lowest solar PPA price and mitigation of interconnection concerns based on commercial operation date.

To help Avista differentiate between the short listed bids from the first to the second rounds, eight short-listed bidders were asked to provide detailed proposals. The short listed bidders were further evaluated and additional due diligence was performed on each of the more detailed offerings, which were then re-ranked according to the selection criteria.

Shortlisted bidders were allowed to refresh their prices in late August 2018 to help differentiate their projects from the competition. Based on the new price information, and the previous project descriptions, a new assessment and project ranking was performed. Confidential Exh. JRT-7C provides additional details about each of the short-listed bidder projects and how they were ranked in the RFP. The price refresh established a clear winner based on PPA price, permitting, and known integration and transmission costs. Ultimately, the cost for the Rattlesnake Flat project along with the results from the evaluation matrix confirmed the project as a top pick amongst the Avista RFP team and Black & Veatch.

Q. How was transmission considered in this decision?

A. Rattlesnake is a 144 MW project that will be directly connected to Avista's Transmission System (12 miles southeast of the town of Lind in Adams County, Washington), so no third-party transmission is required for this project to serve our customers.

3. Board of Directors Involvement

Q. Was Avista's Board of Directors involved with the acquisition of the Rattlesnake Wind PPA by Avista Utilities?

A. Yes. The Company's Board of Directors was apprised of the 2018 Renewables RFP and the evaluation process that was used to compare project bids from which the Rattlesnake Flat Wind PPA was selected. Documentation of Board involvement regarding the Rattlesnake Wind PPA is provided in Confidential Exh. JRT-9C. This confidential exhibit includes presentations to the Board of Directors regarding the Rattlesnake Flat Wind PPA.

4. Documentation of Analysis and the Decision-Making Process

Q. What documentation for the analysis and decision-making process has the Company provided regarding the decision to enter into a contract for the Rattlesnake Flat Wind Project?

A. Confidential Exh. JRT-7C includes the complete documentation concerning the RFP solicitation, and evaluation process that resulted in the selection and signing of the Rattlesnake Flat Wind Power Purchase Agreement.

Q. Does the Company believe that it has met the criteria and provided the requisite information to show that the Rattlesnake Flat Wind PPA was a prudent acquisition?

A. Yes. My testimony and exhibits provide the documentation necessary to demonstrate the long-term economic benefit to customers for the Rattlesnake Flat Wind PPA and provide specific supporting details regarding the Company's analysis and decision. The executed PPA will also help meet the renewable and clean energy goals under Washington's Energy Independence Act, CETA as well as support the Company's own clean energy goals. The Rattlesnake PPA also fits within the analysis performed under the Company's IRPs. The Board of Directors agreed with the recommendation to issue the RFP for 50 aMW of RPS-qualified renewable energy in 2018 and was apprised of management's recommendation to negotiate a PPA with Rattlesnake Flat Wind, LLC under terms and conditions consistent with their bid proposal. The Company has provided and explained all of the analytical work that was completed related to this acquisition through a competitive RFP with the aid of an independent evaluator, as well as participation by both the Washington and Idaho Commission Staffs in the entire RPF process.

Q. Does the PPA with Rattlesnake Wind comply with RCW 80.80, the emissions performance standard?

A. Yes, it does. This PPA automatically complies with RCW 80.80 under WAC 173-407-120 (c) because it is powered exclusively be renewable wind resources.

Q. Does this conclude your pre filed direct testimony?

A. Yes, it does.