Exh. AGA-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-240006

DOCKET UG-240007

DIRECT TESTIMONY OF

ALEXIS G. ALEXANDER

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Alexis G. Alexander. I am employed as the Director of Generation Production and Substation Support at Avista Corporation, located at 1411 East Mission Avenue, Spokane, Washington. I was recently named Director of IT Infrastructure but given my background in Generation Production and Substation Support, I will sponsor this testimony through the pendency of the case.

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

A. Yes. I graduated from Eastern Washington University in 2008 with a Bachelor of Science in Electrical Engineering and an emphasis in Power and a Master of Business Administration in 2014. I joined the Company in 2008 as an Electrical Engineer. My first five years with the Company I spent as a Controls and Automation Engineer. From there, I have held several positions all within the same area of the Company. In 2015, I was the Spokane River Operations Manager, overseeing six hydropower plants and associated operating staff.

In 2017, I accepted the position of Senior Construction and Maintenance Manager, where I supported construction and maintenance in power generating facilities and substations across Avista's service territory. After nearly five years in that role I was promoted to Director of Generation Production and Substation Support (GPSS), with responsibilities including project delivery, maintenance and operations in the power generating facilities as well as the construction and maintenance for substations. As mentioned earlier, I was recently selected as the Director of IT Infrastructure.

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

A. I will provide an overview of the Company's planned investments in our generating facilities and explain the factors driving our continuing investment in these assets. I will explain how our efforts to maintain the health and performance of our assets, including compliance with mandatory federal standards, are driving a continuing demand for new investment. I will also explain how and why we have realigned our critical resources to support our effort to optimize our generating fleet. I will also describe our environmental affairs projects, that support compliance with, and management of, the licenses issued by the Federal Energy Regulatory Commission authorizing the Company to operate its hydroelectric facilities. While I address these capital additions for the periods July 1, 2023, through December 31, 2026 in detail within my testimony and exhibits, Company witnesses Ms. Benjamin and Ms. Schultz incorporate the capital additions, and incremental expense associated with these investments, within the Company's request for rate relief over the Two-Year Rate Plan effective in December 2024. A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. Exh. AGA-2 is Avista's Generation capital Business Cases for the July 2023 – December 2026 generation projects, all of which are discussed later in my testimony.

II. OVERVIEW OF GENERATION CAPITAL INVESTMENT STRATEGY

Q. What is Avista's Generation Capital Investment Strategy?

A. Avista's generation capital investment strategy is to modernize the generation fleet for optimal performance by 2030, an accelerated asset improvement plan as compared to previous years. Modernization includes upgrading assets to current and anticipated future performance standards. Optimal performance in this case would also include broadening generation operating ranges to support system renewable integration and increased load variation at the most reasonable cost.

Q. Will you please explain the accelerated asset improvement plan?

A. The plan will include a steady increase in capital deployment over the course of the next 7 years. Traditional capital spend for Avista's generation assets is between $40 million - $45 million annually, but that will necessarily need to increase in coming years. This typically includes the normal wear and tear investment needed to maintain operation and one to two generator modernization projects each year. Unfortunately, the asset degradation rate has outpaced the rate of modernization, leaving power generating units at risk for reliability.

Q. What are the drivers for the 2030 modernization strategy?

A. There are multiple drivers for the 2030 modernization strategy: First is Avista's clean energy goal of serving customers with 100% clean energy by 2045 and the short-term goal of being carbon neutral by 2027. To achieve our goal, we must improve the performance and reliability of our generating resources. Next is renewable integration. As variable renewable resources are integrated into the electric system, previous systems utilized for base load are called on to fill the voids, resulting in increased starts and stops as well as broadened operating ranges. Finally, prior to electrification and decarbonization, asset condition was the primary driver for capital investments. Avista continues to operate a legacy system which requires increased attention to, and investment in, generating resources.

Avista's generating fleet is comprised of assets that range from up to 60 to 120 years in operation. Most assets of this size are intended to have 50-60 year life spans. Due to the age, criticality, and potential catastrophic failure in the event of loss, it is imperative that Avista continue to invest in these assets in a responsible way. While we are focused first on our most 'at risk' assets (those with the greatest risk of failure or the greatest consequence of failure), the Company also needs to continue to invest in our newer assets as well to ensure that they too continue to provide reliable service.

To minimize the immediate impact to generation availability and cost to our customers, we have had to rethink the way we replace, repair, and maintain our assets. In GPSS, we have redistributed the workforce to align with the specific needs of each facility and to support our plants and keep them available while they wait for wholesale upgrades. We have coordinated our maintenance efforts with our replacement schedules to assure availability and assigned engineering resources to smaller projects critical to plant availability yet still aligned with the overall optimization initiative. We have classified this ongoing work into three new business cases based on the type of work or the driver for the work:

- **Operational Sustainment** – this is the ongoing capital investment our plants need to stay operational and available to our customers. Due to the large nature of our assets, most of them end up being capital expenditures even if they are relatively simple "replace in kind" efforts.

- **Asset Lifecycle Management** – this program supports the various plant projects within all the Avista-owned generating facilities. These projects are fairly routine and time-based projects intended to extend the life of a system or an asset. They are not intended to replace the full system but instead bring the system back to its original performance objective.

- **Operational Safety and Compliance** – This program supports the various compliance and safety-related projects within all of the Avista-owned generating facilities.

Beyond these efforts are the larger project investments. These projects are supported with an appropriate project manager (based on the project type, impact, and complexity) and rely on both engineering consultants and internal engineering for design and design review to ensure compliance with Avista standards. Whether large or small, these projects are each supported by a Business Case, as contained in Exh. AGA-2.

III. OVERVIEW OF 2023 - 2024 GENERATION PRO FORMA CAPITAL PROJECTS

Q. Please describe the capital planning process that Generation Production and Substation Support (GPSS) conducts before generation capital projects are submitted to the Capital Planning Group.

A. The capital planning process in 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[1] and Oracle Primavera Cloud (OPC) enterprise asset management software as the central repository 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.

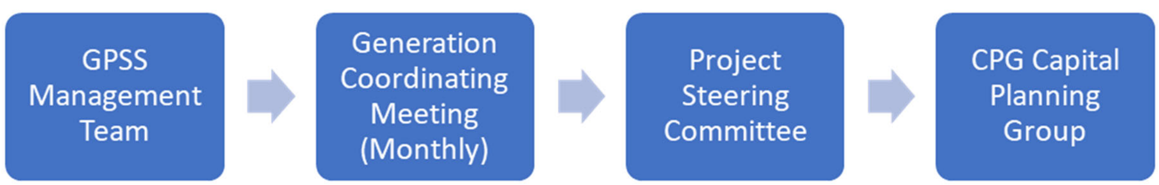
The GPSS management team meets twice every year to review the long-range forecast, confirm that it is up-to-date and to close completed projects. New projects are highlighted and

[1] Avista utilizes IBM's Maximo asset management system - www.ibm.com/products/maximo/asset-management.

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 decisions are made at these meetings. The following illustrates the process:

<u>Illustration No. 1: Capital Planning Process</u>



Q. Company witness Mr. Christie 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. **<u>Customer Requested</u>** – 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. **<u>Mandatory and Compliance</u>** – 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.

Q. Would you please provide a listing of the generation capital additions in 2023 - 2024 that the Company is seeking to include in general rates in this case?

A. Yes. As discussed by Company witness Ms. Benjamin, Avista's capital witnesses (including me) have summarized each Business Case with projects or programs completed and pro formed by the Company between July 2023 through December 2024.[2] Provisional Capital investments by Business Case for the periods 2025 and 2026 are also discussed in more detail below in Section IV of my testimony.

Table No. 1 below lists the pro forma projects and costs for the July 1, 2023 – December 31, 2024 Generation capital investments included in this case. A description of each capital project is provided below. For provisional capital projects completed in the 2025 – 2026 timeframe, a more detailed description including alternatives considered, how the project benefits customers, and any direct offsetting benefits are covered in Section IV of my testimony.

As explained by Ms. Benjamin and described further below, these projects or programs are summarized by the following categories: (1) Large or Distinct Projects, (2) Mandatory & Compliance Projects, (4) Programs and (3) Short Lived Assets. This grouping is consistent with past filings. Exh. AGA-2 provides the full Business Cases supporting each of the generation capital projects for 2023 - 2026.[3]

[2] Capital investments made in 2023 - 2024 will be reviewed in the provisional capital process of Dockets UE-220053 and UG-220054. A report will be filed by March 31, 2024 for review of 2023 capital additions and March 31, 2025 for review of 2024 capital.
[3] Colstrip additions have been excluded from Avista's capital additions for 2023-2026, as Colstrip assets are recovered through separate Tariff Schedule 99.

Table No. 1: 2023 - 2024 Generation Pro Forma Capital Projects

WA GRC Plant Category	Project #	Business Case		07.2023-12.2023 TTP (System)	2024 TTP (System)	Exh. AGA-2 Page #
Large or Distinct Projects	1	Cabinet Gorge Station Service		$ 5,140,107	$ -	3
	2	Cabinet Gorge Stop Log Replacement		$ 1,196,523	$ -	13
	3	Cabinet Gorge Unwatering Pumps		$ 383,000	$ -	21
	4	Generation DC Supplied System Update		$ 356,240	$ -	27
	5	Generation Masonry Building Rehabilitation		$ -	$ 490,303	34
	6	KF 4160 V Station Service Replacement		$ -	$ 1,134,952	43
	7	KF Secondary Superheater Replacement		$ -	$ 99,888	50
	8	KF_Fuel Yard Equipment Replacement		$ 407,496	$ -	60
	9	KF_ID Fan & Motor Replacement		$ -	$ 2,008,437	72
	10	Little Falls Crane Pad & Barge Landing		$ -	$ 498,893	81
	11	Little Falls Plant Upgrade		$ 168,091	$ -	87
	12	Long Lake Plant Upgrade		$ -	$ 500,000	94
	13	Monroe Street Abandoned Penstock Stabilization		$ 749,999	$ 747,811	109
	14	Nine Mile Powerhouse Roof Replacement		$ 854,052	$ 1,312,654	119
	15	Nine Mile Unit 3 Mechanical Overhaul		$ -	$ 5,554,098	126
	16	Noxon Rapids Spillgate Refurbishment		$ 3,700,000	$ 194,036	136
	17	Noxon Rapids Unit 2 Generator Rewind		$ -	$ 299,321	144
	18	Peaking Generation Business Case	[3]	$ 332,169	$ 285,728	155
	19	Post Street Substation Crane Rehab		$ -	$ 1,614,227	165
	20	Upper Falls Trash Rake Replacement		$ 1,448,672	$ 185,540	175
Large or Distinct Projects Total				$ 14,736,435	$ 14,925,888	
Mandatory & Compliance	21	Cabinet Gorge Dam Fishway		$ 158,008	$ 600,000	185
	22	Clark Fork Settlement Agreement		$ 4,621,099	$ 3,027,380	193
	23	KF_Ash Landfill Expansion		$ 13,092	$ -	201
	24	Long Lake Stability Enhancement		$ -	$ 1,000,000	212
	25	Operational Safety and Compliance	[3]	$ -	$ 637,698	222
	26	Right-of-Way Use Permits		$ 122,160	$ 250,002	230
	27	Spokane River License Implementation		$ 1,453,808	$ 838,800	236
	28	WSDOT Franchises		$ 284,150	$ 150,000	243
Mandatory & Compliance Total				$ 6,652,317	$ 6,503,880	
Programs	29	Asset Lifecycle Management	[3]	$ -	$ 868,123	250
	30	Asset Monitoring System	[3]	$ 248,731	$ -	258
	31	Automation Replacement	[3]	$ 400,000	$ 588,220	263
	32	Base Load Hydro	[3]	$ 861,783	$ 461,474	272
	33	Base Load Thermal Program	[3]	$ 1,673,666	$ -	282
	34	Operational Sustainment	[3]	$ -	$ 7,976,356	293
	35	Regulating Hydro	[3]	$ 2,434,328	$ 703,845	301
Programs Total				$ 5,618,509	$ 10,598,018	
Short-Lived Assets	36	HMI Control Software		$ 4,016,838	$ 2,676,153	311
Short-Lived Assets Total				$ 4,016,838	$ 2,676,153	
Misc. accrual reversals, corrections or additional TTP				$ 80,511	$ 57,596	
Grand Total				**$ 31,104,523**	**$ 34,761,535**	

[1] Includes system pro froma capital for the period July 1, 2023 through December 31, 2023.
[2] Totals exclude Idaho and Oregon direct business cases from revenue requirement in this case.
[3] Select Generation business cases are being consolidated into three programs based on driver: Operation Sustainment, Asset Lifecycle Management, and Operational Safety and Compliance. See Alexander Testimony.

Q. Has the Company calculated and included a description of any offsetting factors to the capital projects in this case?

A. Yes. For those capital projects that have <u>direct</u> benefit offsets, I have included a description of the offsets in the project description. Company witness Ms. Andrews provides an explanation regarding how the <u>direct</u> offsets are factored into the revenue requirement of this case, and an explanation of the Company's efficiency adjustment included in this case. The efficiency adjustment of 2% was used where there were no <u>direct</u> offsetting benefits, and where the projects were not otherwise required for mandatory and compliance purposes, as discussed by Ms. Andrews.

Q. It appears that project or program numbers 1, 5, 7, 12, 21, 22, 23, 25, 26, 27, 28, 29, 33, 34, 36 listed above in Table No. 1 are continuing projects and programs which will also appear listed in Table No. 2 below, and which are fully described in the below section of your testimony. Is that the case?

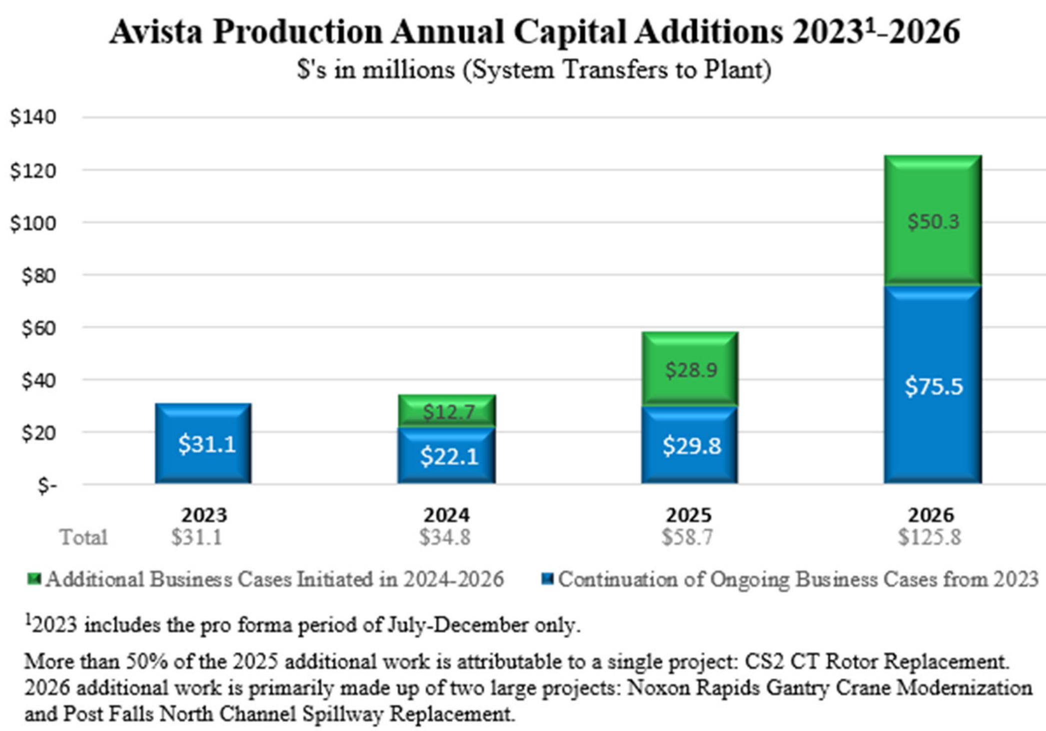
A. Yes, the above listed investments are ongoing programs or projects that have substantial investments in 2023 - 2024, and which will continue to occur in 2025 - 2026. The projects included with descriptions below (Section IV.) in my testimony include the following:

- 1 – Cabinet Gorge Station Service,
- 5 – Generation Masonry Building Rehabilitation,
- 7 – KF Secondary Superheater Replacement,
- 12 – Long Lake Plant Upgrade,
- 21 – Cabinet Gorge Dam Fishway,
- 22 – Clark Fork Settlement Agreement,
- 23 – KF Ash Landfill Expansion,
- 25 – Operational Safety and Compliance,
- 26 – Right-of-Way Use Permits,
- 27 – Spokane River License Implementation,
- 28 – WSDOT Franchises,
- 29 – Asset Lifecycle Management,
- 33 – Base Load Thermal Program,
- 34 – Operational Sustainment, and
- 36 – HMI Control Software.

Q. Is the support for these projects and programs in 2023-2024 the same as you described below for 2025-2026?

A. Yes, the support is the same, and therefore I will address that in the context of the 2025-2026 discussion. The business cases referenced below in my testimony are applicable for the transfers-to-plant included for 2023-2026. Illustration No. 2 below portrays the Generation Production Capital Investments from 2023 through 2026 included in this case, distinguishing between what are ongoing projects from 2023, and new projects introduced in 2024-2026.

<u>Illustration No. 2: Production Capital Additions 2023-2026</u>



As you can see from Illustration No. 2, most of the capital investment relates to ongoing, multi-year efforts that continue over time, at various funding levels. The rationale and justification for these ongoing projects, however, does not change over time, only the funding levels. New incremental projects are discussed below, the largest of which is the Post Falls North Channel

Spillway Rehabilitation project of $30.8 million over the Two-Year Rate Plan.

Q. Regarding 2023 and 2024 capital investments, when did, or will, the projects or programs receive their final review after they are put into service?

A. The Commission approved of the level of capital investments through 2024, contingent upon the provisional capital review filings in March of 2024 for 2023 capital investments and in March of 2025 for 2024 capital investments, in the Company's last general rate case.

Q. For the 2025 to 2026 capital additions for which you are responsible, is the Company seeking to include all of those investments in rates in this case?

A. Yes.

Q. Does each Business Case associated with a project discuss factors such as timing, cost, alternatives considered, and savings?

A. Yes, and that information will not otherwise be repeated here (please see Exh. AGA-2 for each Business Case).

Q. Would you please describe the 2023 - 2024 capital projects that you sponsor in your testimony that will <u>not</u> be discussed in section IV below?

A. Yes. As discussed below the remaining 2023–2024 capital projects include the following:

Project #2 – Cabinet Gorge Stop Log Replacement ($1,196,523 in 2023)

Cabinet Gorge Spillgates are original to the plant (early 1950's vintage). Stop logs are used to isolate spillway gates from the reservoir for the Cabinet Gorge Hydroelectric project. Each stop log assembly comprises nine individual stop log elements or units, which when combined, will allow dewatering of one spillway gate. Without these structures, we cannot efficiently and safely perform needed, critical spillgate work. The spillgates are old and in need of replacement and needs to occur before the Cabinet Gorge Spillgate Upgrade project is expected to start in 2025. Additionally, if repairs are not made, there is risk of a spillgate being out of operational use or a possible gate failure, which could result in an uncontrolled release of water. The supporting business case for this project can be found in Exh. AGA-2, starting at page 13.

Project #3 – Cabinet Gorge Unwatering Pumps ($383,000 in 2023)
Cabinet Gorge Hydroelectric Development (HED) was built in 1952. The plant has retained most of its original equipment which is now aging and at end of life. It is necessary to upgrade many of the plant's original systems. One of those critical systems is the unwatering pumps which are used to pump out water from normal plant leakage. The pumps, original to the plant, are progressively requiring increasing maintenance. The project is to replace all six unwatering pumps with new pumps. The supporting business case for this project can be found in Exh. AGA-2, starting at page 21.

Project #4 – Generation DC Supplied System Update ($356,240 in 2023)
The Generation DC Supplied System program covers all the generation and control facilities. This system is the backbone for supplying power to the protective relays, breakers, controls and communication systems. With North American Reliability Corporation (NERC) requirements being followed and design enhancements being implemented, the DC system is being monitored, tested and continues to remain reliable. As changes have occurred on generating units or in the balance of plant systems, the DC load requirement, however, has significantly increased and the time duration for the systems to supply this critical load has increased. Our current practice is to replace the battery banks per manufacturers life cycle recommendations, but this practice is not addressing the additional load added to the systems. Finally, there are compliance requirements from NERC for inspections, maintenance and testing of the battery banks to ensure they are in good working order and will perform when called upon. The supporting business case for this project can be found in Exh. AGA-2, starting at page 27.

Project #6 – Kettle Falls 4160 V Station Service Replacement ($1,134,952 in 2024)
All generation facilities require station service to provide electric power to the plant. Station service components include motor control centers, load centers, emergency load centers, various breakers, transformers, and conductors. Station service is an elaborate system with multiple built-in redundancies and multiple voltages designed to protect the plant's electrical system. The plant's low voltage 4160-volt switch gear has been identified by AIG insurance inspection as being out of compliance. With aging equipment the plant is experiencing challenges with service and parts to maintain the breakers. The plant is currently installing new fuel yard equipment which will require new and upsized power needs in the fuel yard. The plant fuel yard project team has put in place a temporary work around to power the new yard, but this solution is not permanent. This project will replace the 4160-volt station service. This replacement will correct the insurance deficiency and increase reliability to the plant critical loads. The supporting business case for this project can be found in Exh. AGA-2, starting at page 43.

Project #8 – Kettle Falls Fuel Yard Equipment Replacement ($407,496 in 2023)
The Kettle Falls Generating Station is a biomass fueled power plant that processes on average 500,000 green tons of waste wood from area sawmills. The wood delivered to the facility is trucked in by contractors utilizing semi-trucks and chip trailer. On average the plant received 65-80 loads of fuel each day with surges to 100 deliveries in a 24 hour period. The original fuel yard system did not allow the plant to operate consistently with safe best practices, environmental stewardship, and production. This project replaced the major fuel handling equipment to create a safer system for employees and contractors. Equipment replaced included

truck scales, truck dumpers, fuel conveyors, hog and disc screen and other auxiliary equipment. The supporting business case for this project can be found in Exh. AGA-2, starting at page 60.

Project #9 – KF_ID Fan & Motor Replacement ($2,008,437 in 2024)
The induced draft (ID) fan at Kettle Falls Generating Station is a critical component in the combustion process. The ID fan pulls a draft on the combustion fire box and discharges the flue gas through the electrostatic precipitator and out the stack. The ID fan is considered a "dirty" fan in which it is operating with fly ash in the flue gas. The fly ash is abrasive on the internal components of the boiler. The fan shroud, case, cage, and dampers are requiring significant annual maintenance each year to build up the worn area. The fan motor reaches max amperage during wet wood combustion and often hits the max fan damper position. This project involves replacing the ID and motor to appropriately accommodate the needs of the plant and installing auxiliary equipment such as ducting or foundations. The supporting business case for this project can be found in Exh. AGA-2, starting at page 72.

Project #10 – Little Falls Crane Pad & Barge Landing ($498,893 in 2024)
The existing crane pad and trash boom anchor at Little Falls are at their end of useful lives. The sheet pile wall is severely rusted and deteriorating in several locations including where it adjoins the river bottom. The foundation is eroding to the point where if too much weight was put on the crane pad there could be complete failure and equipment could fall into the forebay. The only way to currently use the crane pad is to adjust outriggers far enough away from the water's edge which causes partial obstruction to Spokane Indian Tribe's Martha Boardman Rd. The new crane pad and barge landing will provide necessary logistical and safe access for the Little Falls Intake Project (headgates, supporting structure, motors, and trash rake), as well as the Little Falls Controlled/Gated Spillway Project to repair concrete and replace flashboard function on the spillway dam. The current off-loading and staging causes obstruction and congestion to the road as well as the proximity to the roadway increases safety hazards for workers and site personnel. The supporting business case for this project can be found in Exh. AGA-2, starting at page 81.

Project #11 – Little Falls Plant Upgrade ($168,091 in 2023)
The Little Falls Plant Upgrade Program began in 2012 and is in the final phases of implementation. The scope of the plant upgrade was to replace nearly all of the older and less reliable equipment with new equipment. This includes replacing two of the turbines, all four generators, all generator breakers, three of the four governors, all of the automatic voltage regulators (AVR's), removing all four generator exciters, replacing the unit controls, replacing the unit protection system, and replacing, modernizing the station service and balance of plant support systems. The last remaining project for the plant upgrade is the completion of the Plant Sump. The supporting business case for this project can be found in Exh. AGA-2, starting at page 87.

Project #13 – Monroe Street Abandoned Penstock Stabilization ($749,999 in 2023 and $747,811 in 2024)
The Monroe Street Powerhouse in downtown Spokane was initially constructed in 1890 and has undergone several modernization projects over the last 129 years. During the 1972 modernization, three of the original penstock intakes were plugged with concrete and sealed

with a layer of shot-crete. The three 10 foot diameter steel penstocks were only partially removed, leaving an approximate 250 foot length of each buried under what is now Huntington Park. It is unknown if the penstocks were also backfilled with material, posing a risk of implosion. These penstocks run underneath parts of the access road, crane staging area, and walking path through the park. The park is open to the public, and the access road and crane areas are critical to maintaining the safe and efficient operation of the Monroe Street Hydroelectric Development. During the 2018 maintenance assessment, these penstocks were identified as a high risk due to their location, unknown condition, and observed groundwater. This project includes further investigation of the intake dam and penstocks to better quantify the risk, and implement a plan to mitigate those risks. The supporting business case for this project can be found in Exh. AGA-2, starting at page 109.

Project #14 – Nine Mile Powerhouse Roof Replacement ($854,052 in 2023 and $1,312,654 in 2024)

The powerhouse roof at Nine Mile needs replacement due to age and deterioration. The current membrane leaks and the existing roof trusses are in an overstressed condition that requires remediation. As part of this work, the failed roof membrane system will be replaced. The supporting steel truss members will either be upgraded to increase their structural capacity or the concrete roof slab panels will be replaced with lighter weight roofing material to reduce load on the steel trusses. The supporting business case for this project can be found in Exh. AGA-2, starting at page 119.

Project #15 – Nine Mile Unit 3 Mechanical Overhaul ($5,554,098 in 2024)

The original Unit 3 was replaced with a new American Hydro unit in 1995. Unit 3 experienced cracked buckets on the runners in 2010. This was found to be due to heavy wear due to erosion from sediment and cavitation damage. The cracks were repaired; however, the sediment wear has continued, and bucket failure is anticipated. The installed roller guide bearing also does not provide the thrust bearing support it was designed to, causing the upstream generator guide bearing to take the entire thrust loading of the machine. This condition puts increased stress and wear on the generator bearings and increases the risk of failure. During a 2018 Maintenance Assessment, this bearing was identified as high risk due to its current condition. If left unaddressed, the Unit is likely to experience bucket or bearing failure. This project is to execute a mechanical overhaul of the Unit including installing new Francis Runners, new downstream water lubricated bearing and pedestal, new combination thrust/guide bearing with thrust shaft, and refurbishment of the wicket gate stems and all operating components. This alternative would provide a lasting solution to the problems outlined above and avoid a costly unanticipated failure. Direct O&M savings for this project relate to maintenance charges in responding to failed components and mitigate the risk of unanticipated failures. The annual estimated value of the Direct Offsets for 2025 is $50,000. The supporting business case for this project can be found in Exh. AGA-2, starting at page 126.

Project #16 – Noxon Rapids Spillgate Refurbishment ($3,700,000 in 2023 and $194,036 in 2024)

The eight Spillgates at Noxon Rapids HED are over 60 years old and are the original gates. The Spillgates are critical equipment which control the flow of water over the dam during spill conditions when the water flowing in the river exceeds that which passes through the turbines in the plant. They are also protection for the dam during high flow periods or in the event that the plant or units trip to prevent overtopping or flooding of the dam. The gates require repair or replacement due to age, Energy Imbalance Market usage requirements, and structural analysis which reveals that the current gates may not be designed to meet the loading requirements during operation and due to seismic conditions. The spillgate issues must be resolved in the near future for the safety and reliability of the plant personnel and equipment. The supporting business case for this project can be found in Exh. AGA-2, starting at page 136.

Project #17 – Noxon Rapids Unit 2 Generator Rewind ($299,321 in 2024)
The Generator frame and core are original. The core is 60 years old in 2023. The stator coils have been replaced during its life span. These coils are the source of the energy that is supplied to the grid. They have a limited life span and as the insulation breaks there is a fault to the core. This project is to replace the coils and core because a new core and coil set could have a potential for increasing the generator efficiency and/or output. Replacing the coils and the core would allow for a better overall generator design that would yield a longer service life due to the modern laser cut lamination having more optimum coil fit. The supporting business case for this project can be found in Exh. AGA-2, starting at page 144.

Project #18 – Peaking Generation Business Case ($332,169 in 2023 and $285,728 in 2024)
Avista's Peaking Generation plants offer operational flexibility and are utilized to support energy supply needs. Thermal Peaking Generation power provides options for Avista's System Operations and Power Supply groups to maximize value to Avista and its customers. These plants represent more than 255 MW of power and include Rathdrum Combustion Turbines, Boulder Park Generating Station and Northeast Combustion Turbine, all natural gas fired power plants. The operational availability for these generating units in these plants is paramount. The purpose of this program is to fund smaller capital expenditures and upgrades that are required to maintain safe and reliable operation. 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). The business drivers for this project in this program is a combination of Asset Condition, Failed Plant, and addressing operational deficiencies. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to plant operational support issues. Starting in 2024, the work under this business case will begin to transition into the new Operational Sustainment, Safety and Compliance, and Asset Lifecycle Management Business Cases based on their specific project driver. The supporting business case for this project can be found in Exh. AGA-2, starting at page 155.

Project #19 – Post Street Substation Crane Rehab ($1,614,227 in 2024)
The 35 Ton Niles Bridge Crane at the Post Street Substation is original to 1907 and services the interior of the building. The primary function for this crane is to service the Upper Falls and Monroe Street GSU's, substation 115kv transformers, switchgear, and miscellaneous other substation equipment. The crane's controls and electrical are mostly original and have degraded in capability over time. Recent experience with the crane exhibited issues with controls and overheating/stalling with extended use. The current state of electrical components on this crane are not capable of supporting the pick of a transformer without extensive refurbishing. This negatively impacts the ability to respond to a failure in a critical downtown substation and increases risk. The problem is aggravated by the lack of ability to use a large enough standard

mobile crane inside the building as an alternative. The project includes a replacement of the existing crane electrical and controls, refurbishment of the mechanical components, and replacement of the existing hoist and trolley system with a modern arrangement. The supporting business case for this project can be found in Exh. AGA-2, starting at page 165.

Project #20 – Upper Falls Trash Rake Replacement ($1,448,672 in 2023 and $185,540 in 2024)

The Upper Falls trash rake has, since its installation, presented an environmental risk due to the hydraulic system that utilizes to function. When in use, the hydraulic system is suspended over the Upper Fall unit intake and the Spokane River. Should a hydraulic line fail during raking operation, some amount of hydraulic fluid would end up in the river, leading to an environmental cleanup exercise. The current trash rake is undersized, leading to issues during raking operations. Often, the rake stalls out mid-operation due to the weight of accumulated debris it is trying to recover. The rake is also limited in its ability to lift logs and tress which can accumulate in front of the rakes, leading to potential personnel safety issues with operators being required to cut up the logs and trees while in very close proximity to the river's edge. Often times this is an operator leaning out over the handrail to address the problem. The supporting business case for this project can be found in Exh. AGA-2, starting at page 175.

Project #24 – Long Lake Stability Enhancement ($1,000,000 in 2024)

The major driver for this business case is regulatory. During a FERC annual inspection, the inspector noticed a seeping joint in an airshaft and requested that Avista evaluate the internal plane stability of the intake and spillway dams – this inspection was performed shortly after the Wanapum Dam failure incident. The analysis performed evaluates all loading conditions the dams may experience including full-pool (normal) operations, probable maximum flood (PMF), and seismic conditions. The analysis revealed that Long Lake dam does not meet the internal plane stability minimum safety factor during a PMF event. Avista submitted a preliminary study to the FERC and is waiting for final design before sending the FERC the full scope of the project and timeline to address mitigation. The recommended solution will be heavily informed by the above, however, is anticipated to be some level of additional anchoring at the facility as well as possible added concrete mass to the dam structures. The supporting business case for this project can be found in Exh. AGA-2, starting at page 212.

Project #30 – Asset Monitoring System ($248,731 in 2023)

The Asset Monitoring Systems are needed to track the condition of our Assets in both our Hydro and Thermal Generation Plants. They are not part of the Generation Control System that is used for real-time control and monitoring. There is a need to update the existing systems and install new systems to monitor the condition of our Assets. These Asset Monitoring Systems are used to influence our Maintenance and Capital planning. The budgeted amounts are based on 2022 quotes for replacing, updating, and installing new systems. These systems will interface with the corporate network and therefore need to be updated periodically with changing software and security needs. Work under this program will transfer to the new Asset Lifecycle Management Business Case in 2024 and beyond. The supporting business case for this program can be found in Exh. AGA-2, starting at page 258.

Project #31 – Automation Replacement ($400,000 in 2023 and $588,220 in 2024)

The Automation Replacement project systematically replaces the unit and station service control equipment at our generating facilities with a system compatible with Avista's current control standards for reliability. Upgrading control systems within our generating facilities allows us to continue providing reliable energy. The Distributed Controls Systems (DCS) and Programmable Logic Controllers (PLC) are used to control and monitor Avista's individual generating units as well as each total generating facility. The DCS and PLC work in this capital program is needed to reduce the higher risk of failure due to the age of the currently installed equipment. The current DCSs are no longer supported, and availability of spare modules are limited. The modules in service have a high risk of failure as they are over 20 years old. Avista's hydro facilities were designed for base load operation but are now increasingly called on to quickly change output in response to the variability of wind and solar generation, to adjust to changing customer loads, other regulating services needed to balance system load requirements and assure transmission reliability and EIM operations. The controls necessary to respond to these new demands include speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e. PLC), and the protective relay system. In addition to reducing unplanned outages, these new systems allow Avista to maximize ancillary services for its own assets on behalf of customers rather than procuring them from other providers. All new work of this type planned in 2024 and beyond will occur under the new Operational Sustainment Business Case. The supporting business case for this program can be found in Exh. AGA-2, starting at page 263.

Project #32 – Base Load Hydro ($861,783 in 2023 and $461,474 in 2024)

Avista's Base Load Hydro plants are all located on the upper Spokane River and are "run of river" plants which means they have little to no storage capacity, and their operation is subjected to the flow in the Spokane River and the lake level requirements of Lake Coeur d'Alene. The facilities in this program include Post Falls, Upper Falls, Monroe Street and Nine Mile Hydroelectric Developments. This program also includes capital projects at the Generation Control Center and on the Generation Control Network, as well as some projects at the Post Street 115kV Substation, where the two downtown hydro plants (Upper Falls and Monroe Street) are tied into the electric grid. This program funds smaller capital expenditures and upgrades required to maintain safe and reliable operation. Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. The business drivers for the projects in this program are a combination of asset condition, failed (or failing) plant, and addressing operational deficiencies. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to plant operational support issues. Without this program it would be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This would jeopardize plant availability and greatly impact the value to our customers and the stability of the grid. Starting in 2024, the work under this Business Case will begin to transition into the new Operational Sustainment, Safety and Compliance, and Asset Lifecycle Management Business Cases based on their specific project driver. The supporting business case for this program can be found in Exh. AGA-2, starting at page 272.

Project #35 – Regulating Hydro ($2,434,328 in 2023 and $703,845 in 2024)

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 services necessary to provide a stable electric grid and to maximize value to Avista and its customers. These 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. The purpose of this program is to fund smaller capital expenditures and upgrades that are required to maintain safe and reliable operation. Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. The business drivers for the projects in this program is a combination of asset condition, failed (or failing) plant, and addressing operational deficiencies. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to plant operational support issue. Starting in 2024, the work under this business case will begin to transition into the new Operational Sustainment, Safety and Compliance, and Asset Lifecycle Management Business Cases based on their specific project driver. The supporting business case for this program can be found in Exh. AGA-2, starting at page 301.

IV. OVERVIEW OF 2025 - 2026 GENERATION CAPITAL PROJECTS

Q. What generation capital projects are included in this case for 2025 - 2026?

A. Please refer to Table No. 2 below for the generation capital projects included for 2025 - 2026.

Table No. 2: 2025 - 2026 Non-Colstrip Generation Capital Projects

WA GRC Plant Category	Project #	Business Case		2025 TTP (System)	2026 TTP (System)	Exh. AGA-2 Page #
Large or Distinct Projects	1	Cabinet Gorge Station Service		$ 11,259,147	$ -	3
	37	Coyote Springs 2 CT Rotor Replacement		$ 14,891,744	$ -	324
	5	Generation Masonry Building Rehabilitation		$ 232,932	$ -	34
	7	KF Secondary Superheater Replacement		$ 3,473,234	$ -	50
	12	Long Lake Plant Upgrade		$ 1,500,000	$ 45,000,000	94
	38	Nine Mile Units 3 & 4 Control Upgrade		$ 5,292,874	$ -	335
	39	Noxon Rapids Gantry Crane Modernization		$ -	$ 19,500,000	348
	40	Post Falls HED Redevelopment Program		$ -	$ 5,000,000	358
	41	Post Falls North Channel Spillway Rehabilitation		$ 5,000,000	$ 25,800,000	371
Large or Distinct Projects Total				$ 41,649,931	$ 95,300,000	
Mandatory & Compliance	21	Cabinet Gorge Dam Fishway		$ 399,879	$ 72,902	185
	22	Clark Fork Settlement Agreement		$ 2,663,700	$ 3,291,708	193
	23	KF_Ash Landfill Expansion		$ -	$ 11,076,524	201
	25	Operational Safety and Compliance	[3]	$ 1,967,828	$ 4,365,255	222
	26	Right-of-Way Use Permits		$ 250,000	$ 249,996	230
	27	Spokane River License Implementation		$ 954,600	$ 909,600	236
	28	WSDOT Franchises		$ 149,999	$ 150,000	243
Mandatory & Compliance Total				$ 6,386,006	$ 20,115,985	
Programs	29	Asset Lifecycle Management	[3]	$ 1,813,667	$ 1,450,001	250
	33	Base Load Thermal Program	[3]	$ 482,311	$ -	282
	34	Operational Sustainment	[3]	$ 6,264,758	$ 8,788,005	293
Programs Total				$ 8,560,736	$ 10,238,006	
Short-Lived Assets	36	HMI Control Software		$ 2,078,530	$ 132,015	311
Short-Lived Assets Total				$ 2,078,530	$ 132,015	
Grand Total				**$ 58,675,203**	**$ 125,786,006**	

[1] Includes system pro froma capital for the period July 1, 2023 through December 31, 2023.
[2] Totals exclude Idaho and Oregon direct business cases from revenue requirement in this case.
[3] Select Generation business cases are being consolidated into three programs based on driver: Operation Sustainment, Asset Lifecycle Management, and Operational Safety and Compliance. See Alexander Testimony.

Q. With respect to each business case, where can a more complete discussion of "alternatives" considered, "benefits to customers", "cost controls", and "savings be found"?

A. As noted above in Section III., because this information can generally be found in each business case itself (See Exh. AGA-2), I have generally only provided a description of the project or program and additional context in my testimony below.

Q. These projects, taken as a whole, are all characterized as "provisional" in nature. What does that mean?

A. As explained by Ms. Benjamin, projects for 2025 through 2026 have been characterized as provisional. First, as provisional, the Company has segregated the capital investments into category designations discussed in the Commission's "Used and Useful Policy Statement," dated January 31, 2020 in Docket U-190531, including capital investments grouped as "Large or Distinct", "Programmatic", "Short-Lived" and "Mandatory and Compliance," for ease of review and audit. Second, "provisional" designates these capital additions as subject to final "review and refund" in a future period. Ms. Benjamin discusses the Company's proposal for Provisional Reporting for capital additions, by year, for 2025 through 2026.

Q. When will the 2025 - 2026 projects or programs receive their final review after they are put into service?

A. As discussed by Company witness Ms. Benjamin, provisional capital for 2025 through 2026 will be reviewed through the annual provisional capital reporting, filed on or before March 31st after each completed reporting period, to assure that they are in service, used & useful, and the final expenditures reviewed.

Q. Has the Company calculated and included a description of any offsetting benefits to the capital projects in this case for 2025 - 2026?

A. Yes. As notes above, for those capital projects that have direct offsetting benefits, I have included a description of the offsets in the project descriptions provided below.

Project #1 – Cabinet Gorge Station Service ($5,140,107 in 2023 and $11,259,147 in 2025)
Cabinet Gorge Hydroelectric Development (HED) is located on the Clark Fork River in Bonner County, Idaho. With four generators, it has a 270 MW output capacity. Built in 1952, the plant has retained most of its original equipment which is now aging and at end of life. In particular, the station service equipment is vital to the plant's continued operation. Station service equipment includes load centers, transformers, switchgear, power centers and neutral grounding resisters. This equipment is used to operate the generating plant. It includes energy consumed for plant lighting, power, and auxiliary facilities in support of the electricity generation system. It is recommended that this aging equipment be replaced to ensure the continued safe operation of the plant. Safe operation of the plant contributes to grid optimization, reliability, and personnel safety. As many other equipment upgrades are underway at Cabinet Gorge, the timing of these station service replacements has been coordinated to reduce plant outages. In

terms of risk, if this equipment is not upgraded, failure poses substantial hazards not only to the plant's operation but also to plant personnel as failed equipment can cause significant bodily injury and fire danger. The supporting business case for this project can be found in Exh. AGA-2, starting at page 3.

Project #37 – Coyote Springs 2 CT Rotor Replacement ($14,891,744 in 2025)

Coyote Springs 2 is a 280 MW combined cycle power plant located in Boardman, OR that provides both base load and variable generation as needed by Avista's Balancing Authority. The facility is owned by Avista and operated and maintained by Portland General Electric. Additionally, there is a Long-Term Service Agreement (LTSA) with General Electric that covers most components on the Combustion Turbine and Generator, but not the replacement of the rotor at its normal end of life. The LTSA does cover replacement cost of a rotor that fails within its GE specified operational life (144,000 hours for the rotor currently in service). General Electric utilizes engineering, experience, and best practices in the fleet to provide recommendations and guidance as to when certain pieces of equipment should be replaced or rebuilt to reduce the likelihood of equipment failures. For the combustion turbine rotor, the recommended replacement is after 144,000 hours of operation. For Coyote Springs 2 the year we anticipate arriving at 144,000 operating hours, based on historical operational data, is 2026. The supporting business case for this project can be found in Exh. AGA-2, starting at page 324.

Project #5 – Generation Masonry Building Rehabilitation ($490,303 in 2024 and $232,932 in 2025)

Several buildings for Avista's power plants are constructed of masonry and are approaching one hundred years in age. These buildings include The Little Falls Power House and Gate Building, The Long Lake Power House, the Nine Mile Power House, The Post Street Building, and The Post Falls Power House and Substation Building. The grout and brick in many cases has begun to fail which is creating a serious personnel and public hazard as bricks become loose in the walls and parapets and can fall to the ground. This safety issue has become critical, especially during the freeze and thaw cycles in the spring. This project funds a comprehensive inspection of each building to create a refurbishment plan which will remedy the issue long term at each facility. Projects currently in flight will continue in this business case until completed while starting in 2024, new projects identified, will transition into the new Operational Sustainment, Safety and Compliance, and Asset Lifecycle Management business cases based on their specific project driver, as described in Section II of my testimony above. The supporting business case for this project can be found in Exh. AGA-2, starting at page 34.

Project #7 – KF Secondary Superheater Replacement ($99,888 in 2024 and $3,473,234 in 2025)

The Kettle Falls Generating Station processes nearly 450,000 tons of waste wood annually. During the combustion process the waste wood is metered into the boiler and onto the traveling grate where it is burned. Air is blown in and around the fire to ensure complete and efficient combustion. The combustion air is drawn from outside the boiler building from the forced draft fan at ambient temperature then blown into the air heater to increase the temperature of the combustion air. The high temperature combustion air increases the efficiency of the combustion process and reduces air emissions. The air heater has a history of dew point failure where the tubes begin to crack and fail within a few inches of the tube sheet. In 2010, the air heater was rebuilt using new convective tube technology by CMS (Corrosion Monitoring Services). Nearly half of the tubes were replaced, and a comprehensive maintenance plan was put in place. CMS has supported those efforts for the last 11 years, and in 2021, the air heater had 9 tubes removed from service due to corrosion failure. CMS has advised from their experience that once the unit begins having tube failure, the project owner can expect to see double the failure from the previous year each year going forward. This project is to replace the air heater to restore air heater efficiency to the plant. The supporting business case for this project can be found in Exh. AGA-2, starting at page 50.

Project #12 – Long Lake Plant Upgrade ($1,500,000 in 2025 and $45,000,000 in 2026).
The equipment needs to be upgraded for continued reliability as soon as possible. The existing equipment ranges in age from 20 to more than 100 years old. We have experienced an increase in forced outages at Long Lake over the past several years, almost zero in 2011 and increasing every year since then. This is caused by equipment failures on several different pieces of equipment. The other major driver for this project is safety. The switching procedure for moving station service from one generator to the other resulted in a lost time accident and a near miss in the past 5 years. In addition, the station service disconnects represent the greatest arc-flash potential in the Company. This area is roped off and substantial safety equipment is required to operate the disconnects. This project will reconfigure this system to eliminate requiring personnel to perform this operation and avoid the arc-flash potential area. In total, the program includes a full plant condition assessment, replacement of all generating units, generator step-up transformers (GSUs), station service, and many of the mechanical, electrical, and controls systems and equipment have met their end of useful life. Direct offsets associated with this project include an increase in production and a reduction in labor and equipment for unplanned maintenance and breakdowns. The annual estimated value of these Direct Offsets for 2025 is $50,000 and $100,000 in 2026. The supporting business case for this project can be found in Exh. AGA-2, starting at page 94.

Project #38 – Nine Mile Units 3 & 4 Control Upgrade ($5,292,874 in 2025)
Nine Mile Units 3 and 4 controls were installed in the early 1990's and are at the end of their intended life. Further, there is an increased likelihood of forced outages and subsequent loss of revenue and reliability. During the 2018 Maintenance Assessment, the unit controls were rated in poor condition and high in risk due to their age and current condition. The switchgear floor is overloaded which poses a safety risk. In 2010, the switchgear floor was found to be inadequate for any loading above and beyond what it is currently supported, and partially replaced during the Unit 1 and 2 replacement projects. The reminder of the floor will need to be replaced to ensure adequate floor loading can be achieved. This project will include new speed controllers (governors), voltage controls (automatic voltage regulator or AVR), primary unit control system (i.e., Unit PLC), and an upgraded protective relay system on units 3 and 4. Also included is replacement of the switchgear floor inside the Nine Mile powerhouse that will be utilized for relocation of the unit controls and voltage regulation equipment. The supporting business case for this project can be found in Exh. AGA-2, starting at page 335.

Project #39 – Noxon Rapids Gantry Crane Modernization ($19,500,000 in 2026)
Noxon Rapids construction was completed in 1959. Noxon has the capability of producing over

500 MW of peaking power. A key component of the facility is the gantry crane. The gantry crane is utilized to perform required maintenance and upgrades to the turbine/generators. The crane is rated for maximum lifting capacity of 325 tons. The gantry crane is now over 60 years old. Further, parts are difficult to source, and the crane does not conform to current safety standards. Past failures with the crane have caused delays in projects. A functional crane is critical to completing future planned work including the Unit 2 Core and Winding Replacement, Excitation Replacement, the U3 Core and Winding Replacement, and U5 Turbine runner replacement. Without a functional crane, work cannot be performed. This could negatively affect generator availability which can have a negative impact on EIM performance. This project is to replace the existing gantry crane in-kind. The supporting business case for this project can be found in Exh. AGA-2, starting at page 348.

Project #40 – Post Falls HED Redevelopment Program ($5,000,000 in 2026)

The Post Falls Hydroelectric Development (HED) started operation in 1906 and has been operating continuously since that time. The generators, turbines, and governors (turbine speed controller) are original equipment and are still in service. While the plant is still operational, the generating equipment, protective relaying, unit controls, and many other components of the operating equipment are mechanically and functionally failing. The turbines are estimated to be 50% efficient contrasted to modern turbines which can exceed 90% efficiency. Because of the age of the plant, it presents some safety issues that have evolved over time including arc flash hazard to operating and maintenance personnel. The Post Falls Substation is also a wood station design and needs replacement. The Post Falls project is subject to several critical operational requirements that support key recreational facilities, fishery, and other FERC license requirements. This project will redevelop Post Falls HED by shutting down the plant, removing the old equipment, and replacing it in entirety with new. Included in this scoping effort was a needed substation replacement. The supporting business case for this project can be found in Exh. AGA-2, starting at page 358.

Project #41 – Post Falls North Channel Spillway Rehabilitation ($5,000,000 in 2025 and $25,800,000 in 2026)

The North Channel spillway at Post Falls is comprised of 9 total spillgates – one large rolling sector gate and 8 tainter style radial gates. The North Channel spillway is a critical asset to Post Falls, being that it is a main spillway to divert water downstream once plant capacity is reached. The North Channel spillway continues to show its age, with continuing concrete deterioration, failing mechanical gate hoist equipment, and gate issues. Following an engineering assessment in 2021 by an outside consultant firm, the project is to rehabilitate the tainter gates, modernize gate lift mechanisms, perform extensive concrete repair work, install a permanent emergency generator, and to either replace the rolling sector gate with 4 tainter gates or perform a major rehabilitation of the rolling sector gate. The supporting business case for this project can be found in Exh. AGA-2, starting at page 371.

Project #21 – Cabinet Gorge Dam Fishway ($158,008 in 2023, $600,000 in 2024, $399,879 in 2025, and $72,902 in 2026)

The Clark Fork Settlement Agreement (CFSA), incorporated into the Clark Fork FERC License, requires Avista to implement the Native Salmonid Restoration Plan (NSRP), which includes a step-wise approach to investigating, designing, and implementing fish passage at the

Clark Fork Project. Appendix C of the CFSA commits Avista to fund Fishway design and construction as well as annual operations. Fish passage is intended to restore connectivity of native salmonid species in the lower Clark Fork watersheds. During relicensing, the U.S. Fish & Wildlife Service (USFWS) reserved its authority under Section 18 of the Federal Power Act to require fish passage at both Noxon Rapids and Cabinet Gorge dams, in order to pursue the NSRP more collaboratively. Those efforts, including involvement of native American tribes and state agencies, as well as other stakeholders, continued over 15 years to the current project. The supporting business case for this project can be found in Exh. AGA-2, starting at page 185.

Project #22 – Clark Fork Settlement Agreement ($4,621,099 in 2023, $3,027,380 in 2024, $2,663,700 in 2025, and $3,291,708 in 2026)

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 and historic/cultural resources related to our Clark Fork hydro operations. The capital projects are all implemented in cooperation with state and federal agencies, Native American Tribes, local governments, and other interested parties. 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, as 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 a 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 to 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. The supporting business case for this project can be found in Exh. AGA-2, starting at page 193.

Project #23 – KF Ash Landfill Expansion ($13,092 in 2023, and $11,076,524 in 2026)

Kettle Falls Generation Station burns on average 450,000 green tons of wood waste annually. This combustion process creates roughly 30,000 cubic yards of ash that is trucked and stored at the 177-acre parcel south of the plant site. The landfill area is approximately 15 acres nested inside of a 42-acre fenced parcel designated for landfill operations and development. The current ash landfill is reaching its full capacity and is expected to be completely filled between 2025 and 2028 depending on plant dispatch and ash production. This project will construct a new Phase 4 lined landfill built to current standards and will incorporate the closure costs of Phase 3 as part of the construction of the new disposal area. The supporting business case for this project can be found in Exh. AGA-2, starting at page 201.

Project #25 – Operational Safety and Compliance ($637,698 in 2024, $1,967,828 in 2025, and $4,365,255 in 2026)

This program will support the various compliance and safety-related projects within all of the Avista-owned generating facilities. The projects are intended to address compliance and/or safety related matters at the facilities. Projects will be low in complexity and coordination. This program is critical in supporting facility compliance with agencies including NERC, FERC, WEC and OSHA. Identified projects will be governed by the Plant Manager, Operations Engineering Manager, and Senior Operations & Maintenance Manager. The GPSS Operations team will coordinate and manage a 5-year plan of identified projects to sustain the safe and reliable operations of the Avista-owned generation assets. The supporting business case for this project can be found in Exh. AGA-2, starting at page 222.

Project #26 – Right-of-Way Use Permits ($122,160 in 2023, $250,002 in 2024, $250,000 in 2025, and $249,996 in 2026)

Avista owns and maintains electric transmission, distribution, and natural gas facilities which cross public lands managed by a variety of state, federal and local agencies, as well as entities who own extensive tracts, such as railroads. Traditionally, the Company has secured long-term rights-of-way permits for these facilities but has been required to renew them through an annual billing process. The cost of renewing these permits continues to increase, ranging from 3% to 10% annually depending on the agency, thereby increasing annual O&M expenses. This Business Case proposal is to secure long-term agreements with lump-sum payments to reduce overall expenses related to labor of tracking, researching, and processing these annual permits. In some cases, we have been able to negotiate a lower annualized cost over the term of the permit by paying a lump sum up front. In either case, we reduce costs to the Company and our customers. The supporting business case for this project can be found in Exh. AGA-2, starting at page 230.

Project #27 – Spokane River License Implementation ($1,453,808 in 2023, $838,800 in 2024, $954,600 in 2025, and $909,600 in 2026)

The Spokane River License Implementation 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. 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. The supporting business case for this project can be found in Exh. AGA-2, starting at page 236.

Project #28 – WSDOT Franchises ($284,150 in 2023, $150,000 in 2024, $149,999 in 2025, and $150,000 in 2026)

The WSDOT Franchise Project renews expired franchises for Avista facilities located within Washington State highway rights-of-way. In accordance with WAC 468-34 and RCW 47.44, Avista enters into 25-year agreements with the Washington State Department of Transportation (WSDOT) to permit Avista to construct, operate and maintain electric and natural gas facilities within Washington highway rights-of-way. These agreements are referred to as franchises. WSDOT manages franchises by reaches of a state highway within a county. Avista has 35 such franchises, 29 of which are expired. Franchise applications cannot be submitted without a completed "Control Zone" analysis and mitigation plan for every above-ground object within the highway right of way. The supporting business case for this project can be found in Exh. AGA-2, starting at page 243.

Project #29 – Asset Lifecycle Management ($868,123 for 2024, $1,813,667 for 2025, and $1,450,001 in 2026)

This program will support the various plant projects within all the Avista-owned generating facilities. These projects are fairly routine and time-based projects intended to extend the life of a system or an asset. They are not intended to replace the full system but instead bring the system back to its original performance and objective. This program is critical in continuing to support asset management program lifecycle replacement schedules. Identified projects will be governed by the Plant Manager, Operations Engineering Manager, and Senior Operations & Maintenance Manager. The GPSS Operations team will coordinate and manage a 5-year plan of identified projects needed to sustain the safe, reliable, affordable operations of the Avista-owned generation fleet. The supporting business case for this program can be found in Exh. AGA-2, starting at page 250.

Project #33 – Base Load Thermal Program ($1,673,666 in 2023 and $482,311 in 2025)

Avista's Base Load Thermal plants include Coyote Springs 2 and the Kettle Falls Generating Station. These two base load plants provide different operational flexibility to serve Avista's customer's energy demands. Coyote Springs 2 is a natural gas-fired combined cycle unit which generates 300 MWs. It is equipped with automation to adjust unit output to match changing system loads and other types of services necessary to provide a stable electric grid. Kettle Falls is a base load renewable wood biomass resource with the ability to store energy in its fuel supply for long periods of time to optimize energy markets to best serve Avista's capacity, energy and renewable resource needs. The supporting business case for this program can be found in Exh. AGA-2, starting at page 282.

Project #34 – Operational Sustainment ($7,976,356 in 2024, $6,264,758 in 2025, and $8,788,005 in 2026)

This program will support the operational sustainability of the Avista-owned generating facilities. These projects primarily include moderate investments in system retrofits or replacements necessary to maintain the operation of the facilities. This program is critical in continuing to support asset management program lifecycle replacement schedules until larger operational enhancement program investments are made. Identified projects will be governed by the Plant Manager, Operations Engineering Manager, and Senior Operations & Maintenance Manager. The GPSS Operations team will coordinate and manage a 5-year plan of identified projects needed to sustain the safe, reliable, and affordable operations of the Avista-owned generation assets. The supporting business case for this program can be found in Exh. AGA-2, starting at page 293.

Project #36 – HMI Control Software ($4,016,838 in 2023, $2,676,153 in 2024, $2,078,530 in 2025, and $132,015 in 2026)

The existing Human Machine Interface (HMI) software, Wonderware, reached its end of life as support ended in 2017. HMI Control Software is used to develop control screens and to operate and monitor generating systems within Avista Hydroelectric Developments and Thermal Generating facilities. The existing architecture is also outdated and requires the existing software to be loaded and run on each individual computer at each generating facility. Moving to a new HMI platform will allow for upgrading to a server-based architecture. The HMI Control Software update is a multi-year effort to transition the controls software at all GPSS generating facilities from Wonderware to Ignition. As a part of this update, supporting software and hardware will also need to be upgraded as to ensure communication and support across all parts of our controls system. The timing of this transition is critical due to the expiring support for both Wonderware and Windows 7 (the current, and only, operating system functional with Wonderware). The supporting business case for this project can be found in Exh. AGA-2, starting at page 311.

Q. Does this conclude your pre filed direct testimony?

A. Yes, it does.