DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL FOR
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
DAVID.MEYER@AVISTACORP.COM

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-23-01 CASE NO. AVU-G-23-01 DIRECT TESTIMONY OF SCOTT J. KINNEY

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

I. INTRODUCTION

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

A. My name is Scott J. Kinney. I am employed as the Vice President of Energy Resources 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 Gonzaga University in 1991 with a Bachelor of Science in Electrical Engineering and I am a licensed Professional Engineer in the State of Washington. I joined the Company in 1999 after spending the first eight years of my career with the Bonneville Power Administration. I have held several different positions at Avista beginning as a Senior Transmission Planning Engineer. In 2002, I moved to the System Operations Department as a Supervisor and Operations Support Engineer. In 2004, I was appointed as the Chief Engineer, System Operations and as the Director of Transmission Operations in June 2008. I became the Director of Power Supply in January 2013 and Vice President of Energy Resources in September 2022.

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.

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

A. My testimony provides an overview of Avista's electric and natural gas resource planning and power and natural gas 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 the Company's Two-Year Rate Plan filed in this case, including capital additions associated with the Company's investment in Colstrip Unit Nos. 3 and 4 pro formed in this case (i.e. the 2022 Dry Ash project). My testimony will conclude with a discussion of the Chelan PUD Power Purchase Agreement.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit No. 6, Schedules 1 – 7. Exhibit No. 6, Schedule 1 is Avista's 2021 Electric Integrated Resource Plan, Appendices and Update. Confidential Exhibit No. 6, Schedule 2C is Avista's Energy Resources Risk Policy. Exhibit No. 6, Schedule 3 contains the 2021 Natural Gas IRP. Exhibit No. 6, Schedule 4 includes the capital business cases for the generation capital projects discussed later in my testimony. Confidential Exhibit No. 6, Schedule 5C contains the 2020 Renewable RFP Report and Documentation. Confidential Exhibit No. 6, Schedule 6C includes the Chelan PUD Power Purchase Agreement. Finally, Exhibit No. 6, Schedule 7 is the Western Resource Adequacy Program (WRAP) detailed design document

II. ELECTRIC 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 Energy Resources Department (Energy Resources) is responsible for dispatch decisions related to those resources for which the Company has dispatch rights. Energy Resources 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 2021 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 expected 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 Exhibit No. 6, Schedule 1. An update to the 2021 IRP was filed on April 30, 2021, to include the 10-year contract with Chelan PUD for a 5% slice of the output from Rocky Reach and Rock Island hydroelectric facilities from the 2020 RFP. The 2023 Electric IRP is currently in development. An external draft of the 2023 IRP will be released on March 17, 2023, and the final IRP is scheduled to be filed with the Commission on June 1, 2023.

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

A. The Preferred Resource Strategy (PRS) in the 2021 Electric IRP guides the Company's resource acquisitions, subject to any additional legislative or regulatory requirements. The IRP provides details about future resource needs, specific resource costs, resource-operating characteristics, and scenarios used for evaluating the mix and timing of resources included in 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 considering new legislation or other market opportunities. Avista's 2021 Electric IRP and Update are included as Exhibit No. 6, Schedule 1. The 2021 IRP was filed with the Commission on March 31, 2021, and updated on April 30, 2021, in Case No. AVU-E-21-04 and acknowledged in Order No. 35257.

Avista's 2021 PRS, as amended by the April 30th Update, includes the addition of a mix of new wind, natural gas-fired CTs and internal combustion engines, battery storage, solar, liquid air storage, Mid-Columbia hydroelectric contracts and plant upgrades. The PRS also includes a portfolio of demand response and energy efficiency programs. The new resources are offset by the loss of coal and natural gas-fired resources, and expiring wind, solar and hydroelectric contracts from the Company's resource portfolio. The timing and type of these resource additions and subtractions included in the PRS for the 2021 IRP are provided in Table Nos. 1 through 3 below.

Table No. 1: 2021 Electric IRP Preferred Resource Strategy (2022 – 2031)

Resource	Jurisdiction	Time Period	ISO Conditions (MW)	Equivalent Winter Peak Capacity (MW)	Energy Capability (aMW)
Colstrip 3 & 4	System	TBD	-222	-222	-206
Montana wind	WA	2025	100	33	45
Post Falls modernization	System	2026	8	4	4
Lancaster PPA	System	2026	-257	-283	-209
Kettle Falls modernization	System	2027	12	12	10
Natural gas CT	WA	2027	84	93	76
Natural gas CT	ID	2027	84	96	76
Montana wind	WA	2028	100	33	45
Natural gas ICE	ID	2031	55	54	50
Mid-Columbia Hydro Extension	WA	2031	75	44	33
Total New Resources			**518**	**369**	**339**
Net of Removed Resources			**39**	**-136**	**-76**

Table No. 2: 2021 Electric IRP Preferred Resource Strategy (2032 – 2041)

Resource	Jurisdiction	Time Period	ISO Conditions (MW)	Equivalent Winter Peak Capacity (MW)	Energy Capability (aMW)
Montana wind	WA	2034	100	28	45
Rathdrum upgrade	System	2034	5	5	4
Northeast CT	System	2035	-62	-43	0
Natural gas CT	System	2036	84	93	76
Adams-Neilson Solar	WA	2037	-19.2	0	-5
Solar w/ storage	System	2038	100	2	26
4-hour storage (lithium-ion)	System	2038	50	7	-2
Rattlesnake Flat	System	2040	-145	-7	-55
Boulder Park	System	2041	-25	-25	-14
Montana wind	WA	2041	100	26	45
Natural gas ICE	ID	2041	36	35	33
Total New Resources			**475**	**196**	**227**
Net of Removed Resources			**224**	**121**	**153**

Table No. 3: 2021 Electric IRP Preferred Resource Strategy (2042 – 2045)

Resource	Jurisdiction	Time Period	ISO Conditions (MW)	Equivalent Winter Peak Capacity (MW)	Energy Capability (aMW)
Palouse Wind	WA/ID	2042	-105	-5	-36
Solar w/ storage	WA	2042	117	2	31
4-hour storage (lithium-ion)	WA	2042	58	9	-2
Solar w/ storage	WA	2043	122	2	31
4-hour storage (lithium-ion)	WA	2043	61	9	-2
Liquid Air Energy Storage (LAES)	WA	2044	13	7	-1
Solar w/ storage	WA	2045	149	3	40
4-hour storage (lithium-ion)	WA	2045	75	11	-2
4-hour storage (lithium-ion)	ID	2045	16	2	-1
Total New Resources			**611**	**45**	**94**
Net of Removed Resources			**506**	**40**	**58**

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 Exhibit No. 6, Schedule 2C, 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 IRP's Preferred Resource Strategy, while taking advantage of competitive opportunities to satisfy electric resource supply needs in the long-term. 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 2022 All-Source RFP?

A. Yes. The 2022 All Source RFP sought resource acquisitions to meet needs identified in the 2021 Electric IRP described earlier in my testimony. The IRP identified resource needs beginning in 2026 that included a 162 MW of winter capacity, 127 MW of summer capacity as well as renewable and monthly energy needs. The RFP received a favorable response from over 20 developers with nearly a dozen technologies, 32 proposals with options equaling 56 total projects that were analyzed. Avista hired Sapere Consulting to provide independent evaluator (IE) services.

The draft RFP and evaluation methodology was shared with Commission Staff and stakeholders. Avista incorporated public comments, received required Commission approval in Washington, and released the RFP on February 18, 2022. Avista proactively engaged prospective bidders prior to bids closing at the end of March 2022. Avista analyzed preliminary information received in parallel with the IE to establish a short list in June 2022 that included 10 projects including a mix of wind, solar, battery, natural gas, biomass and demand response. Detailed proposals were received in late July 2022 and a second round of analysis was conducted by both Avista and its IE. A price refresh was requested by early September 2022 to allow bidders time to incorporate the new Federal Inflation Reduction Act.[1] By the end of September 2022, scoring was complete, and Avista leadership approved the request to initiate contract negotiations with the top finishers. Avista's 2022 All Source RFP results offer an opportunity to maintain and expand reliability while furthering our company-wide renewable energy goals. Negotiations have begun in earnest and are expected to take three to six months.

Q. Will the results of the RFP be incorporated into the development of the 2023 IRP?

A. Yes, depending upon the date of contract execution. If contracts are signed prior to the need to finalize the 2023 IRP, the resources will be added to the Company's mix and the IRP models will be rerun to determine an updated PRS based on the smaller near-term resource need.

III. PLANNING FOR NATURAL GAS COMMODITY RESOURCE PROCUREMENT

Q. Please describe Avista's natural gas portfolio as it relates to the

[1] https://www.irs.gov/inflation-reduction-act-of-2022

procurement of the natural gas commodity for its local distribution company ("LDC") customers.

A. Avista manages natural gas procurement and related activities on a system-wide basis with several regional supply options available to serve LDC customers. The Company purchases natural gas for its LDC customers in wholesale markets at multiple supply basins in the western United States and western Canada. Purchased natural gas is transported from these various US or Canadian-sourced supply basins through six inter-connected pipelines within the region and delivered to city gates or put into the Jackson Prairie Natural Gas Storage Facility ("JP") for future use. Avista holds firm contractual transportation rights on five of these pipelines, as well as firm withdrawal capability from JP, helping diversify where supply can be received to meet customers' needs among the three jurisdictions.

JP is an underground aquifer natural gas storage facility located in Chehalis, Washington. Through a joint ownership agreement, Avista, Puget Sound Energy, and Williams Northwest Pipeline each hold one-third equal, undivided interest of JP. Presently, Avista <u>owns</u> a total of 8,528,013 dekatherms (Dth) of working gas capacity at JP. This capacity comes with a withdrawal capability (deliverability) of 398,667 Dth per day. Jurisdictionally, this amount is broken out as follows:

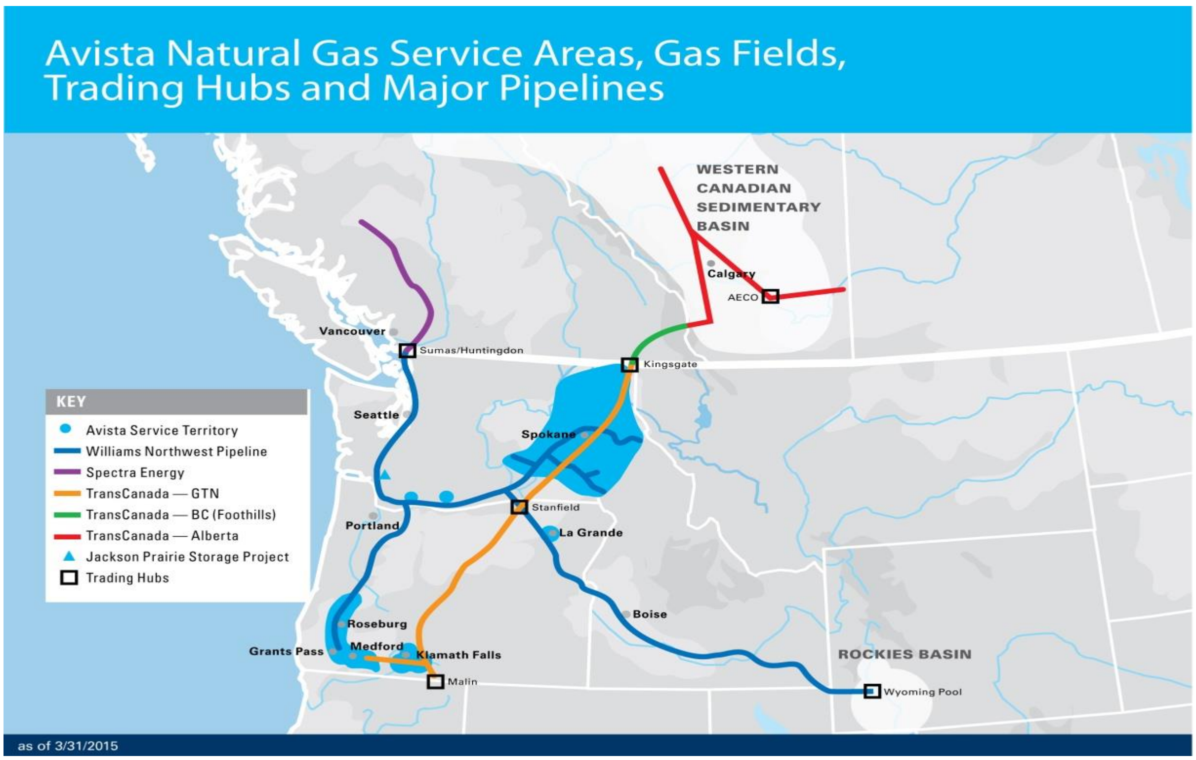
<u>Table No. 4: Jackson Prairie Working and Withdrawal Capacity by Jurisdiction</u>

Jurisdiction	Working Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)
Washington/Idaho	7,704,676	346,667
Oregon	823,337	52,000
Total Owned	8,528,013	398,667

Access to regionally located storage provides several benefits to Avista customers, including improving reliability and flexibility of supply, mitigating daily price volatility and peak demand price spikes, capturing price spreads between time periods, and numerous other economic benefits.

Illustration No. 1 below is a map showing our service territory, natural gas trading hubs, interstate pipelines, and the Jackson Prairie Natural Gas Storage Facility.

<u>Illustration No. 1: Avista Natural Gas System Map</u>



Wholesale natural gas prices are a fundamental component of both natural gas procurement and integrated resource planning. Pacific Northwest natural gas prices can be affected not only by regional factors, but by global energy markets, and supply and demand factors from other regions within the United States and Canada. Price volatility and delivery constraints can have an impact on where our natural gas is sourced. Avista's diverse portfolio of natural gas supply resources allow the Company to make natural gas procurement decisions based on the reliability and economics that provide the most benefit to our customers.

Being that future natural gas prices cannot be accurately predicted; the Company has developed a Natural Gas Procurement Plan ("Plan") to ensure reliable supply and a level of price certainty in volatile markets. The Company recently changed the Plan from past practices in light of the recent natural gas price volatility the region has experienced to ensure reliable supply and a level of price certainty in these more volatile markets since future natural gas prices cannot be accurately predicted. Market conditions, analysis, and experience shape the updated Plan's overall strategy, which still includes a comprehensive program of hedging, storage utilization, and index purchases. This approach is diversified by transaction time, term, counterparty, and supply basin. The Plan provides general guidelines regarding the use, procurement, and execution of transactions as authorized in Avista's Energy Resources Risk Policy. Although the specific provisions of the Plan will change based on ongoing analyses and experience, this Plan utilizes a combination of strategies to reduce the impacts of fluctuating commodity prices.

The Plan provides general guidelines regarding the use, procurement, and execution of transactions as authorized in Avista's Energy Resources Risk Policy discussed earlier in my testimony and available in Confidential Exhibit No. 6, Schedule 2C. Although the specific provisions of the Plan will change based on ongoing analyses and experience, this Plan utilizes a combination of strategies to reduce the impacts of fluctuating commodity prices.

Hedge Windows allow the Company to capture, or fix, future natural gas prices for a targeted portion of the portfolio. A Hedge Window is bounded by dates and market price parameters, including three Operative Boundaries, three Lower Control Limits, and a Timed Trigger Date. Quantitative mathematics are used to determine the Operative Boundaries and the Lower Control Limits. If the Price @ 2 Sigma goes above an Operative Boundary, the boundary is triggered, and a hedge may be procured. Up to three Operative Boundary triggers may occur in a window. Conversely, if the current market price falls below a Lower Control Limit, the boundary is triggered, and a hedge may be procured. The Plan allows discretion for decision making as market conditions warrant. Management may determine that it is appropriate to take other action, partial action, or no action, with respect to transaction execution and will document these decisions accordingly.

The Natural Gas Supply Department continuously monitors the results of the Plan, evolving market conditions, variation in demand profiles, new supply opportunities, and regulatory conditions. Although the initial windows and targets are established in the initial design phase, the Plan allows discretion for ultimate decision making as market conditions warrant. The Plan is reviewed with senior management and state regulators in the fall of each year. Any material changes to the Plan made throughout the year as market conditions, available resources and/or changes in demand dictate, are communicated to Avista's Senior Management and Commission Staff.

Q. What delivery period does the natural gas Procurement Plan include?

A. The target delivery periods for the Procurement Plan cover 36 months. The first five to eleven months are addressed in monthly blocks depending on the current month. After these monthly blocks, a minimum of four seasonal blocks are addressed in consecutive November – March and April – October blocks. Additional November – March or April – October blocks are added so that in any given delivery period, there are between 30 and 36 months to be monitored and eligible for a hedge. By the time the delivery period is reached, each individual month will have been available for hedging for a full 36 months prior to delivery.

Q. Please describe the components of the Natural Gas Procurement Plan.

A. Each year a comprehensive review of the previous year's Plan is performed. The review includes analysis of historical and forecasted market trends, fundamental market analysis, demand forecasting, and transportation, storage and other resource considerations, with the load forecast being the basis of the Plan. Avista secures/purchases natural gas supply through the transactions and procedures described below to serve load and optimize resources for the benefit of customers:

1. **Fixed-Price Purchases**: To provide a level of price certainty in volatile natural gas commodity markets, Energy Supply will hedge some of its load with fixed-price transactions, either with fixed-price physical purchases or with financial swaps or financial futures, which will be matched to purchases of index-priced physical products prior to the products settlement. These hedges will be structured to diversify procurement in terms of timing of the transaction and duration of committed supplies.

2. **Storage Injections and Withdrawals**: Avista owns and contracts for storage services at Jackson Prairie. Avista has a contractual operational requirement to have its share of Jackson Prairie full by September 30 of each year. Energy Supply retains flexibility in terms of the timing and volume of the injection and withdrawal schedules. Actual storage injections and withdrawals will be executed to optimize the economic value of storage within the reliability constraints of the project and the ability to serve retail customers' peak day needs.

3. **Index-Based Physical Purchases**: Energy Supply generally purchases physical index-based natural gas for up to the difference between the average daily load forecast for each month and the sum of the fixed-price purchases and projected storage withdrawals. Energy Supply retains flexibility to modify the components of its purchases in a month due to operational or other reasons. The selected indices may be first-of-month indices or daily-based indices.

4. **Daily Adjustments Due to Load Variability**: To the extent actual loads differ from the average daily load forecast for the month, the difference will be managed through a combination of: a) daily purchases or sales of natural gas, or b) withdrawals from, or injections into, natural gas storage facilities.

5. **Use of Derivative Contracts**: Subject to limitations in the Energy Resources Risk Policy, Energy Supply may enter into derivative-based contracts intended to reduce or

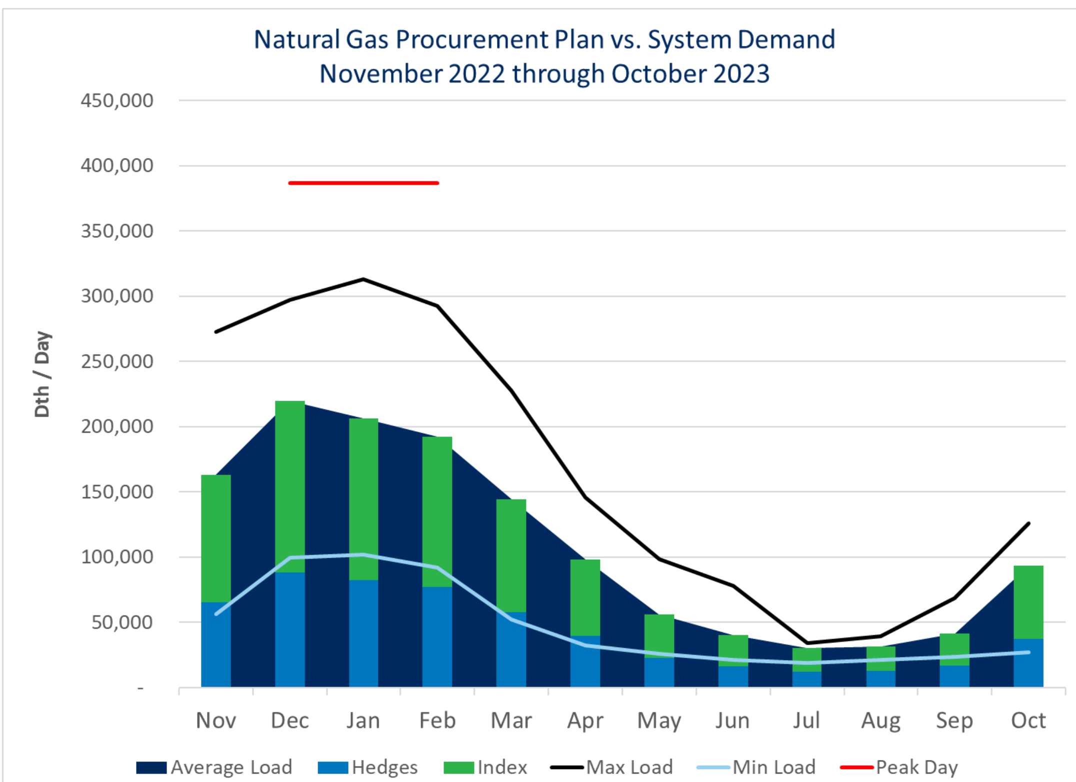
manage exposure to rising prices or fluctuating loads.

6. **Resource Optimization**: Energy Supply may enter into transactions that create value for customers using unutilized supply, transportation, or storage assets. Utilization of these resources reduces fixed costs and lowers overall costs to customers.

Q. Please describe how the Procurement Plan manages volatility.

A. The Plan focuses on managing the costs associated with serving varying retail load with supply from a wholesale market with price volatility. To manage these seasonal, monthly, and daily volume swings, Avista shapes the components of the Plan by month (i.e., more natural gas is hedged for the winter months than for the summer). Illustration No. 2 below includes a chart that shows the demand volatility.

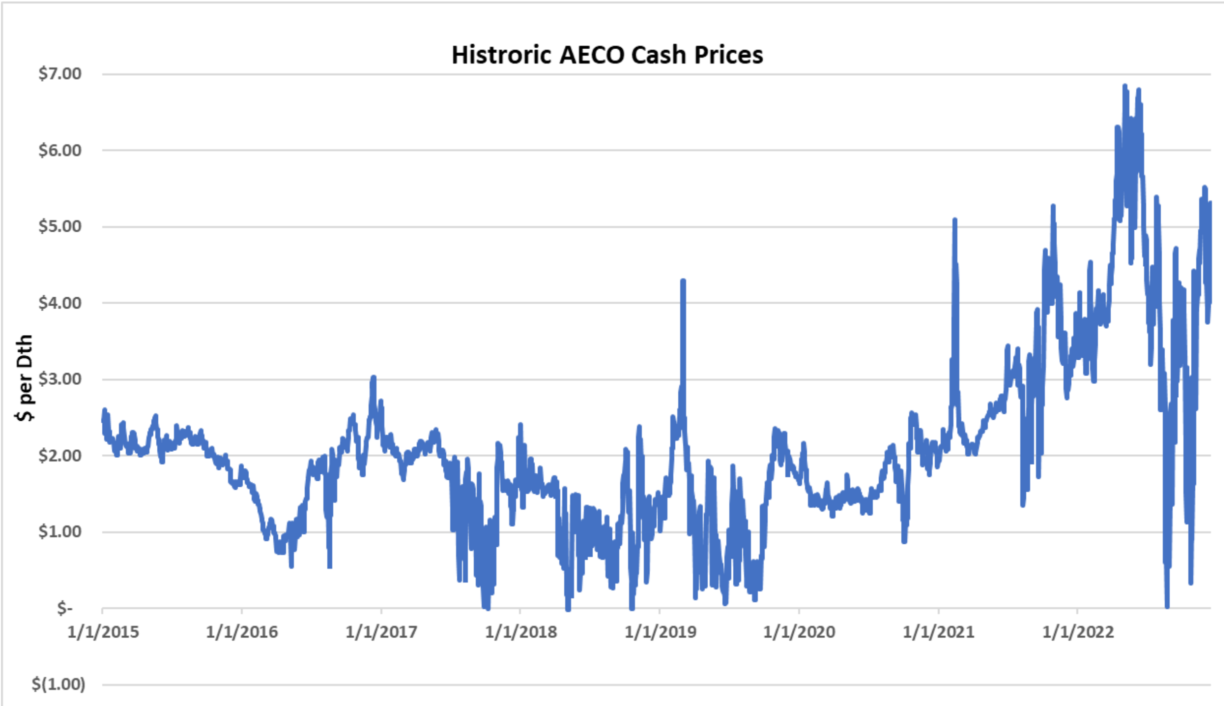
<u>Illustration No. 2: Natural Gas Procurement Plan vs. System Demand</u>



Price volatility can also vary widely by season, month, and day. Illustration No. 3

below includes a chart depicting the natural gas price volatility over time.

Illustration No. 3 – Historic Natural Gas AECO Prices



Avista cannot predict with accuracy what natural gas prices may be. Our experience and intelligence related to market fundamentals guide our procurement decisions. By layering in fixed price purchases over time, setting upper and lower pricing levels on the Hedge Windows, managing the VaR of our LDC natural gas portfolio's open position on a daily basis, and actively managing storage resources, Avista is able to meet our goal of providing a meaningful measure of price stability and certainty, and competitive prices for our customers.

IV. 2021 NATURAL GAS INTEGRATED RESOURCE PLAN

Q. Please provide an overview of the Company's development of its 2021 Natural Gas Integrated Resource Plan.

A. The 2021 Integrated Resource Plan ("IRP") was filed with the Commission on

March 31, 2021. The IRP includes forecasts of natural gas demand and any supply-side transportation resources and demand-side measures needed for the coming 20-years, which will help Avista continue to reliably provide natural gas to our customers. A copy of the Avista's 2021 Natural Gas Integrated Resource Plan is included as Exhibit No. 6 - Schedule 3.

Q. What are the summary highlights from the 2021 IRP?

A. Highlights from the 2021 IRP are as follows:

- Marginally higher firm system-wide expected customer growth rates, combined with use per customer continuing to trend lower, kept the long-term natural gas demand forecast relatively flat and helped eliminate the need to acquire new resources within the 20-year planning horizon in Washington, Idaho, or Oregon for the Expected Case.

- Peak day design weather has been updated from a coldest on record to a 99% probability based on the most recent 30 years of data by planning area.

- Oregon and Washington have signaled a policy shift in terms of decarbonization policy. Meeting these objectives will be a primary focus in the 2023 IRP.

Q. Has the Company's 2021 Natural Gas IRP been acknowledged by this Commission?

A. Yes. The Commission acknowledged the Company's 2021 IRP on November 12, 2021, in Case No. AVU-G-21-02.

Q. When will the Company file its next natural gas IRP?

A. Avista plans to file the 2023 natural gas IRP during the pendency of this case, on or before March 31, 2023.

V. OVERVIEW OF 2022 –2025 GENERATION CAPITAL PROJECTS

Q. Please discuss the capital investments you sponsor included in the Company's Two-Year Rate Plan.

A. As discussed by Company witnesses Ms. Schultz and Ms. Benjamin, Avista's capital witnesses, including myself, describe the capital projects included in the Company's proposed Two-Year Rate Plan, reflecting pro forma ("PF") capital additions for the period between July 1, 2022 and August 31, 2025. For the generation projects, my testimony and Exhibit No. 6, Schedule 4 provides an overview of the need for the investments made and detail how those projects benefit our customers.

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 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. <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. **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.

Q. For the capital additions in the 2022 through 2025 timeframe, 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 projects completed since the end of the test year (twelve-months ended June 30, 2022) and over the proposed Two-Year rate Plan beginning September 1, 2023, through August 31, 2025. Details about the generation-related capital projects over the period included in this case are discussed below. Table No. 5 below provides the system cost of each generation capital project pro formed in this case for the July 1, 2022, through August 1, 2025, period. Additional details about specific generation capital projects associated with Colstrip Units 3 and 4 are covered in a later section of my testimony.

Table No. 5: 2022 through 2025 Non-Colstrip Major Generation Capital Projects

Generation Capital Projects (System) In $(000's)				
Investment Driver				
Business Case Name	**2022[1]**	**2023**	**2024**	**2025[2]**
Mandatory and Compliance				
Cabinet Gorge Dam Fishway	$ 1,897	$ 235	$ -	$ -
Clark Fork Settlement Agreement	2,673	3,523	3,027	2,056
Right-of-Way Use Permits	75	250	250	167
Spokane River License Implementation	652	826	564	398
Failed Plant and Operations				
Base Load Thermal Program	$ 2,002	$ 2,181	$ 1,250	$ 947
Noxon Rapids HVAC	-	-	190	-
Peaking Generation Business Case	310	473	400	259
Asset Condition				
Asset Monitoring System	$ -	$ -	$ 250	$ 250
Base Load Hydro	682	923	675	101
Cabinet Gorge HVAC Replacement	-	-	1,753	-
Cabinet Gorge Station Service	7,647	5,140	-	-
Cabinet Gorge Stop Log Replacement	-	1,199	-	-
Cabinet Gorge Unit 1 Governor Upgrade	-	599	-	-
Cabinet Gorge Unwatering Pumps	319	400	-	-
Generation DC Supplied System Update	300	421	459	180
HMI Control Software	2,000	7,070	1,735	-
KF 4160 V Station Service Replacement	-	-	2,135	-
KF D10R Dozer Certified Power Train Rebuild	-	-	-	600
KF Secondary Superheater Replacement	-	-	3,500	-
KF_Fuel Yard Equipment Replacement	28,170	1,005	-	-
KF_ID Fan & Motor Replacement	-	-	1,650	-
Little Falls Crane Pad & Barge Landing	-	2,997	-	-
Little Falls Plant Upgrade	355	-	-	-
Long Lake Plant Upgrade	-	-	-	38,000
Monroe Street Abandoned Penstock Stabilization	-	897	-	-
Nine Mile HED Battery Building	800	-	-	-
Nine Mile Powerhouse Crane Rehab	850	-	-	-
Nine Mile Powerhouse Roof Replacement	-	997	-	-
Nine Mile Unit 3 Mechanical Overhaul	-	-	-	4,600
Nine Mile Units 3 & 4 Control Upgrade	-	-	-	4,700
Noxon Rapids Generator Step-Up Bank C Replacement	-	-	-	1,507
Noxon Rapids Spillgate Refurbishment	750	3,300	1,532	-
Post Street Substation Crane Rehab	-	500	-	-
Regulating Hydro	2,512	1,883	1,800	1,270
Upper Falls Trash Rake Replacement	-	1,501	-	-
Performance & Capacity				
Energy Imbalance Market	$ 140	$ -	$ -	$ -
Energy Market Modernization & Operational Efficiency	592	498	500	249
Generation Plant Annunciation Systems	-	150	147	-
Customer Service Quality and Reliability				
Automation Replacement	$ -	$ 795	$ 465	$ 200
Total Planned Generation Capital Projects	**$ 52,726**	**$ 37,763**	**$ 22,282**	**$ 55,484**

(1) Includes system pro forma capital additions for the period of July 01, 2022 though December 31, 2022.
(2) Includes system pro forma capital additions for the period of January 01, 2025 though August 31, 2025.

Q. Would you please explain the generation capital projects included in this case for 2022 through 2025?

A. Yes. The capital projects include generation capital investments grouped as Mandatory and Compliance, Failed Plant and Operations, Asset Condition, Performance and Capacity, and the Customer Service Quality and Reliability investment categories. Brief descriptions of each project, the reasons for the projects, and the timing of the decisions follow. Additional details can be found in Exhibit No. 6, Schedule 4 – Generation and Environmental Capital Project Business Cases.

<u>Mandatory and Compliance Generation Capital Projects</u>

Cabinet Gorge Dam Fishway ($1,897,000 in 2022, $235,000 in 2023)
The Clark Fork Settlement Agreement (CFSA) and FERC License require 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. Fish passage is intended to restore connectivity of native salmonid species in the lower Clark Fork watersheds, primarily bull trout, an Endangered Species Act listed species. 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 collaboratively. Those efforts, including involvement of Native American tribes and state agencies, as well as other stakeholders, have been ongoing since 2000.

In 2017, the CFSA and FERC License were amended to incorporate a commitment to design and construct a fish passage facility at Cabinet Gorge Dam (fishway). Construction of the fishway was substantially completed in 2022, and fishway operations began. Given that the fishway is the first designed specifically for bull trout, and consists of a site-specific design, some operational components require ongoing modifications. Some of this work and overall project closeout will extend into 2023. The fishway has successfully captured bull trout and other salmonid species, allowing ongoing implementation of successful fish passage.

Clark Fork Settlement Agreement ($2,673,000 in 2022, $3,523,000 in 2023, $3,027,000 in 2024, $2,056,000 in 2025)
The ongoing operation of the Clark Fork Project is guided by the Clark Fork Settlement Agreement (CFSA) and FERC License No. 2058, which established the terms of the 45-year license issued to Avista. Imbedded in the License is the requirement to continue to consult agencies, tribes and other stakeholders. In addition, the CFSA and License provide decision-making participation for the settlement signatories, resulting in ongoing negotiations on

implementing license terms. The CFSA and License also include several funding commitments to help achieve long-term resource goals in the Clark Fork and related watersheds.

Avista is required to develop an annual implementation plan and report, addressing all Protection, Mitigation and Enhancement (PM&E) measures of the License. Implementation of these measures addresses ongoing compliance requirements with Montana and Idaho Clean Water Act requirements, the Endangered Species Act, and state, federal and tribal water quality standards and regulations. License articles also describe operational requirements for items such as minimum flows, reservoir levels, dam and public safety requirements, land use, habitat, fisheries, recreation, land management, wildlife and other natural resources, and related matters. The investment drivers for this project are predominantly Mandatory and Compliance in nature.

Right-of-Way Use Permits ($75,000 in 2022, $250,000 in 2023, $250,000 in 2024, $167,000 in 2025)

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, we have secured long-term rights-of-way permits for these facilities, but have been required to renew them through an annual billing process. The cost of renewing these permits continues to increase each year, ranging from 3% to 10% annually, depending on the agency or entity, thereby increasing annual O&M expenses. This capital project secures long-term agreements with lump-sum payments to reduce overall expenses related to the labor of tracking, researching, and processing these annual permits. In some cases, we have negotiated 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.

Spokane River License Implementation ($652,000 in 2022, $826,000 in 2023, $564,000 in 2024, $398,000 in 2025)

This capital spending category covers the ongoing implementation of PM&E programs related to the FERC License No. 2545 and several other settlement agreements for the Spokane River Project including the Post Falls, Upper Falls, Monroe Street, Nine Mile and Long Lake dams. These capital projects include items enforceable by FERC, mandatory conditioning agencies, and through settlement agreements. The FERC License defines how Avista operates the Spokane River Project and includes several hundred requirements that must be met to retain this License. The License is issued pursuant to the Federal Power Act, and it embodies requirements for 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 also expressed through specific license articles relating to fish, terrestrial resources, water quality, recreation, education, cultural, and aesthetic resources at the Spokane River Project. The License incorporates specific funding requirements to a 50-year settlement agreement between local and state agencies, as well as the Coeur d'Alene and Spokane Tribes. The License references our requirements for land management, dam safety, public safety and monitoring requirements, which apply for the term of the License and 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.

Failed Plant and Operations Generation Capital Projects

Base Load Thermal Program ($2,002,000 in 2022, $2,181,000 in 2023, $1,250,000 in 2024, $947,000 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 adjustment 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 woody 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.

Projects for Coyote Springs 2 are identified and prioritized during the Annual Budgeting process, with emergent projects discussed during the Monthly Owners committee meetings between Avista and Coyote Springs management. Some of the projects that fall within this business case are joint projects between Portland General Electric (the plant operator) and Avista. These projects are also reviewed in an owner committee setting during monthly meetings at the plant. Kettle Falls Generation Station projects are identified and prioritized through the plant's Budget Committee. Both plants utilize the GPSS ranking matrix system to evaluate projects. Individual projects which are identified are then reviewed and approved or denied by the Manager of Thermal Operations and Maintenance, specific plant managers and/or GPSS management before they are scheduled and implemented. Some projects completed under this program may require additional financial analysis if they are sufficiently large or if there are several options to meet the objective. These larger projects are reviewed with finance personnel to ensure they are in the best financial interests of our customers.

As noted by Ms. Schultz, the Company has included direct offsetting O&M benefits related to capital additions where available, resulting in O&M expense reductions for this Business Case in Rate Year 1 of $9,500 system ($3,275 ID share) within PF Adjustment 3.12.

Noxon Rapids HVAC ($190,000 in 2024)

The Noxon Rapids powerhouse needs to have a new HVAC System with significant cooling and heating capacity to be able to support a satisfactory work environment for plant personnel and enable sufficient cooling for critical electrical equipment. The current ventilation system in the powerhouse at Noxon Rapids is not operational. The system was installed in 1959 and parts are no longer available. The system needs to be replaced because the original ventilation system controls are no longer functional and have been removed. There is no cooling or heating capacity with the current ventilation system and the current air handling system can only be operated manually for ventilating and exhausting powerhouse air. There is no filter system for plant make up air which results in outside smoke from wildfires and dust in the outside air from entering the plant. Additional transformers and electrical equipment planned to be installed within the powerhouse will significantly increase internal plant heat loading. It is critical that this project is completed prior to the completion of the planned Noxon Rapids Generator excitation upgrade which is expected to be completed within the next seven years. This new HVAC system will provide the needed plant cooling of this new equipment and provide sufficient heating, filtered ventilation and air conditioning in support of normal operations of the plant. Without this system replacement, plant personnel will be subjected to unacceptably high internal powerhouse temperatures and critical electrical equipment will fail due to inadequate cooling.

Peaking Generation Business Case ($310,000 in 2022, $473,000 in 2023, $400,000 in 2024, $259,000 in 2025)

The Peaking Generation program focuses on the ongoing capital maintenance expenditures required to keep Boulder Park, the Rathdrum Combustion Turbines, and the Northeast Combustion Turbines operating at or above their current performance levels. This program plans to keep the operating expenses of these plants as low as possible while ensuring starting and operating reliability by providing funding for specific efforts to allow the plants to accomplish those objectives. Work includes replacement of items identified through asset management decisions and programs necessary to maintain reliable and low operating costs of these plants. The program includes initiatives to meet FERC, NERC and EPA mandated compliance requirements.

<u>Asset Condition Generation Capital Projects</u>

Asset Monitoring System ($250,000 in 2024, $250,000 in 2025)

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.

Base Load Hydro ($682,000 in 2022, $923,000 in 2023, $675,000 in 2024, $101,000 in 2025)

The Base Load Hydro program covers the ongoing capital maintenance expenditures required to keep the Upper Spokane River Plants (Post Falls, Upper Falls, Monroe Street, and Nine Mile) operating at their current performance levels while meeting FERC and NERC mandated compliance requirements. This program focuses on ways to maintain compliance and reduce overall O&M expenses while maintaining a reasonable level of unit availability. Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. Most of these projects are short in duration, and many are completed in reaction to plant operations issues.

Cabinet Gorge HVAC Replacement ($1,753,000 in 2024)

The current ventilation system in the powerhouse at Cabinet Gorge is still the original system and equipment that was installed in 1952. The system needs to be replaced because the original ventilation system controls are no longer functional and have been removed. There is no cooling capacity with the current ventilation system and the current air handling system can only be operated manually for ventilating and exhausting powerhouse air. There is no filter system for plant make up air which results in outside smoke from wildfires and dust in the outside air from entering the plant. The current summer temperatures in the powerhouse routinely rise to 90°F and additional transformers and electrical equipment planned to be installed within the powerhouse over the next three years will significantly increase internal plant heat loading.

The new Station Service upgrade which is expected to be completed in 2023 will produce an additional heat load in the plant. This new HVAC system will provide the needed plant cooling of this new equipment and provide sufficient heating, ventilation and air conditioning in support of normal operations of the plant. Without this system replacement, plant personnel will be subjected to unacceptably high internal powerhouse temperatures and critical electrical equipment will fail due to inadequate cooling.

Cabinet Gorge Station Service ($7,647,000 in 2022, $5,140,000 in 2023)

The 1952 Cabinet Gorge Hydroelectric Development has retained most of its original equipment which is now at end of life. 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.

This capital project replaces aging equipment to ensure the continued safe operation of the plant. Failure to upgrade this equipment would pose substantial hazards to the plant's operation and to plant personnel as failed equipment can cause significant bodily injury and fire danger.

Cabinet Gorge Stop Log Replacement ($1,199,000 in 2023)

Cabinet Gorge Spillgates are original early 1950's vintage equipment at the project and are in need of replacement. Without a set of reliable stop logs we cannot accomplish the spillgate work that is expected to take place over the next several years. Stop logs are used to isolate spillway gates from the reservoir for Cabinet Gorge. Each stop log assembly comprises nine individual stop log elements or units, which when combined, allow dewatering of one spillway gate. Each stop log unit is predominantly a welded steel structure designed to fit inside stop log guides embedded inside a large concrete structure, and to minimize water seepage by means of a rubber seal that is compressed under unit self-weight and hydrostatic forces. Without these structures, we cannot efficiently and safely perform the upcoming spillgate work.

Currently, Cabinet Gorge spillgates need repair due to missing rivets, bent members, worn-out seals and heavy corrosion. The Cabinet Gorge spillgates ranked poorly when the condition assessment was performed. If repairs are not made, there is a risk of a spillgate being out of operational use or a possible gate failure, which could result in an uncontrolled release of water, which could result in issues for public and plant safety. It is critical that this project is completed prior to the completion of the planned Cabinet Gorge Spill gate upgrade which is expected to be started in 2025.

Cabinet Gorge Unit 1 Governor Upgrade ($599,000 in 2023)
Governors for Cabinet Gorge Units 2, 3 and 4 were all upgraded to an open platform Programable Logic Controller (PLC) based control system. The current governor controller on Unit 1 is a GE Mark VIe that is not an open platform control system. Open platform control systems allow for in-house modifications as opposed to bringing in the manufacturer for each settings change. This capital project will upgrade the Unit 1 governor controller to the same open platform PLC based control system to be consistent with the other three units at Cabinet Gorge as well as other units across the Spokane River. Consistency across all governor equipment platforms reduces the response time for the relay technicians, electricians, and mechanics in cases of troubleshooting and during forced outages. This also reduces response time by eliminating dependency on outside vendors, thus reducing outage duration and improving unit and overall plant reliability and availability.

Cabinet Gorge Unwatering Pumps ($319,000 in 2022, $400,000 in 2023)
This capital project replaces the unwatering pumps. The unwatering system at Cabinet Gorge consist of two unwatering sumps, each housing three pumps, one 50HP and two 200HP pumps. The 50HP (1,000 GPM) pumps are used to pump out water from normal plant leakage. The 200HP (5,000 GPM) pumps are used to drain out generating units when performing routine maintenance. The currently installed pumps, which are original to the plant, are progressively requiring increasing maintenance. This project replaces all six pumps with new pumps. The risks for not completing these upgrades include an inability to perform critical maintenance, potentially flooding the plant, and thereby jeopardizing Avista's ability to serve its customers.

Generation DC Supplied System Update ($300,000 in 2022, $421,000 in 2023, $459,000 in 2024, $180,000 in 2025)
The Generation DC Supplied System program covers all the generation and control facilities. It is the backbone for supplying power to the protective relays, breakers, controls and communication systems. With NERC requirements being followed and design enhancements being implemented, the DC system is being monitored, tested and continues to remain reliable. Experience shows that we must continually monitor, review and maintain our DC system. The equipment manufacturers provided an estimated life span for the batteries and auxiliary equipment. Some of these estimates have been wrong and some equipment has required early change out due to failing tests or other issues with the equipment. Proven manufacturers are being used to improve the reliability and lifespan of this equipment.

HMI Control Software ($2,000,000 in 2022, $7,070,000 in 2023, $1,735,000 in 2024)
This capital project includes the purchase and installation of new Human-Machine Interface (HMI) control software at 12 generating facilities to prevent limitations that will introduce

security risks. The existing HMI software runs on Windows 7 and Microsoft stopped supporting Windows 7 after 2020. Cyber security risks increase if we do not stay current with supported operating systems. Replacing unsupported HMI software allows the Company to upgrade control computers to supported operating systems such as Windows 10 which helps to control cyber security vulnerabilities and other issues associated with unsupported software.

In addition, developing new control screens on a new software platform will modernize control screens and allow operators to carry out their responsibilities more effectively. Control Screens will need to be developed for each generating facility; therefore, a planned approach allows engineers and technicians to develop screens to coordinate with control upgrades. Engineering will assist with developing a new server-based architecture and developing and commissioning HMI control screens.

Kettle Falls 4160 V Station Service Replacement ($2,135,000 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, multiple voltages designed to protect the plant's electrical system. The Kettle Falls low voltage 4160 V 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 maintains the breakers. The plant's new fuel yard equipment requires 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 capital project will replace the 4160 V station service. This replacement will correct the insurance deficiency and increase reliability to the plant critical loads.

Kettle Falls D10RDozer Certified Power Train Rebuild ($600,000 in 2025)
In 2025, the CAT D10R used in the Kettle Falls fuel yard will reach a milestone service interval requiring a CAT Certified Power Train Rebuild which includes service to the transmission, final drives, and engine. This capital project was first identified from plant maintenance staff and plant fuel equipment operators, along with the original equipment manufacturer (OEM) of the D10R. Using past maintenance logs along with a projection of status of the machine and OEM maintenance recommendations it has been determined that the listed project will be due to be completed 2025. The D10R is one of two critical assets responsible for moving nearly 500,000 green tons of waste wood around the storage area annually.

Kettle Falls Secondary Superheater Replacement ($3,500,000 in 2024)
The Kettle Falls Generating Station processes nearly 450,000 tons of waste wood annually. During the combustion process the heat generated is transferred to the boiler internal water and steam systems. Water is heated until it becomes steam, which is conditioned in the drum before entering two sections of superheater steam pendants. The first section is the primary superheater which takes high pressure saturated steam from the steam drum and converts it into dry superheated steam. The secondary superheater conditions the steam to maintain final steam conditions at 950 F at 1,550 psi to be used in the steam turbine to produce renewable

energy.

After a 1997 inspection revealed excessive corrosion caused severe tube wall thinning, both sections of the superheater were replaced in 1998. The replacement superheater tube material was upgraded from the original design with engineering studies showing potential of a 20-year life expectancy from the upgrade. Testing from Industrial Inspection and Analysis revealed the secondary superheater has undergone localized wall thinning from erosion. The analysis indicates the superheater tubes have experienced significant non-uniform scaling and tube wall loss on the exterior surfaces up to 54% of the wall thickness. This capital project will replace the secondary superheater to restore plant reliability.

Kettle Falls Fuel Yard Equipment Replacement ($28,170,000 in 2022, $1,005,000 in 2023)

The Kettle Falls Generating Station was constructed in 1983 to generate power using wood waste from area sawmills that is trucked to the plant with contracted hauling companies. Trucking companies use semi-trucks and 53-foot trailers to transport the material from sawmills to the Kettle Falls plant. Washington State increased the legal hauling capacity on the State highways allowing an increase in trailer lengths from 48 to 53 feet in 1985. This increase in allowed trailer length and haul weight created efficiencies in transportation of materials but created a deficiency in the Kettle Falls fuel handling system. The original scale was too short for a truck and 53-foot trailer to fit on, thus requiring drivers to lift the tag axle to weigh their load. The truck dumpers were also not rated to lift the larger payload and physically could not fit a truck and fully loaded 53-foot trailer. An operational work around was developed for the drivers to detach the truck from the longer trailers prior to offloading the wood waste. A contract driver died in 1983 while helping another driver during the disconnecting process and another contract driver was seriously injured while attempting to manually offload an overloaded truck prior to unloading on the truck dumpers in 2015.

After more than 35 years, much of the Kettle Falls plant equipment has reached the end of useful life. Many of the fuel yard components are failing and replacement parts are no longer available. The new fuel yard system will provide additional margin needed to assure compliance with visibility and particulate (PM) emission standards. Other equipment deficiencies including a short truck scale, steep conveyor angles resulting in equipment downtime during cold weather events, inadequate wood screening, and a failing hammer hog will be fixed.

The new fuel yard equipment includes inbound and outbound scales, two larger capacity truck dumpers, conveyance, disc screen and hammer hog, and an operating building. The new system will be greenfield construction allowing the plant to continue accepting material while construction and commissioning of the new equipment occurs. The new system will eliminate deficiencies with the scaling process, create safer dumping of the trucks with larger capacity dumpers, control fugitive emissions with covered equipment, increase truck turn time, and lower fuel transportation cost.

As noted by Ms. Schultz, the Company has included O&M offsets related to capital additions where available, resulting in O&M expense reductions for this Business Case in Rate Year 1 of $30,000 system ($10,341 ID share) within PF Adjustment 3.12.

Kettle Falls ID Fan & Motor Replacement ($1,650,000 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. Fly ash is abrasive on the internal components of the boiler. The fan shroud, case, cage, and dampers require significant annual maintenance 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 capital project will replace the ID fan and motor to appropriately accommodate the needs of the plant. This solution includes implementing a variable frequency drive (VFD) which addresses fluctuations in loads expected from fuel moisture and the ability to operate in a flexible EIM market. A VFD also improves fan and motor efficiency during operations minimizing the wear that has become an annual maintenance concern. The change in equipment requires ducting changes and potential foundation modifications.

Little Falls Crane Pad & Barge Landing ($2,997,000 in 2023)
The existing crane pad/trash boom anchor at Little Falls are at their end of useful life. 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 Road.

This project includes the design and construction of a new crane pad/barge landing/trash boom anchor system. This is a critical path project to prepare for future 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. This project also includes demolition and removal of the existing crane pad and trash boom as well as environmental protection and mitigation.

Little Falls Plant Upgrade ($355,000 in 2022)
The Little Falls Plant Upgrade Program began in 2012 and is in the final phases of implementation. Driven initially by the age of the infrastructure at the plant, Alternative 3, a full replacement of all four generating units and all obsolete supporting equipment, was selected, implemented, and put into service. With three project components left (Plant Sump, Drain Field, and Panel Room Roof/Enclosure for the new controls equipment) most of the project scope has been completed and risks mitigated. The remaining work has very little risk exposure and minimal impact on the plant's current operations.

Long Lake Plant Upgrade ($38,000,000 in 2025)

The Long Lake equipment ranged from 20 to more than 100 years old when this project began. We had experienced an increase in forced outages at Long Lake from almost zero occurrences in 2011 and increasing in number every year since then. The increasing number of outages was caused by equipment failures on different pieces of equipment. The primary drivers for the Long Lake Plant Upgrade included Performance & Capacity, Asset Condition, and Failed Plant & Operations. The planned course of action was to replace the existing units in kind. The Plant Upgrade began in 2017 and will continue until estimated completion in December 2029.

Currently, the turbines are thrusting too much (a sign of significant wear), including a failure in 2015. The 1990 vintage control system is failing, and only secondary markets can support this equipment. Inspections of other components of the generator show the stator core is "wavy" where the core lamination steel should be straight. The "wave" pattern is a strong indication of higher-than-expected losses occurring in the generator.

With the increase in generator output, the output of the generator step up transformer (GSU) has also increased to its rating. The existing GSU's are over 30 years old and operating at the high end of their design temperature, these are now approaching their end of useful life and need to be replaced proactively rather than waiting for a failure to occur. The other major driver for the program is Station Service disconnect switching safety.

As noted by Ms. Schultz, the Company has included O&M offsets related to capital additions where available, resulting in O&M expense reductions for this Business Case in Rate Year 2 of $270,000 system ($93,069 ID share) within PF Adjustment 24.06.

Monroe Street Abandoned Penstock Stabilization ($897,000 in 2023)

The 1890 Monroe Street Powerhouse has undergone several modernizations. 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 approximately 250 feet 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 facility. 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 implementation of a plan to mitigate those risks. The scope of work includes an initial engineering evaluation, including investigatory drilling, with stabilization efforts likely to include grouting of the intake and penstock.

Nine Mile HED Battery Building ($800,000 in 2022)

This project is to build a battery storage building for the batteries supplying the Nine Mile Falls HED's critical power system to improve reliability and safety. The battery room will be located near the switchyard and underground conduit will be installed to the powerhouse containing power and control cables. During emergency situations, the critical power system is required to continually monitor and control the turbine generators and spillway for safe operations of the river and its flow. The 125 VDC battery banks are the most essential component of the critical power system, and the health of the batteries needs to be closely monitored. The existing location of batteries on the switchgear floor is susceptible to extreme temperatures that greatly reduce reliability and performance. The location of the batteries is also a safety issue, because they contain hazardous material and expel potentially explosive hydrogen gases during discharge. In addition, the structural integrity of the existing floor needs to be reinforced as equipment is added or replaced. A new building with climate control and hydrogen monitoring dedicated to battery storage will enhance the critical power system reliability and eliminate safety hazards.

Nine Mile Powerhouse Crane Rehab ($850,000 in 2022)

The Nine Mile Falls Generator Bay and Access Bay bridge cranes were replaced in 1993. Both cranes are Kone brand 35-ton cranes with service class for both cranes being H1 – light duty. The Nine Mile powerhouse cranes are now beyond their useful life. Their H1 duty cycle is too low to support continuous work during future unit overhauls with both replacement controls and mechanical parts no longer supported by the manufacturer and must be custom fabricated. The Generator floor crane trolley is now out of service, limiting Avista's capability to respond to a turbine generator failure. During the 2018 Maintenance Assessment, the cranes were identified as high risk due to their current condition. This capital project includes replacement of each crane's hoist and trolley system and installing a modern hoist and trolley. This modern in-kind replacement of the current powerhouse cranes will provide a lasting solution to meet current and future crane demands.

Nine Mile Powerhouse Roof Replacement ($997,000 in 2023)

The Nine Mile Falls generation plant is over 100 years old. The roof trusses and concrete slab is original construction, and the roofing membrane was possibly updated in 1984 with temporary patches and repairs since. Many inspections conducted over the years have determined that the roof is leaking and deteriorating, and the June 2021 inspection by Garland Roofing stated that "overall the roof system has come to the end of its serviceable life" and is badly in need of complete replacement. As the engineering team has investigated the roof's condition, more information has come to light revealing that the roof's steel truss members in their current state are overstressed supporting the roof system weight (concrete roof slab and roofing membrane material) alone with no extra capacity for live loads, such as snow. Additional concerns include the condition of the 100-year-old steel trusses, which have experienced some damage and corrosion over the years and still have the same 100-year-old coating system. This capital project addresses the overstressed condition of the steel trusses and replaces the failed roof membrane system. The supporting steel truss members will either be upgraded to increase their structural capacity or the concrete roof slab panels be replaced with lighter weight roofing material to reduce load on the steel trusses.

Nine Mile Unit 3 Mechanical Overhaul ($4,600,000 in 2025)

The original Nine Mile 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 caused by 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 the 2018 Maintenance Assessment, this bearing was identified as high risk due to its current condition. If left unaddressed, Unit 3 is likely to experience bucket or bearing failure resulting in extended down time and lost generation. This capital project consists of a mechanical overhaul of Unit 3 including installing new Francis Runners, downstream water lubricated bearing and pedestal, combination thrust/guide bearing with thrust shaft, and refurbishment of the wicket gate stems and all operating components.

Nine Mile Units 3 & 4 Control Upgrade ($4,700,000 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 and there is an increased likelihood of forced outages. A controls upgrade including speed controllers (governors), voltage controls (automatic voltage regulator or AVR), primary unit control system (i.e., Unit PLC), and the upgraded protective relay system is needed on Units 3 and 4. During the 2018 Maintenance Assessment, the Unit controls were rated in poor condition and high in risk due to their age and current condition. This project also includes replacement of the switchgear floor inside the Nine Mile powerhouse that will be utilized for relocation of the unit controls and voltage regulation equipment. In 2010, this floor was found to be inadequate for any loading above and beyond what it is currently supported and was partially replaced during the Unit 1 and 2 Replacement Project. The reminder of the floor needs to be replaced to ensure adequate floor loading can be achieved.

Noxon Rapids Generator Step-Up Bank C Replacement ($1,507,000 in 2025)

Unit 5 at Noxon Rapids HED has its own generator step-up transformers referred to as Bank C. This is original equipment and has been well maintained. Periodic oil samples of each transformer are taken, and test results are compared to IEEE standards to help determine the health of the asset. As these numbers change, it helps explain what is going on inside the transformer and how things are wearing out. There are no spares for these transformers so if anyone of them fail then the generating unit they serve will be out of service. This project will the Bank C generator step-up transformer.

As noted by Ms. Schultz, the Company has included O&M offsets related to capital additions where available, resulting in O&M expense reductions for this Business Case in Rate Year 2 of $4,725 system ($1,629 ID share) within PF Adjustment 24.06.

Noxon Rapids Spillgate Refurbishment ($750,000 in 2022, $3,300,000 in 2023, $1,532,000 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. They also protect the dam during high flow periods, or if the plant or units, trip to prevent overtopping or flooding of the dam. The gates require repair or replacement due to age, future EIM 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. Fully functioning spillgates is a FERC requirement and part of the Dam Safety program.

This capital project refurbishes and strengthens specific identified weaker members of the gate to meet necessary FERC and design standards to meet all operating conditions. As the FERC continues to review the seismic hazard assessment at Noxon Rapids, it may require more significant enhancements across the entirety of the plant. The strengthening project at this time was prudent to ensure that the spillgates meet all normal operating requirements.

Post Street Substation Crane Rehab ($500,000 in 2023)

The 35 Ton Niles Bridge Crane at the Post Street Substation is original to 1907 and services the interior of the building. This crane services the Upper Falls and Monroe Street GSUs, substation 115kv transformers, switchgear, and miscellaneous other substation equipment. It is a low frequency of use, high consequence if unavailable when needed, piece of equipment. The crane's controls and electrical are mostly original and have degraded in capability over time resulting in 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 impacts the ability to respond to a failure in a critical downtown substation and increases risk. A standard mobile crane is too large for the building. This capital project includes 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.

Regulating Hydro ($2,512,000 in 2022, $1,883,000 in 2023, $1,800,000 in 2024, $1,270,000 in 2025)

Avista's regulating hydro plants have reservoir storage. This storage provides these plants with operational flexibility to support energy supply, provide peaking power, provide continuous and automatic adjustment of output to match the changing system loads, and to supply other types of services necessary for grid stability and to maximize value to Avista and its customers. The regulating plants include the four largest hydro plants on Avista's system representing more than 950 MW of capacity. These plants 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.

This program funds smaller capital expenditures and upgrades required to maintain safe and reliable plant operation to provide customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System. 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 address plant operational support issues. Without this funding source, it would be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This could jeopardize plant availability and impact the plant's value to customers and the stability of the grid.

Upper Falls Trash Rake Replacement ($1,501,000 in 2023)
The existing trash rake at Upper Falls is an articulating arm Atlas Polar device. The trash rake presents an environmental risk since its installation due to the hydraulic system that it utilizes to function. When in use, the hydraulic system is suspended over the Upper Fall unit intake and the Spokane River. If a hydraulic line failed during raking operation, some amount of hydraulic fluid would end up in the river, leading to an environmental cleanup exercise. While the rake is in its parked position, the hydraulic system is in very close proximity to the river and poses a threat to leaking. The current trash rake is undersized, leading to issues during raking operations. Often, the rake stalls out mid-operation due to the weight of the accumulated debris it is recovering. The rake also has limited ability to lift logs and trees 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 or even leaning out over the handrail to address the problem. This capital project will replace the trash rake with an appropriately sized system that will allow full reach of the intake racks and accommodate the removal of large sized trees and logs from the river. While still utilizing hydraulics to function, a robust containment system and modern control system can detect and shut off the system if a leak is identified, often resulting in a very small amount of leakage reaching the water's surface.

<u>Performance and Capacity Generation Capital Projects</u>

Energy Imbalance Market ($140,000 in 2022)
Avista signed an Implementation Agreement on April 25, 2019, with the California Independent System Operator (CAISO) to join the Western Energy Imbalance Market (EIM) by April 2022. The Western EIM is a real-time, intra-hour energy market operated by CAISO that facilitates regional resource dispatch on a five-minute basis to dispatch the lowest cost resources across the entire market footprint, while balancing in-hour load and resource obligations. This market allows participants to lower energy costs by either dispatching less expensive resources to meet load obligations, or by increasing revenue through the bidding of excess energy into the market. By the time Avista joined, over 80% of the Western Interconnection load was transacting in the EIM. The liquidity of the hourly bi-lateral market Avista has traditionally transacted in will be significantly impacted because market rules require EIM participants to determine their resource schedules well in advance of the upcoming hour. As such, non-EIM participants have fewer counterparties to transact with close to the operating hour. In addition, as renewable portfolios are increasingly mandated, Avista needs the market to ease the financial pressure of integrating renewable resources, while maintaining reliability.

In July 2020, in partnership with CAISO and the Bonneville Power Administration (BPA), Avista changed their entry date to March 2022, to align with BPA and Tacoma Power. This decision was made to coordinate the testing phases and go-live operations amongst northwest entities for a smoother market entry transition. Avista needed to implement a variety of EIM software solutions, perform metering upgrades at most of its generation and substation interconnection sites, and install generation control systems.

The Program implementation effort began in 2019 and continued through March 2022, with warranty and closing activities through summer 2022. The CAISO allows Entities to join the market annually in April, with a fixed CAISO-set schedule for testing phases and market go-live. If Avista had not met the planned go-live date, it would have needed to wait until April 2023 to join the market. Missing the go-live date would have put Avista at risk for maintaining reliable service to our customers, providing energy services at the lowest costs, integrating renewable energy at the lowest costs and hindering de-carbonization efforts.

Energy Market Modernization & Operational Efficiency ($592,000 in 2022, $498,000 in 2023, $500,000 in 2024, $249,000 in 2025)

Avista participates in two energy markets operated by the California Independent System Operator (CAISO) – the Market Redesign Technology Upgrade (MRTU) and the Western Energy Imbalance Market (WEIM). Avista began transacting with the CAISO in June 2017 through participation in MRTU, which allows entities outside the CAISO balancing authority area to submit hourly energy bids at specific transmission intertie locations. This day-ahead market gave Avista access to economically priced solar energy, provided an opportunity to optimize internal resource flexibility by importing generation into CAISO, and provided access to additional generation during resource reliability scarcity events. As of the third quarter of 2022, total net benefit generated from MRTU is approximately $17.1 million, with yearly benefits averaging approximately $2.9 million.

Avista joined the WEIM on March 2, 2022. The WEIM is a real-time, intra-hour energy market that facilitates regional resource dispatch on a five-minute basis to dispatch the lowest cost resources across the entire market footprint, while balancing in-hour load and resource obligations. This market allows participants to lower energy costs by either dispatching less expensive resources to meet load obligations, or by increasing revenue through the bidding of excess energy into the market. With more than 80% of the Western Interconnection load transacting in the WEIM, the liquidity of the hourly bi-lateral market has been significantly impacted, as market rules require participants to determine resource schedules well in advance of the operating hour. As renewable generation portfolios are increasingly mandated, market participation can ease the financial pressure of integrating renewable resources, while maintaining reliability. According to Avista's internal benefit calculation, the total net benefit generated from the WEIM is approximately $6 million as of the second quarter of 2022.

Based on operational improvements and market design changes, the CAISO releases annual market technology updates in partnership with software vendors. Avista's participation is dependent on ensuring the market software suite and associated integrations, are compliant. These upgrades and enhancements must typically be applied simultaneously across multiple systems, with primary impacts to and approvals from Energy Resources, System Operations, Generation Production & Substation Support (GPSS) and the WEIM Settlements team.

Market compliance obligations and business approvals determine when an upgrade is applied. Failure to comply with the upgrades in the given timeframe will disrupt Avista's ability to gain access to cost-efficient power in the market, lead to missed benefit opportunities, and may impact Avista's ability to reliably operate the electric grid.

Generation Plant Annunciation Systems ($150,000 in 2023, $147,000 in 2024)

This capital project will implement a standard annunciation system at all generation facilities. Avista's generation facilities do not currently have a standard plant evacuation and warning system. Each facility has different combinations of audible and visual alerts to inform plant personnel of actions to be taken during emergency situations such as evacuation. Operators, construction and maintenance crews, engineers, and others regularly work at multiple generation facilities and must be familiar with each plant's system. Although customized training has been developed for each facility, the differences across the fleet could result in confusion during an emergency and jeopardize the safety of personnel.

Standardization of annunciation was identified as a necessary safety improvement by the Safety Action Board. As a result of the requested action, Generation Controls Engineer worked closely with plant operations and maintenance/construction crews to develop a standard solution to implement at Avista's generation facilities. The system will provide standard audible alerts to all on-site personnel for multiple condition including plant evacuation, generator start warning, alarm condition with prioritization, and other customizable alerts as required. The implementation of the standard annunciation system will significantly improve overall safety at the plant level by familiarizing personnel with common audible alerts and improve everyone's response to a potentially hazardous situation.

<u>Customer Service Quality and Reliability Generation Capital Projects</u>

Automation Replacement ($795,000 in 2023, $465,000 in 2024, $200,000 in 2025)

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. The computer drivers that are needed to communicate to the DCSs are not compatible with the new computers using Windows 10 operating systems. This creates a cyber-security issue. The software needed to view and modify the logic programs only runs on Windows 95 and Avista has a very limited supply of Windows 95 laptops that are also failing as they age. Replacing the aging DCSs and PLCs before they fail will reduce unexpected plant outages that require emergency repair with like equipment. A planned replacement approach allows engineers and technicians to update logic programs more effectively and replace hardware with equipment that meets current standards.

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.

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

Q. Before discussing the operation of and capital additions for Colstrip Units 3 and 4, would you provide some background about how Avista makes and manages Colstrip capital decisions.

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 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 expected to continue to serve Idaho customers beyond 2025 as determined in the 2021 IRP?

A. Continued capital projects at Colstrip are necessary to maintain present operational plant output expectations required by the plant 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 Idaho and Washington customers. An actual retirement date for Units 3 and 4 has 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 and 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, Montana Department of Environmental Quality (MDEQ) (July 2012), Settlement agreement entered (2016).

Q. Please continue with a description of the Colstrip project impacting the Two-Year Rate Plan in this case.

A. The Company has included one Colstrip pro forma capital project in this Two-Year Rate Plan for inclusion in customer rates. That project was related to the Dry Waste Disposal System project described below.

Table No. 6: 2022 Colstrip Capital Projects

Colstrip Capital Projects (System) In $(000's)								
Investment Driver								
Business Case Name		**2022[1]**		**2023**		**2024**		**2025**
Asset Condition								
Colstrip 3&4 Capital Projects	$	2,450	$	-	$	-	$	-
Total Planned Colstrip Capital Projects	**$**	**2,450**	**$**	**-**	**$**	**-**	**$**	**-**

(1) Includes system pro forma capital additions for the period of July 01, 2022 though December 31, 2022.

Q. Please describe the <u>Design/Build Dry Waste Disposal System</u> project in 2022.

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 related litigation settlement.[2] 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 AOC, developed by the Montana Department of Environmental Quality (MDEQ), sets out an evaluation process that includes site characterization, clean-up criteria, and risk assessment related to groundwater mitigation. The draft and finalized documents can be found on the MDEQ website specific to the Plant

[2] The AOC defines the legally required and agreed upon steps to address groundwater contamination at Colstrip from leaking ash ponds.

groundwater clean-up.[3]

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

A. The Dry Waste Disposal system is legally required as a result of the AOC litigation settlement. The technology itself was chosen after completion of a successful pilot test. 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.

VII. CHELAN PUD HYDRO POWER PURCHASE AGREEMENT

Q. Would you please explain the Chelan PUD Hydro Slice Power Purchase Agreement?

A. Avista's 2020 Integrated Resource Plan (IRP) identified the need for additional renewable resources in support of progress towards meeting clean energy goals of carbon neutrality by 2027 and 100 percent clean electricity by 2045. In order to fulfill these needs, on June 26, 2020, Avista issued a "Request for Proposals" (RFP) soliciting bids for renewable energy, capacity, and associated environmental attributes. The goal of the RFP process was to acquire resources that met Avista's renewable energy goals, and which were less than Avista's avoided costs including a clean energy component. Any long-term resource acquisition below these costs would deliver net-value to customers in Idaho and Washington. Bids received on July 22, 2020, included over 40 wind, solar, hydro and biomass offers, many with storage options, for a total of over 3,000 MW.

[3] https://deq.mt.gov/cleanupandrec/Programs/colstrip.

Avista evaluated these bids, as discussed below, and began contract negotiations with two parties: Chelan County Public Utility District ("Chelan") and a biomass facility. The biomass facility pulled their bid from consideration in early 2021, and Chelan was awarded a contract with an execution date of March 25, 2021. A full timeline of events for the 2020 RFP is included in the 2020 Renewable RFP Summary Report, provided in Confidential Exhibit No. 6, Schedule 5C, contains the 2020 Renewable RFP Report and Documentation. The contract with Chelan is provided as Confidential Exhibit No. 6, Schedule 6C.

Q. What are the terms of the contracts with Chelan?

A. The terms of these contracts resulted in the acquisition of a 5% Fixed Cost Slice (88 MW / 51 aMW) of Chelan's "Chelan Power System" (CPS) consisting of Rocky Reach and Rock Island hydro projects located on the Columbia River plus a second contract for an additional 5% Fixed Cost Slide (88 MW / 51 aMW) of CPS from 2026 through the end of 2045. This contract increases to 10% on January 1, 2031, when an existing Chelan PUD contract expires on December 31, 2030, and continues at a 10% slice until 2045. The first contract will supply Avista with output from the combined operation of Chelan's Rocky Reach and Rock Island hydro-electric projects with planned delivery of renewable energy and capacity to Avista for 10 years, beginning on January 1, 2024, and continuing through December 31, 2033. The second contract will supply Avista with output from the combined operation of Chelan's Rocky Reach and Rock Island hydro-electric projects with planned delivery of renewable energy and capacity to Avista for 20 years, beginning on January 1, 2026, and continuing through December 31, 2045.

A full summary of the RFP process and justifications for signing the Chelan PPA is provided as Confidential Exhibit No. 6, Schedule 5C. Confidential Exhibit No. 6, Schedule

5C which contains supplemental documentation in addition to the main summary report:

- Exhibit A – Evaluation Methodology
- Exhibit B – Avista 2020 Renewables RFP Instructions and Preliminary Proposal Information
- Exhibit C – Avista 2020 Renewable RFP Document
- Exhibit D.1 – Evaluation Matrix 9/8/20
- Exhibit D.2 – Financial Analysis 9/14/20
- Exhibit E.1 – Short List Bid Scoring Summary 9/4/20
- Exhibit E.2 – Financial Analysis 9/30/20
- Exhibit F – Commission Staffs Update 9/22/20
- Exhibit G.1 – Evaluation Matrix Short List Bids 10/14/20
- Exhibit G.2 – Financial Analysis Summary 10/14/20
- Exhibit H – Management Approvals
- Exhibit I – Updated Presentation 3/12/21

Q. Would you provide additional background concerning the timing of the RFP?

A. Yes. Based on needs identified in the 2020 IRP and considering industry indicators, Avista determined the opportune time to solicit bids for new renewable resources through the RFP was in the Summer 2020. These indicators included the continued sunsetting at the time of the Production Tax Credit (PTC), pricing and developer activity, competition for preferred projects and locations, technology advancements and competition for least cost resources. The 2020 Renewable RFP resulted in competitively priced proposals that delivered the renewable benefit; additionally some proposals provided significant flexible and dispatchable energy benefits from existing projects with known performance.

Q. At the time of the 2020 Renewables RFP, please explain how the Company determined that a new resource was necessary.

A. As previously described, the need for additional renewable energy resources was identified in the 2020 IRP. The goal was to acquire resources that met Avista's renewable energy goals and were less than avoided costs including a clean energy component. As such, taking into consideration industry indicators and project lead times, Avista determined it was the opportune time to solicit pricing for new renewable resources through an RFP in the Summer of 2020. The Company's Board of Directors was apprised of the 2020 Renewables RFP and the evaluation process that was used to compare project bids from which the Chelan PPAs were selected.

Q. How did Avista evaluate and consider alternatives to the Chelan PUD Hydro PPA?

A. The RFP was open to parties who owned, proposed to develop, or held rights to new renewable resource generating facilities. The 2020 RFP utilized similar methodologies as the 2018 RFP. Avista had engaged a third-party consultant for the 2018 RFP to gain an outside perspective as it related to the RFP. For the 2020 RFP, Avista utilized similar methodologies proven out in the 2018 RFP. Finally, Avista did not accept proposals for renewable energy certificates only.

As specified in the RFP, Avista sought proposals from eligible renewable resources. The proposals were required to outline the acquisition of approximately 120 MW (alternating current, or AC) with a minimum net annual output of 5 MW AC that satisfied the requirements of the RFP. Bidders could submit more than one proposal or proposals with multiple developments, and projects could be new or existing eligible resources, including wind, solar, geothermal, biomass, hydroelectric or other eligible renewable resources. Avista also considered proposals that included storage. Avista's objective was to secure eligible renewable resource(s) under terms and conditions that were economical and favorable to

Avista's customers. Bidders assumed the risks related to federal tax incentives.

The Company produced an evaluation criteria and methodology for scoring bids in consultation with Black & Veatch, a third-party independent evaluator, for the 2018 RFP. The 2020 RFP used a similar methodology. The methodology provided in Exhibit A of Confidential Exhibit No. 6, Schedule 5C was shared and discussed with the Staffs of both the Idaho and Washington Commissions.

The general qualifications for each proposal were evaluated and weighted on six characteristics listed in Table No. 7. The weightings for each characteristic were determined based on their importance in helping the Company meet its resource development goals stated in the 2020 IRP. Within each characteristic, points could be <u>subtracted or added</u> to the initial 100 points based on responses to the RFP and Avista's interpretation of the submitted data. Avista reserved the right to modify the scoring criteria in consultation with Commission Staff of Idaho and Washington if proposals were received that contained circumstances not considered in the original methodology.

<u>Table No. 7: 2020 Renewables RFP Evaluation Criteria and Weightings</u>

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

Avista utilized a two-step bid process. The first step included evaluating and ranking projects based on preliminary information by allowing developers to submit a condensed initial bid utilizing the template shown in Exhibit B of Confidential Exhibit No. 6, Schedule 5C. The evaluation and ranking of the preliminary information focused on conformance of each bidder's submittal with the requirements of the RFP and the proposed net price, among other factors. The initial evaluation and ranking, performed in a fair and consistent manner, produced a short list of bids. Once the short list was compiled, short-listed bidders submitted detailed proposals in accordance with Exhibit C of Confidential Exhibit No. 6, Schedule 5C. Each short-listed bidder's detailed proposal was evaluated against the other short-listed bidders' detailed proposals.

The two-step approach was well-received with 25 developers submitting 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 Commission Staff of Idaho and Washington. Seven projects were selected for a short list and were asked to provide detailed responses to the proposal. The first screening began after preliminary information was received on July 22, 2020. This screen focused on removing from further consideration those 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 project 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) and a few projects were from existing generation resources. The complete evaluation matrix is found in Exhibit D.1 and the financial analysis is provided in Exhibit D.2 of Confidential Exhibit No. 6, Schedule 5C.

There was a clear break in the rankings after the top seven proposals. Out of the top eight ranked projects, three were wind projects, two were hydro and one each of solar and biomass. One was removed from further consideration as it only bid a 5-year term and did not meet the minimum PPA term requirements of the RFP. To help differentiate between the short-listed bids from round 1 to round 2, between August 21, 2020, through September 9, 2020, seven short-listed bidders were asked to provide detailed proposals. The short-listed bidders were further evaluated using the detailed information and additional due diligence was performed on each offering. The evaluation matrix for the detailed proposals is included in Exhibit E.1 and the financial analysis is included in Exhibit E.2 of Confidential Exhibit No. 6, Schedule 5C. A presentation of the RFP process and short-listed bidders was made to the Idaho Commission Staff on September 24, 2020, and is available in Exhibit F of Confidential Exhibit No. 6, Schedule 5C.

Avista allowed shortlisted bidders to refresh their prices in early September 2020, 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. The complete evaluation matrix of the seven short-listed projects is provided in Exhibit G.1 and the financial analysis including re-pricing is provided in Exhibit G.2 of Confidential Exhibit No. 6, Schedule 5C. Based on the financial and full evaluation matrix analysis Chelan PUD's 5% fixed cost hydro slice and a biomass project were selected for further negotiations (Chelan initially bid their 5% and 10% proposals as separate, either/or proposals). The biomass project pulled their bid from further consideration in early January 2021.

Q. Were any adjustments made to the final bidders after the withdrawal of the biomass project proposal in the 2020 RFP?

A. Yes. After the biomass project pulling their bid from consideration, the Company reengaged Chelan on their <u>second bid</u> which also ranked in the top three of the evaluation matrix. The Company closed out its 2020 RFP with a second contract with Chelan for an additional 5% (88 MW/51 aMW) with delivery starting on January 1, 2026. This contract increases to 10% on January 1, 2031, when an existing Chelan PUD contract expires on December 31, 2030, and continues until 2045.

Q. Is the 20-year Chelan deal (the second contract) that begins in 2026 included as part of this general rate case?

A. No, it is not. With a beginning date of January 1, 2026, this contract is outside of the test period (twelve-months-ending 06.30.2022) and outside the scope of the Two-Year Rate Plan ending August 31, 2025. This contract will be evaluated for prudence in the Company's next general rate case, or in the 2026 Annual PCA filing. We have included brief testimony on this matter as the contract is directly tied to the same RFP that led to the first Chelan contract, and therefore providing that update in this testimony completes the discussion of the work and contracts related to that RFP.

Q. How was transmission considered in this decision?

A. The cost of transmission was considered for all the bidders. No new transmission facilities needed to be developed for the 2024 or 2026 Chelan PPAs.

Q. What documentation for the analysis and decision-making process has the Company provided regarding the decision to enter into the Chelan contract?

A. Confidential Exhibit No. 6, Schedule 5C includes the complete documentation concerning the RFP solicitation, and evaluation process that resulted in the selection and signing of the Chelan PUD Hydro Power Purchase Agreement. My testimony and exhibits provide the documentation necessary to demonstrate the long-term economic benefit to customers for the Chelan contract and provides specific supporting details regarding the

Company's analysis and decision. The executed PPA will help meet the Company's own clean energy goals as well as incorporate an existing reliable hydro resource that provides capacity and flexible ramping capability for the benefit of Avista's customers. The Chelan contract also fits within the analysis performed under the Company's IRP. The Company has provided and explained all of the analytical work that was completed related to this acquisition through a competitive RFP, as well as participation by both the Idaho and Washington Commission Staffs in the entire RPF process.

VIII. WESTERN REGIONAL ADEQUACY PROGRAM (WRAP) UPDATE

Q. What led to the development of the WRAP?

A. The western interconnected regional power system is currently undergoing a resource transition. The recent and impending retirement of thermal generators within the West and the replacement of these resources with increasing variable energy resources (VERs), has led to concerns about whether the region will continue to have an adequate supply of electricity during critical peak load hours. In the past several years, resource adequacy studies have identified an immediate challenge to the regional electricity system's ability to provide reliable electric service during high demand conditions.

These developments threaten to upset the balance of loads and resources within the region and, if not properly addressed, will increase the risk of supply disruptions during winter and summer peak conditions. This situation will increase reliability and financial risk for utilities and their customers and hinder the ability of the system to meet state environmental goals and legal requirements.

Q. Please discuss the proposed schedule for WRAP implementation.

A. Beginning in early 2019, the Western Power Pool (WPP) led a coordinated review among its member utilities to explore the nature of the potential resource adequacy risks and investigate mechanisms to assure a high likelihood of adequate supply to meet customer demand under a wide array of scenarios. The investigation included evaluating a Forward Showing planning mechanism and an Operational Program to help utilities that are experiencing extreme events meet customer demand through a regional resource adequacy (RA) Program. This work was led through a Steering Committee made up of subject matter experts from each participating utility and oversight from an Executive Committee. The Steering Committee also contracted with the Southwest Power Pool (SPP) to help develop the final program design requirements, since SPP operates a similar RA Program in its footprint. The design development occurred over two stages from October 2019 through August 2021. The Steering Committee agreed to a final detailed design that was approved by the Executive Committee in August 2021. Participants were asked to commit to a non-binding trial (Phase 3A) of the Forward Showing component of the WRAP by the end of September 2021. Phase 3A includes operating under the WRAP rules for both a winter and summer critical season with no penalties applied for not meeting program compliance. At the end of 2022, participants will be asked to commit to the full WRAP including binding compliance with both the Forward Showing and Operational Program requirements. The final binding program is proposed to start in the summer of 2025 pending FERC approval of the tariff filed by the WPP in August of 2022. Delaying the start of the full binding program for a few years will allow program participants to get experience operating in the program and give time to make any modifications or enhancements based on operating experience.

Q. Please describe how the WRAP works.

A. Regional RA Programs have been developed across North America to ensure reliability by providing a regional framework that enables participants to leverage load and resource diversity benefits by meeting their collective customer demand jointly rather than individually. It also establishes a robust, standardized, and transparent view of regional loads and resources. The WRAP was designed based on principles from other regional RA Programs that were modified to meet the planning and operational requirements of western utilities. As designed, the WRAP includes two components: a Forward Showing planning requirement, and an Operational Program to provide access to regional diversity in the operating timeframe. Exhibit No. 6, Schedule 7 is the Western Resource Adequacy Program detailed design document.

The Forward Showing Program includes a requirement for each participant to show in advance of a critical season that it has enough capacity either owned or under contract to meet its individual program obligations. The Program includes two critical seasons: winter and summer. The winter season is defined from November 1 through March 15 and the summer season is defined from June 1 through September 15. Approximately seven months prior to the beginning of the next critical season, each participant will submit data to SPP, who has been selected as the WRAP Program Operator, including its load forecast and resources planned to be used to show compliance under the program. SPP will review the data submitted by each participant and determine whether they comply with the program. Participants that don't meet the minimum compliance requirement will be given two months to cure the deficiency through either purchasing or contracting for additional capacity. If a participant is not able to meet its obligation three months prior to the start of the critical season, then it will be considered out of compliance and have to pay a penalty under the full program but not during the Phase 3A trial period.

Table No. 8 provides a summary of the program's critical seasons. SPP will also conduct resource adequacy assessments for the spring and fall months to see if the critical seasons need to be redefined in the future and will also conduct a 2-3 year assessment to give participants an indication of where they are trending to help them make longer term resource decisions.

Table No. 8 – WRAP Critical Binding Seasons

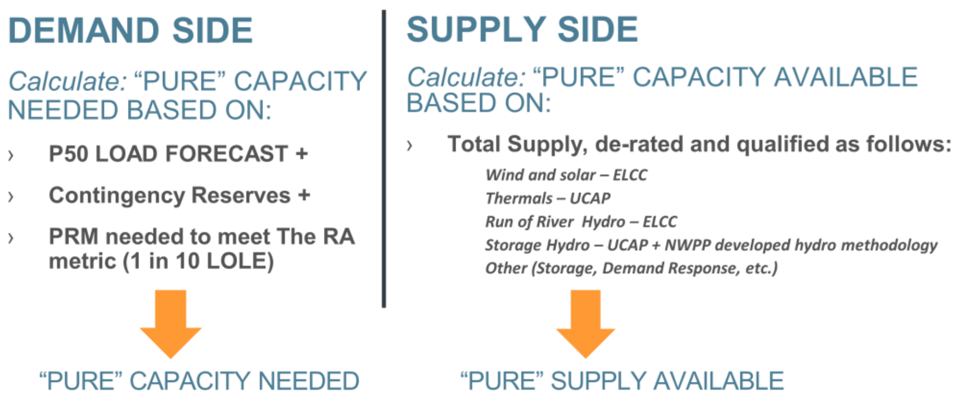
Season	Binding/ Advisory	Duration	Compliance Showing Date	Cure Period
Winter	Binding	Nov-March 15	March 31	June 1 – July 31
Summer	Binding	June-Sept 15	October 31 (of prior year)	Jan 1 – Feb 28
Spring	Advisory	April-May	N/A	N/A
Fall	Advisory	October	N/A	N/A

Q. Why was the WRAP Forward Showing component developed?

A. The WRAP Forward Showing component was developed to leverage regional load and generation diversity and utilize common resource planning methodologies and reliability metrics. SPP, acting as the Program Operator, will determine the capacity credit for different resource technology utilizing agreed-to industry methodologies based on historical data provided by program participants. SPP will also determine the WRAP footprint planning reserve margin (PRM) based on a loss of load equivalent (LOLE) metric equal to 0.1. This LOLE equates to allowing for one loss of load event day every ten years and is used as the reliability metric in several other North American RA programs. The WRAP PRM will be added to each participant's load forecast developed with common assumptions plus each participants NERC contingency reserve requirement to calculate the total demand for each utility.

The total demand and the resources selected to meet the demand will be submitted by each participant to SPP by the deadline required ahead of each critical season. SPP will review the capacity credit for each resource and check to make sure that a participant has submitted enough resources to meet its total program demand for the upcoming critical season. Illustration No. 4 provides an illustrative summary of how the WRAP Forward Showing component works.

<u>Illustration No. 4– Forward Showing Compliance</u>



Q. Lastly, will the WRAP also include an Operational Program?

A. Yes. The WRAP will also include an Operational Program to provide participants an opportunity to access regional resource diversity in the operating time period if conditions are significantly different than what was planned in the Forward Showing assumptions. The specific design of the Operational Program still needs to be developed but a framework has been created. Entities that meet a certain day ahead capacity shortfall criteria would be eligible for assistance from other participants that have excess planned capacity, which they would hold back in case the short participant actually needs energy assistance during the next operating day. SPP as the Program Operator would perform the monitoring and calculation of each participants day ahead position and then allocate hold back requirements to those entities that have extra capacity. During the actual operating day, SPP will conduct hour ahead analysis to determine if participants are still in need of energy assistance. If participants meet the hour ahead request criteria then participants that still have extra capacity will schedule the energy to a specified trading hub, like the Mid-C, and the participant that is in need of assistance will then schedule the energy from the hub to their system. There will be a compensation mechanism for capacity that is held back on a day ahead basis and for any energy that is actually delivered in the operating day. The Operational Program detailed design will be finalized during the Phase 3A non-binding trial.

Q. Does Avista plan to participate in the WRAP and what is the approximate cost to customers associated with Avista's participation?

A. Avista has agreed to participate in the non-binding Forward Showing trial phase of the WRAP. Avista has funded approximately $110,000 for Phase 1 and 2 WRAP development. Avista's estimated allocated share to fund Phase 3A implementation and the associated non-binding trial period is $225,000 and Avista's estimated share to support Phase 3B development including FERC filing, NWPP independent Board selection and transition, and Operational Program development is $125,000. Approximately $45,000 of the Phase 3A costs were paid for in 2021 and the remaining costs up to $180,000 will be funded in 2022. The costs to fund preliminary Phase 3B development up to $125,000 will be paid for during 2022 as needed. The estimated cost for Avista to continue to participate in the WRAP is estimated to be $350,000 in 2023, $250,000 in 2024 and then transition to $175,000 annually starting in 2025. These costs are estimates and subject to change depending upon how many participants commit to the full WRAP program and the final development and implementation costs. For purposes of this Two-Year Rate Plan, Avista pro formed approximately $121,000 (Idaho share of $350,000) in Adjustment No. 3.00P as an adjustment to production operating expense.[4]

Table No. 9 provides a summary of actual funding through November 2022 and Table No. 10 provides future estimated funding requirements.

Table No. 9 – Actual WRAP Funding Through November 2022

Program Phases	2019	2020	2021	2022	Total
WRAP Phase 1	$3,700				**$3,700**
WRAP Phase 2		$26,500			**$26,500**
WRAP Phase 2b		$22,300	$57,800		**$80,100**
WRAP Phase 3A/B			$45,000	$225,200	**$270,200**
	$3,700	**$48,800**	**$102,800**	**$225,200**	**$380,500**

Table No. 10 – Estimated WRAP Funding Levels

Program Phases	2022	2023	2024	2025+
WRAP Phase 3A	$180,000	$0	$0	$0
WRAP Phase 3B	$125,000	$350,000	$250,000	$175,000
	$305,000	**$350,000**	**$250,000**	**$175,000**

Q. What are the customer benefits associated with Avista's participation in the WRAP?

A. The WRAP provides benefits of enhanced coordination and increased visibility and transparency across the regional power system. It seeks to enhance and increase interconnected system reliability while maintaining existing individual utility responsibilities

[4] While Company witness Mr. Kalich sponsors the overall PF Adjustment 3.00P to reflect overall power supply related expenses, I sponsor the specific generation O&M expense for these WRAP expenses.

for reliable operations and resource planning, purchasing, and delivery of energy. Current planning and procurement to meet resource adequacy needs is performed by individual utilities under the oversight of state regulators, cooperative boards, and city councils. Individual utilities develop plans and procure resources that are sufficient to meet their forecasted peak load requirements plus a calculated PRM to address uncertainty. In order to ensure resource adequacy, utilities rely on combinations of self-owned generation, bilateral contracts, planned market purchases, and available transmission capacity. This entity-by-entity planning framework has been sufficient since the region as a whole has been resource sufficient with extra capacity above total regional demand that has been accessible through market purchases. As the regions resource mix transitions to more variable resources this siloed approach to resource adequacy planning introduces significant risk to system reliability and is only effective if all the following criteria are met:

1. Each Load Responsible Entity (LRE) calculates its own generation and transmission needs using a robust methodology,

2. Each LRE builds, or enters into firm contracts with, physical resources and acquires the sufficient transmission to meet its own needs,

3. New resources are approved in a timely manner, relative to utility needs,

4. LREs do not collectively rely excessively on "market purchases" that exceed the physical capability of the Western resource and transmission systems to meet their service obligations,

5. LREs have accurately (and consistently) assessed the capacity contribution of their resources.

If all of these criteria are not met, the total generation and transmission capacity available to the region could fall below what is required to maintain interconnected system reliability. Today, the individualized nature of the current planning framework can make it difficult for regulators, board members, stakeholders, and utilities to understand whether, where, and when new capacity is needed in the region. The WRAP augments these existing frameworks to increase visibility into the true status of resources and transmission in the region and works to reduce the risk of not being able to serve customer load.

Further, even if the region had enough capacity installed to meet projected needs, without the WRAP there is no guarantee that resource capacity and transmission for deliverability is appropriately contracted to meet the region's needs in the most critical hours. Without regional coordination, the footprint's capacity could be contracted to other regions experiencing ever-growing capacity shortfalls or may not be utilized and scheduled in such a way as to meet the needs of utilities within the footprint without the centralized communication and coordination provided by the WRAP.

One of the key benefits of the program is its ability to unlock the load and resource diversity within the region. By ensuring availability and access to that diversity via the Operational Program, utilities participating in the program have the potential to carry less PRM going into a peak season than they would otherwise have to carry on a stand-alone basis. This can lead to a reduction in future resource need lowering cost to customers. The Operational Program will allow participants to maximize the benefit of the load diversity across the region during periods where some participants are peaking, and other participants are experiencing lower load levels. In addition, during times when VERs are performing above their accredited levels or participants are experiencing a lower level of forced generation outages, that additional capacity may be made available to deficient participants through the Operational Program when they are experiencing generation shortfall, excessive forced outages (generation and transmission), or load levels higher than planned.

The Operational Program allows participants to collectively manage periods of risk of capacity shortfall by prescriptively sharing available capacity and deliverability plans. As designed, the WRAP will help provide transparency, regional insights, and coordination as the region collectively plans for the future.

Q. Does this conclude your pre filed direct testimony?

A. Yes, it does.