Exh. SJK-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-22___

DOCKET NO. UG-22___

DIRECT TESTIMONY OF

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Scott J. Kinney. I am employed as the Director of Energy Supply 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 B.S. 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, where my primary responsibilities involve management and oversight of short- and long-term resource planning, acquisition of power resources, and power trading. In July 2021, I assumed the responsibility of managing the Gas Supply department.

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

A. My testimony provides an update on Avista's Western Energy Imbalance Market (EIM) integration efforts and plan to join the market on March 2, 2022, Avista's participation in the Western Resource Adequacy Program (WRAP) trial, an update on Avista's natural gas resource procurement plan, and an overview of the Company's 2021 Natural Gas Integrated Resource Plan (IRP).

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring four exhibits. Exh. SJK-2 is the "EIM Modernization and Operational Efficiency" business case. Exh. SJK-3 includes the Energy and Environmental Economics (E3) EIM benefit analysis report. Exh. SJK-4 the Western Resource Adequacy Program detailed design document. Finally, Exh. SJK-5 is Avista's 2021 Natural Gas Integrated Resource Plan.

II. ENERGY IMBALANCE MARKET (EIM) UPDATE

Q. Would you please provide a summary of the Commission's findings in Avista's last general rate case related to the Company's decision to join the Energy Imbalance Market?

A. Yes. In Docket UE-200900, et. al., the Commission approved the Partial Settlement Stipulation that outlined the agreement among the Settling Parties in that proceeding on the treatment of EIM capital, expenses, and benefits.

Q. What did the Settling Parties agree to as it relates to Avista joining the EIM?

A. The Settling Parties agreed to include EIM capital and expenses in base rates as proposed by Avista. Avista also included a $5.8 million annualized system EIM benefit (for the 7 months Avista will participate in the EIM during the current rate effective period; this benefit is

$3.4 million (system)). Avista also agreed to participate in a collaborative, or Staff investigation, concerning the modeling of EIM benefits, and that if a collaborative or investigation did not conclude before this general rate case, Avista agreed to examine the accuracy of the benefit estimate in its next GRC. I will discuss this later in my testimony.

Q. What did Avista include as it relates to EIM capital and expenses as proposed and as agreed-to by the Settling Parties?

A. As described in the Joint Testimony in Support of the Partial Settlement Stipulation in Docket Nos. UE-200900, et. al., Table No. 1 below summarizes the electric EIM Adjustment 3.18 balances per Staff 107 Supplemental 3.

Table No. 1 – EIM Adjustment 3.18 – As Filed versus Updated[1]

Adjustment 3.18 - EIM	
In 000's	
Plant in Service	$ 13,908
A/D	(1,150)
ADFIT	(181)
Net Rate Base	$ 12,577
Operating Expense	$ 1,691
Depreciation Expense	1,709
Expense	$ 3,400
Net operating Income	$ (2,620)
Revenue Requirement Impact	$ 4,707

As shown in Table No. 1 above, net rate base pro formed on an AMA basis during the rate period totaled approximately $12.6 million (Washington-share), after reflecting A/D and ADFIT. Also included are Washington's share of depreciation expense of approximately $1.7 million

[1] Net operating income and revenue requirement were revised based on the approved cost of capital in final Order 08 05 in Docket UE-200900, et. al. as discussed below.

associated with pro forma investment and operating expenses of approximately $1.7 million, reflecting incremental labor expense, information technology ("IT") expense, system integrator (Utilicast) and CAISO implementation fee expenses. Therefore, the net effect of this updated adjustment above 2019 test period levels, increased overall net electric rate base by $12,577,000, and increased expense by $3,400,000. Also shown in Table No. 1 is the net operating income (NOI) and revenue requirement at time of the filed settlement. These balances were revised based on the approved cost of capital in Final Order 08/05, resulting in a final approved NOI of $2.618 million, and a resulting revenue requirement for the EIM adjustments of $4.652 million.[2]

Q. What is the status of Avista's EIM integration effort?

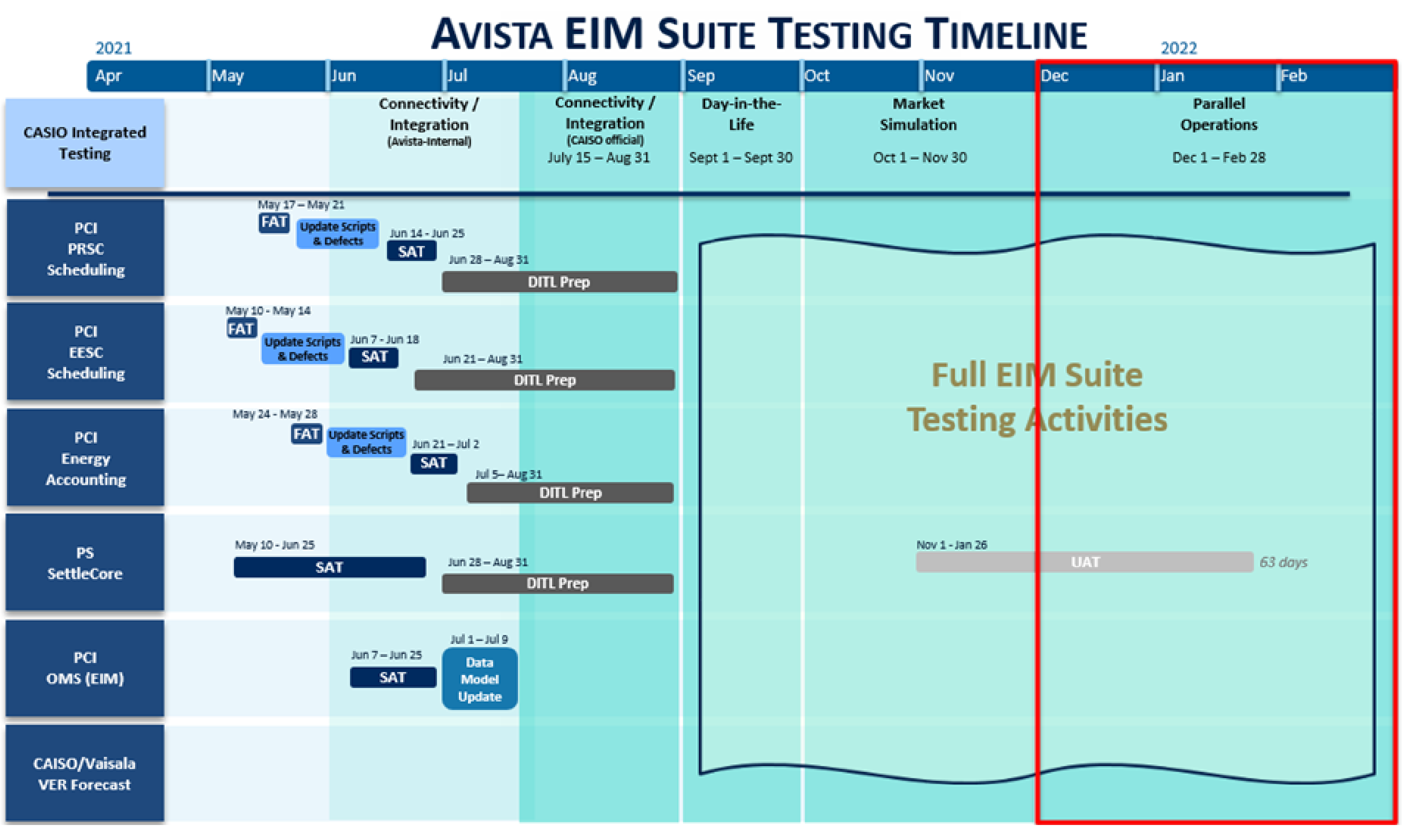
A. Avista signed the EIM Implementation Agreement with the California Independent System Operator ("CAISO") on April 25, 2019 with a planned go-live date of March 2, 2022. Since that time, Avista has completed more than 60 metering and generation controls upgrades, integrated eight new market software applications to support market operations, and hired all planned new EIM support staff. The equipment upgrades were completed in the summer of 2021 and have all transferred to plant. The software applications have been installed and are being utilized to support the different CAISO testing phases that began September 1, 2021 and will conclude with the parallel testing phase that began December 1, 2021 and will continue through the go-live date on March 2, 2022. With the exception of one EIM operator and the System Operator Training Administration hire planned for 2022, fifteen of the planned seventeen new EIM support employees have been hired and are working to support market integration, training and parallel operations testing. Although hiring all six EIM operators prior to December 2021 was

[2] Supporting documentation of the 2021 – 2022 EIM costs and benefits were included in testimony (Exh. SJK-1T) and exhibits (Exh. SJK-2 through Exh. SJK-12), in Docket UE-200900, et. al.

planned, the Company has been challenged to hire all new EIM operators due to multiple unplanned retirements in System Operations. That said, the Company intends to have a full EIM operator team prior to market entry.[3]

Figure No. 1 below provides a summary of the software project milestones and testing phases that have been completed to date.

<u>Figure No. 1 – Avista EIM Suite Testing Timeline</u>



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[3] Company witness Ms. Andrews includes incremental labor expense associated with these new employees, above test period labor (twelve-months ending 09.2021), totaling $1.2 million system (previously approved by the Commission in Docket UE-200900, et. al., per Order 08/05). Additional expenses of $246,000 for IT, CAISO and Utilicast incremental expenses were also included. Washington share of these total expenses of $947,000 above test period levels, as well as 2021 (October – December) and 2022 capital additions discussed below in Table No. 2, were included by Ms. Andrews in Exh. EMA-2, "Pro Forma EIM Capital 2021-2022 Additions and Expense" Adjustment 3.17. See also Ms. Andrews' workpapers provided to all Parties after the filing of the Company's case.

As shown in Figure No. 1, Avista is currently in the parallel operations testing phase which is the last phase prior to go-live. During this final testing phase, Avista also anticipates receiving FERC approval of required changes to Avista's Open Access Transmission Tariff (OATT), Market Based Rate Authority (MBR), and FERC EIM Readiness Criteria. The OATT and MBR have already been submitted to FERC for review and Avista has completed more than half of the Readiness Criteria items that will be filed by CAISO. Avista is actively working on the remaining Readiness Criteria items in anticipation of CAISO's submission to FERC by the end of January.

Q. What are the estimated capital EIM integration and annual costs from 2021 to 2024?

A. As previously determined in Order 08/05 in Dockets UE-200900, et. al., the Commission approved Washington's share of the 2021 and 2022 EIM capital integration costs. Those costs are subject to review and refund based on a final evaluation and report that will be filed with the Commission by the Company in July of 2022. Table No. 2 below provides a summary of the capital transfer to plant additions (system) to support EIM integration for 2021 and 2022 (previously approved) and forecasted annual capital for 2023 and 2024 included in this case to support market software system modernizations and upgrades.

Table No. 2 – System EIM Capital transfer to Plant 2021-2024[4]

WA GRC Plant Group	Business Case	2021 TTP (System)	2022 TTP (System)	2023 TTP (System)	2024 TTP (System)	Exh. SJK-2 Page #
EIM	Energy Imbalance Market	$ 10,554,903	12,016,376	-	-	2
	Energy Imbalance Market Modernization & Operational Efficien	-	-	499,974	585,791	14
Total Energy Imbalance Market (EIM)		$ 10,554,903	$ 12,016,376	$ 499,974	$ 585,791	
Exh. SJK-1T Total 2021-2024 Capital Additions		$ 10,554,903	$ 12,016,376	$ 499,974	$ 585,791	

[4] Washington share of the capital additions for 2023 and 2024 in Table No. 2 above, are included in Ms. Andrews Exh. EMA-2 "Provisional EIM Capital 2023 Additions AMA" Adjustment 4.08 and "Provisional EIM Capital 2024 Additions AMA" Adjustment 5.12. See also Ms. Andrews' workpapers provided to all Parties after the filing of the Company's case. Per Ms. Andrews, Overall EIM costs included in the Company's case for RY1 results in an increase in revenue requirement of $3.3 million over test period levels, and an incremental reduction of $107,000 in RY2 results over RY1 levels, due to the reduction in net plant for A/D and ADFIT for short-lived assets.

The capital spends and transfers to plant in 2021 ($10,554,903 system) were primarily associated with completing the substation interchange and generation meter upgrades/replacements and the generation control upgrades required by CAISO to operate in the market. A portion of the 2021 costs were associated with the Outage Management software application that was completed and installed in two phases. The capital spends and transfers to plant in 2022 ($12,016,376) are associated with the integration and testing of the market software applications required to ensure efficient operations including submitting resource bids, outage management, settlements, energy management, and variable energy forecasting. The final 2021 and 2022 capital spend and transfer to plant will be documented in a final EIM integration report to be provided by the Company in July 2022 and will be available for review by all parties.

As with any software application, there will be annual license costs and required upgrades to coincide with market enhancements and updates developed by the CAISO. Avista anticipates the capital costs to be $499,974 (system) in 2023 and $585,791 (system) in 2024 based on discussions with software vendors and internal reviews. These costs are included in Exh. SJK-2, EIM Modernization and Operational Efficiency business case.

Q. Is Avista including EIM benefits in this rate filing?

A. Yes. Avista recognizes that it will begin to receive EIM benefits after it officially begins market participation in March of 2022. The Company recognizes that the EIM will provide benefits to our customers through lowering resource dispatch costs and/or through additional revenue created from dispatching resources not committed to serve Avista customers that can be bid into the market to serve demand across the EIM footprint. However, at the time of this rate filing, Avista will not have joined the EIM and therefore doesn't have any actual operating data to predict future benefits. The best benefit estimate the Company has at this time is based on the results of the EIM benefit assessment conducted by Energy and Environmental Economics (E3). The E3 study, provided as Exh. SJK-3, estimated an annual <u>system</u> benefit range from $2 to $12 million depending on multiple factors and scenarios. Until Avista joins the market it is unclear how these factors will influence actual benefits, <u>however, the Company's best estimate includes annual system benefits at approximately $5.8 million (system) once fully operational</u>. This baseline value was calculated through consultation with E3 and by averaging the four most likely EIM scenarios out of the 24 scenarios evaluated by E3. The Company recognizes there is uncertainty associated with calculating EIM benefits, but believes E3's baseline annual benefit level of $5.8 million (system) is an appropriate starting point until the Company obtains EIM operating experience. By including EIM benefits the "matching principle" set forth by previous Commission orders is being adhered to. It is also the same level of overall benefit that was included in baseline power supply in our most recent general rate case, Dockets UE-200900, et. al.[5]

Avista is committed to working with its Power Supply stakeholder group to develop an appropriate EIM benefit forecast model and methodology. Avista will schedule multiple workshops during 2022 to discuss options and work towards an adequate methodology. In order to provide consistency and incorporate other EIM entities findings, a portion of the evaluation will include a review of Puget Sound Energy and PacifiCorp's draft EIM benefit methodologies to evaluate what may be prudent to include in the Company's methodology. After a preliminary methodology is developed, the Company plans to use actual data from market participation to conduct a back cast and compare the modeled benefits to actual observed benefits. Based on

[5] In Dockets UE-200900, et. al., only seven months of Washington's-share of the estimated $5.8 million in benefits were included in baseline power supply costs, given that Avista will not join the EIM until 5 months into the rate effective period. In this proceeding, the Company has included Washington's share of the annual system amount of $5.8 million, as discussed by Company witness Mr. Kalich, in his new proposed authorized net power supply pro forma and ERM baseline starting Rate Year 1, effective December 2022.

conversation with existing market participants, Avista believes at least a full year of actual market operations – capturing market behavior and benefits across all four seasons – will be needed to inform the final methodology. Once a final EIM benefit methodology is developed, verified, and agreed to by the stakeholder group, the Company will incorporate it into future rate case filings.

III. WESTERN RESOURCE ADEQUACY PROGRAM (WRAP)

Q. What led to the development of the WRAP?

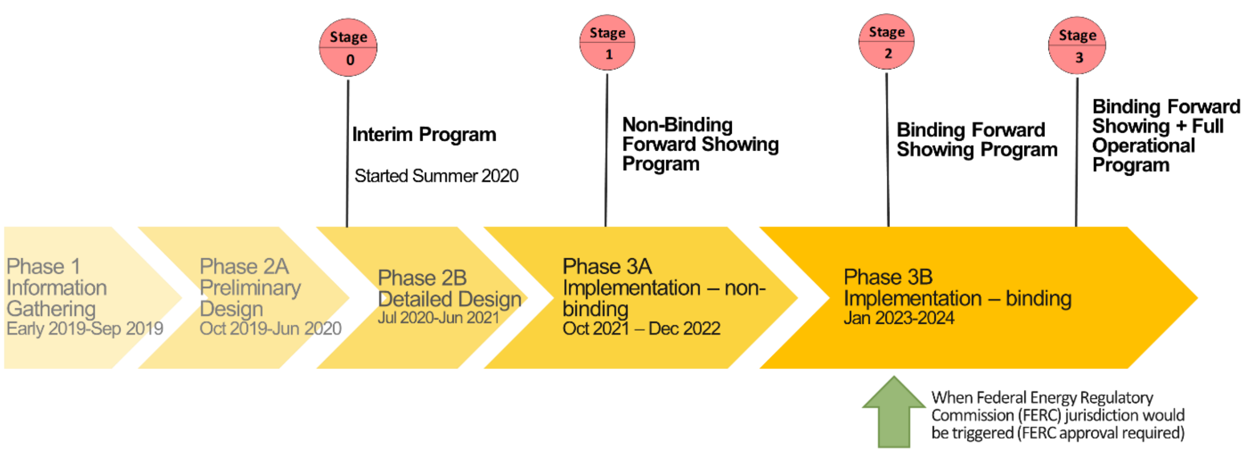
A. The western interconnected regional power system is currently undergoing a resource transition. The recent and impending retirement of thermal generators within the West and the replacement of these resources with increasing variable energy resources (VERs), has led to concerns about whether the region 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 Northwest Power Pool (NWPP) 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 early 2023 and will require FERC approval. Figure No. 2 provides an overview of the WRAP development schedule.

Figure No. 2 – WRAP Development and Implementation Schedule



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. Exh. SJK-4 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 are in compliance 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. 3 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. 3 – WRAP Critical Binding Seasons

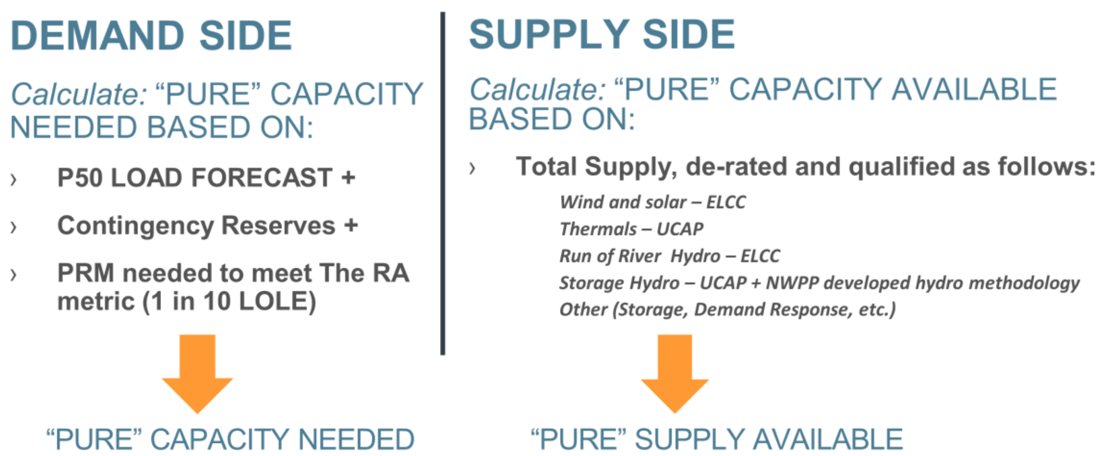
Season	Binding/ Advisory	Duration	Compliance Showing Date	Cure Period
Winter	Binding	Nov-March 15	March 31	June 1 – July 31
Summer	Binding	June-Sept 15	October 31 (of prior year)	Jan 1 – Feb 28
Spring	Advisory	April-May	N/A	N/A
Fall	Advisory	October	N/A	N/A

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. Figure No. 3 provides an illustrative summary of how the WRAP Forward Showing component works.

Figure No. 3 – Forward Showing Compliance



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 allocated share to fund Phase 3A implementation and the associated non-binding trial period is $200,000 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 participate in the full WRAP implementation and start up (Phase 3B) is estimated to $250,000 in 2023 and 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. Table No. 4 provides a summary of actual funding through November 2021 and Table No. 5 provides future estimated funding requirements.

Table No. 4 – Actual WRAP Funding Through November 2021

Program Phases	2019	2020	2021	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			$45,000	**$45,000**
	$3,700	**$48,800**	**$102,800**	**$155,300**

Table No. 5 – Estimated Future WRAP Funding Levels

	2022	2023	2024	2025+
WRAP Phase 2b	$180,000	$0	$0	$0
WRAP Phase 3b	$125,000	$250,000	$250,000	$175,000
	$305,000	**$250,000**	**$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 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. Finally, will WRAP assist in integrating new renewable resources in the region?

A. Yes. WRAP leverages the resource diversity that exists across the program's footprint and will reduce the risk of capacity shortfalls. When resources produce more energy than planned, WRAP participants can utilize the additional output to help meet unplanned resource shortfalls through the Operational Program. WRAP also utilizes consistent planning criteria and models to calculate resource capacity contributions. Utilizing consistent planning methods will lead to an equitable determination of resource contributions to meet peak load and provide an indication of the preferred location of new resources to maximize generation output and transmission deliverability.

IV. NATURAL GAS RESOURCE PROCUREMENT PLAN

Q. Is the Company proposing any changes to the cost of natural gas for its natural gas customers in this case?

A. No, Avista is not proposing changes in this filing related to the commodity cost of natural gas or upstream pipeline transportation resource costs. Changes in the commodity cost of natural gas, and the cost of natural gas pipeline transportation included in customers' rates are addressed in the Company's annual Purchased Gas Cost Adjustment (PGA) filing. The Company filed its annual PGA in September 2021, and new rates were effective November 1, 2021.

Q. Please describe Avista's natural gas portfolio as it relates to the procurement of natural gas 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 all six pipelines, as well as firm withdrawal capability from JP, helping diversify where supply can be received in order to meet customers' needs among the three jurisdictions.

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

Table No. 6 – Natural Gas Capacity at Jackson Prairie (System)

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 other economic benefits. Illustration No. 1 below is a map showing our service territory, natural gas trading hubs, interstate pipelines, and natural gas storage facilities.

Illustration No. 1 - Natural Gas Infrastructure Map

Wholesale natural gas prices are a fundamental component of both 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.

The Company has developed a Natural Gas Procurement Plan (Plan) to ensure reliable supply and a level of price certainty in volatile markets since future natural gas prices cannot be accurately predicted. Market conditions, analysis, and experience shape the Plan's overall strategy, which includes 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. A portion of the hedges are focused on concentration risk by utilizing Dynamic Hedge Windows (Hedge Windows), while another portion of hedges target reducing risk in a volatile commodity price environment by utilizing Risk Responsive Hedging methods.

Hedge Windows allow the Company to capture, or fix, future natural gas prices for a targeted portion of its portfolio. A Hedge Window is bounded by dates and market parameters, including an upper control limit (UCL), a lower control limit (LCL), and an expiration date. Quantitative mathematics and statistical calculations are used to determine these boundaries. Hedge Windows remain "open" as long as the current commodity price remains between the UCL and the LCL, and the window has not reached its time expiration. Once the current commodity price goes beyond the UCL or the LCL, or the window has reached time expiration, the Hedge Window has been triggered and 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 accordingly.

In addition to the Hedge Windows described above, which guide execution of hedges up to a predetermined minimum hedge ratio, Risk Responsive Hedging is utilized to help manage the Value at Risk (VaR) of the Company's LDC natural gas portfolio's open position on a daily basis.

Regional forward natural gas prices are the basis for the VaR analysis. The analysis utilizes a confidence level and historic volatility to calculate a portfolio VaR, and combines it with the current mark-to-market portfolio price to develop a price risk metric. This price risk metric is compared to a predetermined threshold, known as the Operative Boundary, on a daily basis. If the price risk metric exceeds the Operative Boundary, then one or more suggested hedges may be executed to bring the price risk metric back within the Operative Boundary. In any case, hedge volumes should not exceed the predetermined maximum hedge ratio. Similar to the Hedge Windows, the Company always maintains some level of discretion and may choose to take other action, partial action, or no action, with respect to transaction execution and will document accordingly.

The Energy Supply Department continuously monitors the results of the Plan, evolving market conditions, variation in demand profiles, new supply opportunities, and regulatory conditions. Although various windows and targets are established in the initial design phase, the Plan allows discretion for ultimate decision making as market conditions warrant. Material changes to the Plan 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 include five to eleven prompt months depending on the current month, as well as seasonal strips (November-March or April-October) for a period of up to 36 months from the current month.

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 with changes approved by the Company's Risk Management Committee and shared with Commission Staff. The review includes updating load and demand forecasts, analysis of historical and forecasted market trends, fundamental market analysis, and transportation, storage, and other resource considerations. In order to serve load and optimize resources for the benefit of customers, the Company secures/purchases natural gas supply through the transactions and procedures described below:

1. **Fixed-Price Purchases:** To provide a level of price certainty in volatile natural gas commodity markets, Gas 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.

   The fixed-price purchases portion of the Plan, or hedges, are comprised of the following two components as previously described:

   - Dynamic Window Hedges
   - Risk Responsive Hedge Tool

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. Gas 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:** Gas 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. Gas 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.

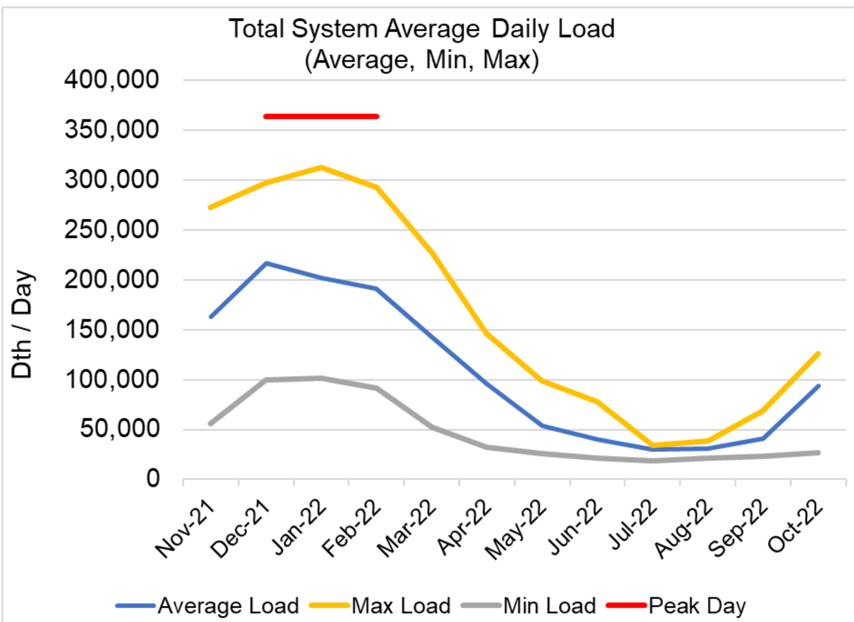
5. **Use of Derivative Contracts:** Subject to limitations in the Energy Resources Risk Policy, Gas Supply may enter into derivative-based contracts intended to reduce or manage exposure to rising prices or fluctuating loads.

6. **Resource Optimization:** Gas 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.

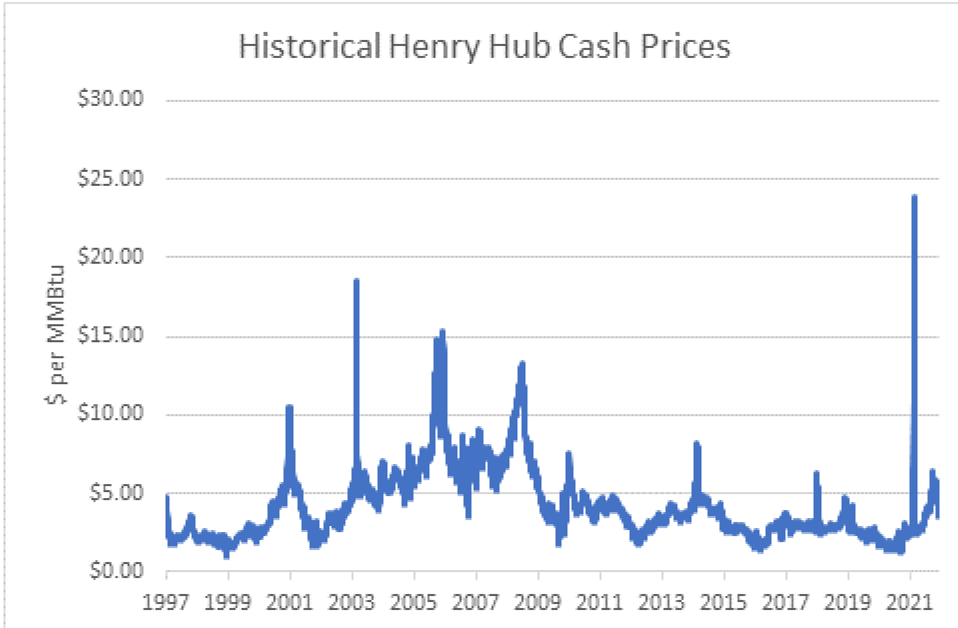
A. The Plan focuses on managing the costs associated with serving varying retail load with supply from a wholesale market with price volatility. In order to manage these seasonal, monthly, and daily volume swings, Avista shapes the components of the Plan by month (i.e., more natural gas is hedged for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

<u>Illustration No. 2 - Annual Demand Volatility</u>



Price volatility can also vary significantly by season, month, and day. Illustration No. 3 below includes a chart depicting natural gas price volatility over time.

Illustration No. 3 - Historic Henry Hub Pricing



Avista cannot predict with accuracy what future 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 attempting to achieve a measure of price stability and certainty, and competitive prices for our customers.

V. 2021 NATURAL GAS INTEGRATED RESEOURCE 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 April 1, 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 Company's 2021 Natural Gas Integrated Resource Plan is included as Exh. SJK-5.

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

A. Highlights from the 2021 IRP are as follows:

- Marginally lower 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.

- A new methodology for peak day weather planning will help to address climate change and trends for each planning area. These areas include La Grande, Roseburg, Medford, and Klamath Falls in the State of Oregon. As compared to the prior standard of coldest on record, the new methodology uses a statistical approach to determine the 99% probability of a peak event considering the past 30 years of coldest average day each year in each planning area.

- An alternative scenario was introduced to help evaluate proposed carbon reduction policies. In consideration of Oregon Executive Order 20-04, the scenario approaches a least cost methodology to meet emission reductions with supply side resources. Future IRP's will move further along this pathway to explore different approaches to meet new carbon reduction requirements as program details are developed.

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

A. No, the Company filed its 2021 IRP on April 1, 2021 and it is currently under review by the Commission (Docket UG-190724).

Q. Does this conclude your direct testimony?

A. Yes.