Exh. TLK-4T

WUTC DOCKET: UE-200900 UG-200901 UE-200894
EXHIBIT: TLK-4T
ADMIT ☑ W/D ☐ REJECT ☐

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-200900

DOCKET NO. UG-200901

DOCKET NO. UE-200894

REBUTTAL TESTIMONY OF

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, business address and present position with Avista Corporation.

A. My name is Tara L. Knox and my business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as the Manager of Regulatory Accounting Initiatives in the Regulatory Affairs Department.

Q. Have you filed direct testimony in this proceeding?

A. Yes. I have filed direct testimony in this case addressing Avista's Revenue Normalization adjustment and the Company's electric Class Cost of Service Study presented in this general rate case (Exh. TLK-1T through Exh. TLK-3).

Q. What is the scope of your rebuttal testimony?

A. I discuss several different topics in my rebuttal testimony. First, I explain the Company's provisional acceptance of Staff witness Jordan's proposed Pro-forma Revenue Normalization adjustment. Second, I will rebut Public Counsel witness Mr. Watkins' concerns regarding the reliability and usefulness of the Company's electric and natural gas cost of service studies. Finally, I address the reasonableness of Inland Empire Paper witness Dr. Kaufman's hybrid embedded and marginal cost study.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exh. TLK-5, which identifies AMI benefits included in the Company's cost of service studies. A Table of Contents for my testimony is as follows:

Description		**Page**

II. STAFF REVENUE NORMALIZATION ADJUSTMENT

Q. Starting with Staff witness Ms. Jordan, does the Company accept her proposed revision to electric revenue requirement adjustment 3.01?[1]

A. Yes, Ms. Jordan has reflected in her testimony the fact that a large Schedule 25 customer will close its factory and no longer take usage during the rate year. Therefore, it is appropriate to revise the pro-forma revenue normalization adjustment to reflect this closure of a large industrial customer.

Q. Is there a caveat associated with acceptance of this adjustment?

A. Yes. Included in Staff's adjustment is an estimate of the power supply cost savings associated with the reduction in load.[2] The estimate was determined by multiplying the sales reduction by the retail revenue credit rate produced by the proposed ERM base presented in Company witness Mr. Kalich's Exhibit No. CGK-6. Power supply costs will be updated 60 days prior to the rate effective date, which in turn will change the proposed ERM base and the associated retail revenue credit rate. If the planned closure of this customer had been known prior to the Company's filing, the load impact would have been incorporated into the normalized historical loads used for power supply modelling and the pro-forma revenue normalization adjustment would

[1] Exh. ELJ-1T, pages 5 and 6.
[2] Exh. ELJ-4, page 1, line 7.

not reflect any power supply costs.

Q. Will the power supply update incorporate the expected load reduction from the closure of this industrial customer into the updated power supply adjustment?

A. Yes. When the Company runs the power supply update, it will incorporate the loss of the load from this customer into the normalized historical loads, thereby capturing the cost savings in the updated power supply adjustment. Including the load adjustment in the power supply modelling properly aligns the proposed ERM Base costs with revised Washington retail loads from the revised rate design model, producing the revised Retail Revenue Credit rate for the ERM.

Q. Has the Company included the proposed load revision to the revenue adjustment and power supply adjustment in its rebuttal revenue requirement?

A. Yes. Company witness Ms. Andrews has included the reduction in revenue in adjustment 3.01 and a proxy for the reduction to the proforma power supply expense in adjustment 3.00. As stated above, the actual reduction to power supply expense will be included in the Company's 60-day power supply update.

III. PUBLIC COUNSEL COST OF SERVICE STUDY ISSUES

Q. Moving on to Cost of Service, did Commission Staff have any issues with the electric and natural cost of service studies presented in this case?

A. No. Ms. Jordan stated that the Company's cost of service studies (both electric and natural gas) met the requirements of the new cost of service presentation and methodology rules found in Chapter 480-85 of the WAC.[3] Ms. Jordan went on to explain the Staff perspective on

[3] Exh. ELJ-1T page 7.

utilizing Cost of Service parity ratio results as a guideline for rate spread decisions.[4]

Q. Mr. Watkins testimony included objections to the new peak credit methodology required by WAC-480-85-060.[5] Do you agree with his assessment?

A. While I agree that moving to the renewable future peak credit is a big shift in the proportion of generation costs that are considered demand-related, I do not agree that this is a problem with cost of service studies produced today. The Commission adopted these rules with an eye to the future where renewable resources provide energy, but reliable capacity is going to be problematic. Therefore, a methodology that emphasizes demand in the assignment of generation costs is reasonable.

Q. Would the revenue-to-cost parity ratios that Staff used to inform their rate spread recommendations have been materially different if the peak credit had been reversed to reflect 67 percent energy-related and 33 percent demand-related?

A. No. The following illustration shows the parity ratios produced by the Company's cost of service study as filed compared to the study re-run with the peak credit ratio reversed.

Illustration No. 1 – Comparison of Electric Parity Ratios

Compare Electric Parity Ratios	Cost Study As Filed	Cost Study Reversed Peak Credit	Change
Customer Class	*Parity Ratio A*	*Parity Ratio B*	*B - A*
Residential, 01/02	0.82	0.83	0.01
General Service, 11/12	1.24	1.24	0.00
Large General Service, 21/22	1.25	1.25	0.00
Extra Large General Service, 25	1.15	1.11	-0.04
Pumping Service, 30/31/32	1.03	1.00	-0.03
Lighting, 41 - 48	1.12	1.09	-0.03

[4] Exh. ELJ-1T pages 9 and 10.
[5] Exh. GAW-1T pages 8 through 19

The negligible differences shown in Illustration No. 1 indicates that alternative assumptions associated with the peak credit in this cost of service study were not a major factor in the overall results particularly for the residential, general service, and large general service customer classes.

Q. On page 21, line 7 and 8 of Mr. Watkins testimony, he states that the demand estimates "are largely based on an outdated load profile study that is 12 years old (2009)". Is that true?

A. No. My understanding is that Mr. Watkins found an outdated reference in a narrative tab included in my peak demand estimation workpaper that was solely included to aid users of the workbook to understand the calculation process. The "Load Shape" and "Peak Calc NCP" tabs (referred to in the narrative) of the peak demand estimation workpaper were updated in 2016 (for Docket UE-160228) with information from the 2014 load study presented to this Commission in Docket UE-150204. The updated version of this workpaper has been utilized to estimate test year demand in all cases since UE-160228, including this one.

Q. Mr. Watkins analyzed the estimation error associated with System Coincident Peak Demand monthly estimates.[6] Several different Coincident Peak allocation factors were used in the new cost of service methodology. Which Coincident Peak estimation workpaper was used for his analysis?

A. As shown on Exhibit GAW-3 Mr. Watkins observations are based on the "System and Distribution Demand 12CP 12.2019.xls" workpapers.

Q. Which coincident peak allocation factors are derived from that workpaper and what costs are those allocators used on?

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[6] Exh. GAW-1T pages 20 and 21 and Exh. GAW-3

A. The coincident peak portion of that workpaper supports D02 which is the average of the twelve monthly system coincident peaks used to allocate transmission costs and D03 which is the average relative share of the summer and winter distribution system coincident peaks used to allocate distribution substation costs. The summer peak occurred in August and the winter peak occurred in February, both months that were not flagged as problematic in Mr. Watkins analysis.

Q. What was the basis for the demand allocations associated with the peak credit demand proportion of generation costs?

A. Per WAC 480-85-060, the new cost of service methodology requires demand-related generation costs to be allocated based on load net of renewable generation, using 12 monthly coincident peaks. The class usage at peak times associated with the load net of renewable generation was estimated in the workpaper "Peak Net of Renewable Demand 12 CP 12.2019.xlsx".

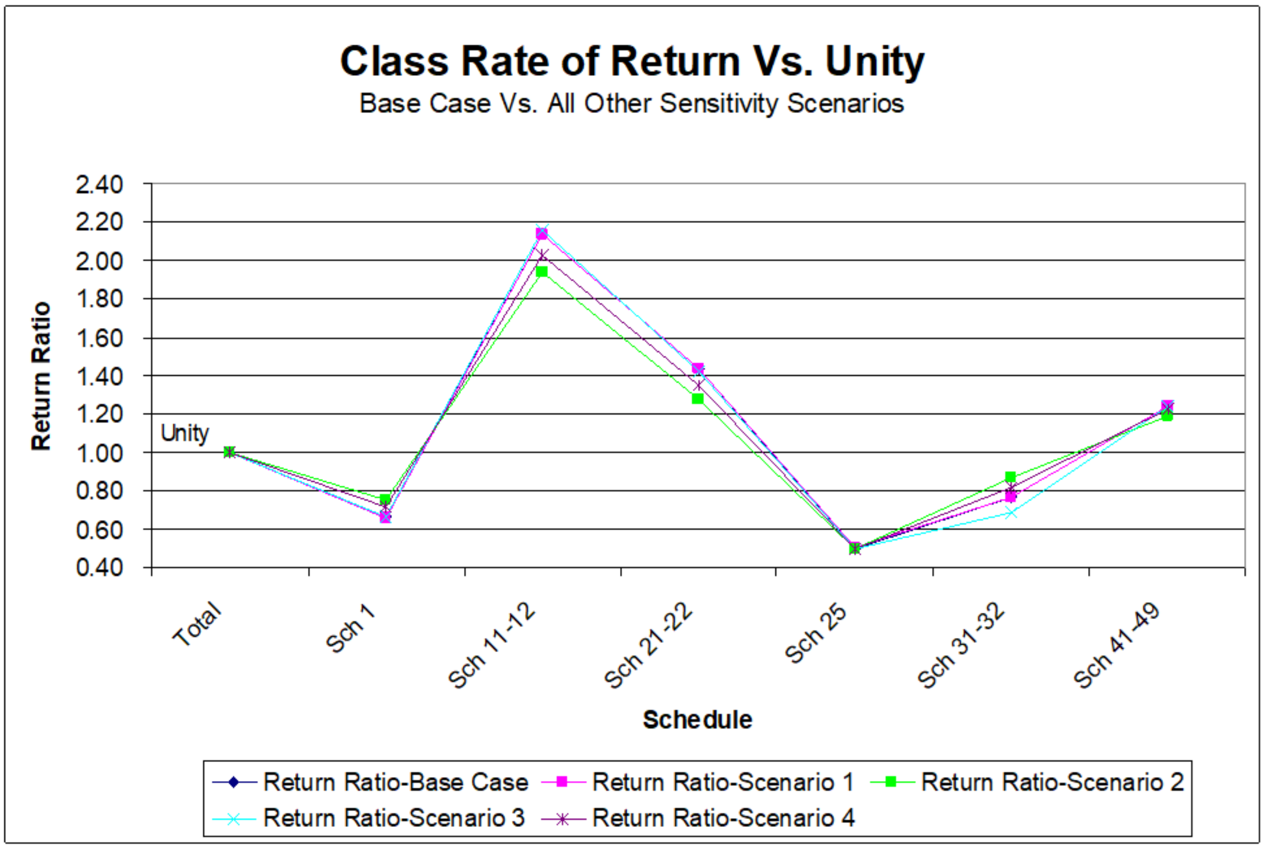
Q. How do the estimation errors for the peak times used for demand-related generation costs compare to the distribution system peak times in Mr. Watkins analysis?

A. Overall, the Washington estimation error is less in the peak net of renewable resources analysis. As shown on Exhibit GAW-3 the total forecast (estimation) error in the distribution system peak analysis was (403.77) MW or -3.59%. In the peak net of renewable resources analysis, equivalent total estimation error was (225.88) MW or -2.38%.

Q. Mr. Watkins implies that demand allocations based on the Company's test year peak demand estimation process utilized between load studies do not provide usable results. Have you ever tested the sensitivity of overall cost of service results to potential inaccuracies in the demand allocators?

A. In the Company's 2009 case (Docket UE-090334), I prepared four demand allocator sensitivity scenarios to establish that the cost of service study could provide a sound foundation for rate spread purposes. The analysis examined the impact of extreme class to class assumptions on both the coincident peak and non-coincident peak allocation factors. Illustration No. 2 below showed that the fine tuning that more precise demand allocations might provide would not change the overall implications of the cost of service study. The unit of measure represented in this chart is the return ratio which is more sensitive than the revenue-to-cost parity ratio.

<u>Illustration No. 2 – Class Rate of Return Scenario Results from UE-090334</u>



Given that the return ratio statistic illustrated in the chart is more sensitive to small changes than the Commission's preferred revenue-to-cost parity ratio, even if there may be some estimation issues inherent in the demand allocators, they are unlikely to have a material impact on the implications of the cost study.

Q. On page 22 and page 30 of his testimony, Mr. Watkins states that the class cost

of service study does not include or reflect any of the estimated AMI benefits. Is this true?

A. No. All estimated AMI benefits that Ms. Andrews identified as part of revenue requirement are included in both the electric and natural gas cost of service studies. The difficulty with the AMI benefits (savings) is that they are representative of costs that otherwise would have increased the Company's revenue requirement, and therefore exist due to their absence. Approximately $2.4 million of the savings were reflected in the 2019 test year, in other words, 2019 costs were lower than they would have been if the AMI project had not been in progress. Additionally, Ms. Andrews electric and natural gas column 3.16 adjustments specifically reduced pro forma operating expenses $2.986 million electric and $0.995 million natural gas. Furthermore, by including the full $9 million (combined electric and natural gas) of twelve months ended September 30, 2022 O&M expense reductions, my electric cost of service exhibit Exh. TLK-3 and Company witness Mr. Anderson's natural gas cost of service exhibit Exh. JCA-3 also accounted for the absence of $2.4 million incremental expense due to expected re-deployment of resources that would otherwise not have been available.

Q. Mr. Watkins also points out a difference between "Mr. DiLuciano's updated total (electric and gas) AMI savings for 2021 and 2022" and the savings identified in Exhibit TLK-3 electric and Exhibit JCA-3 natural gas.[7] Are there AMI benefits that do not get reflected in the Company's revenue requirement?

A. In addition to direct savings that reduce the Company's costs, there are other benefits that accrue directly to customers. Ms. Andrews worked with the AMI project team to identify which categories represented direct benefits to customers, which were revenue requirement cost reductions, and the cost savings which were expected to be redeployed. Exh.

[7] Exh. GAW-1T page 24, line 5 electric, and page 31, line 11 natural gas.

TLK-5 shows all the 2021 and 2022 benefits and cost savings included in Table 4-2 on page 51 of Exhibit JDD-2r (March 2021 Revision to the Avista Utilities Advanced Metering Infrastructure (AMI) Project Report) and indicates whether each sub-category was considered a revenue requirement reduction or a direct customer benefit. The direct customer benefits do not have an impact on cost of service and are rightfully excluded from the revenue requirement and related cost of service studies.

Q. You refer to the AMI report that was updated March of 2021? Did the changes in that update materially change the costs and benefits associated with the AMI project or the Company's cost of service studies?

A. No. The impact of updating pro forma adjustment 3.16 reduces the Company's requested electric revenue requirement by approximately $456,000 and the Company's natural gas revenue requirement by approximately $280,000. I do not believe the update would have materially changed the parity implications of the Company's cost of service studies.

Q. Mr. Watkins objects to the Company's use of a common cost allocation for the AMI benefits instead of a customer-based allocation.[8] Why were the revenue requirement savings allocated using the common cost allocator?

A. As stated above, nearly half of the revenue requirement savings either were already reflected in the historical test year (2019 savings) or were redeployed and became part of other costs. The incremental amount shown in Ms. Andrews adjustment was included as an administrative and general expense reduction which was subject to the common cost allocation. Therefore, the common cost allocation factor was selected to identify total savings that were

[8] Electric Exh. GAW-1T pages 23 through 25 and Exh. GAW-4. Natural gas Exh. GAW-1T pages 30 through 33 and Exh. GAW-5.

embedded in the cost studies as shown in Exh. TLK-3 (electric) and Exh. JCA-3 (natural gas). Reflecting on Mr. Watkins testimony, he has a valid point that the incremental adjustment could have reasonably been categorized as customer cost reductions,[9] and redeployed resources could have been deemed to have been used for other customer-related purposes.

Q. Have you for electric operations or Mr. Anderson for natural gas operations performed any analysis on the impact on the Company's cost studies of treating the savings as reduced customer-related costs instead of an offset to common costs?

A. Yes. The only impact to the cost of service studies would have been associated with the incremental cost reduction over and above the savings that were reflected in the 2019 historical test period. Illustration No. 3 below shows the cost of service parity ratio results from the cost of service studies as filed compared to the studies re-run with the incremental AMI savings (both direct reduction and redeployed savings) treated as customer-related costs.

[9] See savings sub-categories identified on Exh. TLK-5.

Illustration No. 3 – Comparison of Electric and Natural Gas Parity Ratios

Compare Electric Parity Ratios	**Cost Study As Filed**	**Cost Study AMI Savings by Customer**	**Change**
Customer Class	*Parity Ratio A*	*Parity Ratio B*	*B - A*
Residential, 01/02	0.82	0.82	0.00
General Service, 11/12	1.24	1.24	0.00
Large General Service, 21/22	1.25	1.24	-0.01
Extra Large General Service, 25	1.15	1.15	0.00
Pumping Service, 30/31/32	1.03	1.02	-0.01
Lighting, 41 - 48	1.12	1.11	-0.01

Compare Natural Gas Parity Ratios	**Cost Study As Filed**	**Cost Study AMI Savings by Customer**	**Change**
Customer Class	*Parity Ratio A*	*Parity Ratio B*	*B - A*
General Service, 001/002	0.91	0.91	0.00
Large General Service, 111/112	1.70	1.67	-0.03
Interruptible Sales Service, 132	1.40	1.37	-0.03
Transportation Service, 146	0.91	0.89	-0.02

The negligible differences shown in Illustration No. 3 indicate that alternative assumptions associated with AMI O&M savings in these cost of service studies would not materially change the overall results.

Q. What do you conclude regarding Mr. Watkins assertion that the electric and natural gas cost of service studies should not be relied upon for rate spread purposes?[10]

A. I believe I have shown that Mr. Watkins concerns are unfounded or immaterial. During the cost of service rulemaking Dockets UE-170002 and UG-170003, the Commission requested each electric and natural gas utility provide cost of service scenarios testing various potential classification and allocation methodologies. The Commission found that to "the surprise of the Commission and several stakeholders, the results of the requested scenarios submitted by

[10] Exh. GAW-1T page 25 electric, and page 33 natural gas.

the electric and natural gas utilities showed negligible or no impact to a cost of service study from the selection of any particular methodology modeled."[11]

IV. IEP HYBRID MARGINAL AND EMBEDDED COST STUDY

Q. Turning to the electric Cost of Service assertions included in IEP witness Dr. Kaufman's testimony. Have you reviewed Dr. Kaufman's hybrid marginal and embedded cost study?

A. Yes. During contract negotiations I was asked to provide a version of the Company's Docket UE-200900 filed cost of service study model with Schedule 25 separated into two columns, an IEP subset and all other Schedule 25 customers. I identified all direct assignment and allocation factor components associated with IEP in the test year to accomplish the segregation. Dr. Kaufman began his analysis with this model.

Q. Are the results of your Schedule 25 IEP separation study included in Exhibit LDK-5C?

A. Yes, the results at uniform proposed return (cost) are shown in the third column of the first table on page 1 of Exh. LDK-5C (under the heading Current COS model UE-200900 Total)[12]. Pages 7 through 16 of Exh. LDK-5C are the summaries and allocation factor pages showing how he modified the IEP segregated total to reflect how costs would have been assigned to a 50 MW subset of IEP usage within the Company's embedded cost model.

Q. Do you have any issues with Dr. Kaufman's 50 MW block embedded cost analysis?

[11] Dockets UE-170002 and UG-170003, General Order R-599, page 6, paragraph 24.
[12] Also shown on page 21of LDK-1CT as Confidential Table 9.

A. It works fine for the way he used it to identify the cost at unity (results at uniform proposed return) shown in the first column of the first table on page 1 of Exh. LDK-5C[13]. However, if someone wanted to make assertions regarding the results at present or proposed revenues, his exhibit details would be somewhat misleading. While he changed all the energy and demand allocator inputs to reflect a subset of IEP load, he did not correspondingly adjust the present or proposed revenue. This results in a slight mismatch in terms of the net operating income, rate of return, return ratio, and revenue-to-cost ratios that may be found on pages 7 through 10 of Exh. LDK-5C.

Q. Did you review the long-run marginal cost analysis included in the exhibit?

A. Yes, but only for how it was used in comparison to the embedded portions of the study which I found to be reasonable. However, Company power supply and transmission experts did review his marginal cost assumptions and provided input that was incorporated into the final study. Therefore, the Company considers this analysis reasonable.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

[13] Also shown on page 21of LDK-1CT as Confidential Table 9.