BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

AVISTA CORPORATION, d/b/a AVISTA UTILITIES,

Respondent.

DOCKETS UE-170485 and UG-170486 (*Consolidated*)

POST-HEARING BRIEF OF AVISTA CORPORATION

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I. <u>INTRODUCTION</u>

1 The Company filed a Three-Year Rate Plan ("Rate Plan") as the framework for rate relief. This is what we understood to be a common objective of several parties – i.e., to break what the Commission has described as a nearly continuous cycle of rate filings by Avista over recent years. Under the Rate Plan, Avista is proposing electric and natural gas revenue increases to occur May 1, 2018, May 1, 2019 and May 1, 2020. The Three-Year Rate Plan will provide a degree of predictability of retail rates for customers, while allowing the Company the opportunity to manage its costs in an effort to earn its allowed rate of return. In order for the Three-Year Rate plan to accomplish its intended purpose, it is important to properly recognize the level of plant that will be providing service to customers, beginning in Year One of the Rate Plan, as well as the Company's power supply costs which are based on the application of a proven AURORA$_{XMP}$ methodology. Moreover, accepting Staff's cost of debt to exclude the impact of interest rate hedges would have a punitive effect for actions taken to benefit customers. Finally, the Commission should also recognize the continuing efficacy of the Fuel Conversion Program. These

are among the more important issues that will be addressed in this Brief – all of which may have a significant impact on the Company.[1]

2 The revenue requirement for Year 1 was developed through a pro forming process of the 2016 historic test period. Years 2 and 3 were built on the use of a revenue growth factor, or "K-Factor," as previously employed by the Commission to set rates for Puget Sound Energy (PSE). Both the Company and Staff used the pro formed Rate Year 1 (May 1, 2018) as the starting point for Years 2 and 3, and built off of that. Because of that, it becomes all the more important to get the pro forming process for the first year right, because everything escalates from there. "Get it wrong, and the problem compounds itself, with even greater revenue requirement deficiencies in Years 2 and 3," as noted by Mr. Morris.[2]

3 Table No. 2, as excerpted from Ms. Andrews' Rebuttal Testimony,[3] is a summary of the revenue requirement positons by Staff, as well as Public Counsel, ICNU and NWIGU. As noted in the table, Public Counsel, ICNU and NWIGU oppose a Rate Plan that is otherwise supported by Avista and Staff.

Table No. 2

Summary of Proposed Revenue Requirement Positions (000s)						
	Electric			Natural Gas		
	May 1, 2018	May 1, 2019 (1)	May 1, 2020 (1)	May 1, 2018	May 1, 2019 (1)	May 1, 2020 (1)
Avista As-filed	$ 61,356	$ 13,983	$ 14,432	$ 8,269	$ 4,220	$ 4,417
Avista Rebuttal	$ 54,387	$ 13,459	$ 13,882	$ 6,630	$ 3,690	$ 3,842
Staff (2)	$ 10,034	$ 9,520	$ 9,740	$ 1,107	$ 2,698	$ 2,784
Public Counsel	$ 7,486	(3)		$ (530)	(3)	
ICNU	$ 197	(3)		n/a	(3)	
NWIGU	n/a	(3)		$ 1,592	(3)	
(1) Rate Years 2 and 3 based on Revenue Growth Factor on prior year proposed revenues.						
(2) Main difference with Staff is cost of capital, removal of power suppy update and level of capital additions.						
(3) Public Counsel, ICNU and NWIGU oppose a Three-Year Rate Plan.						

1 Docket Nos. UE-160228 and UG-160229, Order 06 at ¶6, fn. 5
2 Exh. SLM-6T, pp.8:14 – 9:2.
3 Exh. EMA-10T, p.8:1-10.

4 As shown in Table No. 3 below, approval of any of the recommended revenue increases proposed by Staff, Public Counsel, or ICNU/NWIGU in Table No. 2 above for Rate Year 1 (2018), would result in a return on equity (ROE) of over 140 to 230 basis points under that currently authorized (9.5%).[4]

Table No. 3

Resulting ROE of Proposed Revenue Positions of Parties		
	ROE Electric	**ROE Natural Gas**
Staff	**8.10%**	**8.00%**
Public Counsel	**7.80%**	**8.10%**
ICNU/NWIGU	**7.20%**	**7.50%**

5 For Rate Year 1, the primary differences between each of the parties, including Staff, Public Counsel, ICNU and NWIGU, and Avista on rebuttal, relate to 1) a lower cost of capital; 2) removal of any update to base power supply costs; and 3) a significantly lower level of capital additions (or rate base) to be included for Rate Year 1.[5]

6 The primary differences between Avista's and Staff's electric and natural gas revenue requirement positions for Year 1 are summarized in Table No. 4 below.[6]

Table No. 4

Line:	Reconcilation of Avista Rebuttal versus Staff Revenue Requirement - Year 1 (000s)					
				Electric	**Natural Gas**	
1	**Staff Filed**			**$ 10,034**	**$ 1,107**	
2	Power Supply			$ 16,609	-	See Company witnesses Kalich / Johnson
	Miscellaneous Contested Adjustments:			$ 1,690	$ 234	See Andrews (Section V. below)
		Electric	Nat. Gas			
3	Working Capital	$ (75)	$ 234			
4	Pro Forma Property Tax (1)	$ 694	-			
5	MT SB #363 Hydro Fee	$ 1,071	-			
6	Net Capital Adjustments			$ 12,632	$ 2,547	See Company witness Schuh & Andrews (Section III. below)
7	Cost of Capital			$ 13,422	$ 2,742	See Company witnesses Thies / McKenzie
8	**Avista Rebuttal**			**$ 54,387**	**$ 6,630**	
	(1) Avista believes Staff errorred in its calculation of its electric pro forma property tax adjustment. Once corrected, Avista and Staff would agree.					

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4 Id., at pp.7:18 – 8:10.
5 Exh. EMA-10T, p.10:9-10.
6 Id., at p.11:5-14.

7 As can be seen in Table No. 4 above, the primary differences between Staff and Avista are shown on lines (2) Power Supply ($16.6 Million electric); (6) Net Capital Adjustments ($12.6 Million electric / $2.5 Million natural gas); and (7) Cost of Capital ($13.4 Million electric / $2.7 Million natural gas).[7]

8 The primary differences between Staff and Avista for Rate Years 2 and 3 of approximately $4.0 Million electric and $1.0 Million natural gas, are due to: 1) the size of the Year 1 revenue increase, and 2) the revenue growth factor used to determine Years 2 and 3, which is applied to the previous year's proposed revenue.[8]

9 As discussed below, the Company experienced better than anticipated "normalized" results for 2017:

- In 2017, the normalized earnings were better than expected, with the Company earning "slightly under" a 9.5% electric ROE and an 11.4% gas ROE, resulting in a combined ROE of 9.7% on its Washington operations.[9]
- This combined result somewhat exceeded its authorized 9.5% ROE. Given the existing sharing mechanism, the Company will return one-half (1/2) of any over-earnings to its customers.
- These better-than-expected earnings were the result of, e.g., lower pension costs, lower medical expenses, and lower O&M costs.[10]/[11]

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7 Additional testimony regarding line (2) Power Supply can be found in the rebuttal testimonies of Company Witnesses Mr. Kalich (Exh. CGK-4T) and Mr. Johnson (Exh. WGJ-6T), and line (7) Cost of Capital can be found in the rebuttal testimonies of Company witnesses Mr. Thies (Exh. MTT-6T) and Mr. McKenzie (Exh. AMM-14T). Company Witnesses Ms. Andrews and Ms. Schuh discuss the adjustments impacting line (6) Net Capital Adjustments at Exh. EMA-10T and Exh. KKS-3T, respectively.

8 Exh. EMA-10T, p.10:1-4.

9 Tr. pp. 378-379.

10 Tr. pp. 383-385.

11 Examples of some unusual and unexpected items included reductions in pension and medical expenses, credit and collection expenses, and software licensing expenses. Pension expenses unexpectedly decreased due to changes in asset allocation and favorable returns on the fund balance. The Company has a self-insured medical plan. Claims under the plan for 2017 have come in lower than projected resulting in lower medical expenses. The accrual for bad debt expenses (write-offs of delinquent customer accounts) decreased during the year because of process improvements in the credit and collections processes. The Company planned to incur certain software

- Because ratemaking is not a backward-looking exercise, the results in 2017 do not argue against the need for rate relief; rather, the evidence of record for 2018 and beyond demonstrates the need for additional rate relief.

Before addressing the particulars surrounding each contested issue, it is important to also recognize that changes in the tax law should not affect the issues in this case. The changes, however, will serve to offset a portion of the requested relief. The Company's response to Bench Request No. 1[12] and its testimony made clear that:

- Customers will see the benefits of recent tax law changes.
- While uncertainty remains concerning multiple tax adjustments (some are offsetting), the Company will make a separate tariff filing on or before March 31, 2018, in which it will propose to flow through those benefits to Washington customers.[13] [Since changed to February 28, 2018, as directed in Bench Request 9.]
- The objective is to synchronize the effective date of these changes with general rate relief in this case, on or about May 1, 2018, allowing tax benefits to offset a portion of Avista's need for rate relief.[14]

II. CAPITAL ADDITIONS MUST BE PROPERLY REFLECTED IN RATES

10 While elaborated on below, the principal contentions of Avista are as follows:

- There has been no challenge to "prudency" of capital additions.
- Staff and other parties have not recognized the level of plant that will be in-service for the benefit of customers during any of the rate years.

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licensing expenses in 2017, but that did not occur due to the timing of certain information technology projects. These unexpected decreases also affected natural gas operations. (Exh. MTT-6T, p.10:1-10)

12 Exh. BR-1.

13 Any subsequent adjustments to the calculation of tax benefits (not expected to be significant) can be "trued –up" in a subsequent amendment to the filed tariff. (See Response to Bench Request No. 1, Exh. BR-1)

14 At time of hearing, based on preliminary information, Company witness Thies testified that Washington's share of the tax relief related to "just the effects of current income taxes" would be in the range of $20 - $30 million. (Tr. p 346) On February 22, 2018 the Company announced through its quarterly earnings release that Avista expects that the benefit to customers on an on-going system basis is approximately $50 - $60 million, exclusive of amounts deferred during 2018 to be returned to customers at a later time. Avista is refining its analysis, and will be providing its response to Bench Request No. 9 by February 28, 2018, indicating that Washington's annual share of long-term or on-going benefits will be approximately $34.5 million. Additional benefits will be returned to customers on a short-term basis associated with 2018 deferred balances. The Commission has provided an opportunity to other parties to file a response to Bench Request No. 9 on or before March 21, 2018.

- Staff's analysis has shortcomings at every step in the process –

Step 1:

→ Although adopting a year-end rate base for the 2016 test period, Staff did not reflect associated depreciation expense, thereby only providing a return "on" and not a return "of" the investment (resulting in a $4 Million impact on electric revenue requirement and a $0.8 Million impact on natural gas revenue requirement, carrying through each year of the Rate Plan).

Step 2:

→ In "proforming" the test period, Staff only picked up seven (7) out of one hundred and twenty-one (121) projects.

→ This was based on an arbitrary "threshold" of 0.5% of net plant for audit purposes, automatically excluding any plant items less than $8.6 Million (electric) and $1.7 Million (natural gas).

→ The Company revised its manner of presentation in this case in order to make it more "user-friendly" for audit purposes, sorting projects into 6 investment drivers and describing each and every one of the 121 projects in testimony and backed up by business cases attesting to the need for, and immediacy of, each project.

→ As a compromise, on rebuttal, the Company revised its revenue requirement to reflect a "functionalization" by plant category when applying the "threshold," thereby including 36 out of 121 plants, but still excluding $23 Million of investment. This was the approach recommended by Staff in the recently-concluded PSE cases (Dkt. No(s). UE-170033 and UG-170034), but inexplicably ignored in Avista's case.

Step 3:

→ Staff, without any explanation, simply stopped its analysis after its limited proforming process in Step 2, without contemplating whether more needed to be done to provide the Company with a reasonable opportunity to earn its return in the 2018 Rate Year. This was inconsistent with the Staff's own testimony in Avista's 2015 and 2016 rate cases where, notwithstanding the use of a proformed test period, Staff Witnesses McGuire (2015) and Hancock (2016) added an attrition adjustment to determine the revenue requirement for the ensuing rate year. That did not happen here for the 2018 Rate Year in this case. Because Years 2 and 3 of the Rate Plan simply escalate from 2018 rate base (via "K-Factor"), the under-recovery perpetuates itself for the remainder of the

Rate Plan. [NOTE: Both Company and Staff argue for a revenue growth factor ("K-Factor") to apply to revenues for Years 2 and 3.]

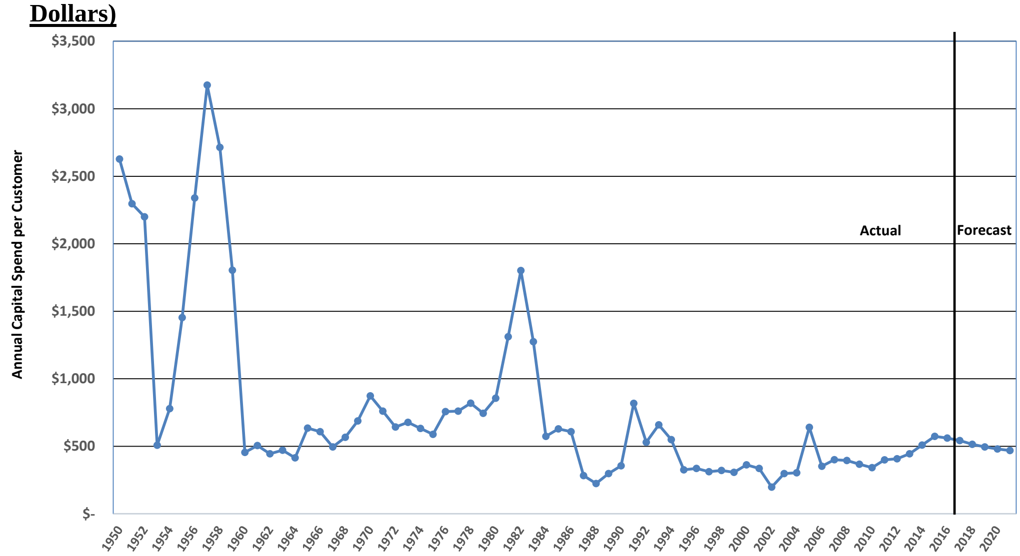
Step 4:

→ Rate Years 2 and 3 include an insufficient level of plant because the "K-Factor" escalator works off an incorrect 2018 base year (see Step 3).

- In conclusion, Staff's analysis understates electric plant rate base by $85 Million in Year One, $76 Million in Year Two, and $90 Million in Year Three. (*See* Chart 1, Exh. EMA-10T, p.29)

11 Before addressing the specifics of each party's proposals concerning capital additions, some additional perspective may prove useful. How does Avista's capital spending at issue in this case compare with its prior spending and how does it compare with the industry-at-large? The illustration below expresses Avista's annual capital spending per customer over time:[15]

Illustration No. 11 – Avista Annual Capital Spend per Customer - 1950-2021 (2016 Dollars)



This shows that capital spending is in keeping with past practice. Moreover, the Company's spending compares quite favorably with the trends in the industry-at-large, as shown below:[16]

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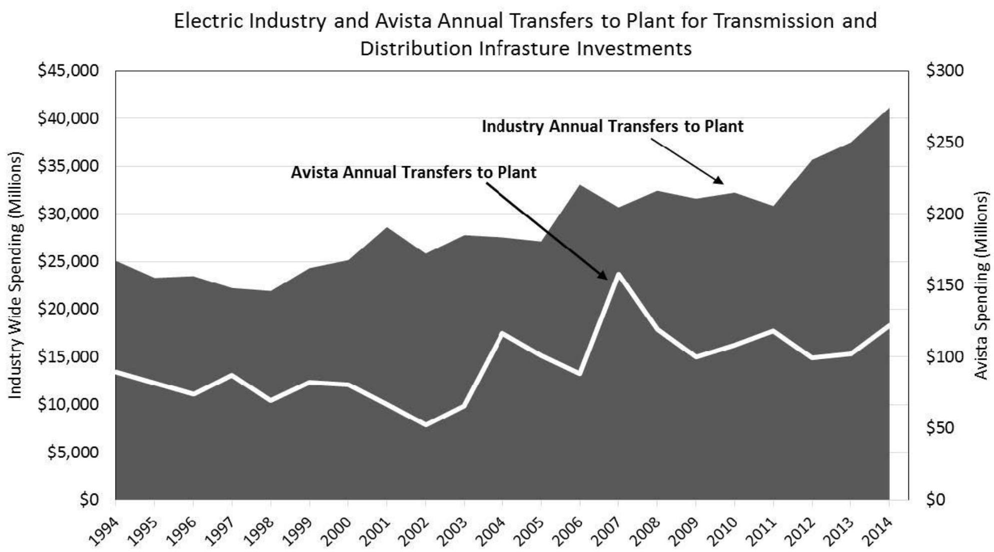
[15] Exh. SLM-1T, p.28.

[16] Exh. HLR-1T at p.8.



A. Step 1: Properly Adjust 2016 EOP Results.

12 As Company Witnesses Schuh (Exh. KKS-3T) and Andrews (Exh. EMA-10T) discuss on rebuttal, for Year 1 of the Rate Plan, Staff began with end-of-period results for 2016. Staff restated the Company's 2016 historical (test period) average-of-monthly-average (AMA) rate base balances to a 2016 EOP basis.[17] Staff, however, excluded depreciation expense when it adjusted its 2016 AMA balances to an EOP basis.

13 Although the Company is supportive of adjusting 2016 AMA balances to an EOP basis, the Company believes it is equally important to adjust the associated depreciation expense to match the rate base balances being adjusted. That "matching" is a fundamental ratemaking principle, as testified to by Ms. Andrews:[18]

> To adjust rate base AMA levels to EOP levels, only allows the Company to recover "the return on" that investment. However, without also including the annualized level of depreciation expense on that same level of rate base, prevents the Company

[17] Exh. EMA-10T, p. 27:17 – 28:17.
[18] Exh. EMA-10T, p.20:6-10.

> from recovering its investment or "return of" that same investment. This mismatch distorts "rate year relationships."[19] In fact, this mismatch distorts the relationship over the full Three-Year Rate Plan. Because this depreciation expense is excluded in Year 1, there is no opportunity to recover it in Years 2 and 3. The resulting impact of Staff excluding the annualized depreciation expense within its 2016 AMA to EOP adjustment is approximately $4.0 Million for electric and $767,000 for natural gas, annually.[20] (Emphasis added)

B. Step 2: Properly Capture Pro Formed Results for 2017.

14 Next, Staff only provided for very limited pro forming of capital additions in 2017, capturing only 7 out of 121 projects that will be in service and used and useful in 2017 – i.e., well before the start of the May 1, 2018 Rate Year. Staff only selected the seven projects for inclusion based on its application of a "threshold" of 0.5% of net plant, thereby excluding any projects less than $8.6 Million for electric and $1.7 Million for natural gas.[21] Further limiting Avista's ability to recover on its prudent investments, of the seven projects selected, Staff only included transfers to plant through August 2017,[22] thereby leaving a substantial portion of 2017 rate base associated with even those 7 projects on the "cutting room floor" (by not going through December 2017).[23]

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19 Ms. Andrews provided a simple illustration of this:

> This can be also be explained using a simple example: a capital project that actually went into service in December of the test year (2016), under generally accepted accounting principles (GAAP) would require that depreciation expense be recorded at ½ of one month for the month it moves into service. For this project ½ of one month would be recorded as expense in the test year (4% of the expense), resulting in 11 ½ months of depreciation expense being excluded during the test year (96% of the expense), although the full project amount is included in rate base. Under Staff's proposal 96% of the depreciation expense would be excluded annually Year 1 through Year 3, understating depreciation expense during the entirety of the Three-Year Rate Plan through May of 2021.

Exh. EMA-10T, p.20, fn.42.

20 Id. at pp.20:10 – 21:2.

21 Exh. KBS-1T, p.19:22-23.

22 Exh. KBS-1T, p.18:8.

23 Finally, even if the Commission accepted Staff's threshold, Staff's calculation should have at least reflected net plant after ADFIT. Staff's adjustment was calculated using the Company's December 31, 2016 electric and natural gas Commission Basis Reports by using the net plant balance before ADFIT. As noted by Ms. Scanlan, in the Company's 2015 case, the Commission even noted that the application of the 0.5% threshold should be on a net rate base basis. (Docket UE-150204 and UG-150205, Order 05, ¶40.) (Exh. KKS-3T, p.11:14-26) *See* Rate base, with respect to plant, is, by definition, net plant after ADFIT. The use of net plant before ADFIT serves only to artificially inflate the calculated "threshold" (thereby further reducing the projects that exceed the threshold). Therefore, the threshold used to calculate the pro forma capital additions should be consistent with the method

15 The Company, in its initial filing, provided extensive documentation for each of the 121 projects, including detailed business cases explaining the need for each, the timing and the cost.[24] In short, the information necessary for Staff and parties to begin their audit process was provided in the Company's filing in May 2017. And yet, Staff only selected seven projects to be audited during the five months prior to the filing of its testimony – leaving 114 projects and $232.6 Million (gross plant) of plant increases in 2017 unaccounted for – all of which are necessary in the ordinary course of business.[25]

16 Avista provided a description of the need and timing for each capital project that was included for purposes of deriving a revenue requirement. More specifically, Company Witnesses Mr. Kinney, Mr. Kensok and Ms. Rosentrater provided hundreds of pages of testimony[26] and exhibits[27] that contained descriptions of each and every project, the timing and need for the projects, and the consequences of not completing the projects in the timeframe considered. As testified to by Company Witness Schuh, this approach was very purposeful.[28]

17 Moreover, Avista responded to over 50 data requests related to capital additions from Staff alone. Further, Staff Witness Ms. Scanlan, replying to an Avista data request, stated that:[29]

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indicated by the Commission. The Company correctly used the net plant after ADFIT balance to calculate this threshold in its filed case. Exh. KKS-3T, pp.11:14 – 12:3.)

24 Exh. HLR-6, Exh. JMK-2, Exh. SJK-4.

25 For electric operations, the use of an $8.6 Million threshold only captures 3 projects (or $11.2 Million). For natural gas operations, the use of a $1.7 Million threshold only captures 5 projects (or $9.9 Million). The use of such a threshold says nothing about the actual level of plant that will be in service and used and useful when rates go into effect in May 2018. Further, it leaves, on the "cutting room floor," 99 electric projects (or $198.2 Million of gross plant), and 37 natural gas projects (or $34.4 Million of gross plant). (As noted previously, for purposes of counting projects specifically for electric service and natural gas service, electric and natural gas projects are counted separately (e.g., a project common to both is counted once for each service type) (Exh. KKS-3T, p.12:6-11).

26 See Exh. SJK-1T, JMK-1T, and HLR-1T.

27 See Exh. SJK-4, JMK-2 and HLR-6.

28 Exh. KKS-3T, p.8:8-15.

29 Exh. KKS-3T, pp. 8:19 – 9:3.

> As part of Staff's review, analysis and audit, Joanna Huang, Kathi Scanlan, and Christopher Hancock, met with Avista's pro forma project business case owners and project leads, Avista witness Karen Schuh, and plant accounting representatives on September 27, 2017, at Avista's Headquarters. We discussed the method and effectiveness of Avista's internal control system for capital projects, including capitalization policy for electric and natural gas operations and capital project request and approval procedures, using the company's "Capital Project Request" Form, Location List, and FERC accounts and task list categorization.

Unfortunately, however, because Staff relied on a threshold of 0.5% of overall net plant for capital projects in the pro forma period, Staff only performed written and/or on-site discovery regarding 10 projects of the 121 projects.[30]

18 Not only did Staff employ an arbitrary threshold of 0.5% of net plant, but it did so in a manner <u>inconsistent</u> with the way it applied the threshold in the recently-concluded Puget Sound Energy rate case.[31] In that case, Staff Witness Wright filed testimony that acknowledged that, unless the "threshold" was applied to net plant on a "functional basis" (i.e., 0.5% of net plant applied to <u>each</u> category of generation, transmission, distribution, and, general plant respectively) it would not produce reasonable results.

19 In his testimony, Mr. Wright explains, similar to Ms. Scanlan, the standards for evaluating pro forma plant adjustments, i.e., are the proposed plant additions "major," "known and measureable," "used and useful," and "prudently incurred."[32] However, when responding to whether he was adhering to the Commission guidance on how to analyze these initial questions, Mr. Wright stated:

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30 These 10 projects correspond to Avista's major pro forma plant projects included in its original case—5 electric, 7 natural gas. One project is common between electric and natural gas service and one natural gas project was inadvertently included, leaving 10 discrete projects. Ultimately, Staff's selected threshold excluded 3 of these projects, leaving only 7 projects (2 electric, 4 natural gas, and 1 common to both electric and natural gas) included in Staff's case. (Exh. KKS-3T, p.9, fn. 16)

31 Docket No. UE-170033 and UG-170034.

32 Exh. EMA-10T, p.26:14-16. Wright, Exh. ECW-1T, p.6:8-12, Puget Docket No. UE-170033 and UG-170034.

> Yes. Although Staff has tailored its review to the specific facts and circumstances in the current rate case, recent Commission orders and guidance strongly inform Staff's analysis.
>
> First, the Commission recently found it reasonable to define a major plant addition as at least 0.5 percent of the utility's rate base. However, Staff found smaller adjustments that would otherwise be reasonable, such as Distribution plant adjustments, would not be captured if the threshold were only applied to gross rate base. Therefore, Staff refined the standard in this case, applying the one-half of one percent threshold to net utility plant in service by category instead of rate base. Staff believes the refinement will allow a better review of plant adjustments in this, and future, rate cases. (Emphasis added) [33 / 34]

20 Essentially, Staff Witness Cooper applied the 0.5% of net plant "threshold" on a "functionalized" basis to each major functional category – i.e., production, transmission, distribution and general plant. This is far different than applying the 0.5% of net plant threshold to the aggregate of all plant and leads to dramatically different results. Staff's application of their "threshold" to all aggregated plant produces an $8.7 Million "threshold" for electric and a $1.7 Million "threshold" for natural gas service, thereby excluding the vast majority of plant-in-service for audit purposes.[35]

21 Ms. Scanlan in this case did not make any effort to use a "functionalized" approach, in order to be consistent with Staff's own position in the then-pending Puget case. Mr. Wright's testimony in the Puget docket (UE-170033 / UG-170034) on behalf of Staff, and using a "functionalized" approach, was filed on June 30, 2017, more than three and one-half months before Ms. Scanlan's testimony on the same issue was filed in this case, allowing more than enough time to consider this method in Avista's case, but it was not.[36]

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33 Exh. EMA-10T, pp. 26:18 – 27:5.

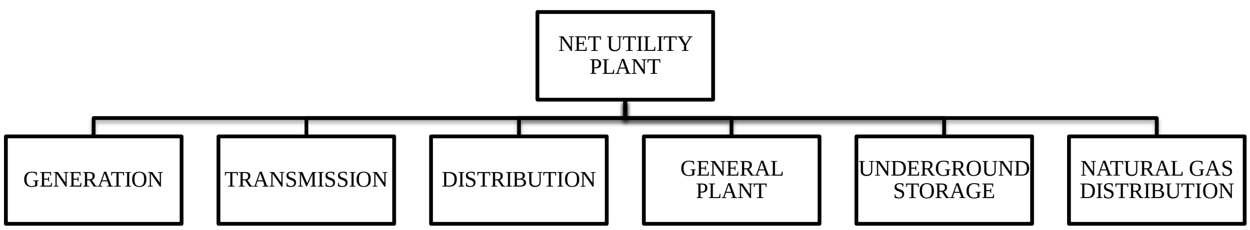
34 Mr. Wright further explains his threshold by "category" included a separate electric and natural gas threshold for each of the following categories as reported in Puget's 2015 FERC Form 1 and 2 reports: 1) Production; 2) Transmission; 3) Distribution; and 4) General plant. *Id.* p. 7, footnote 12. (Exh. EMA-10T, p.27, fn. 62)

35 Exh. SLM-6T, pp.14:8 – 13:13.

36 Exh. KKS-3T, p.15:4-9.

22 On rebuttal, the Company determined a threshold for the pro forma electric and natural gas projects of 0.5% of the Company's net plant by functional group (i.e., a functionalized threshold), as in the Puget Docket (UE-170033 and UG-170034). Instead of using 0.5% on all aggregate plant, the Company used 0.5% of functional plant by FERC accounting groups listed in Avista's FERC form 1, as did Staff in the Puget case.[37] Those accounts are: Generation,[38] Transmission, Distribution, General Plant, Underground Storage and Gas Distribution. Illustration No. 3 below provides a simple schematic of this functionalization:[39]

Illustration No. 3: Electric and Natural Gas Functional Groups



23 Using 0.5% of the Company's net plant by functional group, the Company identified pro forma projects that are above the 0.5% threshold as applied to net plant before ADFIT by functional group.[40] This threshold yielded 31 electric projects and 17 natural gas projects, with a total of 36 discrete projects to be included within Avista's pro forma capital adjustment, instead of Staff's 7 discrete projects for Electric and Natural Gas.[41] These Pro Forma functional group

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37 Exh. KKS-3T, p.16:3-7.

38 For generation projects, Avista functionalized this category into thermal, hydro, and other generation. (Id. at p.16, fn. 28)

39 See Exh. KKS-3T, p.16:7-12.

40 As discussed earlier, Avista believes that it is more appropriate to reflect Net Plant after ADFIT. For rebuttal purposes only, Avista also used Staff's Net Plant before ADFIT Methodology in an effort to reach common ground in this case. (Exh. KKS-3T, fn. 27)

41 (Exh. KKS-3T, p.16, fn. 29) 12 projects are common to both Electric and Natural Gas service in Washington. As a result, the total of 36 discrete projects is composed of 19 Electric projects, 5 Natural Gas projects, and 12 projects common to both.

projects represent actual capital additions as of October 31, 2017, together with the associated Accumulated Depreciation (AD) and ADFIT.[42]

24 Furthermore, to reflect concerns by the parties that projects included meet the "used and useful," and "known and measureable" tests, the Company only included those project costs that actually transferred into service as of October 31, 2017, as noted. Company Witness Schuh also provided levels of plant in service through August and September of 2017, were the Commission not to reach out through October of 2017. (*See* Exh. KKS-3T, p.21:9-17 (Table 7)):

	2017 Pro Forma Additions (Through October)	2017 Pro Forma Additions (Through September)	2017 Pro Forma Additions (Through August)
Electric			
Net Rate Base	$ 62,544	$ 53,029	$ 45,841
Revenue Requirement	$ 11,610	$ 10,055	$ 8,671
Natural Gas			
Net Rate Base	$ 16,488	$ 14,189	$ 12,453
Revenue Requirement	$ 3,170	$ 2,787	$ 2,441

25 The 36 threshold projects selected by the Company out of the total 121 projects originally included in Avista's direct filed case, still results in less than 30% of the projects being selected (or 70% excluded).[43] This concession, in and of itself, will create significant regulatory lag.[44]

42 Id. at p.16:19.

43 Exh. EMA-10T, p.33:16 – p.34:4.

44 As explained by Ms. Andrews, the Company has also included a reduction to expense by way of a "Pro Forma O&M Offsets" adjustment (3.11). Many projects are justified based solely on other investment drivers, as discussed by Mr. Morris. However, to provide a meaningful benefit to customers for real savings expected during the 2018 Rate Year, included in the electric O&M offset adjustment is a reduction to expense of $800,000 related to the project "Street Light Conversion to LED Fixtures" (ER 2584), even though this project is not included as one of the threshold selected projects (i.e. this project was left on the "cutting room floor"). This adjustment provides a 10% reduction in the electric revenue requirement amount included related to the 2017 capital additions. (Electric Pro Forma threshold adjustment revenue requirement total ($11.6 Million) versus electric O&M adjustment (-$1.2 Million)) (Exh. EMA-10T, p.34:5-17).

26 Conversely, the functional group method still excludes 85 discrete projects expected to be in service during 2017 and reflects approximately $23 Million less in overall rate base additions than what the Company included in its original filing.[45] Accordingly, on rebuttal, the Company is now excluding a number of projects that went into service in 2017, not to mention projects that are not included from the January 1 to May 1, 2018 time period that will be in service before new rates go into effect.

27 For the limited subset of projects included in Avista's "functionalized" threshold, Mr. Kinney discusses the generation capital projects in Exh. SJK-5T, Ms. Rosentrater discusses the transmission, electric and natural gas distribution plant, and general plant items in Exh. HLR-7T, and Mr. Kensok discusses the IS/IT capital projects at Exh. JMK-3T. These witnesses also summarize the remaining plant items that have still been excluded altogether from the Company's rebuttal case. Ms. Rosentrater provides some examples of the projects that have effectively been left on "the cutting room floor," but otherwise will be used and useful and in-service in the rate effective period – e.g., required electric relocations/replacement of failed transformers.[46]

28 Mr. Kinney provided examples of projects that will be in service and used and useful when rates go into effect in May of 2018, yet have been excluded even from the Company's rebuttal case – e.g., compliance with FERC licensing requirements and hydro-maintenance.[47]

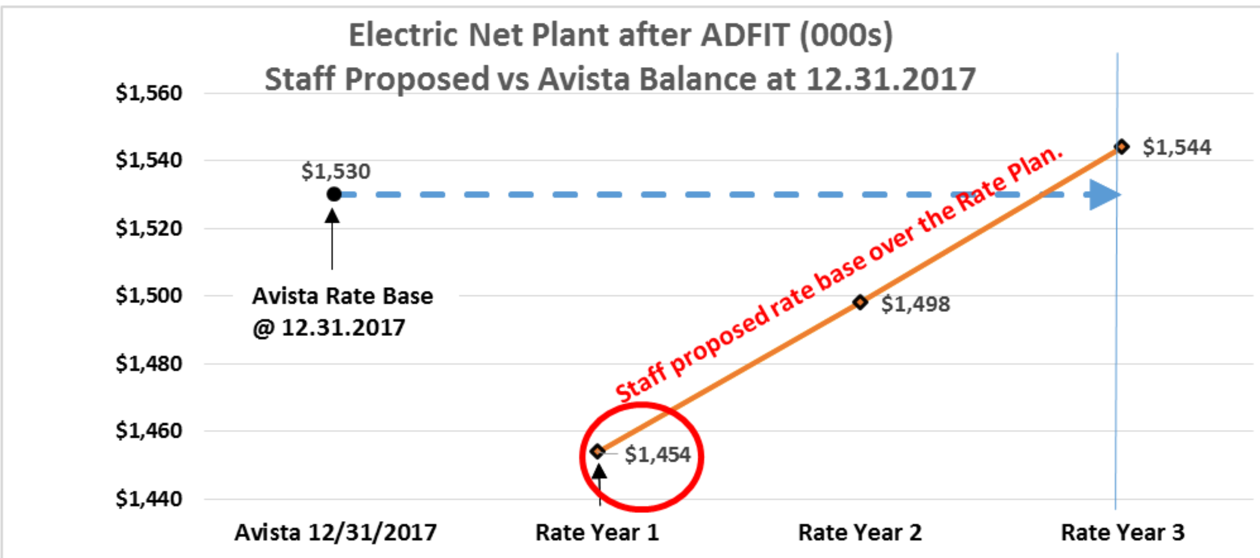
29 Additional projects that will be in service and used and useful when rates go into effect in May of 2018, yet have been excluded even from the Company's rebuttal case, include examples

45 Ibid.
46 Exh. HLR-7T, pp.15:1 – 16:11.
47 Exh. SJK-5T, p.9:6-34.

such as high voltage protection for substations and replacement of an outdated mobile radio system.[48]

30 To put all of this into better perspective, Illustration No. 4, excerpted from Mr. Morris' rebuttal testimony (Exh. SLM-6T at p.10), shows that the level of Washington electric rate base at December 31, 2017, if the Commission were to accept Staff's case, would not be reflected in rates <u>until Year 3</u> of the Rate Plan (i.e., May 1, 2020):

<u>Illustration No. 4: Staff's Net Plant Compared to Avista's at December 31, 2017</u>



31 In the end, Avista, for its part on rebuttal, has essentially agreed to include a combined electric and natural gas rate base "regulatory lag" of $37 Million to $40 Million annually over the Rate Plan, and a revenue requirement loss of approximately $5 to $8 Million annually. This compares to the regulatory lag of <u>over $100 Million **annually**</u> of plant over the Rate Plan that

48 Exh. JMK-3T, p.9:4-34.

would result from Staff's proposals. This would translate into an **annual** combined revenue loss of between $21 Million and $24 Million.[49]

32 Chart No. 1 below[50] further illustrates just how unrepresentative Staff's proposed level of rate base will be during the Rate Plan:

Chart No. 1

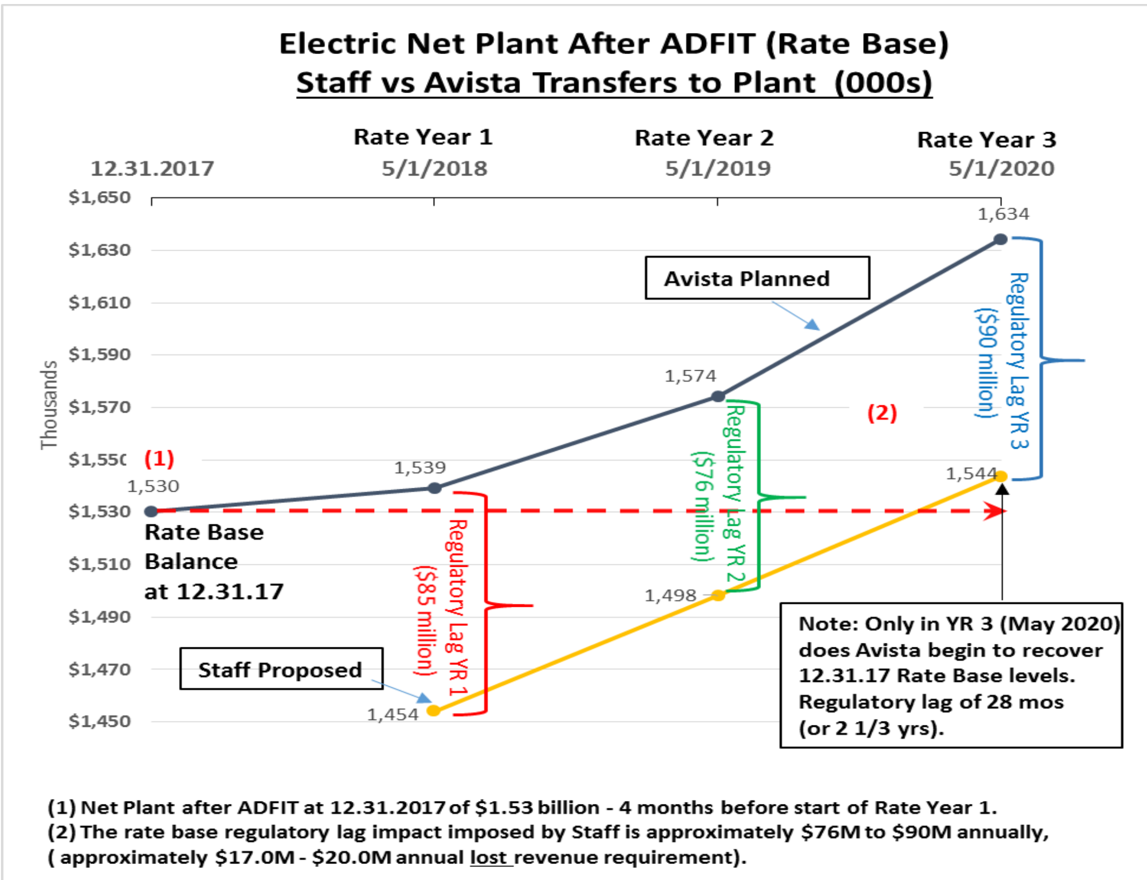


Chart No. 1 above, representing electric only, highlights some very important problems with Staff's rate base proposals:[51]

1) Avista would not begin to recover December 31, 2017 rate base levels that will be used and useful, and benefiting customers prior to Rate Year 3 (beginning May 1, 2020); an imposed "regulatory lag" of 28 months or 2 1/3 years.

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49 Exh. SLM-6T, p.21:10-17.

50 *See* Exh. EMA-10T, p.29:8-22

51 Exh. EMA-10T, p.30:1-16.

2) Under the Three-Year Rate Plan, supported by both Avista and Staff, the Company will not be able to file a new general rate case to reset to more current rate base balances until 2020 for rates effective May 2021, underscoring on the importance of establishing the appropriate balance in Year 1, as a starting point.

3) The electric "regulatory lag" exposure to the Company alone would be approximately $85 Million in Rate Year 1 and grow to $90 Million during Rate Year 3.

4) The revenue requirement impact of that "regulatory lag" exposes the Company to between $17.0 and $20.0 Million of annual lost revenue.

33 Including Staff's natural gas proposed rate base, the combined "regulatory lag" for the Washington jurisdiction would escalate to $100 - $107 Million annually, and result in annual lost revenues between $21.0 - $24.0 Million. This roughly translates into a 140 to 160 basis point shortfall compared to the Company's current authorized 9.5% ROE.[52]

34 Finally, Staff Witness Mr. Hancock proposed using Construction Work in Progress (CWIP) as an alternative to Avista's 2017 EOP adjustment.[53] CWIP on a system basis as of December 31, 2016 is $144.7 Million. Simply using a general allocation, results in a Washington electric and natural gas amount of $70.5 Million and $19.7 Million, respectively.[54] These balances are lower than the amount even Staff has proposed in this case and do not reflect the level of plant in service that will benefit customers during Rate Year 1.[55]

35 Turning to other parties, ICNU/NWIGU joint witness Mr. Mullins did not include an adjustment for 2016 end of period plant as proposed by Staff, and only included two pro forma

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[52] Id. at p.30:20-23. Staff's adjustments for pro forma electric and natural gas capital additions are in error by not including the full transfer-to-plant amounts even through August of 2017. Correcting Staff's adjustments result in an incremental increase of approximately $1.08 Million and $500,916 in gross plant, for electric and natural gas, respectively, to Staff's gross plant additions. Please see Exh. KBS-1T, pp. 20-21, Exh. KBS-3 and Exh. KBS-4. The associated incremental increase to Staff's revenue requirement associated with these corrections would be $277,000 and $140,000 for electric and natural gas, respectively.

[53] Exh. CSH-1T, pp. 43:19-44:2.

[54] Exh. KKS-3T, p.24:10-14.

[55] Ibid. Moreover, the Company does not track CWIP on a Washington electric and natural gas allocated basis. Tracking this on a Washington basis would be an enormous administrative burden increasing operations expense. This is because the Company accrues Allowance for Funds Used During Construction (AFUDC) while projects are in CWIP. The Company would need to stop allocating AFUDC to Washington electric and natural gas projects (to avoid double counting), while still allocating AFUDC to the Company's other jurisdictions. The Company's current accounting system does not have this capability. (Exh. KKS-3T, p.24:4-8)

projects.[56]/[57] Public Counsel included the 11 pro forma study adjustments as proposed by the Company, but did not include the end of period plant adjustment for 2016 as proposed by Staff.[58] No party reached out further into 2017 to include capital additions that otherwise are, or will be, used and useful and serving customers before the May 1, 2018 effective date for Year 1 of the Rate Plan.

36 As concerns the pending depreciation study, Public Counsel, ICNU and NWIGU raised certain concerns with regard to Avista's in-progress depreciation study. Public Counsel Witness Mr. Garrett states that "It is possible that depreciation costs could be low enough that they would offset much of the Company's requested increases particularly in years two and three."[59] ICNU and NWIGU witness Mr. Mullins expresses a concern that "if depreciation rates decline, that will provide a windfall to Avista."[60]

37 Company Witness Schuh, on rebuttal, explained how Avista envisions the filing of its depreciation study when completed. Upon completion of this study (expected in the first quarter of 2018), Avista will file the results of its study with the Commission, as well as with the Idaho Public Utilities Commission and the Public Utility Commission of Oregon. These filings would take the form of accounting petitions requesting the approval to update depreciation rates to the rates suggested by the results of the study. Along with the approval to update the depreciation rates, Avista would request approval to surcharge or rebate customers, through a separate tariff, to reflect the actual depreciation expense associated with the updated depreciation rates.

56 Both Public Counsel and ICNU/NWIGU propose even lower rate base balances than those proposed by Staff. These parties, consistent with Staff, remove the Company's 2017 EOP adjustment. However, unlike Staff, they do not restate 2016 AMA plant related balances to EOP, and they each include different "2017 Threshold Capital Additions" adjustments. For its part, Public Counsel leaves the Company's original 2017 threshold adjustment as filed. However, Mr. Mullins, on behalf of ICNU/NWIGU, uses an arbitrary cut-off to further reduce his proposed rate base balances. Ms. Schuh discusses Avista's concern with Mr. Mullin's method in her responsive testimony. (Schuh rebuttal, Exh. KKS-3T, pp.24:15 – 27:6; Exh. EMA-10T, pp.30:26 – 31:5)

57 Exh. BGM-1T, pp. 23:1-28:5.

58 Exh. MEG-11 (Electric) and Exh. MEG-12 (Natural Gas).

59 Exh. MEG-1T, p.20:8-9.

60 Exh. BGM-1T, p.33:8-9.

Alternatively, in the absence of approval to surcharge or rebate customers, the Commission could approve deferral of the difference for later amortization, between existing depreciation rates and the updated depreciation rates.[61]

38 Finally, it should be remembered that the Company proposes to file with this Commission an Annual Washington Electric and Natural Gas Capital Report by February 15, 2019 and February 15, 2020 (approximately 75 days) prior to new rates going into effect in order to provide the Parties' ample time to review prior to the rate effective date. The annual report would provide actual year-end balances for the calendar year as of December 31st (EOP net plant balances including impact of A/D and ADFIT) and would be compared to the level of plant approved in this case. The Company will also provide transfer to plant detail by expenditure request of the transfers that occurred during the previous year to reconcile with the gross plant balance provided in the summary balances. This would provide assurance to the Commission that the rate increases approved include net plant which actually is in-service and serving customers prior to new rates going into effect.[62]

C. Step 3: Review Step 2 for Reasonable End Result and Further Adjust if Necessary.

39 As previously discussed, Ms. Schuh's testimony notes that the "threshold" of 0.5% of net plant is arbitrary and was simply drawn from an unrelated "budget" rule requiring the filing of annual budget reports (WAC 480-140-040).[63] It was never meant to provide the final answer for ratemaking, but it has become such.[64] Furthermore, although the use of this "threshold" was employed by the Staff in the Company's prior rate cases (over Avista's objection), it only served

61 Exh. KKS-3T, p.28:7-18.
62 Exh. KKS-3T, p.31:8-18.
63 Exh. KBS-1T, p.18:11-12.
64 The Commission, in Docket No. UE-150204 and UG-150205, did not state that the "threshold" in WAC 480-140-040 should be used for all future cases; rather, the Commission states that it was appropriate in that case. To that end, the Commission stated in Order 06, at ¶82 in Docket Nos. UE-160228 and UG-160229 (Avista's 2016 general rate case) that it has "… not established bright-line standards governing the timing or the number of adjustments that can be accepted in a given case, and **has not established a minimum size for pro forma adjustments** to be recognized." (emphasis added) (Exh. KKS-3T, p.10:1-14)

as the starting point for Staff's analysis in those prior cases - not the ending point as is the case here. In the prior cases, after using this "threshold," Staff determined that it did not produce reasonable results and added an attrition adjustment to the pro formed historic test period.[65] Not so here. Staff in the prior two Avista general rate cases did not rely solely on the use of a capital threshold for purposes of deriving a revenue requirement in the rate year. It did not become the "final answer for ratemaking purposes," as testified to by Ms. Schuh:

> In the end, Staff's attrition adjustment escalated revenues, expenses, and rate base to a level more appropriate for the rate effective period. By now exclusively relying on a threshold level of capital as the final answer for ratemaking purposes, and discarding the vast majority of projects that will be in service before new rates go into effect, Staff's revenue requirement will not afford the Company with a reasonable opportunity to earn a fair rate of return in the rate effective period.[66] (Emphasis added)

40 In this case, however, Staff is proposing no further adjustment that would provide Avista with a reasonable opportunity to earn its approved rate of return in Year 1 of the Rate Plan, unlike the 2015 and 2016 cases. Accordingly, Staff's approaches in the 2015 and 2016 cases are very different from this case. In 2015 and 2016, Staff acknowledged that the use of only a pro forma study would be insufficient, and therefore derived an attrition adjustment that added to the Pro Forma Study. Indeed, in the 2015 case, Staff Witness McGuire acknowledged:

> Given that the rates calculated using a modified historical test year generate revenues that fall short of those necessary to provide Avista with a reasonable opportunity to earn a fair rate of return, Staff recommends the Commission provide Avista with an attrition allowance of $14.7 Million for electric operations and $5.4 Million for natural gas operations. This dollar amount corresponds to the difference between Staff's pro forma revenue requirement and the revenue requirement calculated using Staff's attrition analysis.[67]

Likewise in the following year in the 2016 case, Staff Witness Hancock testified:

> Staff recommends the Commission include an attrition adjustment to the modified historical test year analysis based on the attrition studies I present. Staff Witness Ms. Joanna Huang presents Staff's calculation of the revenue requirements for

[65] Exh. SLM-6T, pp.13:15 – 14:5.
[66] Exh. KKS-3T, p.13:3-11.
[67] (Exh. KKS-3T, pp.10:15 – 11:13) See Docket Nos. UE-150204 and UG-150205, Exh. No. CRM-1T, p.28:8-14.

Avista's electric and natural gas services, which incorporates my attrition adjustment. Staff's analysis indicates that, absent an attrition adjustment, Avista will likely experience attrition and that the forces driving attrition are more likely than not outside of the Company's control.[68] (Emphasis added)

41 In this case, however, Staff does not offer an additional attrition adjustment for Year 1 – relying instead on only very limited pro forma adjustments that makes use of an arbitrary threshold that excludes 114 out of 121 capital projects.[69] This shortcoming was highlighted in the cross-examination of Staff Witness Hancock:[70]

Q: [Meyer] But in this case, unlike the last case, Staff's approach, would you agree, in setting year one's revenue requirement starts with a very limited pro forma approach and ends with a very limited pro forma approach without any filling the gap with an attrition adjustment; is that correct?

A: [Hancock] Yes. For year one in this case, Staff's year one revenue requirement recommendation is simply just Staff's modified historical test year with limited pro forma adjustments.

Q: [Meyer] Okay. So there wasn't any analysis to determine in this case whether there was a gap that needed to be filled because a modified limited pro forming did the job or not, correct?

A: [Hancock] Correct.

D. Step 4: Use Appropriate Growth Factors to Revise Revenue Requested for Years 2 and 3.

42 For Rate Years 2 and 3, the electric and natural gas revenue increases are based on revenue growth factors[71] (or an escalation rate) applied to prior year non-ERM and non-gas cost revenues. Similar to Avista, Mr. Hancock applies a revenue growth factor (escalation rate) to his base Year

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68 Ibid.; See Docket Nos. UE-160228 and UG-160229, Exh. No. CSH-1T, p.3:10-16.

69 Staff's only attempt to remove some of the regulatory lag was by restating 2016 plant from an average-of-monthly-averages (AMA) basis to an end-of-period (EOP) basis; this only captures $69.7 Million of the $163.7 Million of additional electric plant that will be in service in the 2018 rate year. (Exh. KKS-3T, p.11, fn. 23)

70 Tr. pp.252:19 – 253:10.

71 The Company labeled this revenue growth factor within its direct filed case a "K-Factor," similar to that used by Puget Sound Energy in 2013 within their multi-year rate plan (Docket Nos. UE-121697 and UG-121705). Nonetheless, based on Mr. Hancock's apparent criticism of the use of this term, the Company is using the term "revenue growth factor."

1 revenue to determine Year 2. Year 2 revenues then become the base for determining Year 3.[72] Both Avista and Staff calculate separate electric and natural gas revenue growth factor percentages, consolidated from the weighted average revenue escalation factors of the following components: (1) depreciation; (2) O&M expense; (3) Taxes Other Than Income; and (4) Net Plant After ADFIT). The result of these components are offset by a fifth component (5) Annual Growth in Sales Revenue.[73]

43 On rebuttal, the Company has revised its revenue growth factors for Rate Years 2 and 3 to 3.14% for electric and 4.14% for natural gas.[74] This varies from Mr. Hancock's revenue growth factors for Rate Years 2 and 3 of 2.32% for electric and 3.2% for natural gas.[75]

44 Table No. 9 below compares the calculation of the electric revenue growth factor proposed by Avista on rebuttal with that proposed by Staff:[76] (The shaded lines 1, 4 and 5 reflect areas of agreement):

Table No. 9 – Electric

Line	Avista Revised Revenue Growth Factor Category	(a) Growth Rate	(b) Revenue Portion of Category	(c) Weighted Avg Escalation (a) x (b)
1	Operating Expenses (1)	2.36%	35.74%	0.84%
2	Depreciation/Amortization	9.13%	20.05%	1.83%
3	Taxes Other than Income	4.53%	9.82%	0.44%
4	Net Plant After ADFIT (2)	3.04%	34.40%	1.05%
5	Annual Growth In Sales Revenue (2)		*100.00%*	-1.02%
	Total Escalator %			**3.14%**

Line	Staff Revenue Escalator Calculation Category	(a) Growth Rate	(b) Revenue Portion of Category	(c) Weighted Avg Escalation (a) x (b)
1	Operating Expenses - (UTC Indices)	2.36%	35.74%	0.84%
2	Depreciation/Amortization	4.70%	20.05%	0.94%
3	Taxes Other than Income	5.13%	9.82%	0.50%
4	Net Plant After ADFIT (2)	3.04%	34.40%	1.05%
5	Annual Growth In Sales Revenue (2)		*100.00%*	-1.02%
	Total Escalator %			**2.32%**

72 Hancock, Exh. CSH-1T, p.34:21-23.
73 A complete description of Avista's calculation of its revenue growth factor can be found at Exh. EMA-1T, starting at page 31, line 15. Staff's descriptions of its calculations can be found at Hancock Exh. CSH-1T, starting at p.34:16.
74 Andrews, Exh. EMA-11, p. 1 (electric) and Exh. EMA-12, p. 1 (natural gas).
75 Hancock, Exh. CSH-4. p. 1 for both electric and natural gas.
76 Andrews, Exh. EMA-11, p. 1 and Hancock, Exh. CSH-4. p. 1.

Similarly, Table No. 10 in Ms. Andrews' testimony compares the calculation of the natural gas revenue growth factor proposed by Avista on rebuttal with that proposed by Staff.[77]

45 Avista and Staff do not agree, however, with regards to certain growth factor components. Mr. Hancock takes exception with the two components "Depreciation" and "Taxes Other Than Income" where Avista has used the historical growth in these components for the period 2013 – 2016. Mr. Hancock, in his Exh. CSH-5, uses 2007 – 2016 to determine his historical growth rates for both of these components. As shown in Table No. 9, above, Mr. Hancock's depreciation growth factor in particular, is almost half that of Avista's, having the effect of significantly understating depreciation expense in Rate Years 2 and 3. (And this is after Staff failed to reflect depreciation expense in its 2016 EOP calculations for Year 1, as discussed above.)

46 As noted, Avista used the historical period 2013-2016.[78] Washington Commission Basis reports from 2013-2016 provide more current results and are more reflective of the increasing trend in capital investment and related costs. As Avista has discussed in its past general rate cases, Avista's need for increased capital investment has increased in recent years, most markedly so in 2013 and beyond.

47 As can be seen in Illustration No. 3 in Ms. Andrews' rebuttal testimony, starting in 2013, the Company began increasing its annual capital investment more significantly than in prior years, until in 2017 when it stabilized at $405 Million through 2021. The relevance with capital expenditures and growth in rate base for depreciation should be clear – the more recent growth in depreciation is driven by the corresponding growth in capital investment in recent years. This is especially true when there has been a disproportionate growth in shorter-lived assets due to the increased investment in information and technology assets over these same years.[79]

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77 Andrews, Exh. EMA-12, p. 1 and Hancock, Exh. CSH-4. P. 1.
78 Andrews direct, Exh. EMA-1T, starting at p. 31-37.
79 Exh. EMA-10T, p.44:1-7.

48 Based on this information, the Company concluded that the 2013-2016 Commission Basis reports reflect a more current growth level of capital and expenses than prior years, such as the 2007-2016 timeframe proposed by Staff. Furthermore, the growth rates produced from the 2013-2016 historical period more closely represents that expected in Rate Years 2 and 3.

49 Interestingly, ICNU and NWIGU provided electric and natural gas Attrition Study models sponsored by Mr. Mullins, even though he does not otherwise support a Three-Year Rate Plan, as otherwise proposed by Avista and supported by Staff. He does, however, suggest if this Commission were to approve a Three-Year Rate plan, his electric and natural gas Attrition Studies "produce a more informed view of revenue requirement than the K-Factor Study [prepared by Avista]."[80]/[81] As explained by Company Witness Andrews:

> Mr. Mullins merely dusted off his 2016 prior Avista general rate case attrition studies, extending them out through 2020, claiming these results are superior to that produced using a "K-Factor" approach as proposed by the Company (and now also supported by Staff). Consistent with my testimony in Docket Nos. UE-160228 and UG-160229, these studies are fraught with inconsistent trending periods and understated growth factors, significantly understating the revenue requirement need and producing results that are not reasonable or appropriate.[82]

50 Ms. Andrews explained the inconsistencies related to the years chosen by Mr. Mullins between the periods 2000-2016 <u>which vary depending upon the specific category of cost he is trending</u>. His regression trending analysis applied to each category of cost also is inconsistently and inappropriately applied across his electric and natural gas models.[83]

III. <u>THE POWER COST ADJUSTMENT SHOULD BE APPROVED AS FILED</u>

51 In this general rate case, the Company has filed a Pro Forma Power Supply Adjustment of $16.6 Million. The final approved Pro Forma Power Supply Adjustment approved in this general

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80 Mullins, Exh. BGM-1T, p.20:10.

81 For Rate Year 2 (May 1, 2019), his electric and natural gas Attrition Studies (including an escalation of depreciation expense and operating expenses) result in increases of approximately $5.1 Million and $1.4 Million, respectively. For Rate Year 3 (May 1, 2020), his electric and natural gas Attrition Studies result in increases of $5.0 Million and $1.4 Million, respectively. (Exh. EMA-10T, pp.64:12 – 65:2)

82 Exh. EMA-10T, p.65:4-10.

83 Exh. EMA-10T, pp.65:11 – 66:12.

rate case will serve as the new level of power supply costs in base rates effective May 1, 2018 (as well as the base for the ERM and electric decoupling).[84]

52 Company Witness Kalich speaks to the Dispatch Model.[85] The Dispatch Model tracks the Company's portfolio during each hour of the pro forma study. Fuel costs and generation for each resource are summarized by month. Total market sales and purchases, and their revenues and costs, are also determined and summarized by month. These values were provided to Company Witness Johnson for use in his calculations. Mr. Johnson adds resource and contract revenues and expenses not accounted for in the Dispatch Model (e.g., fixed costs) to determine net power supply expense.[86]

53 While elaborated below, the principal contentions of Avista are as follows:

- The ERM base has not been adjusted, based on the Power Supply Adjustment, since January of 2016. Staff's rejection of an adjustment in this case would mean that the next opportunity to adjust it would be in May 2021, at the expiration of the Three-Year Rate Plan – a gap of more than five years. The base has already become "stale" and will become much more so if not adjusted now.
- Avista proposes a power supply adjustment, based on $\text{AURORA}_{\text{XMP}}$ modeling and contract changes, of $16.6 Million. Staff proposes no adjustment, and without offering an alternative adjustment.
- Staff suggests that the Company has improperly benefited under the ERM. This is not true. Over the 13 years since the ERM was adopted, the Company has had to "absorb" over $16 Million. (The early "bad years" of 2003-2009 more than offset the favorable years of 2011-2016.) The <u>same</u> modeling has been consistently applied over time.
- The disputed $\text{AURORA}_{\text{XMP}}$ modeling has made use of the same basic inputs (gas prices/hydro conditions/contracts) since its inception, but with certain refinements suggested over time by experts on behalf of Staff and ICNU.
- This case is the first time, since its inception, that Staff has entirely rejected the results of the Power Supply Adjustment. In doing so, Mr. Gomez, having only been recently trained in 2016 on the use of this complex $\text{AURORA}_{\text{XMP}}$ model, pronounced that the Company's analysis was unfit. He does so even though he did

84 Exh. WGJ-1T, p.8:13-17.
85 See Exh. CGK-1T and CGK-4T.
86 See Exh. WGJ-1T and Exh. WGJ-6T.

not run the model and share his results; instead, when he asked the Company to re-run the model to reflect his changes, this actually served to increase the adjustment by $2.7 Million. (The same was true of Public Counsel Witness Wilson, whose suggested changes only served to increase the adjustment by $5.6 Million.)

- The Commission is left with two alternatives based on the evidence provided to them: Approve Avista's $16.6 Million adjustment now or approve no adjustment, as recommended by Staff, Public Counsel and ICNU. The preferred approach, however, adopted in prior cases, is to rerun the Dispatch Model and adjust for power supply, one month prior to the implementation of new rates for years One, Two and Three – based on the long-accepted modeling assumptions that define the Dispatch Model (as reflected in the Company's case). The Company has no interest in establishing power supply costs that are either too high or too low.[87] If, however, we are forced to revisit this debate on every occasion in which we seek to rerun the model prior to new rates becoming effective, we will not have advanced the ball. (See Tr. pp 200-203) What is clear, however, is that the Company cannot remain unprotected during all three years of the Rate Plan. (A mere change of $1 in wholesale natural gas price assumptions over three years equates to a $10 Million annual change in results.)
- Staff's suggested trigger of $10 Million in the ERM will not work; it would require the Company to absorb $14.7 Million of unrecovered power costs during the Rate Plan, as explained below.
- At the end of the day, Staff made no attempt to communicate any concerns with the Dispatch Model prior to the filing of this case. The Company, as always, remains available to discuss concerns over its power supply modeling efforts.

A. Criticisms of Company's Operation of the Dispatch Model are Unfounded.

54 The Company uses EPIS, Inc.'s AURORA$_{XMP}$ market forecasting model ("Dispatch Model") and its associated database for determining power supply costs.[88] The Dispatch Model

[87] Indeed, if present favorable conditions persist, rerunning of the power supply model in April of 2018, would show a substantial reduction of power supply costs well below levels previously modeled ($16.6 million) – not because of modeling errors, per se, as claimed by Staff, but because of more favorable market conditions since our original filing and the associated impacts to the Dispatch Model. It is still important, however, for the Commission to put to rest the litigated disputes in this Docket over how the Dispatch Model should be run, irrespective of the results produced. Otherwise, the parties will continue to raise the same modeling disputes at issue here, every time the Company seeks to rerun the model before new rates take effect. One option for Commission consideration is for the Commission, through a Bench Request, to ask the Company to rerun the Dispatch Model and file the results by April 1, 2018 (based on the Company's modeling assumptions) to reflect the most recent conditions, so that its order in this Docket would be informed by the most recent information.

[88] The Company uses AURORA$_{XMP}$ version 12.2.1050 with a Windows 7 operating system.

optimizes Company-owned resource and contract dispatch during each hour of the May 1, 2018 through April 30, 2019 pro forma year.[89] As testified to on rebuttal by Mr. Kalich:

> No other party to this case has provided modeled results of what they believe to be a correct power supply adjustment, even though all of the tools (AURORA$_{XMP}$ model, or "Dispatch Model") and data have been provided. In the end, if one made the adjustments recommended by Staff Witness Mr. Gomez, it would actually serve to *increase* total system power supply costs by ***$2.7 Million***. The same could be said of Public Counsel Witness Ms. Wilson; when she asked the Company to rerun the power supply model with her suggested inputs, it actually *increased* total system power supply costs by ***$5.6 Million***. As for ICNU witness Mr. Mullins, he was unable to identify any specific concerns with our modeling.[90]

55 Instead of offering the Commission calculations for arriving at alternative power supply costs, Staff, Public Counsel and ICNU only offer "scattershot criticisms" without actually rerunning the model themselves to produce a result, as testified to by Mr. Kalich.[91] Commission Staff had access to the software and the associated files the Company used for this filing. The Company pays for Staff to hold a license for using the AURORA$_{XMP}$ software. Staff was provided with work papers that contained all of the database and other files necessary to run the software. Staff was even offered training in 2017 on the use of the software. With the provided software and data files, Staff could have prepared an alternative power supply proposal – but they did not.[92]

56 Mr. Kalich went on to describe the recent on-site training made available to Staff on how to run the Dispatch Model:

> Both in person and over the phone, we offered to assist Staff in running the software. We even arranged a two-day training session with the software vendor to

[89] The Dispatch Model is a fundamentals-based tool containing demand and resource data for the entire Western Interconnect. It employs multi-area, transmission-constrained dispatch logic to simulate real market conditions. Its true economic dispatch captures the dynamics and economics of electricity markets – both short-term (hourly, daily, monthly) and long-term. On an hourly basis the Dispatch Model develops an available resource stack, sorting resources from lowest to highest cost. It then compares this resource stack with load obligations in the same hour to arrive at the least-cost market-clearing price for the hour. Once resources are dispatched and market prices are determined, the Dispatch Model singles out Avista resources and loads and values them against the marketplace. (Exh. CGK-1T, p.3:8-18)

[90] Exh. CGK-4T at p.1:16-23.

[91] Exh. CGK-4T, p.2:23-25.

[92] Exh. CGK-4T at p.3:1-9.

help Staff understand better how to operate the model. I personally attended the training to be available to Staff for questions, both generally about how we use the software, as well as about any specific questions in our case. I also offered the use of our case files as a basis for the training.[93]

57 Even though no other party has proffered the results of their own model runs, the parties, including Public Counsel and Staff, requested that the Company perform a significant amount of additional analysis for them involving the creation of 23 additional Dispatch Model studies, including the following:

1) Staff requested an update to natural gas prices. Nine studies were required to understand the impact to specific components of the cost changes. The end result of the study is a reduction in the total system power cost of $43,516.[94]

2) Staff requested three historical studies removing market adjustments designed to align Dispatch Model prices to forward markets from cases UE-160228, UE-150204, and UE-140188.[95] These three requests did not involve a total cost calculation, but were necessary to illustrate how actual prices were different from both forwards and fundamental prices in average water conditions.

3) Staff requested removal of the assumption that Dispatch Model prices should align with three-month average forward prices. Not aligning to forward prices results in $731,073 higher total system costs (see response to Staff DR 225, included in Exh. CGK-5, p.4)[96];

4) Staff requested analyses using a different load shape methodology and levels without the Dispatch Model matching its results to forward market prices (see response to Staff DRs 247 and 248, included in Exh. CGK-5, pp. 7-10).[97] Nine studies were necessary to understand the impact of specific components of this cost increase.[98] Staff's load assumptions increase system power supply costs by $2,048,000.

5) Public Counsel requested a study to determine power costs using the most recent assumptions for variable O&M, forced outage rates, maintenance schedules, natural gas and other fuel prices, forecasted loads, and remove matching modeled prices to forward prices (see response to Public Counsel DR 16, included in Exh. CGK-5, p. 13). This study showed the modifications would increase costs by $5,583,640.[99]

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93 Exh. CGK-4T, p.3:11-16.

94 Provided in response to Staff Data Request 094 and 095, included in Exh. CGK-5, p. 1-3.

95 Provided in response to Staff Data Request 224, included in Exh. CGK-5, p. 4-5.

96 Provided in response to Staff Data Request 225, included in Exh. CGK-5, p. 6.

97 Provided in response to Staff Data Request 247 and 248, included in Exh. CGK-5, p. 7-10.

98 This adjustment is $1.655 Million (system) above the Company's filed cost, after considering a correction to the hourly load shapes as described in response to Staff Data Request 151, included in Exh. CGK-5, pp. 11-12. This data request response has attachments that are electronic model runs and are voluminous.

99 Provided in response to Public Counsel Data Request 016, included in Exh. CGK-5, p. 13.

While Mr. Kalich was only left to speculate as to why Staff and Public Counsel did not make any use of these requested model runs, he did note that:

> The results of their adjustments would significantly *increase* power supply costs relative to the Company's filed case; their adjustments would certainly not show the Company overstated or inaccurately modeled power supply expenses as they assert.[100]

Likewise, the Company provided a computer loaded with the software to ICNU. Public Counsel did not request access. With access to the software and data files, both parties could have prepared alternative power supply proposals – but did not.

58 The Company has used the AURORA$_{\text{XMP}}$ Dispatch Model software for approximately 17 years. Mr. Kalich was involved with the original software acquisition and has been involved in all rate filings since its acquisition.[101] Mr. Kalich explained how it has been refined over time:

> The methodology is the result of Commission orders and collaboration with Staff and other intervenors in our prior rate cases. We worked with Staff Witness Mr. Alan Buckley and ICNU witness Mr. Donald Schoenbeck over several prior years to refine the model. As explained below, a customer-benefitting recommendation from ICNU witness Mr. Brad Mullins in our last filed case has been adopted for this proceeding.[102]

The Company worked with Staff Witness Mr. Buckley and ICNU witness Mr. Schoenbeck over the past decade, and the methodology used today was refined in subsequent cases – not simply discarded as is being recommended by the parties here.[103]

59 Mr. Kalich went on to describe the dramatic decrease in power supply costs in the recent past because of falling natural gas and power prices, and above-average hydro conditions. This was not due to any actions by the Company, and all participants in the marketplace experienced these results. We cannot assume that these conditions will continue, and normalized power supply

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[100] Exh. CGK-4T at p.6:1-4.
[101] It has been used for many years by most utilities and organizations modeling power supply costs in the Northwest. It is similarly used by many electric utilities outside of the Northwest. In the Northwest, it is used by the Bonneville Power Administration, Seattle City Light, Puget Sound Energy, PacifiCorp, Idaho Power, and the Northwest Power and Conservation Counsel. (Exh. CGK-4T, p.8:9-13)
[102] Exh. CGK-4T, p.8:16-22.
[103] Exh. CGK-4T, p.9:13-15.

costs should be expected to rise. Further, the Company had secured on behalf of its customers a lucrative contract with Portland General Electric which expired in 2016, the benefits of which are still embedded in the Company's rates. The loss of this contract alone increases total system power supply costs by $16 Million (or $10.6 Million/Washington share).[104]

60 Authorized power supply costs have come in at levels above historical actual costs, but this is not due to inaccurate modeling. Power supply modeling is based on then-current market conditions and normalized conditions. Since 2011, conditions were very favorable, with higher-than-average hydro generation and falling natural gas and electricity prices. This trend was not something that could be forecasted. But it should be no surprise that these conditions would lead to below-authorized costs. However, when conditions were reversed, as witnessed in the previous 2003-10 period, costs were substantially higher than authorized, based on using the same Dispatch Model.[105]

61 It is important to remember that the Company uses power cost calculation assumptions and methodologies when setting the authorized power cost, based on normalized conditions, not based on a forecast. These normalization assumptions include an 80-year hydro record, a three-month average of natural gas and electricity forwards prices, historical test year weather-adjusted loads, five-year averages for energy delivery from long-term resource contracts, and five-year average maintenance and forced outage rates for large thermal plants.

62 Mr. Kalich, on behalf of the Company, addressed each issue raised by Staff Witness Gomez related to Dispatch Model inputs, settings, and out-of-model adjustments. They are briefly described below:

- Concerning Rate Year Loads: The Company did not use projected rate year loads in this or prior filings. It used weather-adjusted historical loads, consistent with past practice and the methodology approved by the Commission. Mr. Gomez is simply

[104] Exh. CGK-4T, p.10:7-15.
[105] Ibid.

mistaken in his belief that the Company uses forecasted rate year loads (see pages 15 and 16 of Exh. DCG-1T).[106]

- Regarding Hourly Shapes: Mr. Gomez is incorrect in his assessment that the methodology used to shape hourly loads contributes to an inaccurate representation of power supply costs. He proposes moving away from the methodology used in previous rate proceedings in favor of using weather-adjusted monthly loads and test-year hourly shapes. Mr. Gomez himself provided no study or analysis to illustrate the impact of his recommended load change. Nevertheless, the Company was interested in understanding its impact on power supply costs. It found, however, it would reduce total power cost by a mere 0.07%.[107] This result shows that moving from historical precedent would not have a material impact on power supply expense modeling, and is simply unnecessary.[108]

- Forced Outage Rates: As concerns Forced Outage Rates on Company peaker plants, the methodology being used by the Company makes use of a five-year historical average for larger facilities, and a fixed five percent for Rathdrum, Northeast, and Kettle Falls CT, and is the same as used in prior filings. Mr. Gomez ignores the fact that the Company forced outage rates on these plants are *lower* than for similar plants operated by our industry peers.[109]

- Variable Operating and Maintenance Costs: Regarding variable operating and maintenance (VOM) costs, the Company does not include VOM costs in its power supply cost calculation, or in the ERM. VOM costs simply aren't used in our calculation of power supply costs.[110]

- Marginal Cost Adders: Concerning Marginal Cost Adders, the main concern Mr. Gomez has with the adjustment appears to be those made to hydro resources. The adjustment is necessary and changes to the dispatch order of hydro are meant to ensure these resources dispatched ahead of other resources, including renewable resources benefitting from production tax credits and RECs. Because they don't affect overall costs, the level of marginal cost adder does not matter so long as it ensures hydro resources dispatch first in the stack.[111]

  Without the adjustment to stimulate the conditions of negative pricing during oversupply events, prices would not go negative in the Dispatch Model and would grossly overstate the value of Company hydro and other renewable facilities. The

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106 Exh. CGK-4T, p.13:12-16.
107 Calculated by taking the difference in Fuel and Market costs between the correct load shapes as identified in the Company's response to Staff Data Request 151, included in Exh. CGK-5, p. 11-12 (and using staff-provided load shapes applied to test period load levels).
108 Exh. CGK-4T, p.14:6-17.
109 Exh. CGK-4T, p.15:1-17.
110 Exh. CGK-4T, p.16:3-12.
111 The value used in the Dispatch Model, -$75/ MWh, therefore could be any number as long as it is sufficient to prevent the plant from not running in the event of oversupply of resources in the market. (Exh. CGK-4T, p.17, fn. 15)

Company has been consistently clear in testimony, data responses, and discussion with the parties as to why we make these adjustments.[112]

Mr. Gomez also mentions the marginal cost adder for Kettle Falls beginning on page 14 of his testimony Exh. DCG-1CT. If the Company had to include a value higher than the actual value of Kettle Falls RECs, such as an approximate doubling of its REC values to $15 per MWh as recommended by Mr. Gomez, the dispatch of Kettle Falls would increase and the plant would run additional hours when it is operating at a loss. This would only serve to increase power supply expenses.[113]

- Resource Dispatch Margins: Mr. Gomez's concerns with Resource Dispatch margins relate to how it adjusts the Dispatch Model to align prices with forward prices. On page 28 Exh. DCG-1CT, at line 11, Mr. Gomez suggests the Commission reject this modeling practice. In Data Request No. 225 Mr. Gomez asked the Company to determine the impact of his recommendations on resource dispatch margins. The response to that data request in Exh. CGK-5 p. 6 shows the result was a $731,073 *increase* in power supply costs. [114]

- Model Settings: Regarding Model Settings, Mr. Gomez claims it was difficult to validate these adjustments and suggests they be rejected by the Commission. Yet he makes this recommendation without any specific analysis to support it, or specific changes to the methodology that would otherwise ensure the Dispatch Model appropriately models power supply expenses. On page 17 of Mr. Kalich's supplemental testimony (Exh. CGK-3T), at lines 14 and 15, he explains that, together, these adjustments change power supply cost by only $44,850; they are immaterial.

- Out-Of-Model Adjustments: Lastly, regarding Out-of-Model adjustments, Mr. Gomez is incorrect on the treatment of the Nichols Pumping and WNP-3 contracts. Mr. Gomez appears to not understand that these are entered into the Dispatch Model in accordance with each contract's obligations; they are not dispatched by the Dispatch Model.[115]

63 Public Counsel Witness Ms. Wilson's testimony in this case is also flawed. Ms. Wilson (beginning at page 4, line 7, of Exh. RSW-1T), notes, as Mr. Gomez did, that the Company's historical power supply costs are lower than authorized since 2011. Again, similar to Mr. Gomez, she suggests that Company inputs, assumptions and forecasts must therefore be flawed.

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[112] Exh. CGK-4T, p.18:11-17.

[113] Exh. CGK-4T, p.19:3-14.

[114] Provided in response to Staff Data Request 225, included in Exh. CGK-5, p. 6. This data request response has attachments that are electronic model runs.

[115] Exh. CGK-4T, p.21:9-19.

64 As explained by Mr. Kalich, from 2011 to 2016, average hydro conditions were 22 aMW above average and varied as high as 633 aMW to a low of 490 aMW (143 aMW range) for an average of approximately 556 aMW, or more than 26 percent over the 14 year period from 2003 to 2016.[116] Though ignored by Ms. Wilson, the opposite condition existed prior to 2011. From 2003 to 2010, hydro was actually *less* volatile than from 2011-2016, ranging from a low of 475 aMW to a high of 560 aMW (85 aMW range), and on average was 17 aMW below the average hydro experienced between 2003 and 2016.[117] Mr. Kalich concluded:

> There are two key take-away points for hydro: 1) hydro conditions have been above-average since 2011 and were below average for the period 2003-2010; and 2) hydro conditions have not been stable as reported by Ms. Wilson, in fact having been more volatile over the past seven years than in the preceding eight years.[118]

65 Ms. Wilson (on page 8, beginning at line 9, of her Exh. RSW-1T) also suggests natural gas prices have been stable as well. Yet natural gas prices are not materially less volatile over the 2011-2016 period than in the 8 years prior. In the recent 2011-2016 period, the standard deviation of natural gas prices as a percent of the average price was 32.6 percent. From 2003-2010, this same calculation is 33 percent. So natural gas prices in recent years are no less volatile than the 2003-2010 period.[119]

66 On behalf of Public Counsel, Ms. Wilson also implies that Company power supply costs are problematic due to matching forward natural gas and electricity prices in the Dispatch Model. Mr. Kalich is quick to point out that this matching *is not* the cause of costs being lower than authorized. In fact, the opposite is true. Not matching forward natural gas and electricity prices would distort the ERM results, raising the Company's requested increase in this filing. As the Company has done for more than a decade, using a methodology approved by this Commission, forward natural gas *and* electricity prices are matched in the Dispatch Model.[120] Changing

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116 Exh. CGK-4T, p.22:11-22.
117 Ibid.
118 Exh. CGK-4T, p.23:3-7.
119 Exh. CGK-4T, p.23:7-12.
120 Exh. CGK-4T, p.24:1-12.

methodologies to move away from matching forward pricing serve to lower normalized power supply costs. Because the Company operates or controls more generation assets than would be expected to be used except under extreme weather conditions, we therefore are typically surplus. Absent matching both natural gas and electricity prices, modeled market prices in the Dispatch Model would be lower and surplus sales would receive a lower offsetting revenue, leading to over $2.77 Million higher costs, as explained in Mr. Kalich's supplemental testimony.[121/ 122]

67 Ms. Wilson at page 15, line 1 of Exh. RSW-1T, suggests Company assumptions cause the Dispatch Model to operate higher-cost resources more than they should. The Dispatch Model dispatches peakers only when their costs are estimated to be higher than the market and reducing overall power supply costs. This means the Dispatch Model overstates the value of peaking resource. The Company could have adjusted out these values by creating constraints to limit peaker dispatch, but this would have increased costs in this case.[123]

68 Finally, as explained by Mr. Kalich in Data Request No. 16, Ms. Wilson asked the Company to recalculate power supply costs with her recommended changes including using current actual forecasts of generator attributes and running costs, not matching forward electricity prices in the model, and using actual load forecasts. These recommendations would ***increase*** power costs by $5,583,640, as shown in our response to Public Counsel Data Request No. 16. [124]/[125]

69 In conclusion, as noted by Mr. Kalich:

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121 Exh. CGK-4T, p.23:7-12. Further these adjustments do not include the out-of-the-model adjustments performed by Witness Johnson. As explained earlier the total adjustment to remove this assumption is $731,073.

122 Ms. Wilson, in Exh. RSW-1T on page 12, starting at line 6, suggests that "if real variability over the hours and days in a month is not captured through the Company's matching of $\text{AURORA}_{\text{XMP}}$ prices to the average of Mid-C futures, the potential for market sales and purchases cannot be properly forecast by the model." She is wrong. The Dispatch Model does include varying hourly prices. (Exh. CGK-4T, p.25)

123 Exh. CGK-4T p.27:1-3.

124 Provided in response to Public Counsel Data Request 016, included in Exh. CGK-5, p.13.

125 Mr. Mullins, on behalf of ICNU, states in his testimony (Exh. BGM-1T, page 31, beginning at line 15) that he agrees with Staff and its "evidence" of arbitrary assumptions by the Company intentionally designed to "inflate" power costs. (Other than bare assertions, Mr. Mullins provides no evidence or analyses to support his claims. He offers no alternative power supply estimate and adds nothing to the record.)

> Both natural gas and hydroelectricity have contributed to the variation in the ERM balances. And only in recent years, where their conditions have been favorable, have power supply costs been below authorized. These two variables provide an explanation for why power costs have been above and below authorized levels over the ERM history. It is <u>not</u> flawed inputs, assumptions, and forecasts, as suggested by Ms. Wilson or Mr. Gomez.[126]

B. <u>The Power Supply Adjustment and the Energy Recovery Mechanism (ERM) are Working as Intended.</u>

70 Mr. Gomez contends that since the Company's actual power supply expenses have been lower than the authorized level included in base rates in five of the last six years, there must be some inherent or intentional bias in the Company's power cost forecasting methodology that consistently overstates power costs and that this has harmed customers and unduly benefitted the Company.[127] His remedy for this alleged bias is to completely eliminate all of the Company's proposed increase in baseline power costs and to let any power cost increases flow through the ERM.[128] The end result of such a position is that, due to the deadband and sharing bands in the ERM, the majority of increased power supply costs will be absorbed by the Company as unrecovered costs.[129]

71 Neither Staff, nor ICNU, nor Public Counsel, however, have provided any empirically-based analysis to support entirely removing the Company's $16 Million increase in pro forma power costs over the amount in current base rates. In the words of Company Witness Johnson:

> . . . neither one has presented any <u>alternative</u> results under their version of correct modeling that would provide an alternative adjustment. In short, they have provided nothing else for the Commission to land on, <u>other than to kick this whole issue down the road</u>.[130] (Emphasis added)

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126 Exh. CGK-4T at 23:14-19.

127 Exh. DCG-1CT, p.9:2-12

128 Exh. DCG-1CT p.35:6-7

129 Exh. WGJ-6T, p.16:1-17. Under the ERM, the difference between actual and authorized power supply expenses are accumulated until the dead band of $4.0 Million is reached. Fifty percent of power cost increases, or 75 percent of the decreases, between $4.0 Million and $10.0 Million, and ninety percent of the power cost increases or decreases in excess of $10.0 Million are recorded as the power cost deferrals and added to the customer deferral-balancing account.

130 Exh. WGJ-6T, p.3:15-17.

72 Mr. Gomez did not review the entire history of power supply costs and the ERM in his testimony. The ERM has been in place for 13 full years beginning in 2003. Over the entire period, power costs have been both higher and lower than the baseline (authorized) amount in base rates. For the first seven years the Company absorbed <u>$41.4</u> Million in unrecovered power costs and customers paid $60.3 Million in surcharges. "Those were not good times for anyone," as testified to by Mr. Johnson.[131]

73 Mr. Johnson went on to observe that, fortunately, power costs have decreased significantly since 2011, and the sharing bands in the ERM have allowed the Company and customers to benefit from the overall reduction in power costs. Power costs have come down by a cumulative $133.1 Million in the years 2012 through 2017 compared to the level of costs in 2011. This is unequivocally a favorable development and is very beneficial for customers. Of the total $133.1 Million reduction in costs, <u>customers have received $108.5 Million</u> (or 82%) in both base power supply cost reductions and ERM rebates, and the Company has retained $24.6 Million (or 18%) through the sharing bands of the ERM.[132]

74 At the end of the day, Mr. Gomez ignores the entire history of the ERM and focuses only on the latter period, 2011 through 2016. Without anything but circumstantial evidence, Mr. Gomez contends the Company retained $24.7 Million[133] of savings through somehow biasing its rate case power cost forecast methodology to over-estimate future power costs.[134]

75 Mr. Johnson provided a history of the ERM results. The first full year of the ERM was 2003. In 2010 there was no ERM accounting, leaving a total of 13 full years of ERM history. In 6 years, the actual power supply expense <u>exceeded</u> the authorized level and in 7 years the opposite occurred. On a dollar basis, <u>over the full 13-year history</u> of the ERM, actual power supply costs have exceeded authorized costs by $37,330,117. Of that total amount, $16,779,560 (as shown in

131 Exh. WGJ-6T, p.4:1-4.
132 Exh. WGJ-6T, p.4:1-13.
133 Exh. DCG-1CT, p.8:15
134 Exh. DCG-1CT, p.9:2-12

Table No. 4) was absorbed by the Company (i.e., was not charged to customers).[135] His Table No. 3 at page 8 of his rebuttal testimony shows the actual and authorized expense for the 13-year history of the ERM.

76 Fortunately, actual power supply costs in 2017 stayed under the ERM authorized base despite the Commission's rejection of the power supply adjustment in Avista's 2016 general rate case. This was due to hydro generation that was well above average expectations and the fact that natural gas prices continued to fall during the year. Hydro generation and natural gas prices (and, correspondingly, wholesale power prices which are affected by those two items) are the most important factors affecting power costs.[136] According to Company Witness Johnson:

> Put another way, power supply conditions in 2017 could not have been better. Instead of seeing approximately $14 Million in increased power supply costs as originally budgeted, lower wholesale power costs, lower natural gas costs, excellent hydro conditions, and resource optimization of the Company's assets mitigated almost all of the projected cost increases. But much of this is attributable to "good luck" and does not mean that the Company's long-standing approach to modelling is somehow deficient.[137]

77 Some power cost increases are absolutely known and measurable and should be beyond dispute. The largest factor is that the PGE contract ended in December 2016.[138] The loss of the PGE contract alone accounts for roughly half, or $10.6 Million, of the Company's increased power cost request, and that has nothing to do with modeling. In the words of Mr. Johnson, "it is a simple fact."[139]/ [140] The ERM is not intended to insulate customers from legitimate cost increases due to

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[135] Exh. WGJ-6T, p.9.
[136] Exh. WGJ-6T, p.13:10-15.
[137] Exh. WGJ-6T, p.13:18-23.
[138] Exh. WGJ-1T, p.5:12-19
[139] Exh. WGJ-6T, p.14:3-6.
[140] Mr. Johnson also noted that:
> "There are also several other contracts that have known and measurable cost increases. For example, the annual payments for the Chelan PUD purchase are contractually fixed and increase each year through 2020. The Lancaster PPA capacity payment increases by both a fixed and variable escalation factor each year and won't decrease. The agreement related to the output of Palouse Wind, and most of the PURPA power purchase contracts, have fixed price schedules that increase each year. The Wells Dam power purchase agreement changes from a project cost contract to a higher cost fixed-rate contractual arrangement starting September 2018." Exh. WGJ-6T, p.14:7-16.

known contract changes. Ignoring known and measurable contract changes in the pro forma period is the equivalent of purposely setting the ERM baseline costs incorrectly, as observed by Mr. Johnson.[141]

78 As for subsequent adjustments, the Company agreed on rebuttal that, if the Commission approves the Company's proposed power supply adjustment for Year 1 of the Three-Year Rate Plan, which includes the known contract changes discussed above, the Company would forego updates in Years 2 and 3.[142] The Company believes that this strikes a reasonable balance between the Company's position and that of Staff. Perhaps during this time, the parties can reach a common understanding of what the Dispatch Model is designed to do.[143]

IV. THE COMPANY PRUDENTLY ENGAGED IN INTEREST RATE HEDGING

79 Mr. McGuire, on behalf of Staff, recommends excluding the 2016 settlement of interest rate swaps from the Company's filed cost of debt.[144] The interest rate swaps, however, were executed in accordance with the Company's Interest Rate Risk Management Plan ("Plan") for the purpose of managing interest rate risk for the benefit of customers.

80 With further elaboration below, the principal contentions of Avista are:

- All hedging was done in <u>strict compliance</u> with an Interest Rate Hedging Plan that has been in place since 2013.
- This Plan was <u>discussed with Staff</u> prior to implementation, and has been included in every general rate filing in the past four years. This is the first time that Staff has taken issue with the results, even though the hedges at issue were entered into in 2016.
- Staff has conducted an after-the-fact assessment of the results – one that does not reflect <u>what was known at the time</u> such hedges were entered into.

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141 Exh. WGJ-6T, p.15:12-14.

142 A better alternative to updating power supply expense in Year 1 only, would be to rerun the Dispatch Model and adjust for power supply, one month prior to the implementation of new rates for years <u>One</u>, <u>Two</u> and <u>Three</u>, but based on the long-accepted modeling assumptions that have, over time, been used as part of the AURORA$_{XMP}$ dispatch model, and as reflected in the Company's testimony.

143 <u>Id</u>. at 15:18-22.

144 Exh. CRM-1T, pp.2-3.

- It should be remembered that the purpose of the hedging program is to protect customers against interest rate volatility at the time of issuance of long-term debt; since this financing typically occurs no more than one time a year, there is "concentration" risk (the interest rate will be determined on the single day of issuance; there is no opportunity to "average" its interest rates over time).

- The argument of Staff that the hedges entered into in 2016 are not in compliance with the approach taken in the Commission's 2017 order on natural gas hedging is faulty on its face.

- There has been no showing that the Company acted imprudently or outside the confines of its Plan.

- Staff makes no mention of the $33.6 Million write-off that will occur, simply based on their recommended reduction in the cost of long-term debt from 5.62% to 5.54%. This write-off is real and substantial.

- In the final analysis, this hedging program was developed on behalf of its customers. The Company should not be punished with a write-off for acting in good faith in accordance with this plan.

- If the Commission is now uncomfortable with these interest rate hedging activities on behalf of customers, the Company is more than willing to stop executing new hedges, after all executed hedges have run their course in 2021.

81 Customers have interest rate risk related to ongoing debt issuances to fund capital expenditures and maturing debt. As explained by Mr. Thies in his testimony, the Company is forecasting $2 billion in capital expenditures over the next five years.[145] Additionally, it has $654.5 Million of debt maturing during the same period. The need to fund such capital expenditures and maturing debt is ongoing. This results in a significant need for the issuance of long-term debt. The Company typically issues long-term debt once per year, thus its concentration exposure to prevailing long-term interest rates occurs all at once rather than across market cycles. This "concentration" exposure creates interest rate risk, or cash flow volatility related to the future interest payments on the long-term debt.

82 Reducing interest rate variability reduces variability in customers' rates. To mitigate the impact of interest rate volatility on customers, the Company engages in risk management

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145 Exh. MTT-6T, p.17:14-21.

techniques to hedge financial exposure associated with interest rate uncertainty through the use of interest rate swaps. Interest rate swaps are a tool utilized to lock in a portion of the interest rate in advance of the actual debt issuance. Entering into multiple interest rate swaps over time reduces the concentration risk that is present when pricing debt issuances on a single date.[146] It should be remembered that the Company implements interest rate risk management activities solely for the benefit of customers.[147]

83 The Commission and Commission Staff have been previously apprised of Avista's interest rate hedging activities. The Company has executed interest rate swaps, for purposes of reducing interest rate risk for our customers as early as 2004 and has been fully transparent in communicating its interest rate hedging activities with both the Commission and Staff, as well as other parties to the rate case. The Interest Rate Risk Management Plan has been included as an exhibit to testimony in every case since it was formalized in 2013, including the current case.[148] The settlement values, either losses or gains, of the interest rate swaps have been clearly included as a component of cost of debt in previous rate cases.[149] When the Company formalized the Interest Rate Risk Management Plan in 2013, it reviewed the Plan (included as Exh. MTT-7) with Staff (Mr. Ken Elgin and Mr. E.J. Keating).[150]

84 The concepts used by the Company in hedging interest rate risk are similar to the concepts for hedging the risks of natural gas commodity costs for local distribution customers. In Docket

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[146] Exh. MTT-6T, p.18:1-9.

[147] Ibid.

[148] In fact, in 2007, the Commission issued an order in Docket No. UE-070311 that addressed the accounting treatment of interest rate hedges, which recognized the agreement to amortize the interest rate hedge over the life of debt to be issued:

> Additionally, the parties recommend that the Commission approve their agreement that the costs of short-term lines of credit may be deferred and amortized over the five year life of the lines of credit, and the costs of interest rate hedges may be deferred and amortized over the life of bonds to be issued upon the maturity of the 9.75% bonds in June of 2008. (Emphasis added) Order No. 05, Docket No. UE-070311, p.7.

[149] Exh. MTT-6T, p.18:12-18.

[150] The presentation made to Commission staff in July 2013 can be found on Exh. MTT-7. Mr. Kevin Christie, Mr. Ryan Krasselt and Mr. Patrick Ehrbar attended for Avista. (Exh. MTT-6T, p.19, fn. 15)

UG-132019, the Commission issued its "Policy and Interpretive Statement on Local Distribution Companies' Natural Gas Hedging Practices" ("Policy Statement"). In that Policy Statement, the Commission discusses the use of hedging to manage customer exposure to market volatility:

> The rate customers pay for natural gas is directly related to the price a utility pays for natural gas from a supplier. Thus, the volatility of natural gas prices presents substantial risk to the utility and its ratepayers; a sharp increase in the price of natural gas supply can result in a sharp increase to a customer's utility bill. To mitigate the impact of market volatility on consumers, LDCs routinely engage in risk management programs. Risk management generally refers to coordinated activities aimed at controlling the impact of adverse events. Because consumers view price increases as adverse events, LDCs managing risk are concerned with controlling the impact of possible price spikes on consumers' bills. Hedging is one risk management tool available to LDCs.[151] (Emphasis added and footnotes omitted)

85 These concepts related to natural gas are similar to what customers face with the cost of debt, in that the volatility of interest rates can result in an increase to a customer's utility bill. Additionally, the mechanics of the interest rate hedging model discussed above are similar to that of the natural gas commodity-hedging model.

86 The Commission began the above-referenced Natural Gas Hedging Investigation in 2012. The investigation was concluded in March 2017 (Docket UG-132019) with the Commission's issuance of the Policy Statement.[152] Mr. McGuire argues that Avista "operates its hedging practices in a manner inconsistent with Commission Policy".[153] Mr. McGuire's reference, however, is to the Commission's Policy Statement on natural gas hedging that was issued on March 13, 2017. Avista's Plan and the hedges that were settled in 2016 were in place prior to the adoption of the Commission Policy. The hedges were entered into during the period April 2013 through July 2016.[154]

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151 Exh. MTT-6T, pp.21:16 – 22:12. Docket No. UG-132019, "Policy and Interpretive Statement on Local Distribution Companies' Natural Gas Hedging Practices." p. 1.

152 In the Policy Statement, the Commission set forth a process, beginning with the local distribution companies 2017 Purchased Gas Cost Adjustment filings, to provide a "Preliminary Hedging Plan" as to how they would integrate risk responsive hedging by 2020 (so called "Full Strategy Implementation"). (Exh. MTT-6T, pp.22:21 – 23:1)

153 Exh. CRM-1T, p.21:10

154 Exh. MTT-6T, p.23:4-9.

87 Even though other Commissions' decisions are not determinative here in Washington, both Idaho and Oregon have reviewed Avista's Interest Rate Risk Management Plan and have accepted Avista's weighted average cost of debt, including the costs of the 2016 settled interest rate swaps.[155]

88 Moreover, as part of the Company's 2017 Audit Plan approved by the Board Audit Committee on February 2, 2017, the Company's Internal Audit department conducted an Interest Rate Risk Management Review with the objective to ensure that interest rate derivative transactions entered into were done in accordance with the Company's Interest Rate Risk Management Plan and accurately recorded. Internal Audit concluded:

> The Interest Rate Risk Management Plan appears to be appropriately documented and there are adequate controls in place to ensure executed interest rate derivative transactions are in compliance with the Interest Rate Risk Management Plan.

See Exh MTT-8 for a copy of this report.[156]

89 The impact of removing the settlement costs for the 2016 debt issuance from the cost of debt would be substantial, forcing an immediate write-off of $33.6 Million in 2018. (In fact, the write-off may well have to include all other existing hedges as well, even those that would not "settle" until 2021.) Mr. Thies was emphatic on this point:

> If the 2016 settled interest rate swap amount of $54 Million is removed from the cost of debt, it would not only decrease the Company's long term cost of debt to 5.54%, but more

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155 Mr. Ihle of the Oregon Public Utility Commission Staff in Docket No. UG-325 (Avista's most recent 2016 Oregon general rate case), conducted a thorough review of the 2016 interest rate hedges and concluded that the Company adhered to its operational guidelines and the hedges were effective. He states:

> Staff stresses that hedge programs should not and generally do not assume that foresight is possible with regard to future values of publicly traded indices, and this is appropriate. Staff does not believe the Company has any special ability to forecast whether interest rates will go up or down in the future. Therefore Staff fully expects that some hedges will ultimately appear favorable and some will appear unfavorable. An unfavorable outcome for a particular hedge in and of itself should not be taken as a sign of an issue or problem with regard to the related hedging program. When examining particular hedges, Staff believes the issues that should be examined are 1) whether the hedges are consistent with an established plan, and 2) whether the hedges were effective. Any analysis beyond this—for example what actions the Company should have expected the Federal Reserve to take with regard to interest rates in the future—is outside what is appropriate for a review of hedges or a hedging program. (Emphasis added)

(OPUC Docket No. UG-325, Staff/1200, pp.12:16 – 13:11) (Exh. MTT-6T, p.24:2-16)

156 *See also* Exh. MTT-6, p.24:18-27.

> importantly it would cause an immediate write-off of approximately $33.6 Million in 2018. As the Company has a prudent interest rate hedging plan, *a loss of this magnitude would cause unjustified financial harm to the Company*.[157] (Emphasis added)

It should be remembered that Mr. McGuire's demonstration that market volatility was relatively low was an after-the-fact calculation of volatility.[158] He does not provide any empirical evidence or analysis that correlates the then current conditions in the market to the future trajectory of interest rates. Simply put, he does not provide analysis that would demonstrate the information available at the time the hedges were executed would have indicated that it was not appropriate to be hedging.[159]

90 In summary, Avista's plan is well designed and utilizes hedge ratios, hedge windows, rate triggers that factor in volatility, and on-going market analysis. Avista in fact had 1) a prudent interest rate risk management plan in place, 2) followed the Plan, 3) made reasonable hedging decisions factoring in changing interest rate environments and 4) appropriately managed interest rate risk for customers.

V. OTHER CONTESTED ADJUSTMENTS

91 Table No. 11 in the rebuttal testimony of Ms. Andrews[160] provides a listing of adjustments proposed by the identified party that Avista accepts on rebuttal and has included in its revised revenue requirement. These include:

Restate Property Tax
Pro Forma Property Tax (Nat. Gas)
Uncollectible Expense
Conversion Factor
Restating Incentives
Pro Forma Incentive Expenses
Pro Forma Director Fees Expense
EOP 2017 Capital Net Rate Base

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157 Exh. MTT-6T, p.25:1-5.
158 Exh. CRM-1T, p. 15
159 Exh. MTT-6T, p.25:6-13.
160 Exh. EMA-10T, p.45.

92 Table No. 12 in Ms. Andrews' rebuttal testimony[161] provides a listing of adjustments opposed by Avista that are proposed by various parties. Reference is made to the rebuttal testimony of Ms. Andrews (Exh. EMA-10T) addressing each of the following contested items, given space limitations in this brief:

Working Capital (pp.51-58)
Restate Debt Interest (flow through) (p.58)
Restate 2016 AMA Rate Base to EOP (p.59)
Pro Forma Labor Non-Exec (pp.59-60)
Pro Forma Property Tax (Electric) (p.61)[162]
Pro Forma 2017 Threshold Capital Adds (p.62)
Pro Forma O&M Offsets (pp.62-63)
New MT Aquatic Invasive Fee (p.63)
Pro Forma Power Supply & Transm Revs (p.64)

VI. CONCLUSION: A THREE YEAR RATE PLAN IS IN THE BEST INTERESTS OF CUSTOMERS

93 Both the Company and Staff support a three-year rate plan. The Company believes it is time to break the cycle of annual rate filings, and provide rate certainty to our customers. Issues have been vetted on a near continuous basis in Avista's annual filings over the last several years. A surcease in annual filings will also provide the opportunity for the parties to meet and confer to explore alternatives to yearly rate filings, doing so outside the context of a contested case.

94 The pending merger request in Dkt. No. U-170970 (Hydro-One) should not affect this rate case. Avista's cost-structure will not materially change, inasmuch as it will continue to operate as it has – with only a different shareholder (Hydro-One). Any savings resulting from incidental savings through SEC filings, board expenses, etc., will be more than offset through the proffered "rate credit" in the merger proceedings.[163] Nor should changes in the tax law impact the three-year

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[161] Exh. EMA-10T, p.51.

[162] At hearing, Staff Witness Ms. White confirmed that her calculation of electric property tax included a calculation error that once corrected agreed with Avista's electric property tax adjustment. (Tr. pp. 283-284)

[163] As explained by Witness Thies, a separate docket has been initiated to address merger related specifics, including future benefits to customers. (*See* Dkt. No. U-170970). The proposed transaction is not designed to target the elimination of jobs, or cost cutting that may lead to a deterioration of customer service, customer satisfaction, safety, reliability, or a deterioration of charitable giving, economic development or innovation in the communities Avista serves. There will be some cost savings immediately following the closing of the transaction, such as

plan – they are what they are, and benefits will flow through to customers irrespective of the Rate Plan.

VII. MODIFICATIONS TO CUSTOMER SERVICE PROGRAMS

A. The Commission Should Allow the LEAP to Continue as Originally Approved in Order No. 01 in Docket UG-152934.

95 The LEAP pilot program should be continued, but not with the added conditions set forth by Staff. The Company believes that the Commission should allow the LEAP to continue as originally approved in Order No. 01 in Docket No. UG-152394.[164] The Company remains willing, however, to work with Staff on additional and/or revised metrics for reporting on the program and on evaluation of the future of the program. As indicated by the number of new residential Schedule 101 hookups, along with the positive customer feedback that indicates the LEAP was instrumental in customers' decision to convert to natural gas, the program has been a tremendous success thus far, as reported by Company Witness Christie.[165] Over its short life, to date it has already offset the need to supply 28,115,220 kWh(s) on an annual basis prospectively – the equivalent of 2,498 homes based on average electrical consumption.[166]

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reduced expenses associated with Avista no longer having publicly traded common stock, fewer non-employee members of the Avista Board of Directors, and other cost savings. These savings, however, will be covered by the proposed Rate Credit. Specifically, Avista and Hydro One are proposing to flow through to Avista's retail customers in Washington, Idaho and Oregon a rate credit of $31.5 Million over a 10-year period, beginning at the time the merger closes. (*See* Exh. MTT—6T, p.27:5-13)

164 The LEAP is a component of the Company's natural gas line extension policy, which it provides customers who install natural gas the ability to receive a credit in an amount equal to any remaining funds from the line extension allowance, after the line construction cost. The credit may only be used towards the purchase and installation of high-efficiency natural gas space and/or water heating equipment, and it may not exceed the customer's total cost of equipment and installation. (Exh. KJC-2T, p.3, fn. 2)

165 Exh. KJC-2T, p.7:9-13.

166 This is the equivalent of eliminating the average electric energy consumption of 2,498 homes annually. This is derived based on the following information in the record: As shown in Exh. KJC-6X (Page 1), for a residential electric-only customer, with a 2,000 square foot home, the annual electric heating load is estimated to be 14,308 kWh. When this customer converts to natural gas with a 90% efficient furnace they displace the kWh they previously used for heating, 14,308 kWh. From March 1, 2016 through August 31, 2017, 2,230 customers converted to natural gas from another fuel source to natural gas (See Exh. JES-10, page 3). Of those 2,230 customers that converted to natural gas, 1,965 were Avista electric customers (See Exh. JES-10, page 3). If one were to assume that on average the 1,965 Avista electric customers that converted to natural gas had a similar home size as assumed above, the total kWhs displaced for these customers annually, would have equaled 28,115,220 kWhs. The average monthly electric energy consumption of a home in Avista's service territory is,

96 The approval was on a temporary basis for a three-year period. This temporary period was considered the "pilot period" after which the Company would evaluate the results, and then would propose continuation of the program or not, modify it, or eliminate it.[167] Avista, however, does support notifying Staff no later than November 30, 2018 on its intent to modify and extend the LEAP, or discontinue the program altogether.[168] The Company welcomes ongoing discussions with Staff and other interested parties in the meantime.[169]

97 Staff is incorrect, however, in claiming that the metrics the Company is currently reporting on will not allow Avista or other parties to determine the success of the program.[170] It is also important to note, as does Mr. Christie, that the program only just passed the halfway point at the end of August 2017, and thus there is adequate time to discuss any future modifications to the metrics currently being evaluated, to determine the success of the program.[171]

98 Staff proposes three metrics for evaluating the success of the program. Regarding cost-effectiveness, the Company does not agree or support the recommendation of a cost-effectiveness test, similar to those used for the Company's DSM programs (i.e., Total Resource Cost Test or Utility Cost Test). The Company uses a Perpetual Net Present Value ("PNPV") methodology for calculating the available line extension amount to be offered to new natural gas customers. Using the PNPV methodology, "the maximum level of economical investment equals the annual distribution margin divided by the required rate of return."[172] Because the Commission has

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938 kWhs/month (See Exh. PDE-1T, p. 10, ln. 19) or 11,256 kWhs/year. Finally, 28,115,220 kWhs/year is the amount of electricity needed to supply 2,498 average residential electric customers per year.

[167] As noted by Staff (Exh. JES-1T, p.6), upon approval of the Company's filing, the Company consulted with Staff on the metrics which it would include in the required semi-annual reporting. These metrics were intended to be used to evaluate the success of the LEAP.

[168] Exh. JES-1T, p. 3

[169] Exh. KJC-2T, p.5:6-9.

[170] Exh. JES-1T, p.9.

[171] Exh. KJC-2T, p.6:2-4.

[172] "Line Extensions for Natural Gas: Regulatory Considerations," National Regulatory Research Institute, February 2013. http://www.nrri.org/documents/317330/aa3828ed-bbfa-4fac-b405-c6045dcf580c, p. 20.

approved this methodology, Avista does not believe it is necessary to also perform a DSM-like cost-effectiveness test on the Company's line extension policy, at this time.[173]

99 The Company does agree, however, with Staff that if the LEAP becomes a full-fledged program after the pilot program, it is appropriate to perform an analysis of the program's effect on future emissions. Lastly, the Company has worked with Staff on the development of the questions to be included in the voluntary survey that customers are asked to complete when participating in the LEAP.[174] Staff's recommendation "to conduct a survey that includes electric customers that have chosen not to take part in the program in order to ascertain areas where the program design or implementation might improve customer use of the program," however, is not feasible.[175] Based on the Company's experience, getting non-participants (if they could even be identified) to voluntarily participate in such a survey is not likely to be successful.[176]

B. The Electric-to-Natural-Gas Fuel Conversion Program Remains a Cost-Effective Electric Conservation Program and Should be Allowed to Continue.

100 The Company's electric-to-natural-gas fuel conversion program has been in place since at least 1990. The program was designed to provide customers with fuel choices and allow them to change from electric source space and water heating to natural gas where desired.[177] Concerns with the Fuel Conversion Program are more appropriately first addressed with the Company's Energy Efficiency Advisory Group, before being vetted in the context of a general rate case. That has not been done.

173 Exh. KJC-2T, p.9:1-10.
174 In response to the survey, over 90% of customers indicated that the LEAP impacted their decision to convert to natural gas, and prior to learning about the LEAP, 71% of customers said they had not previously considered high efficiency equipment. This information clearly shows that the data obtained from the customer surveys speaks more than to just customer satisfaction, but more so to the success and impact of the LEAP. (Exh. KJC-2T, p.11:1-5)
175 Exh. JES-1T, p.11.
176 Exh. KJC-2T, p.11:6-12.
177 Exh. KJC-2T, p.12:11-19.

101 Contrary to Staff, the Company believes that fuel conversions do qualify as "energy" conservation. The Company's fuel conversion program is a cost-effective method[178] to achieve electric savings that also removes electric load from the Company's electric system. Fuel conversions result in energy conservation, as the direct use of natural gas is more efficient than generating electricity from natural gas.[179]

102 The language in WAC 480-109-060(6) also states that conservation is "any reduction in electric power consumption resulting from increases in the efficiency of energy use, production, or distribution." (Emphasis added) Fuel conversions meet the definition of WAC 480-109-060 because 1) there is a reduction of electric power consumption and, 2) the reduction is the result of the increase in the "efficiency of energy use."[180] The language in WAC 480-109-060 requires that there is an "increase in the efficiency of energy use" – "not electricity" use. (Emphasis added)

103 Moreover, Staff argues that fuel conversions should no longer be funded by the Company's Electric DSM Tariff Rider, rather the program should be removed from the Tariff Rider and draw from a more appropriate funding source[181] and they recommend that the Company's 2018-2019 Biennial Conservation Plan ("BCP") not be approved if the Company includes fuel conversions in the plan. Staff also believes the inclusion of Conversion Programs burden electric customers unfairly.[182] As pointed out by Mr. Christie:

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178 The Fuel Conversion Program is cost effective. The individual measures of the Fuel Conversion Program have a benefit-to-cost ratio higher than 1.0 for both the Total Resource Cost ("TRC") Test and the Utility Cost Test ("UCT") (Exh. KJC-2T, p.12:16-19)

179 This echoes the Northwest Power Council's policy statement on the Direct Use of Natural Gas (Exh. KJC-2T, p.13:14-24):

> "The Council recognizes that there are applications in which it is more energy efficient to use natural gas directly than to generate electricity from natural gas and then use the electricity in the end-use application. The Council also recognizes that in many cases the direct use of natural gas can be more economically efficient. These potentially cost-effective reductions in electricity use, while not defined as conservation in the sense the Council uses them, are nevertheless alternatives to be considered in planning for future electricity requirements." (Northwest Power Council's Policy Statement on the Direct Use of Natural Gas, Appendix N, page N-4 of the Seventh Power Plan.) (Emphasis added)

180 Exh. JC-2T, p.14:3-12.

181 Exh. JES-1T, pp.18 and 23

182 Exh. JES-1T, p.23

> Ms. Snyder's comments neglect to mention the benefits that are received by electric customers (electric only and dual fuel) as a result of the fuel conversion program. All customers benefit from the fuel conversion program as it contributes to the deferral of future resource acquisitions and investments in generation, distribution, and transmission projects. As identified in the Company's 2017 Electric IRP, savings derived from conservation programs <u>offset approximately 50%</u> of the expected electric growth in its Washington and Idaho service areas.[183]

104 Discontinuing the Fuel Conversion Program would also harm electric customers who could no longer participate. The costs for heating with electric resistance heat can be <u>between 1.5 to 3 times the cost</u> of heating with natural gas, which would be a detriment to those electric customers who are unable to afford converting without the availability of the fuel conversion program.[184]

105 Next, Staff incorrectly claims that the incentive expenditures for residential fuel conversions dwarf the proposed incentives for all other residential programs.[185] For the 2018-2019 time period, incentives for the Fuel Conversion programs make up 29% of the overall DSM budget – not 42% as claimed by Staff. Ms. Snyder's statement that conversions make up 42% of the overall budget takes into consideration indirect non-incentive utility costs that are allocated to each program for planning purposes only.[186]

106 Moreover, the Conversion Program continues to be cost-effective according to the TRC and the UCT. Ms. Snyder suggests, however, that the Company provide a cost-effectiveness test that <u>combines</u> the LEAP along with the conversion program. The Company does not perform this analysis as LEAP and Fuel Conversions are different and distinct programs. One should remember that the intent of the LEAP is to help to expand natural gas distribution infrastructure to make natural gas more available to all prospective natural gas customers, not just Avista's electric customers,[187] address environmental concerns associated with emissions, and further promote the

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183 Exh. KJC-2T, p.16:1-7.
184 Exh. KJC-2T, p.16:14-17.
185 Exh. JES-1T, p.21
186 Exh. KJC-2T, p.17:13-20.
187 Finally, while the Company believes that the fuel conversion program is in the best interest of its customers, in the event that the Commission directs the program to be discontinued, the Company would work with its Advisory Group to establish a phased approach for discontinuing any portion of the program, knowing that the discontinuance of such a program will have effects on customers who may not be able to convert prior to

efficient end-use of natural gas. The LEAP is not a DSM program nor was it proposed to be treated like a DSM program.[188] The intent of the fuel conversion program is to reduce electric consumption and make homes more energy efficient. In the end, it is critically important that this very successful electric DSM program remain in place, and that any changes to the program should be vetted by the Energy Efficiency Advisory Group.

107 Regarding Avista's Multi-Family Market Transformation Program, this pilot is not a fuel conversion program. The program assists developers by installing the least cost option up front for future tenants, therefore reducing heating costs to customers. Avista proposes taking the issue whether the multi-family new construction program is indeed "market transformational" to its Advisory Group, which includes Staff, to determine an agreeable approach and to develop metrics for better evaluation. [189]

C. The Company Supports the Extension of the LIRAP Plan for an Additional Year, Through 2020.

108 It is reasonable to add one more year to the plan in an effort to continue to reduce the unmet need of the eligible low-income population in Avista's service territory, as well as to match the proposed Three-Year Rate Plan.

109 Staff's expressed concern, however, that the Company did not address the goals adopted by the Commission for Avista's LIRAP.[190] As explained by Mr. Christie[191], the Company did not provide an update on how it plans to implement these goals in this general rate case, as these goals are a part of the ongoing efforts discussed and analyzed by the Energy Assistance Advisory Group, and which the Company has updated the Commission on. The Company, nevertheless, is willing

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discontinuation, the employees of HVAC dealers and contractors, as well as Avista's own employees and contractors. (Exh. KJC-2T, p.23:1-8)

188 Exh. KJC-2T, p.19:6-15.

189 In the event that it is the desire of the Commission to have the Company discontinue its multi-family new construction fuel conversion program, Avista will need to honor contracts with developers that currently extend through December 31, 2019, in any event. See 170485-86-AVA-Cmt-01-12-18 p. 5 ¶6.

190 Hancock, Exh. CSH-1T, p.23

191 Exh. KJC-2T, p.24:23-26.

to work with its Energy Assistance Advisory Group on evaluating how the programs delivered through LIRAP are helping to reach the goals approved by the Commission. The Company does not believe it is necessary to address this in its compliance filing in this rate case, however; rather, the Company can address this in its annual LIRAP report or in its next status update to be filed on or before August 31, 2018.[192]

110 Regarding the proposal by The Energy Project ("TEP") to increase low-income weatherization funds, the Company supports increasing funding by the same amount as the LIRAP, through 2020, rather than the proposal of TEP. Accordingly, the Company does support an increase in funds to support low-income weatherization, however, not to the extent proposed by TEP – i.e., by $350,000 for each year of rate plan - TEP's proposal would increase low-income weatherization funding by approximately 50% (from $2 Million to $3 Million) over the course of a three-year rate plan, if approved. Instead, the Company would propose a similar plan as to that of LIRAP, through 2020, for increased funding to low-income weatherization by 7% per year[193].

D. <u>Avista is Not Supportive of an Opt-Out Option for DSM.</u>

111 Avista does not agree that customers should be able to opt-out of the Company's DSM funding and programs altogether, as proposed by ICNU.[194] Every customer benefits from the Company's DSM programs through an avoidance of increased generation costs over time, among other benefits. These system benefits accrue to <u>all</u> customers, and therefore all customers should share in the costs. The Company does agree, however, that a self-direct option for DSM funding could provide value to Avista and our large customers, but it is more appropriate for such a program to be vetted and discussed through the DSM Advisory Group first. Because a Self-Direct

[192] Exh. KJC-2T, p.25:9-13.
[193] Exh. KJC-2T, p.25:15-22.
[194] Exh. RRS-1CT, pp.40:11-20 – 41:1-2

option could provide value to our large customers,[195] Avista is willing to introduce a Self-Direct program to its DSM Advisory Group in the second half of 2018 for their consideration.[196]/[197]

VIII. COST-OF-SERVICE/RATE SPREAD/DECOUPLING

A. Electric Cost of Service.

112 The Settling Parties have agreed that it is more appropriate to address, in the ongoing generic collaboration (arising out of Docket Nos. UE-160228 and UG-160229), cost-of-service methodologies to be used in future cases. (*See* Exh. JP-1, Multiparty Partial Settlement Stipulation) Accordingly, the Settling Parties did not agree on specific cost-of-service methodologies in this case and agreed to reserve all cost-of-service issues for the generic cost-of-service collaboration.[198]/[199] In addition, given the limited testimony and analysis related to cost-of-service in this proceeding, the Commission lacks a complete and informed record from which it could base its decisions. As stated by Mr. Ehrbar:

> . . . the Settlement allows the parties to focus on cost-of-service issues in the generic collaborative process without having to apply time and resources to both proceedings concurrently. It will also take into account positions of other utilities and interested parties – and is meant to be "generic" in that respect. It is the Company's view that the collaborative process should be allowed to run its course in order for the parties and the Commission to have an opportunity to resolve, and or provide guidance, on as many issues as possible before addressing cost-of-service in any immediate proceeding. The Company fully supports the collaborative process and will continue to participate in good faith in those proceedings.[200]

113 Even so, ICNU Witness Mr. Stephens objects to the peak credit approach used by the Company to classify production and transmission costs on the grounds that investment in production and transmission is primarily incurred due to peak demands. As noted by Company

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195 Exh. KJC-2T, p.27:8-13.
196 Exh. RRS-1CT, pp.40:11-20 – 41:1-2
197 The DSM Advisory Group could take up further in-depth investigation of potential program options, with the intention that Avista would file with the Commission a proposal or status update on or before January 15, 2019.
198 Settlement Stipulation, p. 3, paragraph 5. (Exh. JP-1)
199 Exh. PDE-9T, p.26-21.
200 Exh. PDE-9T, p.3:2-9.

Witness Ehrbar, however, the theory behind the peak credit approach is to provide a balance between the way the system is designed to meet peak load and how the system is used to provide energy every hour of every day.[201]/[202]

114 The Company also disagrees with Mr. Stephens' proposal for a summer/winter 4CP or 5CP demand allocator for production costs. The Company believes the 12-month coincident peak ("12CP") demand allocator provides a more balanced approach that is less likely to vary widely from year to year due to extraordinary weather conditions. Avista agrees with the Commission that peak demand based on only four hours is too narrow of a range.[203] In any event, the results of Mr. Stephens' cost-of-service studies do not materially differ from those of the Company. In fact, Mr. Stephens cost-of-service results seemingly confirm that the results of the study conducted by the Company, and relied upon as the basis for the Settling Parties' rate spread agreement, are directionally accurate in terms of confirming that two rates schedules (Schedules 1/2 and 11/12) are disproportionately out of line from the other rate schedules in terms of unity, as shown in Table No. 1 of Mr. Ehrbar's testimony.[204]

B. Electric and Gas Rate Spread.

115 The electric rate spread as agreed to by the parties in the Settlement Stipulation addresses the fact that certain classes are far enough from unity to warrant action and the agreed upon rate spread would move those classes further toward parity ratios of unity in each year of the rate plan.

116 Should the electric revenue increase approved by the Commission be less than the Company's original request, the effects of ICNU's rate spread disproportionately impact Residential Schedule 1/2 customers. The Settling Parties rate spread, which moves those customers

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201 Exh. PDE-9T, p.4:3-10.
202 In the 2014 Pacific Power case, the Commission stated that it "has long preferred the Peak Credit methodology and consistently has approved its use in cost-of-service studies for Pacific Power, and for both PSE and Avista." (Docket No. UE-140762 et al. *(Consolidated)* Order No. 08 page 81 paragraph 190.)
203 Exh. PDE-9T, p.5:7-13.
204 Exh. PDE-9T, p.6:5-15.

furthest from full cost of service gradually towards unity, is a better way to spread the revenue increase in this case.[205]

C. Decoupling.

117 Staff Witness Mr. Hancock proposes a decoupling "soft-cap":

> The decoupling soft-cap should use a 3% threshold that is independent of any rate increases from the multi-year rate plan. The revenue increase authorized by the decoupling mechanism should first be determined. Then, the revenue increase called for by the rate plan should be applied, followed by the application of the increase in revenues called for by the decoupling mechanism.[206]

The Company agrees with Mr. Hancock's decoupling soft-cap proposal as it relates to the multi-year Rate Plan.

118 Mr. Hancock also proposed that Avista's third-party evaluation of its existing decoupling mechanism should explicitly include a comparison of low-income conservation program participation with general conservation program participation to inform the level of spending on low-income conservation programs.[207] The Company believes that the existing Scope of Work with the selected Three Party Evaluator would already serve to provide the requested analysis.

119 The Company also agrees with Mr. Hancock's proposal to include a natural gas conservation target in any <u>future</u> decoupling proposals.[208] Avista will include a natural gas target in future decoupling proposals, but does not support inclusion of a target during the present five year term because a defined target has yet to be discussed or agreed-upon.[209]

IX. COST OF CAPITAL

A. Return on Equity Recommendations.

120 Mr. McKenzie on behalf of Avista summarizes his principal conclusions after reviewing the ROE testimony of other witnesses:

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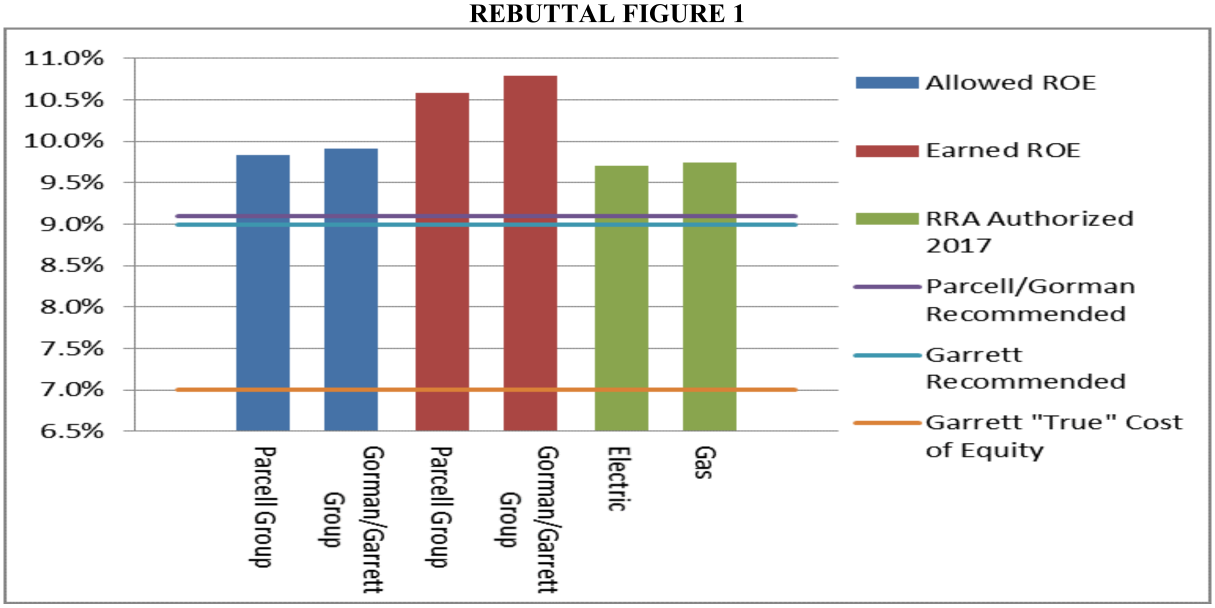
205 Exh. PDE-9T, p.7:12-16.
206 Exh. CSH-1T p.21:16-20
207 Exh. CSH-1T pp.22:19 – 23:1
208 Exh. CSH-1T p.22:1-4
209 Exh. PDE-9T, p.10:17-21.

> The cost of equity recommendations of Mr. Parcell (9.1%), Mr. Gorman (9.1%), and Mr. Garrett (7.0% and 9.0%) are simply too low and fail to reflect the risk perceptions and return requirements of real-world investors in the capital markets. Their recommendations would be significantly below recent average ROEs authorized by other state commissions. In 2016, the average allowed ROE for vertically-integrated electric companies (like Avista) was 9.77%; for the first three quarters of 2017 it was 9.70%. For gas utilities, the average allowed ROE was 9.54% in 2016 and 9.75% for the first three quarters of 2017.
>
> Authorized ROE data for the specific firms in Mr. Parcell's and the Gorman/Garrett proxy groups is even more compelling. As shown in Exh. AMM-15, the authorized ROEs for the firms in Mr. Parcell's proxy group range from 9.37% to 10.50% and average 9.83%; for the Gorman/Garrett group the range is 9.15% to 10.90% with an average of 9.91%.[210]

121 The significant shortfall between the ROE Witnesses' recommendations and the ROE benchmarks discussed in Mr. McKenzie's rebuttal testimony are illustrated in Figure 1 below:[211]

REBUTTAL FIGURE 1



Mr. McKenzie identifies the key deficiencies in each of the other ROE Witness analyses.[212]

<u>Regarding Mr. Parcell (Staff)</u>:

210 Exh. AMM-14T, pp.1:16 – 2:8.
211 Exh. AMM-14T, p.3:1-15.
212 Exh. AMM-14T, p.3:6:17.

- Mr. Parcell's Discounted Cash Flow ("DCF") analysis contains several flaws: His analysis creates a mishmash of results, none of which even reach his 9.1% recommendation, casting doubt on their credibility; his reliance on historical data, including dividend and book value data, are not appropriate; his decision to average individual growth rates together and then compute a single DCF estimate for each company is misguided; and he has computational shortcomings in his retention growth calculation.
- His Capital Asset Pricing Model ("CAPM") analyses also contains numerous flaws, most notably his reliance on historical data when the ROE estimation process is clearly forward-looking, his choice of 20-year Treasury securities as the basis for the risk-free rate when 30-year Treasuries are warranted, and his reference to geometric means which will always bias results downward.
- Mr. Parcell's Comparable Earnings ("CE") approach, while the most reasonable of his methods, also contains significant shortcomings due primarily to his repeated fault of relying on historical data in a process that is forward-looking, his problematic injection of market-to-book ratios into the analysis, and his failure to apply the essential mid-year adjustment factor.
- Finally, his criticisms of Mr. McKenzie's ROE approaches are not valid, including his comments on the current interest rate outlook, low-end ROE outliers, the CAPM and Empirical CAPM ("ECAPM") analyses, size adjustment, the Utility Risk Premium analysis, the Expected Earnings analysis, and Mr. McKenzie's Non-Utility DCF analysis.

<u>Regarding Mr. Gorman (ICNU)</u>:

- Mr. Gorman's DCF approach is compromised because he includes illogical low-end values in his final results, he ignores a readily available and widely followed source of analysts' growth rates, and he relies on a multi-stage growth DCF model that wrongly assumes that investors view growth in gross domestic product ("GDP") as an upper limit on utility growth.
- The CAPM results reported by Mr. Gorman are suspect because they are based on historical data, they fail to correct for an observed bias in the CAPM result, and they ignore the impact of company size on expected returns.
- His risk premium analysis is flawed because he rejects the well-documented, inverse relationship between equity risk premiums and interest rate levels.
- Mr. Gorman's analyses also suffer from many of the same deficiencies identified above in connection with Mr. Parcell's analysis. His failure to consider the ECAPM or to recognize flotation costs is at odds with the conclusions of recognized financial research and his own admission that these are legitimate expenses that should be recovered. Finally, his criticisms of my Expected Earnings approach and Non-Utility DCF analysis are without merit.

<u>Regarding Mr. Garrett (Public Counsel)</u>:

- As noted by Company Witness McKenzie, while Mr. Garrett ostensibly relies on traditional ROE models in forming his opinions, the assumptions that he employs and the conclusions that he reaches are "outside the mainstream of ROE analyses."[213]
- Mr. Garrett says that, based on DCF and CAPM results, the "true" cost of equity in this case is 7.0%. However, he proposes an ROE for the Company of 9.0% based solely on "the interest of achieving a gradual movement toward the appropriate market-based cost of equity."[214] In other words, his final recommendation is not supported by <u>any</u> of the analyses presented in his testimony. As a result, his recommendations should be disregarded in their entirety.[215]
- Mr. Garrett's estimate of the "true" cost of equity of 7.0% is not credible on its face. This result is extreme, and falls far below the lowest ROE awarded by any state regulatory commission in modern history.
- Mr. Garrett mistakenly implies that he has divined the "true" cost of equity capital, when in reality it is impossible to make this claim.
- Mr. Garrett's position that firm-specific risks "have no meaningful effect on the cost of equity estimate" is off-point and violates long-standing, fundamental regulatory precedent.
- His DCF analysis significantly understates the Company's ROE because he uses stale dividend data and his growth rate selection is marred by a mistaken belief that expectations of utility investors are limited to growth in GDP.
- His CAPM analysis suffers from many of the same problems of Mr. Parcell and Mr. Gorman. That is, it is wrongly based on historic and survey data which leads to nonsensical results.

122 The ROE recommendations of the ROE Witnesses do not satisfy fundamental regulatory standards. As discussed by Mr. McKenzie, one fundamental standard underlying the regulation of public utilities, as set forth by the Supreme Court's *Bluefield* and *Hope* decisions, requires that the Company must have the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments of similar risk if it is to maintain its financial flexibility and ability to attract capital.[216]

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213 Exh. AMM-14T, p.5:13-15.
214 Exh. DJG-1T at 62.
215 Exh. AMM-4T, p.5:16-22.
216 Exh. AMM-14T, p.6:21-25.

123 If the utility is unable to offer a return similar to the returns available from other opportunities of comparable risk, investors will become unwilling to supply capital to the utility on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their cost of capital. The recommendations of the ROE Witnesses are below reasonable outcomes and violate regulatory standards, as noted by Mr. McKenzie.[217]

124 Moreover, the recommendations of the ROE witnesses are far below allowed returns over the 2016-2017 timeframe (9.70%-9.77% electric cases, 9.50%-9.75% gas cases) and for the companies in their own proxy groups (9.83% Parcell proxy group, 10.91% Gorman/Garrett proxy group).[218] In considering utilities with comparable risks, investors will always prefer to provide capital to the opportunity with the highest expected return. If a utility is unable to offer a return similar to that available from other investment opportunities with equivalent risks, investors will become unwilling to supply the utility with capital on reasonable terms.

125 Also the expected earned rates of return for the ROE Witnesses' own proxy groups demonstrate that their ROE recommendations are too low. The year-end returns on common equity projected by the Value Line Investment Survey ("Value Line") over its forecast horizon for the firms in the ROE Witnesses' proxy groups are shown in Mr. McKenzie's Exh. AMM-16. Once adjusted to a mid-year basis,[219] reference to expected earnings implied an annual average cost of equity for the utilities referenced by Mr. Parcell of <u>10.6%</u> and <u>10.8%</u> for the Gorman/Garrett group. This prompted Mr. McKenzie to observe:

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217 Exh. AMM-14T, pp.6:21 – 7:6.

218 Exh. AMM-14T, p.8:13-20.

219 Exh. AMM-14T, p.10, fn. 19. Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, which is consistent with the theory underlying this approach. Use of an average return in developing the sustainable growth rate is well supported. *See, e.g.*, Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 305-306, which discusses the need to adjust Value Line's end-of-year data. FERC has affirmed the need for this adjustment to "r" in *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 (2008).

> If Avista is only allowed the opportunity to earn a 9.0% or 9.1% return on the book value of its equity investment, as recommended by the ROE Witnesses, while other comparable utilities are expected to earn an average of 10.6%-10.8%, the implications are clear – Avista's investors will be denied the ability to earn a return that is comparable to those available from investments with comparable risk.[220]

126 Expected rates of return for firms <u>in the competitive sector</u> of the economy <u>are also relevant</u> in determining the appropriate return to be allowed for rate-setting purposes.[221] In fact, even Mr. Parcell recognized that investors gauge their required returns from utilities against those available from utility and non-utility firms of comparable risk. Mr. McKenzie's reference to a low-risk Non-Utility Group is entirely consistent with the guidance of the Supreme Court and the principles outlined in Mr. Parcell's own testimony. And yet, the ROE Witnesses presented no meaningful evidence to rebut the results for Mr. McKenzie's Non-Utility Group, or otherwise demonstrate that his Non-Utility Group is riskier than Avista or his proxy group of utilities. Instead, Mr. Parcell, for instance, simply alluded to the obvious fact that "unregulated enterprises face different risk and operational characteristics than do utilities."[222]/[223] Mr. McKenzie went on to observe:

> The simple observation that a firm operates in non-utility businesses says nothing at all about the <u>overall investment risks perceived by investors</u>, which is the very basis for a fair rate of return. So long as the risks associated with the Non-Utility Group are comparable to Avista and other utilities the resulting DCF estimates provide a meaningful benchmark for the cost of equity.[224]

127 Mr. McKenzie's ROE analysis for the Non-Utility Group is shown on Exh. AMM-12 (at 3). The average ROEs for the Non-Utility group ranged from 10.2%-10.8%. The midpoint of this range is 10.5%.

> Adopting an ROE for Avista that is well below the ROEs for comparable (or lower risk) companies could lead investors to view the Commission's regulatory framework as unsupportive, an outcome that would undermine investors'

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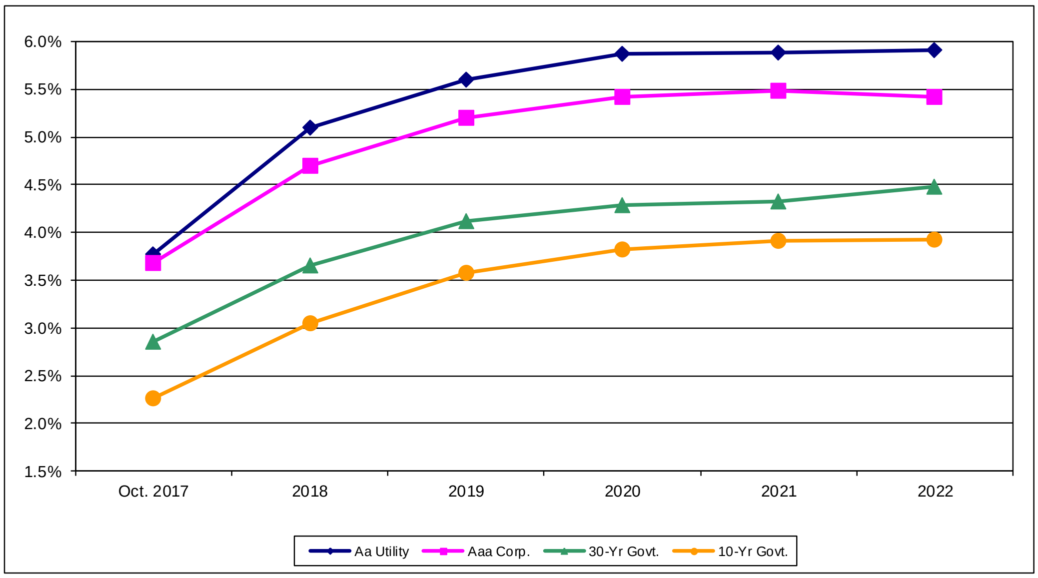
220 Exh. AMM-14T, pp.10:15 – 11:4.
221 Exh. AMM-1T at 41-45.
222 Exh. DCP-1T at 55.
223 Exh. AMM-14T, p.13:4-8.
224 Exh. AMM-14T, p.13:15-19.

willingness to support future capital availability for investment in Washington.[225]/[226]

128 Mr. McKenzie also addresses the expected direction of interest rates and how this impacts the evaluation of a fair ROE in this proceeding. Not surprisingly, he notes that interest rates are expected to increase. Figure 2 (Interest Rate Trends) from his Rebuttal Testimony[227] is set forth below:

REBUTTAL FIGURE 2
INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Sep. 1, 2017)
IHS Global Insight (Aug. 24, 2017)
Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 36, No. 6 (Jun. 1, 2017)

As Figure 2 shows, investors continue to anticipate that interest rates will increase significantly from present levels. As noted by Mr. McKenzie, the interest rate increases shown in the figure

225 Security analysts study regulatory orders in order to advise investors where to invest their money. Moody's Investors Service ("Moody's") noted that, "[f]undamentally, the regulatory environment is the most important driver of our outlook." (Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014). Similarly, S&P concluded that "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance." (Standard & Poor's Corporation, "Key Credit Factors For The Regulated Utilities Industry," *RatingDirect* (Nov. 19, 2013) (Exh. AMM-14T, p.15:13-18)

226 Exh. AMM-14T, p.15:8-12.

227 Exh. AMM-14T, p.17

above are on the order of 150-200 basis points through 2022, which implies higher long-term capital costs over the period when rates established in this proceeding will be in effect.[228]/[229]

129 Recent decisions by the Federal Reserve reinforced investor sentiment that interest rates will trend higher. On June 14, 2017, the Federal Reserve increased the target range for the Federal Funds rate by another 25 basis points to 1.00% – 1.25%. This is in addition to similar increases in March 2017, December 2016, and December 2015. More rate hikes by the Federal Reserve are anticipated.[230]

B. Capital Structure.

130 The capital structure proposals in this case are summarized in the table below:[231]

REBUTTAL TABLE 3
Proposed Capital Structures

	Common Equity	Long-Term Debt	Short-Term Debt
Parcell	48.50%	48.60%	2.90%
Gorman	48.40%	48.70%	2.90%
Garrett	48.50%	48.60%	2.90%
Avista	50.00%	50.00%	0.00%

131 As explained by Mr. McKenzie, a 50% common equity level is consistent with Avista's need to maintain its credit standing and financial flexibility, within the range of capitalizations for the proxy utilities, and recognizes the importance of an adequate equity layer to accommodate the pressures of funding significant capital investments and to balance off-balance sheet commitments (such as purchased power agreements) which carry with them some level of imputed debt.[232]

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228 Exh. AMM-14T, p.17:1-6.

229 Indeed, even Mr. Gorman acknowledges that interest rates are expected to increase. For instance, in selecting the risk-free rate for use in his CAPM analysis, Mr. Gorman used *Blue Chip Financial Forecasts'* projected 30-year Treasury bond yield of 3.60%, while acknowledging that the current rate is 2.81%. (Gorman Direct at 55) Mr. Gorman also utilizes the higher projected Treasury bond yield in his risk premium analysis. With these adjustments, Mr. Gorman clearly recognizes that investors anticipate a substantial increase in future interest rates. (Exh. AMM-14T, p.18:1-4)

230 Exh. AMM-14T, p.19:6-9.

231 Exh. AMM-14T, p.103:12-22.

232 Exh. AMM-14T, pp.103:25 – 104:3.

132 The importance of a healthy equity layer is even more critical in the face of the much lower ROE recommendations from the ROE Witnesses. If the Company is to maintain a balanced risk position, increased operating risk (in this case, reflected in the reduced ROE recommendations of the ROE Witnesses) must be offset with decreased financial risk (reflected in an enhanced common equity ratio).[233]

133 The primary difference between the Company's proposed capital structure of 50% equity and 50% long term debt and Mr. Parcell, Mr. Gorman and Mr. D. Garrett's proposed capital structure is their inclusion of short-term debt in the calculation.

134 One of the rate making "tools" identified by this Commission that can be used to arrive at an end result that provides sufficient revenues is <u>the use of an adjusted capital structure</u>.[234] Both Idaho and Oregon currently use this ratemaking tool of adjusting the capital structure by excluding short-term debt from the capital structure calculation.[235] Avista's currently approved capital structure in Idaho and Oregon includes 50% equity and 50% debt. In this case Avista is proposing a similar adjustment to its capital structure, excluding short-term debt from the capital structure calculation.[236]

135 Maintaining a 50% common equity ratio, excluding short-term debt, has several benefits for customers. A solid financial profile will assist Avista in accessing debt capital markets on reasonable terms in both favorable financial markets and when there are disruptions in the financial markets. Additionally, this common equity ratio solidifies our current credit ratings and moves Avista closer to our long-term goal of having a corporate credit rating of BBB+.[237]

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233 Exh. AMM-14T, p.104:4-8.

234 The WUTC acknowledged at ¶491 in Order No. 08 of Docket No. UE-111048 and UG-111049 of Puget Sound Energy's proceeding, the consideration of adjustments to rate base beyond the historical test period by stating they were open to considering "Use of plant accounts (rate base) measured at the end, or subsequent to the end of the test-year rather than the test-year average," and their openness to consider <u>an "upward adjustment to the equity share in the capital structure</u>." (emphasis added) (Exh. MTT-6T, p.13, fn. 11)

235 Both Idaho and Oregon exclude short-term debt from both the capital structure and the cost of debt. (Exh. MTT-6T, p.14:1-3)

236 Exh. MTT-6T, p.14:1-5.

237 Exh. MTT-6T, p.14:7-13.

136 As shown on page 1 of Exh. AMM-5, Value Line expects an average common equity ratio for the proxy group of utilities of 50.1 percent for its three-to-five year forecast horizon, with the individual common equity ratios ranging from 35.5 percent to 75 percent. The WUTC has previously observed that "[i]t is appropriate . . . to afford more weight to forward considerations than to historic conditions as we determine the appropriate equity ratio to be embedded in prospective rates.[238]

137 The individual operating company capital of the proxy group are presented on page 2 of Exh. AMM-5. As shown there, the operating company equity ratios ranged from 41.6 percent to 61.0 percent. The simple average of these results points to an equity ratio of 52.8 percent; the average weighted by total capitalization for each operating entity was 52.1 percent.

C. <u>Cost of Debt.</u>

138 As it concerns cost of debt, Mr. Parcell on behalf of Staff uses a 5.54% cost of long-term debt based on the recommendation of Staff Witness Mr. McGuire, which excludes the effects of the 2016 settled interest rate swaps in the calculation of cost of debt. This was discussed earlier (which would cause a $33.6 Million write-off in 2018). Other than the treatment of the 2016 settled interest rate swaps, Mr. Parcell's proposed cost of debt is no different from the Company's.

139 Mr. Gorman proposes a long-term cost of debt of 5.31% which he calculates by assuming an estimated refinancing rate for debt that will mature in mid-2018. It is inappropriate for Mr. Gorman to use 2018 pro-forma debt, as the changes in debt costs he is proposing occur in mid-2018 and include forecasted debt issuances. This is entirely inconsistent with how all of the Parties have otherwise limited the amount of capital additions to exclude all 2018 additions, while at the same time reaching out to capture 2018 debt issuances.[239]

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[238] *Order No. 06*, Docket Nos. UG-40640 and UE-40641 (consolidated) (Feb. 18, 2005) at p.32.
[239] Exh. MTT-6T, p.15:1-16.

X. CONCLUSION

140 Avista respectfully requests approval of its Three Year Rate Plan to break the cycle of annual general rate cases and provide a degree of predictability of retail rates for customers. Otherwise accepting Staff's cost of debt, however, to exclude the impact of interest rate hedges would have a punitive effect for actions taken to benefit customers. Moreover, The Company's power supply costs are based on the application of a proven AURORAxmp methodology. Furthermore, the Commission should also recognize the continuing efficacy of the Fuel Conversion Program. Finally, the Company respectfully urges the Commission to properly recognize the level of plant that will be providing service to customers, beginning in Year One of the Rate Plan.

141 RESPECTFULLY SUBMITTED this 22 day of February, 2018.

AVISTA CORPORATION

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