BEFORE THE

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UTILITIES COMMISSION

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
AVISTA CORPORATION DBA AVISTA	)	CASE NO. AVU-E-17-01
UTILITIES FOR AUTHORITY TO INCREASE	)	AVU-G-17-01
ITS RATES AND CHARGES FOR	)	
ELECTRIC AND NATURAL GAS SERVICE	)	
IN IDAHO	)	
	)	

DIRECT TESTIMONY OF RANDY LOBB IN SUPPORT OF THE STIPULATION AND SETTLEMENT

IDAHO PUBLIC UTILITIES COMMISSION

NOVEMBER 3, 2017

Q. Please state your name and business address for the record.

A. My name is Randy Lobb and my business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed?

A. I am employed by the Idaho Public Utilities Commission as Utilities Division Administrator.

Q. What is your educational and professional background?

A. I received a Bachelor of Science Degree in Agricultural Engineering from the University of Idaho in 1980 and worked for the Idaho Department of Water Resources from June of 1980 to November of 1987. I received my Idaho license as a registered professional Civil Engineer in 1985 and began work at the Idaho Public Utilities Commission in December of 1987. I have analyzed utility rate applications, rate design, tariff filings and customer petitions. I have testified in numerous proceedings before the Commission including cases dealing with rate structure, cost of service, power supply, line extensions, regulatory policy and facility acquisitions. My duties at the Commission include case management and oversight of all technical Staff assigned to Commission filings.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to describe the proposed comprehensive settlement in this case and explain Staff's support.

Q. Please summarize your testimony.

A. Based on Staff's review of the Company's application, detailed identification of revenue requirement adjustments, and thoughtful assessment of litigation and settlement alternatives, Staff believes that the proposed Stipulated Settlement (Settlement; Stipulation) is in the public interest, is fair, just and reasonable and should be approved by the Commission.

The two-year rate plan will increase base electric and gas revenues by $12.9 million (5.2%) and $1.2 million (2.9%), respectively, on January 1, 2018, and $4.5 million (1.9%) and $1.1 million (2.7%), respectively, on January 1, 2019. The Settlement includes a two-year rate case stay-out provision, and provides a reasonable balance between the Company's opportunity to earn a return and affordable rates for customers. Staff supports the proposed 9.5% return on equity (ROE) and maintains that the class allocation proposed in the Settlement properly addresses cost of service concerns raise by the various parties by equitably distributing the increased costs based on cost causation. Staff further believes that additional cost of service discussion is warranted and supports the stipulated provision to have such discussions.

The proposed rate design includes a 25 cent per month customer charge increase for residential and small general service electric customers and a $0.75 per month customer charge increase for natural gas customers. Staff believes this properly spreads the increase between fixed and commodity charges.

Finally, Staff supports further investigation of low income weatherization funding by agreeing to evaluate existing programs and funding levels and submit a funding proposal to the Commission by December 31, 2017.

Staff maintains that the Stipulated Settlement signed by five of the seven parties to the case was arrived at through hard bargaining during the settlement conference, the result of compromise by all parties and it should be approved without change by the Commission. The Stipulated Settlement is attached as Staff Exhibit 101.

Q. How is your testimony organized?

A. My testimony is subdivided under the following headings:

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Background

Q. Could you please provide a little background on Avista's original filing?

A. Yes. The Company filed its Application on June 9, 2017 requesting a two-year rate plan for both electric and natural gas service. The Company proposed that electric base revenues increase by $18.6 million or 7.5% on January 1, 2018 and $9.9 million or 3.7% on January 1, 2019. The Company proposed that natural gas base revenues increase by $3.5 million or 8.8% on January 1, 2018, and $2.1 million or 5.0% on January 1, 2019. The Company recommended a 7.81% overall rate of return and a 9.9% ROE.

The Company proposed a 15% move toward cost of service for the various electric customer classes in year one and a prorated revenue increase for each electric service schedule in year two. Gas service schedules were proposed to move approximately one third toward cost of service in year one with revenues spread to each customer class on a prorated basis in year two.

Q. How was the case processed after the Company's filing was received?

A. The Commission issued a notice of filing and granted intervenor status to Clearwater Paper Company, the Community Action Partnership Association of Idaho (CAPAI), the Idaho Conservation League (ICL), Idaho Forest Group and the Sierra Club.

A procedural schedule was approved by the Commission and a Settlement Conference was held on September 29, 2017. All parties except the Sierra Club attended the Conference. Sierra Club and ICL participated in subsequent settlement discussions, but no settlement was reached. A comprehensive Settlement was reached by all parties except the Sierra Club and ICL and the Motion to Approve the Stipulation and Settlement was filed with the Commission on October 20, 2017.

Stipulation Overview

Q. Would you please describe the terms of the Settlement Agreement?

A. Yes. The Settlement provides a two year rate plan for both electric and natural gas service with a two-year rate case stay-out. Under the terms of the agreement, the Company will receive a $12.9 million or 5.2% electric revenue increase effective January 1, 2018 and a $4.5 million or 1.9% increase effective January 1, 2019. Natural gas revenues will increase by $1.2 million or 2.9% on January 1, 2018 and $1.1 million or 2.7% on January 1, 2019. The Company is precluded from filing a general rate case or any other request to defer costs for later recovery except under extraordinary circumstances prior to May 31, 2019. The parties agreed to a 9.5% ROE with a 50% common equity ratio for an overall return of 7.61%.

Key adjustments to the first year electric and gas revenue requirement request include a reduction in the Company's requested ROE, a reduction or delay in capital recovery, and removal or delay in a variety of miscellaneous labor, inspection, environmental, legal, damages and O&M expenses. The Stipulation also specifies a weather normalization adjustment that increases test year natural gas consumption.

The second year electric and natural gas revenue requirement increase allows recovery of capital investment not allowed recovery in year one, targeted capital additions in 2018 using average of monthly average rate base methodology and known expense increase for labor, property taxes and equipment inspection.

Q. What terms are included in the Stipulation for cost of service and rate design?

A. The Stipulation accepts the Company's originally proposed 15 percent first year move toward electric cost of service for all customer classes except Schedule 25 and 25P which would receive 75% of the overall percentage increase. Likewise, the Stipulation adopts the Company's proposed uniform electric revenue increase for all classes in year two.

The Stipulation also adopts the Company's originally proposed natural gas revenue allocation of a 30% move toward cost of service in year one and a uniform increase in year two. The Stipulation does not adopt any specific cost of service study methodology for either electric or natural gas service.

With respect to rate design, the Stipulation specifies a $0.25 monthly increase in electric residential and small commercial customer charges in year one. Natural gas customers will see a $0.75 monthly increase in customer charges in year one as well. The remainder of the revenue requirement increase in year one and in year two for both electric and gas service is collected through Company proposed increases in demand charges and a uniform increase in commodity charges.

Q. What other terms are included in the Stipulation?

A. The Stipulation specifies that interested parties will convene a workshop to discuss cost of service issues and meet to establish appropriate funding levels for low income weatherization. The Stipulation also specifies that interested parties will confer on natural gas service and meter placement rules. The Company also commits as part of the Stipulation to establish service quality/performance measures in Idaho similar to those currently in place in Washington.

Staff Investigation

Q. Could you please describe Staff's investigation leading up to the settlement conference?

A. Yes. Staff's approach prior to the settlement conference was to extensively review the Company's filing, identify adjustments to its revenue requirement request and prepare to file testimony for a fully-litigated proceeding.

Three Staff auditors were assigned to the case and actually began reviewing 2016 results of operations before the Company filed its Application in June of 2017. After the filing, the auditors reviewed the capital budgets, capital spending trends, O&M expenses and trends, and verified all of the Company's calculations and assumptions with regards to the overall revenue requirement. The auditors spent two weeks on-site at Avista's corporate headquarters in Spokane, reviewing over 100,000 transactions, selected samples and performed transaction testing in accordance with standard audit practices. The auditors reviewed the Company's labor expense, incentive plans, and employee benefits including health insurance and retirement to insure an appropriate level of expenditure.

Thirteen other technical staff consisting of engineers, utility analyst and consumer investigators were also assigned to the case and submitted over 110 production requests as part of its comprehensive investigation. Staff reviewed both completed and proposed Company investments, evaluated expenditures including pensions, salaries, and operation and maintenance, investigated power supply modelling, weather normalization, class cost of service methodologies and compared rate design alternatives for both electric and natural gas service.

Given the Company's two-year rate proposal, Staff also evaluated the merits of using forecasted or budgeted expenses and investment to set test year annual revenue requirement rather than using an historic test period.

Q. What type of adjustments to the Company's proposed electric revenue requirement did Staff identify?

A. Staff focused on adjustments in four primary areas; 1) rate of return; 2) 2017/2018 capital investment and O&M expenses; 3) salaries; and 4) miscellaneous test year expenses. Staff identified 28 individual electric revenue requirement adjustments totaling approximately $9 million or 49% of the Company's original electric revenue requirement request.

Staff applied many of the adjustments on the electric side to the requested revenue requirement increase for natural gas. Staff also identified a gas adjustment associated with weather normalization. Staff's natural gas adjustments totaled approximately $3 million or approximately 87% of the Company's original request.

Q. How did Staff evaluate the second year revenue requirement request?

A. Staff reviewed the capital and expense budget/forecast for 2018 and 2019 as proposed for the second year of the Company's proposed two-year rate plan. For the second year of the rate plan, Staff eliminated all of the capital additions budgeted for 2019 and most of the proposed additions in 2018. Staff also removed the requested 2019 salary increases. The Staff proposed adjustments decreased the Company proposed electric increase by approximately $8 million or 81%. Likewise, Staff adjustments reduced the Company proposed natural gas increase by approximately $1.9 million or 89% for the second year.

Q. How did Staff evaluate other aspects of the Company's proposal?

A. Staff spent considerable time evaluating power supply expenses, weather normalization, class cost of service methodology and rate design by comparing expenses, rates and methodology to those proposed by the Company in the last general rate case. Other than the weather normalization adjustment that increases test year gas consumption, Staff identified no other adjustment or modification to rates or methodology.

Settlement Process

Q. Could you please describe the settlement process?

A. Yes, the Settlement workshop was held on September 29, 2017, with all parties except the Sierra Club in attendance. Negotiations began with each intervening party identifying their issues of concern and what they expected to achieve through settlement or litigation. Issues raised included cost of service, low income weatherization funding, rate case stay-outs and issues related to Avista's Colstrip generating station.

Staff then presented its investigative results with a step by step discussion of each of the 29 first year identified revenue requirement adjustments. The presentation included rational for each adjustment and a proposal for the second year of the rate plan. Staff also provided a proposal for gas service rules, a proposal for electric service standards and a statement of support for Company proposed cost of service and rate design positions.

After a lengthy discussion of the various revenue requirement adjustments and identified issues, the Company developed a counter proposal and presented it to the parties for discussion. Staff evaluated the Company proposal based on previous discussion and an assessment of how successfully an adjustment might be defended at hearing. Staff then developed and presented a counter proposal. The parties continued to negotiate on individual adjustments and what revenue should reasonably be collect in the first and second year of a rate plan. The parties ultimately reached compromise and settled on a tentative agreement.

Q. Was that the end of settlement negotiations?

A. No. Additional conference calls and email discussion continued on cost of service details, terms of a rate case stay-out, low income weatherization funding, and costs associated with the Colstrip coal fired generating plant. The Stipulated Settlement was then filed with the Commission on October 20, 2017.

Q. Was settlement reached by all parties on all issues?

A. No. The parties could not reach agreement on issues relating to Colstrip. Consequently, neither ICL nor Sierra Club are parties to the Settlement.

Settlement Evaluation

Q. How did Staff determine that the overall Settlement was reasonable?

A. In every settlement evaluation, Staff and other parties must determine if the agreement is a better overall outcome than could be expected at hearing. Staff looked at each revenue requirement adjustment for both electric and natural gas service and determined that the overall agreement for a two-year rate plan with stay-out provisions was as good as or better than what could be achieved through litigation this year and next. Other parties, made up of customer groups and low income representatives agreed with Staff in support of the Settlement.

In addition, Staff evaluated this case by identifying the issues that have driven the last several rate filings. In those cases and this one, capital investment is the primary driver of increased revenue requirement requests. While the increase proposed for year one is somewhat higher than annual electric increases of the past, Staff maintains that the overall increase of 7.1% and 5.6% for electric and gas service, respectively, over a two year period is reasonable. These capital driven increases are approximately 63% of the Company's electric service request and approximately 41% of the Company's natural gas service request.

Revenue Requirement

Q. Please explain why Staff believes the 9.5% Return on Equity and capital structure with 50% equity and 50% debt are reasonable.

A. The Stipulation reflects a ROE of 9.5% based on a capital structure of 50% equity and 50% debt. Staff believes a 50%/50% capital structure is representative of Avista's actual equity ratio of 49.9% as of December 31, 2016, and as projected at December 31, 2017. Staff maintains that the 9.5% ROE is consistent with the most recent Commission Order No. 33757 issued April 28, 2017, for Intermountain Gas

Company. It also is consistent with authorized returns granted for electric and gas utilities operating in the Northwest. The 9.5% ROE allows Avista to maintain its financial viability so it might attract new capital from the market to fund new capital investments and refinance maturing debt issuances.

Q. Could you please describe Staff's other proposed revenue requirement adjustments?

A. Yes. Besides the adjustment for ROE, Staff identified 28 other individual adjustments that reduced first year revenue requirement by approximately $6.4 million or 40% of the Company's request. These adjustments included elimination of 2018 proforma expense increases, reduction or elimination of improper test year expenses and reduction/elimination of test year capital additions. Staff's proforma expense adjustments totaling about $2 million included a 2018 property tax increase, 2018 salary increases, and budgeted expense for underground equipment inspection. Improper test year expenses totaling about $1.8 million included adjustments to executive pay, advertising, legal, environmental, and O&M expenses. Capital adjustments totaling approximately $3.1 million in revenue requirement included removal of meter data management, prepaid pensions, website investment, Tech Refresh, and Tech Expansion. These adjustments, when combined with reduced ROE reduces the requested first year increase by about 48%.

With the exception of the weather normalizing adjustment, Staff's proposed adjustments to natural gas revenue requirement in the first year were an allocated portion of the adjustments proposed on the electric side. Weather normalization reduced the required revenue increase by about $1.17 million and when combined with the other adjustments decrease the Company's proposed increase by approximately $3 million or 87%.

Q. Why does Staff support the first year revenue requirement increase specified in the Settlement?

A. Staff supports the first year revenue requirement increase because it represents a reasonable compromise of adjustments that may or may not have been accepted at hearing. Staff believes the $5.7 million or 31% reduction in the proposed increase comes relatively close to what Staff believes could be achieved at hearing. The largest single adjustment conceded by Staff for purposes of settlement was a $1.2 million adjustment removing prepaid pension from working capital. On this adjustment, Staff believes it would have been difficult to prevail at hearing. However, Staff recognizes that customers could benefit from prepaid pension in the future.

Q. Why does Staff support a second year revenue requirement increase as specified in the Settlement?

A. Staff believes there is benefit to a two-year rate plan for customers by phasing in an increase over a longer period of time. Staff also recognizes the efficiency gained for customers, the Company, and the Commission by reducing general rate case filing costs. Staff maintains that the two-year rate plan results in a lower increase for customers than could be achieved through two separate rate filings. Finally, Staff believes that the rate case stay-out has real value to customers by prohibiting Company requests for regulatory assets or expense deferrals during the stay-out period. This assures that base rates will not increase after the stay-out period ends due to cost incurred during the two-year rate plan.

Q. How can Staff support a revenue requirement increase in year two without allowing forecasted expenses and investment?

A. Staff has a long history of rejecting forecasted/budgeted test year expenses and investment in favor of historic test years with limited proforma adjustments. In this case, Staff agreed to five expense and investment items that would be allowed for recovery in year two. Three of these items were removed from revenue requirement in year one but allowed in year two because they were relatively known and measurable. These are property taxes, a non-executive labor salary increase of 3% and expenses for safety related underground equipment inspection.

Investment allowed for recovery in year two was narrowly focused to include investment in meter data management previously removed from year one. While Staff maintains that the investment is somewhat premature given the status of Avista's AMI program in Idaho, the investment is compatible with existing Idaho metering facilities and needed to allow meter facilities upgrades in Idaho.

The other investment allowed in the second year is for several specific hydropower relicensing, safety and reliability projects. The projects include Little Falls, Clark Fork and Spokane River on the electric side and Aldyl A pipeline replacement on the natural gas side.

Although these projects are included in second year revenue requirement, they are only partially allowed for recovery by applying an Average of Monthly Averages (AMA) to establish rate base. This rate base calculation allows the investment to earn a return and be included in the revenue requirement for only part of the year based on when a project goes on line rather than included in rate base as if it were in service for the full year. Staff maintains that this limited treatment of increased expenses and new investment in year two represents a reasonable compromise between forecasted/budgeted test years and the value of multi-year rate plans.

Cost Allocation and Rate Design

Q. Why does Staff support the Stipulation provisions addressing class cost allocation?

A. The class cost of service study provided by the Company in this case applies the same methodology used by the Company in its last general rate case, Case No. AVU-E-16-03. In fact, Staff has had the opportunity to review all aspects of Avista's cost of service many times over the last few years. While attempts have been made to gradually move classes more fully to cost of service, the results have been mixed and progress slow.

In this particular case, the large industrial parties questioned the process of partial movement to cost of service and the appropriate underlying methodology that has been employed. The Company has historically used a 12 monthly coincident peak (12CP) cost of service methodology to allocate costs to the various customer classes. Avista industrial customers believe that a seven monthly coincident peak methodology (7CP) is more representative of how cost are incurred and how they should be allocated to high load factor customers. Staff agrees that movement toward full cost of service over the years has been slow and disagreement still remains over the most appropriate cost of service methodology.

Consequently, rather than the Company proposed movement of 15% toward electric cost of service, Staff supports the settlement compromise to increase Avista Schedule 25 and 25P by 75% of the overall revenue requirement increase each year as specified in the Stipulation. This provision decreases the amount allocated to the industrial customers who are above cost of service and increases the amount allocated to residential customers who are below cost of service. Staff also recognizes the potential impacts of a 7CP cost of service approach and supports a workshop for interested parties to further discuss the merits of various cost of service methodologies.

Q. What impact does this settlement provision have on the revenue requirement increase for each customer class?

A. Staff Exhibit 101, pages 13 and 14 show the relative impact on each customer class in each year of the two-year rate plan. While the overall electric increase in year one is 5.2%, it is 5.7% for the residential class and 3.9% for Schedules 25 and 25P. In year two, the overall increase is 1.8% or 1.9% for the residential class and 1.3% for Schedules 25 and 25P.

The year one increase under the Company's original allocation proposal (and the stipulated revenue requirement increase) would have resulted in a 5.4% increase for the residential class, a 4.85% increase for Schedule 25 and a 4.5% increase for Schedule 25P. Second year increases would have been 1.77%, 1.6% and 1.5% for residential, Schedule 25 and Schedule 25P, respectively. Staff believes this modest adjustment in allocating the revenue increase is a reasonable compromise for the purpose of this case.

All parties supported the Company's proposed class allocation of the natural gas revenue requirement increase but no agreement was reached on the appropriate electric or gas cost of service methodology to be used in future rate cases.

Q. Why does Staff support an increase in the residential customer charge?

A. Staff supports the $0.25 and $0.75 per month increase in customer charges for residential electric and natural gas service, respectively, for several reasons. The first reason deals generally with the large amount of fixed costs incurred by the Company relative to the small amount of fixed costs collected by the Company through rates. This mismatch in how costs are incurred and how they are collected can result in an under collection of fixed cost needed to support Company operations.

The second reason Staff supports a small customer charge increase is based on the results of a low income consumption study conducted by the Company showing that low income customers use more energy on average than other residential customers. A modest increase in the customer charge reduces the necessary increase in commodity charges. Thus, many low income customer bills will be slightly lower than they otherwise would be.

Finally, the increase in the customer charge will reduce the level of fixed costs that are subject to recovery through the Company's fixed cost adjustment mechanism (FCA). Staff maintains that collecting fixed cost through individual customer charges may be more equitable than collecting fixed costs through FCA commodity charges.

Q. Does Staff support the other aspects of the stipulated rate design?

A. Yes. In addition to supporting the first year residential customer charge increases, Staff also supports the various customer and demand charge increases originally proposed by the Company in year one with remaining revenue requirement in year one collected from increased commodity charges for both gas and electric service. Staff further supports increasing only the commodity rate for all electric and gas service schedules in year two of the two-year rate plan.

Low Income Weatherization

Q. What does the Stipulation specify in terms of low income weatherization and what is the basis for Staff's support?

A. The Stipulation specifies that interested parties will conduct a workshop to discuss the status of Avista's low income weatherization program, how the money is currently spent and whether additional funding is needed and available. Staff recognizes that the issue of adequate funding for these programs has not been addressed for several years and believes that it is appropriate to do so now. Due to the time constraints inherent in settlement negotiations, and because funding comes from Avista's electric and gas energy efficiency tariff riders, Staff believes that a more thorough but expedited post-settlement review will allow Avista, Staff, CAPAI and other interested parties the opportunity to research, review and discuss these programs and determine whether funding should be increased. Avista will make any necessary filings resulting from this effort by year end 2017.

Staff further maintains that Commission Order No. 32788 specifies the conditions upon which additional low income funding should be considered. The workshop will provide all parties the opportunity to make that assessment. The December 31, 2017, deadline will also allow CAP agencies to plan their programs for calendar year 2018 with known funding levels.

Other Terms and Conditions

Q. Could you please describe the service quality performance standard provision in the Stipulation and the basis for Staff's support?

A. Yes. Avista has established Service Quality Performance Standards, Customer Guarantees and a Service Quality Measure Report Card for its customers in Washington. The Company has agreed to work with Staff and other interested parties to develop similar performance standards, guarantees and reports for its Idaho customers. Staff notes that the Commission approved a similar program for Rocky Mountain Power, which brought service quality into sharper focus and resulted in measurable performance improvements. Avista has agreed to submit any necessary changes requiring Commission approval by July 2018.

Q. What does the Stipulation provide with respect to natural gas rules and why is the provision supported by Staff?

A. Avista committed to work with Staff and other interested parties to review the Commission's Service Rules for Gas Utilities as well as the Company's meter placement and protection policies and practices. The Gas Service Rules include service standards (pressure, heat content and measurement of gas) as well as provisions for meter testing and maintaining records and maps of transmission, distribution and storage facilities. Avista has adopted meter placement and protection policies to ensure the safe delivery of gas and electricity to its customers. Staff anticipates that these reviews will identify rules, policies and practices that need to be revised. Avista has agreed to submit any necessary changes requiring Commission approval by July 2018.

Q. Does this conclude your testimony in this case?

A. Yes, it does.

David J. Meyer, Esq.
Vice President and Chief Counsel of
Regulatory and Governmental Affairs
Avista Corporation
1411 E. Mission Avenue
P.O. Box 3727
Spokane, Washington 99220
Phone: (509) 495-4316, Fax: (509) 495-8851

Brandon Karpen
Deputy Attorney General
Idaho Public Utilities Commission Staff
P.O. Box 83720
Boise, ID 83720-0074
Phone: (208) 334-0312, Fax: (208) 334-3762

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION DBA AVISTA UTILITIES FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE IN IDAHO	)	CASE NO. AVU-E-17-01 AVU-G-17-01 **STIPULATION AND SETTLEMENT**

This Stipulation is entered into by and among Avista Corporation, doing business as Avista Utilities ("Avista" or "Company"), the Staff of the Idaho Public Utilities Commission ("Staff'), Clearwater Paper Corporation ("Clearwater"), Idaho Forest Group, LLC ("Idaho Forest"), and the Community Action Partnership Association of Idaho ("CAPAI"). These entities are collectively referred to as the "Settling Parties". The Idaho Conservation League ("ICL"), and the Sierra Club, do not join in the Settlement Stipulation. The Settling Parties understand this Stipulation is subject to approval by the Idaho Public Utilities Commission ("IPUC" or the "Commission").

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I. INTRODUCTION

1. The terms and conditions of this Stipulation are set forth herein. The Settling Parties agree that this Stipulation represents a fair, just and reasonable compromise of all the issues raised in the proceeding, is in the public interest and its acceptance by the Commission represents a reasonable resolution of the multiple issues identified in this case. The Settling Parties, therefore, recommend that the Commission, in accordance with RP 274, approve the Stipulation and all of its terms and conditions without material change or condition.

II. BACKGROUND

2. On June 9, 2017, Avista filed an Application with the Commission for authority to increase revenue effective January 1, 2018 and January 1, 2019 for electric and natural gas service in Idaho. The Company proposed a Two-Year Rate Plan with an increase in electric base revenue of $18.6 million or 7.5% for 2018, and $9.9 million or 3.7% for 2019. With regard to natural gas, the Company proposed an increase in base revenue of $3.5 million or 8.8% for 2018 (5.7% on a billed basis), and $2.1 million or 5.0% for 2019 (3.3% on a billed basis). By Order No. 33808, dated June 30, 2017, the Commission suspended the proposed schedules of rates and charges for electric and natural gas service.

3. Petitions to intervene in this proceeding were filed by Clearwater, Idaho Forest, CAPAI, Idaho Conservation League, and the Sierra Club. The Commission granted these interventions through IPUC Order Nos. 33804, 33815 and 33829.

4. A settlement conference was noticed and held in the Commission offices on September 29, 2017, and was attended by the Settling Parties to this case.[1] As a compromise of

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[1] The Sierra Club was unable to attend the settlement conference.

positions in this case, and for other consideration as set forth below, the Settling Parties agree to the following terms:

III. TERMS OF THE STIPULATION AND SETTLEMENT

5. Overview of Settlement and Revenue Requirement. The Settling Parties agree that Avista should be allowed to implement revised tariff schedules designed to increase annual base electric revenue by $12.9 million, or 5.2% (on a billed basis the increase is 5.1%), effective January 1, 2018, and increase base revenues by $4.5 million, or 1.9% (on a billed basis the increase is 1.7%), effective January 1, 2019. For natural gas, the Settling Parties agree that Avista should be allowed to increase natural gas base revenue by $1.2 million, or 2.9% (1.9% on a billed basis), effective January 1, 2018, and $1.1 million, or 2.7% (1.8% on a billed basis), effective January 1, 2019.

6. Two Year Stay-Out. The Parties agree that, in recognition of the two-year rate plan covered by this Stipulation (January 1, 2018 – December 31, 2019), Avista will not file another electric or natural gas general rate case to increase base rates before May 31, 2019, and any such rates will not go into effect prior to January 1, 2020. This does not apply to tariff filings authorized by or contemplated by the terms of the Power Cost Adjustment (PCA), Fixed Cost Adjustment (FCA), the Purchased Gas Adjustment tariff (PGA), or other miscellaneous annual filings. Avista agrees that the base rates established by this Stipulation will, in conjunction with the PCA, PGA, and DSM Rider, provide Avista with the opportunity to recover all foreseen and unforeseen costs for the period January 1, 2018 through December 31, 2019 (the "Stay-out Period"). Accordingly, Avista agrees that it will not file deferred accounting requests or requests to create a regulatory asset during the Stay-out Period, except in extraordinary circumstances. For purposes of this paragraph extraordinary circumstances will not include changes in inter-jurisdictional allocation

methodology, accounting changes, or costs related to the Company's participation in Energy Imbalance Markets.

7. Cost of Capital. The Settling Parties agree to a 9.5 percent return on equity, with a 50.0 percent common equity ratio. The capital structure and resulting rate of return is as set forth below:

Component	Capital Structure	Cost	Weighted Cost
Debt	50%	5.72%	2.86%
Common Equity	50%	9.50%	4.75%
Total	100%		**7.61%**

A. ELECTRIC REVENUE REQUIREMENT

8. Overview of Electric Revenue Requirement (January 1, 2018). Below is a summary table and descriptions of the electric revenue requirement components agreed to by the Settling Parties effective January 1, 2018:

Table No. 1

SUMMARY TABLE OF ADJUSTMENTS TO ELECTRIC REVENUE REQUIREMENT
EFFECTIVE JANUARY 1, 2018
(000s of Dollars)

		Revenue Requirement	Rate Base
	Amount as Filed:	**$ 18,571**	**$ 796,609**
	Adjustments:		
a.)	Cost of Capital	$ (2,604)	
b.)	Company 2017 Net Rate Base Updates	$ 58	$ (1,926)
c.)	Miscellaneous Company Updates: Regulatory Amortization, Uncollectibles, Maintenance and IS/IT Expenses.	$ 112	
d.)	Remove Officer Incentives and Reduce Non-Officers Incentives	$ (393)	
e.)	Reduce Officer Labor Expenses	$ (115)	
f.)	Reduce 2017 IS/IT Capital Projects	$ (276)	$ (1,762)
g.)	Delay Meter Data Management Project Recovery to January 1, 2019	$ (1,075)	$ (6,834)
h.)	Remove 2018 Expense: Delay Recovery to Janaury 1, 2019		
i.)	2018 Labor Increase	$ (447)	
ii.)	2018 Underground Equipment Inspection Expense	$ (270)	
i.)	Miscellaneous Adjustments: Board of Director Expenses, Injuries and Damages, Legal and Environmental Expenses, Removal of Expiring Lease Expense and Inclusion of O&M Savings	$ (671)	
	Adjusted Amounts Effective January 1, 2018	**$ 12,890**	**$ 786,087**

a. Cost of Capital. As previously described (see Paragraph 7 above). This adjustment reduces the overall revenue requirement by $2.604 million.

b. Company 2017 Net Rate Base Updates. Reflects adjustments to net rate base to update information related to 2017 capital additions, including related depreciation expense, as well as the impact on Accumulated Depreciation and Accumulated Deferred Federal Income Taxes, to reflect balances as of December 31, 2017. This adjustment increases the overall revenue requirement by $58,000 and reduces net rate base by $1.926 million.

c. Miscellaneous Company Updates. Reflects adjustments to expenses to update information related to removal of the expiring Colstrip credit amortization, uncollectible expense, maintenance expense associated with the Company's Colstrip generation plant, and annualized incremental Information Service/Information Technology (IS/IT) labor positions added in 2017. This adjustment increases the overall revenue requirement by $112,000.

d. Remove Officer Incentives and Reduce Non-Officer Incentives. Reflects the removal of all officer incentives. This adjustment also reduces incentives for Non-Officers to a 100% payout ratio. This adjustment decreases the overall revenue requirement by $393,000.

e. Reduce Officer Labor Expenses. Reduces officer labor expenses to an agreed-upon level. This adjustment decreases the overall revenue requirement by $115,000.

f. Reduce 2017 IS/IT Capital Projects – Reduces certain capital investments related to IS/IT refresh and expansion projects planned during 2017. This adjustment decreases the overall revenue requirement by $276,000, and reduces net rate base by $1.762 million.

g. Delay Meter Data Management Project Recovery to January 1, 2019. Removes the Meter Data Management System expected to go into service in 2017. This system is delayed for recovery until January 1, 2019. This adjustment decreases the overall revenue requirement by $1.075 million, and reduces net rate base by $6.834 million.

h. Remove 2018 Expense: Delay Recovery to January 1, 2019.

   i. 2018 Labor Increase. Removes the 2018 incremental non-executive labor increases, and includes them with the January 1, 2019 rate change. This adjustment decreases the overall revenue requirement by $447,000.

   ii. 2018 Underground Inspection Equipment Expense. Removes the 2018 underground equipment inspection costs, and includes them with the January 1, 2019 rate change. This adjustment decreases the overall revenue requirement by $270,000.

i. Miscellaneous Adjustments. Reflects the net change in operating expenses related to: 1) removing requested additional Board of Director expenses ($270,000); 2) removing legal expenses allocated to Idaho electric in error ($42,000); 3) removing expenses associated with certain leases expiring during the 2018 rate year ($192,000); 3) removing certain 2016 environmental cleanup costs allocated to Idaho electric in error ($48,000); 4) inclusion of the O&M savings associated with the Company's new website application ($23,000); 5) reducing the six-year average of injuries and damages ($11,000); and 6) the net effect of removing certain other miscellaneous A&G expenses ($85,000). The net effect of this adjustment decreases the overall revenue requirement by $671,000.

9. Overview of Electric Revenue Requirement (January 1, 2019). Below is a summary table and descriptions of the incremental Electric revenue requirement components agreed to by the Settling Parties effective January 1, 2019:

Table No. 2

SUMMARY TABLE OF ADJUSTMENTS TO ELECTRIC REVENUE REQUIREMENT
EFFECTIVE JANUARY 1, 2019
(000s of Dollars)

		Revenue Requirement	Rate Base
	Rate Base Amount Effective January 1, 2018		**$ 786,087**
	Incremental Revenue Adjustment to January 1, 2018 Rate Change (see Tabel No. 1):		
a.)	Add Meter Data Management Project	$ 1,075	$ 6,834
b.)	Add 2018 Related Capital and Expenses:		
i.	2018 Capital Additions on an AMA Basis	$ 1,938	$ 2,071
ii.	Property Tax Expense on 2018 Plant Additions	$ 613	
iii.	2018 Annualized Labor Increase	$ 648	
iv.	2018 Underground Equipment Inspection Expense	$ 270	
	January 1, 2019 Incremental Revenue Adjustment and Rate Base Amount (above January 1, 2018 Rate Change - see Table No. 1)	**$ 4,544**	**$ 794,992**

a. Add Meter Data Management. Adds the Meter Data Management System expected to go into service in October of 2017. This system is included for recovery effective January 1, 2019. This adjustment increases the overall revenue requirement by $1.075 million, and increases net rate base by $6.834 million.

b. Add 2018 Expenses.

i. 2018 Capital Additions on an AMA Basis. Includes certain 2018 capital additions on an AMA basis. This adjustment increases the overall revenue requirement by $1.938 million, and increases net rate base by $2.071 million.

ii. 2018 Property Taxes. Includes property tax expense associated with 2018 capital additions. This adjustment increases the overall revenue requirement by $613,000.

iii. 2018 Annualized Labor Increase. Includes the 2018 annualized non-executive labor increases. This adjustment increases the overall revenue requirement by $648,000

iv. 2018 Underground Inspection Equipment Expense. Includes the 2018 underground equipment inspection costs. This adjustment increases the overall revenue requirement by $270,000.

B. NATURAL GAS REVENUE REQUIREMENT

10. Overview of Natural Gas Revenue Requirement (January 1, 2018). Below is a summary table and descriptions of the natural gas revenue requirement components agreed to by the Settling Parties effective January 1, 2018:

Table No. 3

SUMMARY TABLE OF ADJUSTMENTS TO NATURAL GAS REVENUE REQUIREMENT EFFECTIVE JANUARY 1, 2018 (000s of Dollars)

		Revenue Requirement	Rate Base
	Amount as Filed:	**$ 3,480**	**$ 144,807**
	Adjustments:		
a.)	Cost of Capital	$ (470)	
b.)	Company 2017 Net Rate Base Updates	$ 324	$ 2,199
c.)	Miscellaneous Company Updates: Uncollectibles and IS/IT Expenses.	$ 20	
d.)	Adjust Weather Normalization	$ (1,162)	
e.)	Remove Officer Incentives and Reduce Non-Officers Incentives	$ (105)	
f.)	Reduce Officer Labor Expenses	$ (29)	
g.)	Reduce 2017 IS/IT Capital Projects	$ (43)	$ (214)
h.)	Remove Meter Data Management Project: Delay Recovery to January 1, 2019	$ (415)	$ (1,860)
i.)	Remove 2018 Labor Expense: Delay Recovery to Janaury 1, 2019	$ (120)	
j.)	Miscellaneous Adjustments: Board of Director Expenses, Injuries and Damages, Advertising Expenses, Legal Expenses, Removal of Expiring Lease Expense and Inclusion of O&M Savings/Expenses.	$ (300)	
	Adjusted Amounts Effective January 1, 2018	**$ 1,180**	**$ 144,932**

a. Cost of Capital. As previously described (see Paragraph 7 above). This adjustment reduces the overall revenue requirement by $470,000.

b. Company 2017 Net Rate Base Updates. Reflects adjustments to net rate base to update information related to 2017 capital additions, including related depreciation expense, as well as the impact on Accumulated Depreciation and Accumulated Deferred Federal Income Taxes, to reflect balances as of December 31, 2017. This adjustment increases the overall revenue requirement by $324,000 and increases net rate base by $2.199 million.

c. Miscellaneous Company Updates. Reflects adjustments to expenses to update information related to uncollectible expense and annualized incremental IS/IT labor positions added in 2017. This adjustment increases the overall revenue requirement by $20,000.

d. Adjust Weather Normalization. Reflects a natural gas weather normalization adjustment, which increases test year billing determinants, thereby increasing test year (present) revenue. This adjustment decreases the overall revenue requirement by $1.162 million.

e. Remove Officer Incentives and Reduce Non-Officer Incentives. Reflects the removal of all officer incentives. This adjustment also reduces incentives for Non-Officers to a 100% payout ratio. This adjustment decreases the overall revenue requirement by $105,000.

f. Reduce Officer Labor Expenses. Reduces officer labor expenses to an agreed upon level. This adjustment decreases the overall revenue requirement by $29,000.

g. Reduce 2017 IS/IT Capital Projects – Reduces certain capital investments related to IS/IT refresh and expansion projects planned during 2017. This adjustment decreases the overall revenue requirement by $43,000, and reduces net rate base by $214,000.

h. Delay Meter Data Management Project Recovery to January 1, 2019. Removes the Meter Data Management System expected to go into service in 2017. This system is delayed for recovery until January 1, 2019. This adjustment decreases the overall revenue requirement by $415,000, and reduces net rate base by $1.860 million.

i. Remove 2018 Labor Expense: Delay Recovery to January 1, 2019. Removes the 2018 incremental non-executive labor increases, to be included with the January 1, 2019 rate change. This adjustment decreases the overall revenue requirement by $120,000.

j. Miscellaneous Adjustments. Reflects the net change in operating expenses related to: 1) removing requested additional Board of Director expenses ($70,000); 2) removing legal expenses allocated to Idaho natural gas in error ($3,000); 3) removing expenses associated with certain leases expiring during the 2018 rate year ($53,000); 3) removing advertising expenses allocated to Idaho natural gas in error ($25,000); 4) inclusion of the O&M savings associated with the Company's new website application ($6,000); 5) reducing the six-year average of injuries and damages ($127,000); and 6) the net effect of removing certain other miscellaneous A&G expenses ($16,000). The net effect of this adjustment decreases the overall revenue requirement by $300,000.

11. Overview of Natural Gas Revenue Requirement (January 1, 2019). Below is a summary table and descriptions of the incremental Natural Gas revenue requirement components agreed to by the Settling Parties effective January 1, 2019:

Table No. 4

	SUMMARY TABLE OF ADJUSTMENTS TO NATURAL GAS REVENUE REQUIREMENT EFFECTIVE JANUARY 1, 2019 (000s of Dollars)	Revenue Requirement	Rate Base
	Rate Base Amount Effective January 1, 2018		**$ 144,932**
	Incremental Revenue Adjustment to January 1, 2018 Rate Change (see Tabel No. 1):		
a.)	Add Meter Data Management Project	$ 415	$ 1,860
b.)	Add 2018 Related Capital and Expenses:		
i.	2018 Capital Additions on an AMA Basis	$ 414	$ (852)
ii.	Property Tax Expense on 2018 Plant Additions	$ 122	
iii.	Annualized 2018 Labor Increase	$ 181	
	January 1, 2019 Incremental Revenue Adjustment and Rate Base Amount (above January 1, 2018 Rate Change - see Table No. 1)	**$ 1,132**	**$ 145,940**

a. Add Meter Data Management. Adds the Meter Data Management System expected to go into service in October of 2017. This system is included for recovery effective January 1, 2019. This adjustment increases the overall revenue requirement by $415,000, and increases net rate base by $1.860 million.

b. Add 2018 Related Capital and Expenses.

i. 2018 Capital Additions on an AMA Basis. Includes certain 2018 capital additions on an AMA basis. This adjustment increases the overall revenue requirement by $414,000, and decreases net rate base by $852,000[2].

ii. 2018 Property Taxes. Includes property tax expense associated with 2018 capital additions. This adjustment increases the overall revenue requirement by $122,000.

iii. 2018 Annualized Labor Increase. Includes the 2018 annualized non-executive labor increases. This adjustment increases the overall revenue requirement by $181,000

[2] Removing the impact of 2018 capital additions, as well as removing the impact on accumulated depreciation and accumulated deferred federal income taxes on total net plant during 2018, has the result of decreasing overall net rate base.

C. OTHER SETTLEMENT COMPONENTS

11. PCA Authorized Level of Expense. The new level of power supply revenues, expenses, retail load and Load Change Adjustment Rate resulting from the January 1, 2018 settlement revenue requirement for purposes of the monthly PCA mechanism calculations are detailed in Appendix A.

12. Electric and Natural Gas Fixed Cost Adjustment Mechanisms Authorized Base. The new level of baseline values for the electric and natural gas fixed cost adjustment mechanism (FCA) resulting from the January 1, 2018 and January 1, 2019 settlement revenue requirements are detailed as follows:

- Appendix B – 2018 Electric FCA Base
- Appendix C – 2019 Electric FCA Base
- Appendix D – 2018 Natural Gas FCA Base
- Appendix E – 2019 Natural Gas FCA Base

D. COST OF SERVICE/RATE SPREAD/RATE DESIGN/LOW INCOME

13. Cost of Service/Rate Spread (Base Rate Changes). The Settling Parties do not agree on any particular cost of service methodology. In recognition, however, that certain rate schedules are generally above their relative cost of service or could be with modest modifications to allocation methodology, the Settling Parties agree that Schedules 25 and 25P should receive 75% of the overall percentage base rate changes for the January 1, 2018 and January 1, 2019 increases. All other schedules, except Schedule 1, should receive a pro-rata allocation of the Company's original request. The remaining revenue requirement should be spread to Schedule 1. For natural gas, the Settling Parties agreed to a pro-rata allocation of the Company's original request for base rate changes on January 1, 2018 and January 1, 2019, but with restated present base revenue reflecting the effects of the agreed-upon natural gas weather normalization adjustment.

14. Rate Design. The Settling Parties agree to the rate design changes proposed by the Company in Mr. Ehrbar's direct testimony for both the January 1, 2018 and January 1, 2019 base rate increases.[3] For the electric Residential Basic Charge (Schedule 1), the Settling Parties agreed that it will increase from $5.75 per month to $6.00 per month effective January 1, 2018, an increase of $0.25 per month. For the natural gas General Service Basic Charge (Schedule 101), the Settling Parties agreed that it will increase from $5.25 per month to $6.00 per month effective January 1, 2018, an increase of $0.75 per month. For the rate changes effective January 1, 2019, the base revenue increases would be collected through the volumetric energy rates, with no changes to the basic charges. Appendix F provides a summary of the current and revised rates and charges (as per the Settlement) for electric and natural gas service.

15. Resulting Percentage Increase by Electric Service Schedule. The following tables reflect the agreed-upon percentage increase by schedule for electric service:

Effective January 1, 2018

Rate Schedule	Increase in Base Rates	Increase in Billing Rates
Residential Schedule 1	5.7%	5.9%
General Service Schedules 11/12	5.0%	5.2%
Large General Service Schedules 21/22	5.4%	5.7%
Extra Large General Service Schedule 25	3.9%	4.7%
Clearwater Paper Schedule 25P	3.9%	4.8%
Pumping Service Schedules 31/32	5.9%	6.1%
Street & Area Lights Schedules 41-48	5.2%	5.1%
Overall	**5.2%**	**5.6%**

[3] This includes the proposed removal of High-Pressure Sodium Vapor lighting options and the customer area light calculation methodology described in the direct testimony of Company witness Mr. Ehrbar on pp. 22-23. In addition, the Settling Parties agree with Mr. Ehrbar's proposal to offset the current Schedule 97 (Electric Earnings Test Deferral) rebate of $2.7 million, which expires on December 31, 2017 (as outlined on pp. 8-9 of his direct testimony), with $1.5 million related to the electric earnings test for calendar year 2015 .

Effective January 1, 2019

Rate Schedule	Increase in Base Rates	Increase in Billing Rates
Residential Schedule 1	1.9%	2.3%
General Service Schedules 11/12	1.7%	2.1%
Large General Service Schedules 21/22	1.8%	2.3%
Extra Large General Service Schedule 25	1.3%	2.2%
Clearwater Paper Schedule 25P	1.3%	2.2%
Pumping Service Schedules 31/32	2.0%	2.4%
Street & Area Lights Schedules 41-48	1.8%	1.9%
Overall	**1.8%**	**2.3%**

16. Resulting Percentage Increase by Natural Gas Service Schedule. The following tables reflect the agreed-upon percentage increase by schedule for natural gas service:

Effective January 1, 2018

Rate Schedule	Increase in Base Rates	Increase in Billing Rates
General Service Schedule 101	3.2%	2.2%
Large General Service Schedules 111/112	1.4%	0.7%
Interruptible Service Schedules 131/132	0.0%	0.0%
Transportation Service Schedule 146	3.0%	3.0%
Special Contracts Schedule 148	0.0%	0.0%
Overall	**2.9%**	**1.9%**

Effective January 1, 2019

Rate Schedule	Increase in Base Rates	Increase in Billing Rates
General Service Schedule 101	3.0%	2.1%
Large General Service Schedules 111/112	1.3%	0.7%
Interruptible Service Schedules 131/132	0.0%	0.0%
Transportation Service Schedule 146	2.7%	2.7%
Special Contracts Schedule 148	0.0%	0.0%
Overall	**2.7%**	**1.8%**

17. Electric Cost of Service Workshop. The Settling Parties agree, prior to the Company's next general rate case filing, to meet and confer regarding the Company's electric cost of service study. The purpose of the workshop will be to discuss the merits of differing cost of service methodologies. Based on the input from the workshop, the Company agrees to provide, at a minimum, three cost of service studies reflective of the these differing methodologies in its next general rate case. The Company will provide available information, studies and data requested by any of the Settling Parties so as to enable meaningful workshop participation and discussion of issues. Unless it decides to do so, a Party shall not be bound by workshop discussions and may contest cost of service and rate spread issues in subsequent proceedings.

18. Collaboration on Low Income Issues. The Company and interested parties will meet and confer to consider whether the Low Income Weatherization Program and Energy Conservation Education Program funding should be increased from the current Commission-approved levels of $700,000 and $50,000 respectively. Discussion topics will include the need for additional funding, how additional funds will be used, how much additional funding will be necessary, and what impact the increase will have on the energy efficiency tariff rider (Schedules 91 and 191) balance. If participants agree that a funding increase is necessary, the Company agrees to make any necessary filing(s) with the Commission on or before December 31, 2017.

19. Natural Gas Service Rules. The Company and interested parties will meet and confer to review the Commission's Service Rules for Gas Utilities (IDAPA 31.31.01) to determine which provisions should be retained and/or modified, and, if the participants agree, incorporate those changes into the Company's tariff. Any changes requiring Commission approval, e.g., tariff revisions, will be submitted by the Company on or before July 1, 2018.

20. Natural Gas Meter Placement Rules. The Company and interested parties will meet and confer to review its meter placement and protection policies and practices and determine,

based on the agreement of the parties, what additional steps should be taken to revise the Company's current policies and practices. Any necessary changes requiring Commission approval, e.g., tariff revisions, will be submitted by the Company on or before July 1, 2018.

21. Service Quality/Performance Measures. Avista has established Service Quality Performance, Customer Guarantees and a Service Quality Measure Report Card for its customers in Washington. The Company and interested parties will work to develop similar performance standards, customer guarantees and a reporting mechanism for its Idaho customers. Following those discussions, the Company will file its proposal with the Commission requesting implementation on or before July 1, 2018.

IV. OTHER GENERAL PROVISIONS

22. The Settling Parties agree that this Stipulation represents a compromise of the positions of the Settling Parties in this case. As provided in RP 272, other than any testimony filed in support of the approval of this Stipulation, and except to the extent necessary for a Settling Party to explain before the Commission its own statements and positions with respect to the Stipulation, all statements made and positions taken in negotiations relating to this Stipulation shall be confidential and will not be admissible in evidence in this or any other proceeding.

23. The Settling Parties submit this Stipulation to the Commission and recommend approval in its entirety pursuant to RP 274. Settling Parties shall support this Stipulation before the Commission, and no Settling Party shall appeal a Commission Order approving the Stipulation or an issue resolved by the Stipulation. If this Stipulation is challenged by any person not a party to the Stipulation, the Settling Parties to this Stipulation reserve the right to file testimony, cross-examine witnesses and put on such case as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlement terms embodied

in this Stipulation. Notwithstanding this reservation of rights, the Settling Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

24. If the Commission rejects any part or all of this Stipulation or imposes any additional material conditions on approval of this Stipulation, each Settling Party reserves the right, upon written notice to the Commission and the other Parties to this proceeding, within 14 days of the date of such action by the Commission, to withdraw from this Stipulation. In such case, no Settling Party shall be bound or prejudiced by the terms of this Stipulation, and each Settling Party shall be entitled to seek reconsideration of the Commission's order, file testimony as it chooses, cross-examine witnesses, and do all other things necessary to put on such case as it deems appropriate. In such case, the Settling Parties immediately will request the prompt reconvening of a prehearing conference for purposes of establishing a procedural schedule for the completion of the case, in accordance with law.

25. The Settling Parties agree that this Stipulation is in the public interest and that all of its terms and conditions are fair, just and reasonable.

26. No Settling Party shall be bound, benefited or prejudiced by any position asserted in the negotiation of this Stipulation, except to the extent expressly stated herein, nor shall this Stipulation be construed as a waiver of the rights of any Settling Party unless such rights are expressly waived herein. Execution of this Stipulation shall not be deemed to constitute an acknowledgment by any Settling Party of the validity or invalidity of any particular method, theory or principle of regulation or cost recovery. No Settling Party shall be deemed to have agreed that any method, theory or principle of regulation or cost recovery employed in arriving at this Stipulation is appropriate for resolving any issues in any other proceeding in the future. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

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27. The obligations of the Settling Parties under this Stipulation are subject to the Commission's approval of this Stipulation in accordance with its terms and conditions and upon such approval being upheld on appeal, if any, by a court of competent jurisdiction.

28. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

DATED this 20th day of October, 2017.

Avista Corporation

By:______________________

David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

By:______________________

Brandon Karpen
Deputy Attorney General

Clearwater Paper Corporation

By:______________________

Peter Richardson
Attorney for Clearwater Paper

Idaho Forest Group

By:______________________

Ronald Williams
Attorney for Idaho Forest Group LLC

Community Action Partnership Association of Idaho

By:______________________

Brad Purdy
Attorney for CAPAI

Exhibit No. 101
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11/03/17 Page 18 of 55

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DATED this 20th day of October, 2017.

Avista Corporation By:__________________ David J. Meyer Attorney for Avista Corporation	Idaho Public Utilities Commission Staff By:__________________ Brandon Karpen Deputy Attorney General
Clearwater Paper Corporation By:__________________ Peter Richardson Attorney for Clearwater Paper	Idaho Forest Group By:__________________ Ronald Williams Attorney for Idaho Forest Group LLC
Community Action Partnership Association of Idaho By:__________________ Brad Purdy Attorney for CAPAI	

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R. Lobb, Staff
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DATED this 20th day of October, 2017.

Avista Corporation	Idaho Public Utilities Commission Staff
By:__________	By:__________
David J. Meyer Attorney for Avista Corporation	Brandon Karpen Deputy Attorney General
Clearwater Paper Corporation	Idaho Forest Group
By: Pet Richardson	By:__________
Peter Richardson Attorney for Clearwater Paper	Ronald Williams Attorney for Idaho Forest Group LLC

Community Action Partnership Association of Idaho

By:__________

Brad Purdy
Attorney for CAPAI

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David J. Meyer
Attorney for Avista Corporation

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By:____________________________
Brandon Karpen
Deputy Attorney General

Clearwater Paper Corporation

By:____________________________
Peter Richardson
Attorney for Clearwater Paper

Idaho Forest Group

By: Ronald L Williams
Ronald Williams
Attorney for Idaho Forest Group LLC

Community Action Partnership Association of Idaho

By:____________________________
Brad Purdy
Attorney for CAPAI

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DATED this ____ day of October, 2017.

Avista Corporation

By:________________________________
David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

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Brandon Karpen
Deputy Attorney General

Clearwater Paper Corporation

By:________________________________
Peter Richardson
Attorney for Clearwater Paper

Idaho Forest Group

By:________________________________
Ronald Williams
Attorney for Idaho Forest Group LLC

Community Action Partnership Association of Idaho

By:________________________________
Brad Purdy
Attorney for CAPAI

APPENDIX A

Avista Corp
AVU-E-17-01 Appendix A
PCA Authorized Expense and Retail Sales
2016 Normalized Loads

PCA Authorized Power Supply Expense - System Numbers (1)

	Total	January	February	March	April	May	June	July	August	September	October	November	December
Account 555 - Purchased Power	$93,098,141	$9,702,833	$10,328,500	$8,924,403	$7,339,924	$5,493,489	$5,495,060	$6,450,838	$7,374,829	$6,454,510	$6,678,058	$9,322,263	$9,533,434
Account 501 - Thermal Fuel	$27,343,606	$2,710,748	$2,436,293	$2,495,479	$1,999,248	$1,543,139	$1,346,033	$2,191,772	$2,428,911	$2,491,210	$2,486,834	$2,527,218	$2,686,722
Account 547 - Natural Gas Fuel	$63,059,053	$8,280,148	$5,188,309	$4,595,190	$2,864,296	$1,538,980	$1,733,333	$5,506,611	$6,911,918	$5,890,075	$5,805,698	$6,416,983	$8,327,513
Account 447 - Sale for Resale	$37,257,163	$3,781,357	$1,822,086	$2,040,710	$2,860,479	$2,523,088	$2,502,706	$4,670,615	$2,827,345	$2,878,367	$2,286,265	$3,502,619	$5,561,524
Power Supply Expense	$146,243,638	$16,912,372	$16,131,016	$13,974,362	$9,342,988	$6,052,520	$6,071,720	$9,478,606	$13,888,313	$11,957,427	$12,684,325	$14,763,845	$14,986,145
Transmission Expense	$17,404,447	$1,367,136	$1,600,335	$1,468,739	$1,449,915	$1,423,359	$1,415,703	$1,470,703	$1,461,595	$1,427,130	$1,424,958	$1,434,978	$1,459,896
Transmission Revenue	$15,149,485	$1,062,694	$1,178,481	$1,177,115	$1,141,305	$1,253,488	$1,398,529	$1,450,378	$1,346,819	$1,372,213	$1,319,316	$1,257,650	$1,191,496
Net REC Revenue	$3,453,000	$293,350	$264,550	$293,350	$283,750	$293,350	$283,750	$293,350	$293,350	$283,750	$293,350	$283,750	$293,350
	$145,045,600												

PCA Authorized Idaho Retail Sales (2)

	Total	January	February	March	April	May	June	July	August	September	October	November	December
Total Retail Sales, MWh (2)	2,953,031	294,914	261,971	251,422	228,917	211,441	204,736	252,026	245,232	206,024	240,501	257,717	298,131

2018 Load Change Adjustment Rate	$24.73 /MWh
2019 Load Change Adjustment Rate	$24.84 /MWh

1) Multiply system numbers by 34.27% to determine Idaho share.
2) 12 months ended December 2016 weather normalized Idaho retail sales, with a pro forma adjustment, as explained by Mr. Kalich.

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APPENDIX B

Avista Utilities
Electric Fixed Cost Adjustment Mechanism (Idaho)
Development of Fixed Cost Adjustment Revenue by Rate Schedule - Electric
AVU-E-17-01 Rates Effective 1/1/2018

			TOTAL	RESIDENTIAL SCHEDULE 1	GENERAL SVC. SCH. 11,12	LG. GEN. SVC. SCH. 21,22	PUMPING SCH. 31, 32	OTHER SERVICE SCHEDULES
1	Total Normalized Test Year Revenue		$ 246,584,000	$ 108,991,000	$ 37,312,000	$ 52,071,000	$ 5,494,000	$ 42,716,000
2	Settlement Revenue Increase		$ 12,889,000	$ 6,169,000	$ 1,861,000	$ 2,811,000	$ 325,000	$ 1,723,000
3	Total Rate Revenue (January 1, 2018)		$ 259,473,000	$ 115,160,000	$ 39,173,000	$ 54,882,000	$ 5,819,000	$ 44,439,000
4	Normalized kWhs (Test Year)		2,953,030,933	1,145,126,003	365,113,814	649,192,595	60,392,324	733,206,197
5	Load Change Adjustment Rate (Ln 14)		$ 0.02488	$ 0.02488	$ 0.02488	$ 0.02488	$ 0.02488	
6	Variable Power Supply Revenue (Ln 4 * Ln 5)		$ 73,471,410	$ 28,490,735	$ 9,084,032	$ 16,151,912	$ 1,502,561	$ 18,242,170
6A	Fixed Production and Transmission Rate per kWh	(New Customers Only)		$ 0.02611	$ 0.02960	$ 0.02591	$ 0.01844	
6B	Fixed Production and Transmission Revenue	(New Customers Only)	$ 73,651,688	$ 29,893,572	$ 10,807,995	$ 16,821,138	$ 1,113,453	$ 15,015,529
7	Subtotal (Ln 3 - Ln 6)	(Test Year Customers)	$ 159,804,761	$ 86,669,265	$ 30,088,968	$ 38,730,088	$ 4,316,439	**Excluded From Fixed Cost Adjustment**
7A	Subtotal (Ln 3 - Ln 6 - Ln 6B)	(New Customers)	$ 101,168,602	$ 56,775,694	$ 19,280,973	$ 21,908,950	$ 3,202,986	
8	Customer Bills (Test Year)		1,541,160	1,258,258	252,366	13,657	16,879	
9	Settlement Fixed Charges			$ 6.00	$ 13.00	$ 425.00	$ 11.00	
10	Fixed Charge Revenue (Ln 8 * Ln 9)		$ 16,820,200	$ 7,549,548	$ 3,280,758	$ 5,804,225	$ 185,669	
11	Fixed Cost Adjustment Revenue (Ln 7 - Ln 10)	(Test Year Customers)	$ 142,984,561	$ 79,119,717	$ 26,808,210	$ 32,925,863	$ 4,130,770	
11A	Fixed Cost Adjustment Revenue (Ln 7A - Ln 10)	(New Customers)	$ 84,348,402	$ 49,226,146	$ 16,000,215	$ 16,104,725	$ 3,017,317	
12	Load Change Adjustment Rate		$0.02473					
13	Gross Up Factor for Revenue Related Exp		100.59%					
14	Grossed Up Load Change Adjustment Rate		$0.02488					

		Residential	Non-Residential Group
15	Average Number of Customers (Line 8 / 12)	104,855	23,575
16	Annual kWh	1,145,126,003	1,074,698,733
17	Basic Charge Revenues	7,549,548	9,270,652
18	Customer Bills	1,258,258	282,902
19	Average Basic Charge	$6.00	$32.77

Exhibit No. 101
Case Nos. AVU-E-17-01/
AVU-G-17-01
R. Lobb, Staff
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Avista Utilities
Electric Fixed Cost Adjustment Mechanism (Idaho)
Development of Annual Fixed Cost Adjustment Revenue Per Customer - Electric
AVU-E-17-01 Rates Effective 1/1/2018

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
	Existing Customer FCA			
1	Fixed Cost Adjustment Revenue	Page 1	$ 79,119,717	$ 63,864,844
2	Test Year Number of Customers	Revenue Data	104,855	23,575
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$ 754.56	$ 2,708.99
	New Customer FCA			
1	Fixed Cost Adjustment Revenue	Page 1	$ 49,226,146	$ 35,122,257
2	Test Year Number of Customers	Revenue Data	104,855	23,575
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$ 469.47	$ 1,489.80

* Schedules 11, 12, 21, 22, 31, and 32.

Avista Utilities
Electric Fixed Cost Adjustment Mechanism (Idaho)
Development of Monthly Fixed Cost Adjustment Revenue Per Customer - Electric
AVU-E-17-01 Rates Effective 1/1/2018

Line No.	(a)	Source (b)	Jan (c)	Feb (d)	Mar (e)	Apr (f)	May (g)	Jun (h)	Jul (i)	Aug (j)	Sep (k)	Oct (l)	Nov (m)	Dec (n)	TOTAL (o)	
1	**Electric Sales**															
2	*Residential*															
3	- Weather-Normalized kWh Sales	Monthly Test Year	134,773,540	109,184,340	104,461,439	89,424,559	73,283,780	68,485,395	90,156,452	84,289,571	65,446,504	81,832,941	107,082,607	136,704,875	1,145,126,003	
4	- % of Annual Total	% of Total	11.77%	9.53%	9.12%	7.81%	6.40%	5.98%	7.87%	7.36%	5.72%	7.15%	9.35%	11.94%	100.00%	
5																
6	*Non-Residential**															
7	- Weather-Normalized kWh Sales	Monthly Test Year	93,195,023	90,992,765	87,805,557	84,652,946	88,051,305	82,995,898	99,203,732	93,685,221	81,568,577	88,839,679	86,044,341	97,663,689	1,074,698,733	
8	- % of Annual Total	% of Total	8.67%	8.47%	8.17%	7.88%	8.19%	7.72%	9.23%	8.72%	7.59%	8.27%	8.01%	9.09%	100.00%	
9																
10																
11	**Monthly Fixed Cost Adjustment Revenue Per Customer ("RPC")**															
12	*For Test Year Existing Customers*															
13	*Residential*															
14	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 754.56	
15	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(4) x (14)	$ 88.81	$ 71.95	$ 68.83	$ 58.92	$ 48.29	$ 45.13	$ 59.41	$ 55.54	$ 43.12	$ 53.92	$ 70.56	$ 90.08	$ 754.56	
16																
17	*Non-Residential**															
18	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 2,708.99	
19	2016 Monthly Fixed Cost Adj. Revenue per Customer	(8) x (18)	$ 234.92	$ 229.37	$ 221.33	$ 213.38	$ 221.95	$ 209.21	$ 250.06	$ 236.15	$ 205.61	$ 223.94	$ 216.89	$ 246.18	$ 2,708.99	
20																
21																
22	*For New Customers*															
23	*Residential*															
24	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 469.47	
25	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(4) x (24)	$ 55.25	$ 44.76	$ 42.83	$ 36.66	$ 30.04	$ 28.08	$ 36.96	$ 34.56	$ 26.83	$ 33.55	$ 43.90	$ 56.05	$ 469.47	
26																
27	*Non-Residential**															
28	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 1,489.80	
29	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(8) x (28)	$ 129.19	$ 126.14	$ 121.72	$ 117.35	$ 122.06	$ 115.05	$ 137.52	$ 129.87	$ 113.07	$ 123.15	$ 119.28	$ 135.39	$ 1,489.80	
	* Schedules 11, 12, 21, 22, 31, and 32.															
30	Normalized Test Year Usage															
31	Residential Schedule 001		134,773,540	109,184,340	104,461,439	89,424,559	73,283,780	68,485,395	90,156,452	84,289,571	65,446,504	81,832,941	107,082,607	136,704,875	1,145,126,003	
32	General Svc Schedule 011/012		35,677,209	32,638,038	32,194,706	26,832,832	27,876,806	25,659,303	32,421,434	30,578,232	25,603,558	28,827,826	30,183,771	36,620,099	365,113,814	
33	Large Gen Svc Schedule 021/022		53,952,803	55,479,102	50,949,780	54,473,211	55,343,313	50,618,288	58,052,348	54,648,617	49,289,801	55,255,451	53,353,221	57,776,660	649,192,595	
34	Extra Large Gen Schedule 25		30,934,099	28,172,537	30,840,636	28,922,885	29,246,524	28,897,457	29,684,052	30,920,803	29,133,094	30,180,303	29,379,132	30,976,723	357,288,245	
35	Extra Large Gen Schedule 25P		34,821,780	32,532,270	27,238,130	24,807,470	19,729,910	23,256,720	31,864,010	35,206,500	28,782,080	38,565,200	34,117,330	31,651,460	362,572,860	
36	Pumping Schedule 31/32		3,565,011	2,875,625	4,661,071	3,346,903	4,831,186	6,718,307	8,729,950	8,458,372	6,675,218	4,756,402	2,507,349	3,266,930	60,392,324	
37	Street and Area Lights		1,189,853	1,089,157	1,076,010	1,109,609	1,129,068	1,100,399	1,117,528	1,129,571	1,093,959	1,082,770	1,093,222	1,133,947	13,345,092	
38	Total Normalized Test Year Usage		294,914,295	261,971,069	251,421,772	228,917,469	211,440,587	204,735,869	252,025,774	245,231,666	206,024,214	240,500,893	257,716,632	298,130,694	2,953,030,933	
39																
40																
41	Normalized Test Year Customer Bills															
42	Residential Schedule 001		104,681	104,659	104,786	104,674	104,445	104,362	104,498	104,627	105,120	105,159	105,547	105,700	1,258,258	
43	General Svc Schedule 011/012		20,915	20,991	20,979	20,949	21,002	21,009	21,093	21,103	21,076	21,048	21,087	21,114	252,366	
44	Large Gen Svc Schedule 021/022		1,140	1,144	1,131	1,143	1,139	1,133	1,137	1,139	1,145	1,142	1,139	1,125	13,657	
45	Extra Large Gen Schedule 25		11	11	11	11	11	11	11	11	11	11	11	11	132	
46	Extra Large Gen Schedule 25P		1	1	1	1	1	1	1	1	1	1	1	1	12	
47	Pumping Schedule 31/32		1,409	1,411	1,403	1,399	1,404	1,391	1,417	1,408	1,415	1,408	1,411	1,403	16,879	
48	Street and Area Lights		143	143	146	147	148	148	150	155	151	151	154	153	1,789	
49	Total Normalized Test Year Customer Bills		128,300	128,360	128,457	128,324	128,150	128,055	128,307	128,444	128,919	128,920	129,350	129,507	1,543,093	
50																
51	Test Year Average Usage per Customer															
52	Residential		1,287	1,043	997	854	702	656	863	806	623	778	1,015	1,293	10,917	910
53	Non-Residential		3,972	3,864	3,734	3,604	3,740	3,527	4,195	3,961	3,451	3,765	3,640	4,131	45,584	3,799

Sumcost
Scenario: AVU-E-17-01 Settlement Case
Load Factor Peak Credit
Transmission By Demand 12 CP

AVISTA UTILITIES
Revenue to Cost by Functional Component Summary
For the Twelve Months Ended December 31, 2016

Idaho Jurisdiction
Electric Utility

09/29/17

	(b) (c) (d) (e) Description	(f) System Total	(g) Residential Service Sch 1	(h) General Service Sch 11-12	(i) Large Gen Service Sch 21-22	(j) Extra Large Gen Service Sch 25	(k) Extra Large Service CP Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Functional Cost Components at Current Return by Schedule								
1	Production	115,411,512	45,464,829	15,343,432	25,763,208	12,799,054	13,503,398	2,123,135	414,457
2	Transmission	25,526,273	10,215,328	3,733,760	5,829,797	2,493,976	2,816,620	385,214	51,578
3	Distribution	60,065,371	29,117,877	11,034,603	13,010,682	1,952,773	334,898	2,048,469	2,566,070
4	Common	45,579,844	24,192,966	7,200,206	7,466,312	2,700,197	2,490,084	937,183	592,895
5	Total Current Rate Revenue	246,583,000	108,991,000	37,312,000	52,070,000	19,946,000	19,145,000	5,494,000	3,625,000
	Expressed as $/kWh								
6	Production	$0.03908	$0.03970	$0.04202	$0.03969	$0.03582	$0.03724	$0.03516	$0.03106
7	Transmission	$0.00864	$0.00892	$0.01023	$0.00898	$0.00698	$0.00777	$0.00638	$0.00386
8	Distribution	$0.02034	$0.02543	$0.03022	$0.02004	$0.00547	$0.00092	$0.03392	$0.19229
9	Common	$0.01543	$0.02113	$0.01972	$0.01150	$0.00756	$0.00687	$0.01552	$0.04443
10	Total Current Melded Rates	$0.08350	$0.09518	$0.10219	$0.08021	$0.05583	$0.05280	$0.09097	$0.27164
	Functional Cost Components at Uniform Current Return								
11	Production	115,204,615	47,371,556	13,947,215	25,073,652	12,919,313	13,316,328	2,163,751	412,799
12	Transmission	25,544,027	11,417,236	2,959,025	5,438,615	2,556,208	2,716,800	405,102	51,042
13	Distribution	60,062,042	31,838,659	9,054,374	12,161,159	2,000,226	322,864	2,146,369	2,538,391
14	Common	45,772,316	25,455,191	6,393,250	7,194,497	2,734,355	2,444,313	961,409	589,301
15	Total Uniform Current Cost	246,583,000	116,082,641	32,353,864	49,867,923	20,210,102	18,800,305	5,676,630	3,591,534
	Expressed as $/kWh								
16	Production	$0.03901	$0.04137	$0.03820	$0.03862	$0.03616	$0.03673	$0.03583	$0.03093
17	Transmission	$0.00865	$0.00997	$0.00810	$0.00838	$0.00715	$0.00749	$0.00671	$0.00382
18	Distribution	$0.02034	$0.02780	$0.02480	$0.01873	$0.00560	$0.00089	$0.03554	$0.19021
19	Common	$0.01550	$0.02223	$0.01751	$0.01108	$0.00765	$0.00674	$0.01592	$0.04416
20	Total Current Uniform Melded Rates	$0.08350	$0.10137	$0.08861	$0.07682	$0.05657	$0.05185	$0.09400	$0.26913
21	**Revenue to Cost Ratio at Current Rates**	1.00	0.94	1.15	1.04	0.99	1.02	0.97	1.01
	Functional Cost Components at Proposed Return by Schedule								
22	Production	119,320,405	47,123,397	15,867,464	26,643,703	13,155,119	13,911,500	2,195,408	423,815
23	Transmission	27,802,692	11,260,910	4,024,562	6,329,347	2,678,256	3,034,405	420,607	54,604
24	Distribution	64,757,699	31,484,748	11,777,888	14,095,542	2,093,288	361,153	2,222,692	2,722,388
25	Common	47,592,204	25,290,945	7,503,085	7,813,408	2,801,337	2,589,941	980,294	613,193
26	Total Proposed Rate Revenue	259,473,000	115,160,000	39,173,000	54,882,000	20,728,000	19,897,000	5,819,000	3,814,000
	Expressed as $/kWh								
27	**Production**	**$0.04041**	**$0.04115**	**$0.04346**	**$0.04104**	**$0.03682**	**$0.03837**	**$0.03635**	**$0.03176**
28	**Transmission**	**$0.00941**	**$0.00983**	**$0.01102**	**$0.00975**	**$0.00750**	**$0.00837**	**$0.00696**	**$0.00409**
29	Distribution	$0.02193	$0.02749	$0.03226	$0.02171	**$0.00586**	**$0.00100**	**$0.03680**	**$0.20400**
30	Common	$0.01612	$0.02209	$0.02055	$0.01204	$0.00784	$0.00714	$0.01623	$0.04595
31	Total Proposed Melded Rates	$0.08787	$0.10057	$0.10729	$0.08454	$0.05801	$0.05488	$0.09635	$0.28580
	Functional Cost Components at Uniform Requested Return								
32	Production	119,145,838	48,992,167	14,424,358	25,931,438	13,361,291	13,771,888	2,237,774	426,922
33	Transmission	27,829,800	12,438,891	3,223,810	5,925,282	2,784,947	2,959,909	441,352	55,609
34	Distribution	64,726,473	34,151,369	9,731,157	13,218,042	2,174,641	352,172	2,324,810	2,774,282
35	Common	47,770,888	26,528,044	6,669,029	7,532,641	2,859,896	2,555,782	1,005,564	619,932
36	Total Uniform Cost	259,473,000	122,110,472	34,048,353	52,607,404	21,180,775	19,639,751	6,009,500	3,876,745
	Expressed as $/kWh								
37	Production	$0.04035	$0.04278	$0.03951	$0.03994	$0.03740	$0.03798	$0.03705	$0.03199
38	Transmission	$0.00942	$0.01086	$0.00883	$0.00913	$0.00779	$0.00816	$0.00731	$0.00417
39	Distribution	$0.02192	$0.02982	$0.02665	$0.02036	$0.00609	$0.00097	$0.03850	$0.20789
40	Common	$0.01618	$0.02317	$0.01827	$0.01160	$0.00800	$0.00705	$0.01665	$0.04645
41	Total Uniform Melded Rates	$0.08787	$0.10663	$0.09325	$0.08104	$0.05928	$0.05417	$0.09951	$0.29050
42	**Revenue to Cost Ratio at Proposed Rates**	1.00	0.94	1.15	1.04	0.98	1.01	0.97	0.98
43	**Current Revenue to Proposed Cost Ratio**	**0.95**	**0.89**	**1.10**	**0.99**	**0.94**	**0.97**	**0.91**	**0.94**
44	**Target Revenue Increase**	**12,890,000**	**13,120,000**	**(3,264,000)**	**537,000**	**1,235,000**	**495,000**	**515,000**	**252,000**

AVISTA UTILITIES
Revenue Conversion Factor
Idaho - Electric System
TWELVE MONTHS ENDED DECEMBER 31, 2016

Line No.	Description	Factor	
1	Revenues	1.000000	1.000000
	Expenses:		
2	Uncollectibles	0.003563	0.003563
3	Commission Fees	0.002275	0.002275
4	Idaho Income Tax	0.051264	
5	Total Expenses	0.057102	0.005838
6	Net Operating Income Before FIT	0.942898	0.994162
7	Federal Income Tax @ 35%	0.330014	
8	REVENUE CONVERSION FACTOR	0.612884	

Revised per Staff_PR_079, Attachment A

APPENDIX C

Avista Utilities
Electric Fixed Cost Adjustment Mechanism (Idaho)
Development of Fixed Cost Adjustment Revenue by Rate Schedule - Electric
AVU-E-17-01 Rates Effective 1/1/2019

			TOTAL	RESIDENTIAL SCHEDULE 1	GENERAL SVC. SCH. 11,12	LG. GEN. SVC. SCH. 21,22	PUMPING SCH. 31, 32	OTHER SERVICE SCHEDULES
1	Total Normalized Test Year Revenue		$ 246,584,000	$ 108,991,000	$ 37,312,000	$ 52,071,000	$ 5,494,000	$ 42,716,000
2	Year 1 Settlement Revenue Increase		$ 12,889,000	$ 6,169,000	$ 1,861,000	$ 2,811,000	$ 325,000	$ 1,723,000
2A	Year 2 Settlement Revenue Increase		$ 4,544,000	$ 2,179,000	$ 656,000	$ 993,000	$ 115,000	$ 601,000
3	Total Rate Revenue (January 1, 2019)		$ 264,017,000	$ 117,339,000	$ 39,829,000	$ 55,875,000	$ 5,934,000	$ 45,040,000
4	Normalized kWhs (Test Year)		2,953,030,933	1,145,126,003	365,113,814	649,192,595	60,392,324	733,206,197
5	Load Change Adjustment Rate (Ln 14)		$ 0.02499	$ 0.02499	$ 0.02499	$ 0.02499	$ 0.02499	
6	Variable Power Supply Revenue (Ln 4 * Ln 5)		$ 73,796,243	$ 28,616,699	$ 9,124,194	$ 16,223,323	$ 1,509,204	$ 18,322,823
6A	Fixed Production and Transmission Rate per kWh	(New Customers Only)		$ 0.02628	$ 0.02976	$ 0.02615	$ 0.01860	
6B	Fixed Production and Transmission Revenue	(New Customers Only)	$ 74,184,071	$ 30,089,695	$ 10,867,268	$ 16,978,550	$ 1,123,212	$ 15,125,347
7	Subtotal (Ln 3 - Ln 6)	(Test Year Customers)	$ 163,503,580	$ 88,722,301	$ 30,704,806	$ 39,651,677	$ 4,424,796	**Excluded From Fixed Cost Adjustment**
7A	Subtotal (Ln 3 - Ln 6 - Ln 6B)	(New Customers)	$ 104,444,855	$ 58,632,606	$ 19,837,538	$ 22,673,127	$ 3,301,584	
8	Customer Bills (Test Year)		1,541,160	1,258,258	252,366	13,657	16,879	
9	Settlement Fixed Charges			$ 6.00	$ 13.00	$ 425.00	$ 11.00	
10	Fixed Charge Revenue (Ln 8 * Ln 9)		$ 16,820,200	$ 7,549,548	$ 3,280,758	$ 5,804,225	$ 185,669	
11	Fixed Cost Adjustment Revenue (Ln 7 - Ln 10)	(Test Year Customers)	$ 146,683,380	$ 81,172,753	$ 27,424,048	$ 33,847,452	$ 4,239,127	
11A	Fixed Cost Adjustment Revenue (Ln 7A - Ln 10)	(New Customers)	$ 87,624,655	$ 51,083,058	$ 16,556,780	$ 16,868,902	$ 3,115,915	
12	Load Change Adjustment Rate		$0.02484					
13	Gross Up Factor for Revenue Related Exp		100.59%					
14	Grossed Up Load Change Adjustment Rate		$0.02499					

		Residential	Non-Residential Group
15	Average Number of Customers (Line 8 / 12)	104,855	23,575
16	Annual kWh	1,145,126,003	1,074,698,733
17	Basic Charge Revenues	7,549,548	9,270,652
18	Customer Bills	1,258,258	282,902
19	Average Basic Charge	$6.00	$32.77

Exhibit No. 101
Case Nos. AVU-E-17-01/
AVU-G-17-01
R. Lobb, Staff
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Avista Utilities
Electric Fixed Cost Adjustment Mechanism (Idaho)
Development of Annual Fixed Cost Adjustment Revenue Per Customer - Electric
AVU-E-17-01 Rates Effective 1/1/2019

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
	Existing Customer FCA			
1	Fixed Cost Adjustment Revenue	Page 1	$ 81,172,753	$ 65,510,627
2	Test Year Number of Customers	Revenue Data	104,855	23,575
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$ 774.14	$ 2,778.80
	New Customer FCA			
1	Fixed Cost Adjustment Revenue	Page 1	$ 51,083,058	$ 36,541,597
2	Test Year Number of Customers	Revenue Data	104,855	23,575
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$ 487.18	$ 1,550.00

* Schedules 11, 12, 21, 22, 31, and 32.

Avista Utilities
Electric Fixed Cost Adjustment Mechanism (Idaho)
Development of Monthly Fixed Cost Adjustment Revenue Per Customer - Electric
AVU-E-17-01 Rates Effective 1/1/2019

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
1	**Electric Sales**															
2	*Residential*															
3	- Weather-Normalized kWh Sales	Monthly Test Year	134,773,540	109,184,340	104,461,439	89,424,559	73,283,780	68,485,395	90,156,452	84,289,571	65,446,504	81,832,941	107,082,607	136,704,875	1,145,126,003	
4	- % of Annual Total	% of Total	11.77%	9.53%	9.12%	7.81%	6.40%	5.98%	7.87%	7.36%	5.72%	7.15%	9.35%	11.94%	100.00%	
5																
6	*Non-Residential**															
7	- Weather-Normalized kWh Sales	Monthly Test Year	93,195,023	90,992,765	87,805,557	84,652,946	88,051,305	82,995,898	99,203,732	93,685,221	81,568,577	88,839,679	86,044,341	97,663,689	1,074,698,733	
8	- % of Annual Total	% of Total	8.67%	8.47%	8.17%	7.88%	8.19%	7.72%	9.23%	8.72%	7.59%	8.27%	8.01%	9.09%	100.00%	
9																
10																
11	**Monthly Fixed Cost Adjustment Revenue Per Customer ("RPC")**															
12	*For Test Year Existing Customers*															
13	*Residential*															
14	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 774.14	
15	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(4) x (14)	$ 91.11	$ 73.81	$ 70.62	$ 60.45	$ 49.54	$ 46.30	$ 60.95	$ 56.98	$ 44.24	$ 55.32	$ 72.39	$ 92.42	$ 774.14	
16																
17	*Non-Residential**															
18	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 2,778.80	
19	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(8) x (18)	$ 240.97	$ 235.28	$ 227.03	$ 218.88	$ 227.67	$ 214.60	$ 256.51	$ 242.24	$ 210.91	$ 229.71	$ 222.48	$ 252.52	$ 2,778.80	
20																
21																
22	*For New Customers*															
23	*Residential*															
24	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 487.18	
25	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(4) x (24)	$ 57.34	$ 46.45	$ 44.44	$ 38.04	$ 31.18	$ 29.14	$ 38.36	$ 35.86	$ 27.84	$ 34.81	$ 45.56	$ 58.16	$ 487.18	
26																
27	*Non-Residential**															
28	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 1,550.00	
29	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(8) x (28)	$ 134.41	$ 131.24	$ 126.54	$ 122.09	$ 126.99	$ 119.70	$ 143.08	$ 135.12	$ 117.64	$ 128.13	$ 124.10	$ 140.86	$ 1,550.00	
	* Schedules 11, 12, 21, 22, 31, and 32.															
30	Normalized Test Year Usage															
31	Residential Schedule 001		134,773,540	109,184,340	104,461,439	89,424,559	73,283,780	68,485,395	90,156,452	84,289,571	65,446,504	81,832,941	107,082,607	136,704,875	1,145,126,003	
32	General Svc Schedule 011/012		35,677,209	32,638,038	32,194,706	26,832,832	27,876,806	25,659,303	32,421,434	30,578,232	25,603,558	28,827,826	30,183,771	36,620,099	365,113,814	
33	Large Gen Svc Schedule 021/022		53,952,803	55,479,102	50,949,780	54,473,211	55,343,313	50,618,288	58,052,348	54,648,617	49,289,801	55,255,451	53,353,221	57,776,660	649,192,595	
34	Extra Large Gen Schedule 25		30,934,099	28,172,537	30,840,636	28,922,885	29,246,524	28,897,457	29,684,052	30,920,803	29,133,094	30,180,303	29,379,132	30,976,723	357,288,245	
35	Extra Large Gen Schedule 25P		34,821,780	32,532,270	27,238,130	24,807,470	19,729,910	23,256,720	31,864,010	35,206,500	28,782,080	38,565,200	34,117,330	31,651,460	362,572,860	
36	Pumping Schedule 31/32		3,565,011	2,875,625	4,661,071	3,346,903	4,831,186	6,718,307	8,729,950	8,458,372	6,675,218	4,756,402	2,507,349	3,266,930	60,392,324	
37	Street and Area Lights		1,189,853	1,089,157	1,076,010	1,109,609	1,129,068	1,100,399	1,117,528	1,129,571	1,093,959	1,082,770	1,093,222	1,133,947	13,345,092	
38	Total Normalized Test Year Usage		294,914,295	261,971,069	251,421,772	228,917,469	211,440,587	204,735,869	252,025,774	245,231,666	206,024,214	240,500,893	257,716,632	298,130,694	2,953,030,933	
39																
40																
41	Normalized Test Year Customer Bills															
42	Residential Schedule 001		104,681	104,659	104,786	104,674	104,445	104,362	104,498	104,627	105,120	105,159	105,547	105,700	1,258,258	
43	General Svc Schedule 011/012		20,915	20,991	20,979	20,949	21,002	21,009	21,093	21,103	21,076	21,048	21,087	21,114	252,366	
44	Large Gen Svc Schedule 021/022		1,140	1,144	1,131	1,143	1,139	1,133	1,137	1,139	1,145	1,142	1,139	1,125	13,657	
45	Extra Large Gen Schedule 25		11	11	11	11	11	11	11	11	11	11	11	11	132	
46	Extra Large Gen Schedule 25P		1	1	1	1	1	1	1	1	1	1	1	1	12	
47	Pumping Schedule 31/32		1,409	1,411	1,403	1,399	1,404	1,391	1,417	1,408	1,415	1,408	1,411	1,403	16,879	
48	Street and Area Lights		143	143	146	147	148	148	150	155	151	151	154	153	1,789	
49	Total Normalized Test Year Customer Bills		128,300	128,360	128,457	128,324	128,150	128,055	128,307	128,444	128,919	128,920	129,350	129,507	1,543,093	
50																
51	Test Year Average Usage per Customer															
52	Residential		1,287	1,043	997	854	702	656	863	806	623	778	1,015	1,293	10,917	910
53	Non-Residential		3,972	3,864	3,734	3,604	3,740	3,527	4,195	3,961	3,451	3,765	3,640	4,131	45,584	3,799

Sumcost | AVISTA UTILITIES | Idaho Jurisdiction

Scenario: AVU-E-17-01 Settlement Case 2019 | Revenue to Cost by Functional Component Summary | Electric Utility | 09/29/17

Load Factor Peak Credit | For the Twelve Months Ended December 31, 2016

Transmission By Demand 12 CP

	(b) (c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Description	System Total	Residential Service Sch 1	General Service Sch 11-12	Large Gen Service Sch 21-22	Extra Large Gen Service Sch 25	Extra Large Service CP Sch 25P	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Functional Cost Components at Current Return by Schedule								
1	Production	114,646,270	45,111,643	15,228,972	25,609,640	12,734,393	13,438,695	2,109,604	413,323
2	Transmission	25,055,123	9,976,647	3,671,250	5,739,727	2,457,988	2,780,206	378,134	51,171
3	Distribution	59,196,490	28,634,910	10,853,569	12,885,978	1,932,538	325,878	2,023,619	2,539,997
4	Common	47,685,117	25,267,800	7,558,209	7,834,655	2,821,080	2,600,221	982,643	620,509
5	Total Current Rate Revenue	246,583,000	108,991,000	37,312,000	52,070,000	19,946,000	19,145,000	5,494,000	3,625,000
	Expressed as $/kWh								
6	Production	$0.03882	$0.03939	$0.04171	$0.03945	$0.03564	$0.03706	$0.03493	$0.03097
7	Transmission	$0.00848	$0.00871	$0.01006	$0.00884	$0.00688	$0.00767	$0.00626	$0.00383
8	Distribution	$0.02005	$0.02501	$0.02973	$0.01985	$0.00541	$0.00090	$0.03351	$0.19033
9	Common	$0.01615	$0.02207	$0.02070	$0.01207	$0.00790	$0.00717	$0.01627	$0.04650
10	Total Current Melded Rates	$0.08350	$0.09518	$0.10219	$0.08021	$0.05583	$0.05280	$0.09097	$0.27164
	Functional Cost Components at Uniform Current Return								
11	Production	114,418,471	47,048,238	13,652,041	24,902,553	12,831,153	13,225,459	2,148,985	409,983
12	Transmission	25,065,275	11,203,251	2,903,566	5,336,683	2,508,299	2,665,881	397,509	50,085
13	Distribution	59,191,896	31,371,720	8,917,460	12,017,365	1,970,915	312,054	2,118,079	2,484,302
14	Common	47,907,358	26,666,191	6,692,334	7,533,256	2,850,752	2,543,950	1,008,114	612,760
15	Total Uniform Current Cost	246,583,000	116,289,460	32,365,401	49,789,857	20,161,119	18,747,344	5,672,688	3,557,130
	Expressed as $/kWh								
16	Production	$0.03875	$0.04109	$0.03794	$0.03836	$0.03591	$0.03648	$0.03556	$0.03072
17	Transmission	$0.00849	$0.00978	$0.00795	$0.00822	$0.00702	$0.00735	$0.00658	$0.00375
18	Distribution	$0.02004	$0.02740	$0.02442	$0.01851	$0.00552	$0.00086	$0.03507	$0.18616
19	Common	$0.01622	$0.02329	$0.01833	$0.01160	$0.00798	$0.00702	$0.01669	$0.04592
20	Total Current Uniform Melded Rates	$0.08350	$0.10155	$0.08864	$0.07670	$0.05643	$0.05171	$0.09393	$0.26655
21	**Revenue to Cost Ratio at Current Rates**	1.00	0.94	1.15	1.05	0.99	1.02	0.97	1.02
	Functional Cost Components at Proposed Return by Schedule								
22	Production	119,869,116	47,326,710	15,929,577	26,789,546	13,208,909	13,981,881	2,206,571	425,923
23	Transmission	28,111,199	11,379,684	4,061,885	6,412,327	2,704,737	3,071,456	425,845	55,265
24	Distribution	65,427,760	31,765,345	11,638,747	14,335,517	2,120,757	361,096	2,256,221	2,750,076
25	Common	50,608,926	26,867,261	7,998,791	8,337,610	2,966,597	2,743,567	1,045,363	649,737
26	Total Proposed Rate Revenue	264,017,000	117,339,000	39,829,000	55,875,000	21,001,000	20,158,000	5,934,000	3,881,000
	Expressed as $/kWh								
27	**Production**	**$0.04059**	**$0.04133**	**$0.04363**	**$0.04127**	**$0.03697**	**$0.03856**	**$0.03654**	**$0.03192**
28	**Transmission**	**$0.00952**	**$0.00994**	**$0.01112**	**$0.00988**	**$0.00757**	**$0.00847**	**$0.00705**	**$0.00414**
29	**Distribution**	**$0.02216**	**$0.02774**	**$0.03242**	**$0.02208**	**$0.00594**	**$0.00100**	**$0.03736**	$0.20607
30	Common	$0.01714	$0.02346	$0.02191	$0.01284	$0.00830	$0.00757	$0.01731	$0.04869
31	Total Proposed Melded Rates	$0.08941	$0.10247	$0.10909	$0.08607	$0.05878	$0.05560	$0.09826	$0.29082
	Functional Cost Components at Uniform Requested Return								
32	Production	119,686,479	49,214,476	14,489,811	26,049,106	13,421,919	13,834,380	2,247,926	428,859
33	Transmission	28,135,043	12,575,324	3,259,169	5,990,272	2,815,493	2,992,374	446,192	56,219
34	Distribution	65,384,510	34,433,067	9,814,286	13,425,932	2,205,242	351,534	2,355,421	2,799,028
35	Common	50,810,969	28,230,352	7,093,402	8,021,995	3,031,917	2,704,643	1,072,112	656,547
36	Total Uniform Cost	264,017,000	124,453,219	34,656,668	53,487,304	21,474,571	19,882,931	6,121,653	3,940,654
	Expressed as $/kWh								
37	Production	$0.04053	$0.04298	$0.03969	$0.04013	$0.03757	$0.03816	$0.03722	$0.03214
38	Transmission	$0.00953	$0.01098	$0.00893	$0.00923	$0.00788	$0.00825	$0.00739	$0.00421
39	Distribution	$0.02214	$0.03007	$0.02688	$0.02068	$0.00617	$0.00097	$0.03900	$0.20974
40	Common	$0.01721	$0.02465	$0.01943	$0.01236	$0.00849	$0.00746	$0.01775	$0.04920
41	Total Uniform Melded Rates	$0.08941	$0.10868	$0.09492	$0.08239	$0.06010	$0.05484	$0.10136	$0.29529
42	**Revenue to Cost Ratio at Proposed Rates**	1.00	0.94	1.15	1.04	0.98	1.01	0.97	0.98
43	**Current Revenue to Proposed Cost Ratio**	**0.93**	**0.88**	**1.08**	**0.97**	**0.93**	**0.96**	**0.90**	**0.92**
44	**Target Revenue Increase**	**17,434,000**	**15,461,000**	**(2,655,000)**	**1,417,000**	**1,529,000**	**738,000**	**628,000**	**316,000**

AVISTA UTILITIES
Revenue Conversion Factor
Idaho - Electric System
TWELVE MONTHS ENDED DECEMBER 31, 2016

Line No.	Description	Factor	
1	Revenues	1.000000	1.000000
	Expenses:		
2	Uncollectibles	0.003563	0.003563
3	Commission Fees	0.002275	0.002275
4	Idaho Income Tax	0.051264	
5	Total Expenses	0.057102	0.005838
6	Net Operating Income Before FIT	0.942898	0.994162
7	Federal Income Tax @ 35%	0.330014	
8	REVENUE CONVERSION FACTOR	0.612884	

Revised per Staff_PR_079, Attachment A

APPENDIX D

Avista Utilities
Natural Gas Fixed Cost Adjustment Mechanism (Idaho)
Development of Fixed Cost Adjustment Revenue by Rate Schedule - Natural Gas
AVU-G-17-01 Rates Effective 1/1/2018

			TOTAL	GENERAL SERVICE SCHEDULE 101	LARGE GENERAL SERVICE SCH. 111/112	OTHER SERVICE SCHEDULES
1	Total Staff Adjusted Normalized Test Year Revenue		$ 40,652,000	$ 33,197,000	$ 6,950,000	$ 505,000
2	Settlement Revenue Increase		$ 1,180,000	$ 1,073,000	$ 95,000	$ 12,000
3	Total Base Rate Revenue (January 1, 2018)		$ 41,832,000	$ 34,270,000	$ 7,045,000	$ 517,000
4	Normalized Therms (Test Year)		138,212,674	59,156,634	23,271,119	55,784,921
5	WACOG Rate Embedded in Base Rates		$ -	$ -	$ -	$ -
6	Variable Gas Cost Revenue (Ln 4 * Ln 5)		$ -	$ -	$ -	$ -
6A	Fixed Production and Underground Storage Rate per Therm	(New Customers Only)		$ 0.02566	$ 0.02770	
6B	Fixed Production and Underground Storage	(New Customers Only)	$ 2,205,353	$ 1,518,089	$ 644,501	$ 42,763
7	Subtotal (Ln 3 - Ln 6)	(Test Year Customers)	$ 41,315,000	$ 34,270,000	$ 7,045,000	**Excluded From**
7A	Subtotal (Ln 3 - Ln 6 - Ln 6B)	(New Customers)	$ 39,152,410	$ 32,751,911	$ 6,400,499	**Fixed Cost**
						Adjustment
8	Customer Bills (Test Year)		960,302	943,245	17,057	
9	Settlement Fixed Charges			$ 6.00	$ 102.73	
10	Fixed Charge Revenue (Ln 8 * Ln 9)		$ 7,411,736	$ 5,659,470	$ 1,752,266	
11	Fixed Cost Adjustment Revenue (Ln 7 - Ln 10)	(Test Year Customers)	$ 33,903,264	$ 28,610,530	$ 5,292,734	
11A	Fixed Cost Adjustment Revenue (Ln 7A - Ln 10)	(New Customers)	$ 31,740,674	$ 27,092,441	$ 4,648,233	

		Residential	Non-Residential Group
12	Average Number of Customers (Line 8 / 12)	78,604	1,421
13	Annual Therms	59,156,634	23,271,119
14	Basic Charge Revenues	5,659,470	1,752,266
15	Customer Bills	943,245	17,057
16	Average Basic Charge	$6.00	$102.73

Exhibit No. 101
Case Nos. AVU-E-17-01/
AVU-G-17-01
R. Lobb, Staff
11/03/17 Page 38 of 55

Avista Utilities
Natural Gas Fixed Cost Adjustment Mechanism (Idaho)
Development of Annual Fixed Cost Adjustment Revenue Per Customer - Natural Gas
AVU-G-17-01 Rates Effective 1/1/2018

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
	Existing Customer FCA			
1	Fixed Cost Adjustment Revenue	Page 1	$ 28,610,530	$ 5,292,734
2	Test Year Number of Customers	Revenue Data	78,604	1,421
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$ 363.98	$ 3,723.56
	New Customer FCA			
1	Fixed Cost Adjustment Revenue	Page 1	$ 27,092,441	$ 4,648,233
2	Test Year Number of Customers	Revenue Data	78,604	1,421
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$ 344.67	$ 3,270.14

* Schedules 111 and 112.

Avista Utilities
Natural Gas Fixed Cost Adjustment Mechanism (Idaho)
Development of Monthly Fixed Cost Adjustment Revenue Per Customer - Natural Gas
AVU-G-17-01 Rates Effective 1/1/2018

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
1	**Natural Gas Sales**															
2	*Residential*															
3	- Weather-Normalized Therm Delivery Volume	Monthly Test Year	9,319,909	7,933,964	6,757,265	4,377,085	2,457,565	1,514,614	1,193,367	1,180,168	1,401,784	3,930,171	8,004,649	11,086,092	59,156,634	
4	- % of Annual Total	% of Total	15.75%	13.41%	11.42%	7.40%	4.15%	2.56%	2.02%	1.99%	2.37%	6.64%	13.53%	18.74%	100.00%	
5																
6	*Non-Residential Sales**															
7	- Weather-Normalized Therm Delivery Volume	Monthly Test Year	3,010,243	2,765,523	2,386,786	1,725,613	1,384,859	1,066,070	1,083,827	1,332,665	1,028,780	1,762,355	2,685,935	3,038,463	23,271,119	
8	- % of Annual Total	% of Total	12.94%	11.88%	10.26%	7.42%	5.95%	4.58%	4.66%	5.73%	4.42%	7.57%	11.54%	13.06%	100.00%	
9																
10																
11	**Monthly Fixed Cost Adjustment Revenue Per Customer ("RPC")**															
12	***For Test Year Existing Customers***															
13	*Residential*															
14	- Allowed Fixed Cost Adj. Revenue per Customer	Page 2													$ 363.98	
15	- Allowed Monthly Fixed Cost Adj. Revenue per Customer	(4) x (14)	$ 57.34	$ 48.82	$ 41.58	$ 26.93	$ 15.12	$ 9.32	$ 7.34	$ 7.26	$ 8.62	$ 24.18	$ 49.25	$ 68.21	$ 363.98	
16																
17	*Non-Residential Sales**															
18	- Allowed Fixed Cost Adj. Revenue per Customer	Page 2													$ 3,723.56	
19	- Allowed Monthly Fixed Cost Adj. Revenue per Customer	(8) x (18)	$ 481.66	$ 442.51	$ 381.90	$ 276.11	$ 221.59	$ 170.58	$ 173.42	$ 213.24	$ 164.61	$ 281.99	$ 429.77	$ 486.18	$ 3,723.56	
20																
21																
22	***For New Customers***															
23	*Residential*															
24	- Allowed Fixed Cost Adj. Revenue per Customer	Page 2													$ 344.67	
25	- Allowed Monthly Fixed Cost Adj. Revenue per Customer	(4) x (24)	$ 54.30	$ 46.23	$ 39.37	$ 25.50	$ 14.32	$ 8.82	$ 6.95	$ 6.88	$ 8.17	$ 22.90	$ 46.64	$ 64.59	$ 344.67	
26																
27	*Non-Residential Sales**															
28	- Allowed Fixed Cost Adj. Revenue per Customer	Page 2													$ 3,270.14	
29	- Allowed Monthly Fixed Cost Adj. Revenue per Customer	(8) x (28)	$ 423.01	$ 388.62	$ 335.40	$ 242.49	$ 194.61	$ 149.81	$ 152.30	$ 187.27	$ 144.57	$ 247.65	$ 377.44	$ 426.98	$ 3,270.14	
	* Schedules 111 and 112.															
30	Normalized Test Year Usage															
31	Small Service Schedule 101		9,319,909	7,933,964	6,757,265	4,377,085	2,457,565	1,514,614	1,193,367	1,180,168	1,401,784	3,930,171	8,004,649	11,086,092	59,156,634	
32	Large Service Schedule 111/112		3,010,243	2,765,523	2,386,786	1,725,613	1,384,859	1,066,070	1,083,827	1,332,665	1,028,780	1,762,355	2,685,935	3,038,463	23,271,119	
33	Interrupt Service Schedule 131/132		-	-	-	-	-	-	-	-	-	-	-	-	-	
34	Transport Service Schedule 146		258,551	330,679	255,099	294,126	255,691	218,925	201,080	207,868	208,303	216,161	222,877	221,790	2,891,150	
35	Special Contract Transport		5,371,194	5,432,014	4,400,560	3,420,592	3,413,413	2,907,702	6,185,831	3,246,590	4,217,669	8,303,818	167,594	5,826,794	52,893,771	
36	Total Normalized Test Year Usage		17,959,896	16,462,180	13,799,710	9,817,416	7,511,528	5,707,311	8,664,105	5,967,291	6,856,537	14,212,505	11,081,055	20,173,139	138,212,674	
37																
38																
39	Normalized Test Year Customer Bills															
40	Small Service Schedule 101		78,021	78,174	78,273	78,247	78,230	78,297	78,357	78,634	78,840	79,010	79,433	79,729	943,245	
41	Large Service Schedule 111/112		1,411	1,416	1,430	1,425	1,433	1,426	1,428	1,418	1,419	1,420	1,423	1,408	17,057	
42	Interrupt Service Schedule 131/132		-	-	-	-	-	-	-	-	-	-	-	-	-	
43	Transport Service Schedule 146		6	6	6	6	6	6	6	6	6	6	6	6	72	
44	Special Contract Transport		2	2	2	2	2	2	2	2	2	2	2	2	24	
45	Total Normalized Test Year Customer Bills		79,440	79,598	79,711	79,680	79,671	79,731	79,793	80,060	80,267	80,438	80,864	81,145	960,398	
46																
47																
48	Test Year Average Usage per Customer															
49	Residential		119	101	86	56	31	19	15	15	18	50	101	139	752	63
50	Non-Residential		2,133	1,953	1,669	1,211	966	748	759	940	725	1,241	1,888	2,158	16,391	1,364

Exhibit No. 101
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AVISTA UTILITIES
Company Settlement Summary by Function with Margin Analysis
Case 2018 Revenue For the Year Ended December 31, 2016

Natural Gas Utility
Idaho Jurisdiction

Line	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Functional Cost Components at Current Rates								
1	Production				439,493	313,065	123,154	0	3,273
2	Underground Storage				1,693,952	1,143,425	512,561	0	37,966
3	Distribution				26,983,600	21,889,721	4,825,616	0	268,264
4	Common				11,431,954	9,850,686	1,489,089	0	92,179
5	**Total Current Rate Revenue**				**40,549,000**	**33,196,897**	**6,950,421**	**0**	**401,683**
6	Exclude Cost of Gas w / Revenue Exp.				0	0	0	0	0
7	**Total Margin Revenue at Current Rates**				**40,549,000**	**33,196,897**	**6,950,421**	**0**	**401,683**
	Margin per Therm at Current Rates								
8	Production				$0.00515	$0.00529	$0.00529	$0.00000	$0.00113
9	Underground Storage				$0.01985	$0.01933	$0.02203	$0.00000	$0.01313
10	Distribution				$0.31627	$0.37003	$0.20737	$0.00000	$0.09279
11	Common				$0.13399	$0.16652	$0.06399	$0.00000	$0.03188
12	Total Current Margin Melded Rate per Therm				**$0.47526**	**$0.56117**	**$0.29867**	**$0.00000**	**$0.13894**
	Functional Cost Components at Uniform Current Return								
13	Production				439,493	313,065	123,154	0	3,273
14	Underground Storage				1,647,826	1,218,829	391,188	0	37,809
15	Distribution				26,939,249	22,869,870	3,802,038	0	267,341
16	Common				11,522,432	10,108,759	1,321,649	0	92,024
17	Total Uniform Current Cost				**40,549,000**	**34,510,524**	**5,638,029**	**0**	**400,447**
18	Exclude Cost of Gas w / Revenue Exp.				0	0	0	0	0
19	Total Uniform Current Margin				**40,549,000**	**34,510,524**	**5,638,029**	**0**	**400,447**
	Margin per Therm at Uniform Current Return								
20	Production				$0.00515	$0.00529	$0.00529	$0.00000	$0.00113
21	Underground Storage				$0.01931	$0.02060	$0.01681	$0.00000	$0.01308
22	Distribution				$0.31575	$0.38660	$0.16338	$0.00000	$0.09247
23	Common				$0.13505	$0.17088	$0.05679	$0.00000	$0.03183
24	Total Current Uniform Margin Melded Rate per Therm				**$0.47526**	**$0.58338**	**$0.24228**	**$0.00000**	**$0.13851**
25	**Margin to Cost Ratio at Current Rates**				**1.00**	**0.96**	**1.23**	**0.00**	**1.00**
	Functional Cost Components at Proposed Rates								
26	Production				439,486	313,060	123,152	0	3,273
27	Underground Storage				1,765,868	1,205,029	521,349	0	39,489
28	Distribution				27,867,327	22,690,377	4,899,720	0	277,230
29	Common				11,656,320	10,061,430	1,501,200	0	93,690
30	**Total Proposed Rate Revenue**				**41,729,000**	**34,269,897**	**7,046,421**	**0**	**413,683**
31	Exclude Cost of Gas w / Revenue Exp.				0	0	0	0	0
32	**Total Margin Revenue at Proposed Rates**				**41,729,000**	**34,269,897**	**7,046,421**	**0**	**413,683**
	Margin per Therm at Proposed Rates								
33	**Production**				**$0.00515**	**$0.00529**	**$0.00529**	**$0.00000**	**$0.00113**
34	**Underground Storage**				**$0.02070**	**$0.02037**	**$0.02240**	**$0.00000**	**$0.01366**
35	Distribution				$0.32663	$0.38356	$0.21055	$0.00000	$0.09589
36	Common				$0.13662	$0.17008	$0.06451	$0.00000	$0.03241
37	Total Proposed Margin Melded Rate per Therm				**$0.48909**	**$0.57931**	**$0.30275**	**$0.00000**	**$0.14309**
	Functional Cost Components at Uniform Proposed Return								
38	Production				439,486	313,060	123,152	0	3,273
39	Underground Storage				1,723,320	1,274,669	409,110	0	39,542
40	Distribution				27,826,314	23,595,605	3,953,172	0	277,537
41	Common				11,739,880	10,299,777	1,346,360	0	93,742
42	Total Uniform Proposed Cost				**41,729,000**	**35,483,111**	**5,831,795**	**0**	**414,094**
43	Exclude Cost of Gas w / Revenue Exp.				0	0	0	0	0
44	Total Uniform Proposed Margin				**41,729,000**	**35,483,111**	**5,831,795**	**0**	**414,094**
	Margin per Therm at Uniform Proposed Return								
45	Production				$0.00515	$0.00529	$0.00529	$0.00000	$0.00113
46	Underground Storage				$0.02020	$0.02155	$0.01758	$0.00000	$0.01368
47	Distribution				$0.32614	$0.39887	$0.16987	$0.00000	$0.09600
48	Common				$0.13760	$0.17411	$0.05786	$0.00000	$0.03242
49	Total Proposed Uniform Margin Melded Rate per Therm				**$0.48909**	**$0.59982**	**$0.25060**	**$0.00000**	**$0.14323**
50	**Margin to Cost Ratio at Proposed Rates**				**1.00**	**0.97**	**1.21**	**0.00**	**1.00**
51	**Current Margin to Proposed Cost Ratio**				**0.97**	**0.94**	**1.19**	**0.00**	**0.97**

AVISTA UTILITIES
Revenue Conversion Factor
Idaho - Natural Gas System
TWELVE MONTHS ENDED DECEMBER 31, 2016

Line No.	Description	Factor	
1	**Revenues**	1.000000	1.000000
	Expenses:		
2	Uncollectibles	0.003564	0.003564
3	Commission Fees	0.002275	0.002275
4	Idaho State Income Tax	0.051264	0
5	Total Expenses	0.057103	0.005839
6	Net Operating Income Before FIT	0.942897	0.994161
7	Federal Income Tax @ 35%	0.330014	
8	REVENUE CONVERSION FACTOR	0.612883	

Revised per Staff_PR_079, Attachment A

APPENDIX E

Avista Utilities
Natural Gas Fixed Cost Adjustment Mechanism (Idaho)
Development of Fixed Cost Adjustment Revenue by Rate Schedule - Natural Gas
AVU-G-17-01 Rates Effective 1/1/2019

			TOTAL	GENERAL SERVICE SCHEDULE 101	LARGE GENERAL SERVICE SCH. 111/112	OTHER SERVICE SCHEDULES
1	Total Staff Adjusted Normalized Test Year Revenue		$ 40,652,000	$ 33,197,000	$ 6,950,000	$ 505,000
2	Year 1 Settlement Revenue Increase		$ 1,180,000	$ 1,073,000	$ 95,000	$ 12,000
2A	Year 2 Settlement Revenue Increase		$ 1,120,000	$ 1,020,000	$ 89,000	$ 11,000
3	Total Base Rate Revenue (January 1, 2019)		$ 42,952,000	$ 35,290,000	$ 7,134,000	$ 528,000
4	Normalized Therms (Test Year)		138,212,674	59,156,634	23,271,119	55,784,921
5	WACOG Rate Embedded in Base Rates		$ -	$ -	$ -	$ -
6	Variable Gas Cost Revenue (Ln 4 * Ln 5)		$ -	$ -	$ -	$ -
6A	**Fixed Production** and Underground Storage **Rate per Therm**	(New Customers Only)		$ 0.02599	$ 0.02781	
6B	Fixed Production and Underground Storage	(New Customers Only)	$ 2,228,409	$ 1,537,536	$ 647,270	$ 43,603
7	Subtotal (Ln 3 - Ln 6)	(Test Year Customers)	$ 42,424,000	$ 35,290,000	$ 7,134,000	**Excluded From Fixed Cost Adjustment**
7A	Subtotal (Ln 3 - Ln 6 - Ln 6B)	(New Customers)	$ 40,239,194	$ 33,752,464	$ 6,486,730	
8	Customer Bills (Test Year)		960,302	943,245	17,057	
9	Settlement Fixed Charges			$ 6.00	$ 106.18	
10	Fixed Charge Revenue (Ln 8 * Ln 9)		$ 7,470,582	$ 5,659,470	$ 1,811,112	
11	Fixed Cost Adjustment Revenue (Ln 7 - Ln 10)	(Test Year Customers)	$ 34,953,418	$ 29,630,530	$ 5,322,888	
11A	Fixed Cost Adjustment Revenue (Ln 7A - Ln 10)	(New Customers)	$ 32,768,611	$ 28,092,994	$ 4,675,617	

		Residential	Non-Residential Group
12	Average Number of Customers (Line 8 / 12)	78,604	1,421
13	Annual Therms	59,156,634	23,271,119
14	Basic Charge Revenues	5,659,470	1,811,112
15	Customer Bills	943,245	17,057
16	Average Basic Charge	$6.00	$106.18

Exhibit No. 101
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Avista Utilities
Natural Gas Fixed Cost Adjustment Mechanism (Idaho)
Development of Annual Fixed Cost Adjustment Revenue Per Customer - Natural Gas
AVU-G-17-01 Rates Effective 1/1/2019

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
	Existing Customer FCA			
1	Fixed Cost Adjustment Revenue	Page 1	$ 29,630,530	$ 5,322,888
2	Test Year Number of Customers	Revenue Data	78,604	1,421
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$ 376.96	$ 3,744.78
	New Customer FCA			
1	Fixed Cost Adjustment Revenue	Page 1	$ 28,092,994	$ 4,675,617
2	Test Year Number of Customers	Revenue Data	78,604	1,421
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$ 357.40	$ 3,289.41

* Schedules 111 and 112.

Avista Utilities
Natural Gas Fixed Cost Adjustment Mechanism (Idaho)
Development of Monthly Fixed Cost Adjustment Revenue Per Customer - Natural Gas
AVU-G-17-01 Rates Effective 1/1/2019

Line No.	(a)	Source (b)	Jan (c)	Feb (d)	Mar (e)	Apr (f)	May (g)	Jun (h)	Jul (i)	Aug (j)	Sep (k)	Oct (l)	Nov (m)	Dec (n)	TOTAL (o)	
1	**Natural Gas Sales**															
2	*Residential*															
3	- Weather-Normalized Therm Delivery Volume	Monthly Test Year	9,319,909	7,933,964	6,757,265	4,377,085	2,457,565	1,514,614	1,193,367	1,180,168	1,401,784	3,930,171	8,004,649	11,086,092	59,156,634	
4	- % of Annual Total	% of Total	15.75%	13.41%	11.42%	7.40%	4.15%	2.56%	2.02%	1.99%	2.37%	6.64%	13.53%	18.74%	100.00%	
5																
6	*Non-Residential Sales**															
7	- Weather-Normalized Therm Delivery Volume	Monthly Test Year	3,010,243	2,765,523	2,386,786	1,725,613	1,384,859	1,066,070	1,083,827	1,332,665	1,028,780	1,762,355	2,685,935	3,038,463	23,271,119	
8	- % of Annual Total	% of Total	12.94%	11.88%	10.26%	7.42%	5.95%	4.58%	4.66%	5.73%	4.42%	7.57%	11.54%	13.06%	100.00%	
9																
10																
11	**Monthly Fixed Cost Adjustment Revenue Per Customer ("RPC")**															
12	*For Test Year Existing Customers*															
13	*Residential*															
14	- Allowed Fixed Cost Adj. Revenue per Customer	Page 2													$ 376.96	
15	- Allowed Monthly Fixed Cost Adj. Revenue per Customer	(4) x (14)	$ 59.39	$ 50.56	$ 43.06	$ 27.89	$ 15.66	$ 9.65	$ 7.60	$ 7.52	$ 8.93	$ 25.04	$ 51.01	$ 70.64	$ 376.96	
16																
17	*Non-Residential Sales**															
18	- Allowed Fixed Cost Adj. Revenue per Customer	Page 2													$ 3,744.78	
19	- Allowed Monthly Fixed Cost Adj. Revenue per Customer	(8) x (18)	$ 484.41	$ 445.03	$ 384.08	$ 277.68	$ 222.85	$ 171.55	$ 174.41	$ 214.45	$ 165.55	$ 283.60	$ 432.22	$ 488.95	$ 3,744.78	
20																
21																
22	*For New Customers*															
23	*Residential*															
24	- Allowed Fixed Cost Adj. Revenue per Customer	Page 2													$ 357.40	
25	- Allowed Monthly Fixed Cost Adj. Revenue per Customer	(4) x (24)	$ 56.31	$ 47.93	$ 40.82	$ 26.44	$ 14.85	$ 9.15	$ 7.21	$ 7.13	$ 8.47	$ 23.74	$ 48.36	$ 66.98	$ 357.40	
26																
27	*Non-Residential Sales**															
28	- Allowed Fixed Cost Adj. Revenue per Customer	Page 2													$ 3,289.41	
29	- Allowed Monthly Fixed Cost Adj. Revenue per Customer	(8) x (28)	$ 425.50	$ 390.91	$ 337.38	$ 243.92	$ 195.75	$ 150.69	$ 153.20	$ 188.37	$ 145.42	$ 249.11	$ 379.66	$ 429.49	$ 3,289.41	
	* Schedules 111 and 112.															
30	Normalized Test Year Usage															
31	Small Service Schedule 101		9,319,909	7,933,964	6,757,265	4,377,085	2,457,565	1,514,614	1,193,367	1,180,168	1,401,784	3,930,171	8,004,649	11,086,092	59,156,634	
32	Large Service Schedule 111/112		3,010,243	2,765,523	2,386,786	1,725,613	1,384,859	1,066,070	1,083,827	1,332,665	1,028,780	1,762,355	2,685,935	3,038,463	23,271,119	
33	Interrupt Service Schedule 131/132		-	-	-	-	-	-	-	-	-	-	-	-	-	
34	Transport Service Schedule 146		258,551	330,679	255,099	294,126	255,691	218,925	201,080	207,868	208,303	216,161	222,877	221,790	2,891,150	
35	Special Contract Transport		5,371,194	5,432,014	4,400,560	3,420,592	3,413,413	2,907,702	6,185,831	3,246,590	4,217,669	8,303,818	167,594	5,826,794	52,893,771	
36	Total Normalized Test Year Usage		17,959,896	16,462,180	13,799,710	9,817,416	7,511,528	5,707,311	8,664,105	5,967,291	6,856,537	14,212,505	11,081,055	20,173,139	138,212,674	
37																
38																
39	Normalized Test Year Customer Bills															
40	Small Service Schedule 101		78,021	78,174	78,273	78,247	78,230	78,297	78,357	78,634	78,840	79,010	79,433	79,729	943,245	
41	Large Service Schedule 111/112		1,411	1,416	1,430	1,425	1,433	1,426	1,428	1,418	1,419	1,420	1,423	1,408	17,057	
42	Interrupt Service Schedule 131/132		-	-	-	-	-	-	-	-	-	-	-	-	-	
43	Transport Service Schedule 146		6	6	6	6	6	6	6	6	6	6	6	6	72	
44	Special Contract Transport		2	2	2	2	2	2	2	2	2	2	2	2	24	
45	Total Normalized Test Year Customer Bills		79,440	79,598	79,711	79,680	79,671	79,731	79,793	80,060	80,267	80,438	80,864	81,145	960,398	
46																
47																
48	Test Year Average Usage per Customer															
49	Residential		119	101	86	56	31	19	15	15	18	50	101	139	752	63
50	Non-Residential		2,133	1,953	1,669	1,211	966	748	759	940	725	1,241	1,888	2,158	16,391	1,364

Exhibit No. 101
Case Nos. AVU-E-17-01/
AVU-G-17-01
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AVISTA UTILITIES
Company Settlement Summary by Function with Margin Analysis
Case 2019 Revenue For the Year Ended December 31, 2016

Natural Gas Utility
Idaho Jurisdiction

Line	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Functional Cost Components at Current Rates								
1	Production				446,533	318,080	125,127	0	3,326
2	Underground Storage				1,642,040	1,099,594	505,097	0	37,348
3	Distribution				26,376,438	21,361,097	4,751,283	0	264,058
4	Common				12,083,990	10,418,126	1,568,914	0	96,950
5	**Total Current Rate Revenue**				**40,549,000**	**33,196,897**	**6,950,421**	**0**	**401,683**
6	Exclude Cost of Gas w / Revenue Exp.				0	0	0	0	0
7	**Total Margin Revenue at Current Rates**				**40,549,000**	**33,196,897**	**6,950,421**	**0**	**401,683**
	Margin per Therm at Current Rates								
8	Production				$0.00523	$0.00538	$0.00538	$0.00000	$0.00115
9	Underground Storage				$0.01925	$0.01859	$0.02170	$0.00000	$0.01292
10	Distribution				$0.30915	$0.36109	$0.20417	$0.00000	$0.09133
11	Common				$0.14163	$0.17611	$0.06742	$0.00000	$0.03353
12	Total Current Margin Melded Rate per Therm				**$0.47526**	**$0.56117**	**$0.29867**	**$0.00000**	**$0.13894**
	Functional Cost Components at Uniform Current Return								
13	Production				446,533	318,080	125,127	0	3,326
14	Underground Storage				1,593,144	1,178,383	378,207	0	36,555
15	Distribution				26,324,087	22,372,220	3,692,422	0	259,444
16	Common				12,185,236	10,704,143	1,384,968	0	96,126
17	Total Uniform Current Cost				**40,549,000**	**34,572,826**	**5,580,723**	**0**	**395,450**
18	Exclude Cost of Gas w / Revenue Exp.				0	0	0	**0**	**0**
19	Total Uniform Current Margin				**40,549,000**	**34,572,826**	**5,580,723**	**0**	**395,450**
	Margin per Therm at Uniform Current Return								
20	Production				$0.00523	$0.00538	$0.00538	$0.00000	$0.00115
21	Underground Storage				$0.01867	$0.01992	$0.01625	$0.00000	$0.01264
22	Distribution				$0.30854	$0.37819	$0.15867	$0.00000	$0.08974
23	Common				$0.14282	$0.18095	$0.05951	$0.00000	$0.03325
24	Total Current Uniform Margin Melded Rate per Therm				**$0.47526**	**$0.58443**	**$0.23981**	**$0.00000**	**$0.13678**
25	**Margin to Cost Ratio at Current Rates**				**1.00**	**0.96**	**1.25**	**0.00**	**1.02**
	Functional Cost Components at Proposed Rates								
26	Production				446,522	318,072	125,124	0	3,326
27	Underground Storage				1,781,887	1,219,464	522,147	0	40,277
28	Distribution				28,073,873	22,899,245	4,893,541	0	281,087
29	Common				12,546,718	10,853,116	1,593,609	0	99,993
30	**Total Proposed Rate Revenue**				**42,849,000**	**35,289,897**	**7,134,421**	**0**	**424,683**
31	Exclude Cost of Gas w / Revenue Exp.				0	0	0	0	0
32	**Total Margin Revenue at Proposed Rates**				**42,849,000**	**35,289,897**	**7,134,421**	**0**	**424,683**
	Margin per Therm at Proposed Rates								
33	**Production**				**$0.00523**	**$0.00538**	**$0.00538**	**$0.00000**	**$0.00115**
34	**Underground Storage**				**$0.02089**	**$0.02061**	**$0.02244**	**$0.00000**	**$0.01393**
35	**Distribution**				**$0.32905**	$0.38710	$0.21028	$0.00000	$0.09722
36	Common				$0.14706	$0.18346	$0.06848	$0.00000	$0.03459
37	Total Proposed Margin Melded Rate per Therm				**$0.50222**	**$0.59655**	**$0.30668**	**$0.00000**	**$0.14689**
	Functional Cost Components at Uniform Proposed Return								
38	Production				446,522	318,072	125,124	0	3,326
39	Underground Storage				1,740,042	1,287,037	413,080	0	39,925
40	Distribution				28,028,889	23,766,435	3,983,412	0	279,042
41	Common				12,633,547	11,098,418	1,435,500	0	99,628
42	Total Uniform Proposed Cost				**42,849,000**	**36,469,963**	**5,957,116**	**0**	**421,921**
43	Exclude Cost of Gas w / Revenue Exp.				0	0	0	0	0
44	Total Uniform Proposed Margin				**42,849,000**	**36,469,963**	**5,957,116**	**0**	**421,921**
	Margin per Therm at Uniform Proposed Return								
45	Production				$0.00523	$0.00538	$0.00538	$0.00000	$0.00115
46	Underground Storage				$0.02039	$0.02176	$0.01775	$0.00000	$0.01381
47	Distribution				$0.32852	$0.40175	$0.17117	$0.00000	$0.09652
48	Common				$0.14807	$0.18761	$0.06169	$0.00000	$0.03446
49	Total Proposed Uniform Margin Melded Rate per Therm				**$0.50222**	**$0.61650**	**$0.25599**	**$0.00000**	**$0.14594**
50	**Margin to Cost Ratio at Proposed Rates**				**1.00**	**0.97**	**1.20**	**0.00**	**1.01**
51	**Current Margin to Proposed Cost Ratio**				**0.95**	**0.91**	**1.17**	**0.00**	**0.95**

AVISTA UTILITIES
Revenue Conversion Factor
Idaho - Natural Gas System
TWELVE MONTHS ENDED DECEMBER 31, 2016

Line No.	Description	Factor	
1	**Revenues**	1.000000	1.000000
	Expenses:		
2	Uncollectibles	0.003564	0.003564
3	Commission Fees	0.002275	0.002275
4	Idaho State Income Tax	0.051264	0
5	Total Expenses	0.057103	0.005839
6	Net Operating Income Before FIT	0.942897	0.994161
7	Federal Income Tax @ 35%	0.330014	
8	REVENUE CONVERSION FACTOR	0.612883	

Revised per Staff_PR_079, Attachment A

APPENDIX F

AVISTA UTILITIES
IDAHO ELECTRIC, CASE NO. AVU-E-17-01
PROPOSED INCREASE BY SERVICE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2016
(000s of Dollars)

Effective January 1, 2018

Line No.	Type of Service	Schedule Number	Base Tariff Revenue Under Present Rates(1)	Proposed General Increase	Base Tariff Revenue Under Proposed Rates (1)	Base Tariff Percent Increase	Total Billed Revenue at Present Rates(2)	Total General Increase	Percent Increase on Billed GRC Revenue	Sch 97 Earnings Test Increase	Sch 97 Percent Increase on Billed GRC Revenue	Total Billed Revenue at Proposed Rates(2)	Percent Increase on Billed Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Residential	1	$108,991	$6,169	$115,160	5.7%	$112,048	$6,169	5.5%	$470	0.4%	$118,687	5.9%
2	General Service	11,12	$37,312	$1,861	$39,173	5.0%	$38,524	$1,861	4.8%	$150	0.4%	$40,534	5.2%
3	Large General Service	21,22	$52,071	$2,811	$54,882	5.4%	$53,685	$2,811	5.2%	$266	0.5%	$56,762	5.7%
4	Extra Large General Service	25	$19,946	$782	$20,728	3.9%	$19,546	$782	4.0%	$146	0.7%	$20,475	4.7%
5	Clearwater	25P	$19,145	$752	$19,897	3.9%	$18,681	$752	4.0%	$149	0.8%	$19,582	4.8%
6	Pumping Service	31,32	$5,494	$325	$5,819	5.9%	$5,674	$325	5.7%	$25	0.4%	$6,024	6.1%
7	Street & Area Lights	41-49	$3,625	$189	$3,814	5.2%	$3,760	$189	5.0%	$5	0.1%	$3,954	5.1%
8	Total		$246,584	$12,889	$259,473	5.2%	$251,918	$12,889	5.1%	$1,211	0.5%	$266,018	5.6%

Effective January 1, 2019

Line No.	Type of Service	Schedule Number	Base Tariff Revenue Under Present Rates(1)	Proposed General Increase	Base Tariff Revenue Under Proposed Rates (1)	Base Tariff Percent Increase	Total Billed Revenue at Present Rates(2)	Total General Increase	Percent Increase on Billed GRC Revenue	Sch 97 Earnings Test Increase	Sch 97 Percent Increase on Billed GRC Revenue	Total Billed Revenue at Proposed Rates(2)	Percent Increase on Billed Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Residential	1	$115,160	$2,179	$117,339	1.9%	$118,687	$2,179	1.8%	$573	0.5%	$121,439	2.3%
2	General Service	11,12	$39,173	$656	$39,829	1.7%	$40,534	$656	1.6%	$183	0.5%	$41,373	2.1%
3	Large General Service	21,22	$54,882	$993	$55,875	1.8%	$56,762	$993	1.7%	$325	0.6%	$58,080	2.3%
4	Extra Large General Service	25	$20,728	$273	$21,001	1.3%	$20,475	$273	1.3%	$179	0.9%	$20,926	2.2%
5	Clearwater	25P	$19,897	$261	$20,158	1.3%	$19,582	$261	1.3%	$181	0.9%	$20,024	2.2%
6	Pumping Service	31,32	$5,819	$115	$5,934	2.0%	$6,024	$115	1.9%	$30	0.5%	$6,169	2.4%
7	Street & Area Lights	41-49	$3,814	$67	$3,881	1.8%	$3,954	$67	1.7%	$7	0.2%	$4,028	1.9%
8	Total		$259,473	$4,544	$264,017	1.8%	$266,018	$4,544	1.7%	$1,477	0.6%	$272,038	2.3%

(1) Excludes all present rate adjustments (see below).

(2) Includes all present rate adjustments: Schedule 59 - Residential & Farm Energy Rate Adjustment, Schedule 66 - Temporary Power Cost Adjustment, Schedule 91 - Energy Efficiency Rider Adjustment, and Schedule 97 - Earnings Test Deferral.

AVISTA UTILITIES
IDAHO ELECTRIC, CASE NO. AVU-E-17-01
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

Effective January 1, 2018

(a)	Base Tariff Sch. Rate (b)	Present Other Adj.(1) (c)	Present Billing Rate (d)	General Rate Inc/(Decr) (e)	Schedule 97 Earnings Test Increase (f)	Proposed Billing Rate (g)	Proposed Base Tariff Rate (h)
Residential Service - Schedule 1							
Basic Charge	$5.75		$5.75	**$0.25**		**$6.00**	**$6.00**
Energy Charge:							
First 600 kWhs	$0.08449	$0.00267	$0.08716	**$0.00486**	**$0.00041**	**$0.09243**	**$0.08935**
All over 600 kWhs	$0.09434	$0.00267	$0.09701	**$0.00543**	**$0.00041**	**$0.10285**	**$0.09977**
General Services - Schedule 11							
Basic Charge	$12.00		$12.00	**$1.00**		**$13.00**	**$13.00**
Energy Charge:							
First 3,650 kWhs	$0.09704	$0.00337	$0.10041	**$0.00513**	**$0.00041**	**$0.10595**	**$0.10217**
All over 3,650 kWhs	$0.07216	$0.00337	$0.07553	**$0.00192**	**$0.00041**	**$0.07786**	**$0.07408**
Demand Charge:							
20 kW or less	no charge		no charge	**no charge**			**no charge**
Over 20 kW	$5.75/kW		$5.75/kW	$0.25/kW		$6.00/kW	$6.00/kW
Large General Service - Schedule 21							
Energy Charge:							
First 250,000 kWhs	$0.06322	$0.00250	$0.06572	**$0.00340**	**$0.00041**	**$0.06953**	**$0.06662**
All over : (2) Includes all preser	$0.05396	$0.00250	$0.05646	**$0.00290**	**$0.00041**	**$0.05977**	**$0.05686**
Demand Charge:							
50 kW or less	$400.00		$400.00	**$25.00**		**$425.00**	**$425.00**
Over 50 kW	$5.25/kW		$5.25/kW	$0.25/kW		$5.50/kW	$5.50/kW
Primary Voltage Discount	$0.20/kW		$0.20/kW			$0.20/kW	$0.20/kW
Extra Large General Service - Schedule 25							
Energy Charge:							
First 500,000 kWhs	$0.05299	($0.00112)	$0.05187	**$0.00200**	**$0.00041**	**$0.05428**	**$0.05499**
All over 500,000 kWhs	$0.04487	($0.00112)	$0.04375	**$0.00169**	**$0.00041**	**$0.04585**	**$0.04656**
Demand Charge:							
3,000 kva or less	$13,500		$13,500	**$500**		**$14,000**	**$14,000**
Over 3,000 kva	$4.75/kva		$4.75/kva	$0.25/kva		$5.00/kva	$5.00/kva
Primary Volt. Discount	$0.20/kW		$0.20/kW			$0.20/kW	$0.20/kW
Annual Minimum	Present:	$704,290			Proposed:	**$730,740**	
Clearwater - Schedule 25P							
Energy Charge:							
all kWhs	$0.04308	($0.00128)	$0.04180	**$0.00144**	**$0.00041**	**$0.04365**	**$0.04452**
Demand Charge:							
3,000 kva or less	$13,500		$13,500	**$500**		**$14,000**	**$14,000**
3,000 - 55,000 kva	$4.75/kva		$4.75/kva	$0.25/kva		$5.00/kva	$5.00/kva
Over 55,000 kva	$2.25/kva		$2.25/kva	$0.25/kva		$2.50/kva	$2.50/kva
Primary Volt. Discount	$0.20/kW		$0.20/kW			$0.20/kW	$0.20/kW
Annual Minimum	Present:	$635,880			Proposed:	**$657,720**	
Pumping Service - Schedule 31							
Basic Charge	$10.00		$10.00	**$1.00**		**$11.00**	**$11.00**
Energy Charge:							
First 165 kW/kWhs	$0.09605	$0.00306	$0.09911	**$0.00555**	**$0.00041**	**$0.10507**	**$0.10160**
All additional kWhs	$0.08187	$0.00306	$0.08493	**$0.00473**	**$0.00041**	**$0.09007**	**$0.08660**

(1) Includes all present rate adjustments: Schedule 59 - Residential & Farm Energy Rate Adjustment, Schedule 66 - Temporary Power Cost Adjustment, Schedule 91 - Energy Efficiency Rider Adjustment, and Schedule 97 - Earnings Test Deferral

AVISTA UTILITIES
IDAHO ELECTRIC, CASE NO. AVU-E-17-01
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

Effective January 1, 2019

(a)	Base Tariff Sch. Rate (b)	Present Other Adj.(1) (c)	Present Billing Rate (d)	General Rate Inc/(Decr) (e)	Schedule 97 Earnings Test Increase (f)	Proposed Billing Rate (g)	Proposed Base Tariff Rate (h)
Residential Service - Schedule 1							
Basic Charge	$6.00		$6.00	$0.00		$6.00	$6.00
Energy Charge:							
First 600 kWhs	$0.08935	$0.00308	$0.09243	$0.00181	$0.00050	$0.09474	$0.09116
All over 600 kWhs	$0.09977	$0.00308	$0.10285	$0.00202	$0.00050	$0.10537	$0.10179
General Services - Schedule 11							
Basic Charge	$13.00		$13.00	$0.00		$13.00	$13.00
Energy Charge:							
First 3,650 kWhs	$0.10217	$0.00378	$0.10595	$0.00218	$0.00050	$0.10863	$0.10435
All over 3,650 kWhs	$0.07408	$0.00378	$0.07786	$0.00079	$0.00050	$0.07915	$0.07487
Demand Charge:							
20 kW or less	no charge		no charge	no charge			no charge
Over 20 kW	$6.00/kW		$6.00/kW			$6.00/kW	$6.00/kW
Large General Service - Schedule 21							
Energy Charge:							
First 250,000 kWhs	$0.06662	$0.00291	$0.06953	$0.00155	$0.00050	$0.07158	$0.06817
All over : (2) Includes all preser	$0.05686	$0.00291	$0.05977	$0.00132	$0.00050	$0.06159	$0.05818
Demand Charge:							
50 kW or less	$425.00		$425.00	$0.00		$425.00	$425.00
Over 50 kW	$5.50/kW		$5.50/kW			$5.50/kW	$5.50/kW
Primary Voltage Discount	$0.20/kW		$0.20/kW			$0.20/kW	$0.20/kW
Extra Large General Service - Schedule 25							
Energy Charge:							
First 500,000 kWhs	$0.05499	($0.00071)	$0.05428	$0.00087	$0.00050	$0.05565	$0.05586
All over 500,000 kWhs	$0.04656	($0.00071)	$0.04585	$0.00074	$0.00050	$0.04709	$0.04730
Demand Charge:							
3,000 kva or less	$14,000		$14,000			$14,000	$14,000
Over 3,000 kva	$5.00/kva		$5.00/kva			$5.00/kva	$5.00/kva
Primary Volt. Discount	$0.20/kW		$0.20/kW			$0.20/kW	$0.20/kW
Annual Minimum	Present:	$730,740			Proposed:	$739,660	
Clearwater - Schedule 25P							
Energy Charge:							
all kWhs	$0.04452	($0.00087)	$0.04365	$0.00072	$0.00050	$0.04487	$0.04524
Demand Charge:							
3,000 kva or less	$14,000		$14,000			$14,000	$14,000
3,000 - 55,000 kva	$5.00/kva		$5.00/kva			$5.00/kva	$5.00/kva
Over 55,000 kva	$2.50/kva		$2.50/kva			$2.50/kva	$2.50/kva
Primary Volt. Discount	$0.20/kW		$0.20/kW			$0.20/kW	$0.20/kW
Annual Minimum	Present:	$657,720			Proposed:	$665,640	
Pumping Service - Schedule 31							
Basic Charge	$11.00		$11.00	$0.00		$11.00	$11.00
Energy Charge:							
First 165 kW/kWhs	$0.10160	$0.00347	$0.10507	$0.00208	$0.00050	$0.10765	$0.10368
All additional kWhs	$0.08660	$0.00347	$0.09007	$0.00177	$0.00050	$0.09234	$0.08837

(1) Includes all present rate adjustments: Schedule 59 - Residential & Farm Energy Rate Adjustment, Schedule 66 - Temporary Power Cost Adjustment, Schedule 91 - Energy Efficiency Rider Adjustment, and Schedule 97 - Earnings Test Deferral

Exhibit No. 101
Case Nos. AVU-E-17-01/
AVU-G-17-01
R. Lobb, Staff
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AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-17-01
PROPOSED INCREASE BY SERVICE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2016
(000s of Dollars)

Effective January 1, 2018

Line No.	Type of Service (a)	Schedule Number (b)	Base Tariff Distribution Revenue Under Present Rates (1) (c)	Proposed General Increase (d)	Base Tariff Distribution Revenue Under Proposed Rates (e)	Base Tariff Percent Increase (f)	Total Billed Revenue at Present Rates (2) (g)	Total General Increase (h)	Total Billed Revenue at Proposed Rates (2) (i)	Percent Increase on Billed GRC Revenue (j)
1	General Service	101	$33,197	$1,073	$34,270	3.2%	$47,993	$1,073	$49,065	2.2%
2	Large General Service	111/112	$6,950	$95	$7,045	1.4%	$12,776	$95	$12,871	0.7%
3	Interruptible Service	131/132	$0	$0	$0	0.0%	$0	$0	$0	0.0%
4	Transportation Service	146	$402	$12	$414	3.0%	$402	$12	$414	3.0%
5	Special Contracts	148	$103	$0	$103	0.0%	$103	$0	$103	0.0%
6	Total		$40,652	$1,180	$41,832	2.9%	$61,273	$1,180	$62,452	1.9%

(1) Excludes Schedule 150 - Purchased Gas Cost Adjustment, Schedule 155 - Gas Rate Adjustment, & Schedule 191 - DSM
(2) Includes Schedule 150 - Purchased Gas Cost Adjustment, Schedule 155 - Gas Rate Adjustment, & Schedule 191 - DSM

Effective January 1, 2019

Line No.	Type of Service (a)	Schedule Number (b)	Base Tariff Distribution Revenue Under Present Rates (1) (c)	Proposed General Increase (d)	Base Tariff Distribution Revenue Under Proposed Rates (e)	Base Tariff Percent Increase (f)	Total Billed Revenue at Present Rates (2) (g)	Total General Increase (h)	Total Billed Revenue at Proposed Rates (2) (i)	Percent Increase on Billed GRC Revenue (j)
1	General Service	101	$34,270	$1,020	$35,290	3.0%	$49,065	$1,020	$50,085	2.1%
2	Large General Service	111/112	$7,045	$89	$7,134	1.3%	$12,871	$89	$12,959	0.7%
3	Interruptible Service	131/132	$0	$0	$0.00	0.0%	$0	$0	$0	0.0%
4	Transportation Service	146	$414	$11	$425	2.7%	$414	$11	$425	2.7%
5	Special Contracts	148	$103	$0	$103	0.0%	$103	$0	$103	0.0%
6	Total		$41,832	$1,120	$42,952	2.7%	$62,452	$1,120	$63,572	1.8%

(1) Excludes Schedule 150 - Purchased Gas Cost Adjustment, Schedule 155 - Gas Rate Adjustment, & Schedule 191 - DSM
(2) Includes Schedule 150 - Purchased Gas Cost Adjustment, Schedule 155 - Gas Rate Adjustment, & Schedule 191 - DSM

Exhibit No. 101
Case Nos. AVU-E-17-01/
AVU-G-17-01
R. Lobb, Staff

AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-17-01
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

Effective January 1, 2018

Type of Service (a)	Present Base Distribution Rate (b)	Present Billing Rate Adj.(1) (c)	Present Billing Rate (d)	**General Rate Increase (e)**	**Proposed Billing Rate (f)**	**Proposed Base Distribution Rate (g)**
General Service - Schedule 101						
Basic Charge	$5.25		$5.25	**$0.75**	**$6.00**	**$6.00**
Usage Charge:						
All therms	$0.47746	$0.27421	$0.75167	**$0.00617**	**$0.75784**	**$0.48363**
Large General Service - Schedule 111						
Usage Charge:						
First 200 therms	$0.50375	$0.26581	$0.76956	**$0.00990**	**$0.77946**	**$0.51365**
200 - 1,000 therms	$0.31954	$0.26581	$0.58535	**$0.00266**	**$0.58801**	**$0.32220**
1,000 - 10,000 therms	$0.23783	$0.26581	$0.50364	**$0.00198**	**$0.50562**	**$0.23981**
All over 10,000 therms	$0.18381	$0.26581	$0.44962	**$0.00153**	**$0.45115**	**$0.18534**
Minimum Charge:						
per month	$100.75		$100.75	**$1.98**	**$102.73**	**$102.73**
per therm	$0.00000	$0.26581	$0.26581		**$0.26581**	**$0.00000**
Interruptible Service - Schedule 131						
Usage Charge:						
All Therms	$0.21972	$0.14814	$0.36786	**$0.00637**	**$0.37423**	**$0.22609**
Transportation Service - Schedule 146						
Basic Charge	$225.00		$225.00	**$25.00**	**$250.00**	**$250.00**
Usage Charge:						
All Therms	$0.12740		$0.12740	**$0.00337**	**$0.13077**	**$0.13077**

(1) Includes Schedule 150 - Purchased Gas Cost Adjustment, Schedule 155 - and Gas Rate Adjustment, Schedule 191 - DSM

AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-17-01
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

Effective January 1, 2019

Type of Service (a)	Present Base Distribution Rate (b)	Present Billing Rate Adj.(1) (c)	Present Billing Rate (d)	General Rate Increase (e)	Proposed Billing Rate (f)	Proposed Base Distribution Rate (g)
General Service - Schedule 101						
Basic Charge	$6.00		$6.00	**$0.00**	**$6.00**	**$6.00**
Usage Charge:						
All therms	$0.48363	$0.27421	$0.75784	**$0.01724**	**$0.77508**	**$0.50087**
Large General Service - Schedule 111						
Usage Charge:						
First 200 therms	$0.51365	$0.26581	$0.77946	**$0.01725**	**$0.79671**	**$0.53090**
200 - 1,000 therms	$0.32220	$0.26581	$0.58801	**$0.00182**	**$0.58983**	**$0.32402**
1,000 - 10,000 therms	$0.23981	$0.26581	$0.50562	**$0.00136**	**$0.50698**	**$0.24117**
All over 10,000 therms	$0.18534	$0.26581	$0.45115	**$0.00105**	**$0.45220**	**$0.18639**
Minimum Charge:						
per month	$102.73		$102.73	**$3.45**	**$106.18**	**$106.18**
per therm	$0.00000	$0.26581	$0.26581		**$0.26581**	**$0.00000**
Interruptible Service - Schedule 131						
Usage Charge:						
All Therms	$0.22609	$0.14814	$0.37423		**$0.37423**	**$0.22609**
Transportation Service - Schedule 146						
Basic Charge	$250.00		$250.00	**$0.00**	**$250.00**	**$250.00**
Usage Charge:						
All Therms	$0.13077		$0.13077	**$0.00364**	**$0.13441**	**$0.13441**

(1) Includes Schedule 150 - Purchased Gas Cost Adjustment, Schedule 155 and - Gas Rate Adjustment, Schedule 191 - DSM.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 3RD DAY OF NOVEMBER 2017, SERVED THE FOREGOING **DIRECT TESTIMONY OF RANDY LOBB IN SUPPORT OF THE STIPULATION AND SETTLEMENT,** IN CASE NOS. AVU-E-17-01/AVU-G-17-01, BY E-MAILING AND MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

KELLY O NORWOOD
VP STATE & FED REG
AVISTA CORPORATION
PO BOX 3727
SPOKANE WA 99220-3727
E-MAIL: kelly.norwood@avistacorp.com
avistadockets@avistacorp.com

DAVID J MEYER
VP & CHIEF COUNSEL
AVISTA CORPORATION
PO BOX 3727
SPOKANE WA 99220-3727
E-MAIL: david.meyer@avistacorp.com

PETER J RICHARDSON
GREGORY M ADAMS
RICHARDSON ADAMS PLLC
515 N 27TH STREET
BOISE ID 83702
E-MAIL: peter@richardsonadams.com
greg@richardsonadams.com

DR DON READING
6070 HILL ROAD
BOISE ID 83703
E-MAIL: dreading@mindspring.com

ELECTRONIC ONLY
CLEARWATER PAPER CORP.
carol.haugen@clearwaterpaper.com
marv@malewallen.com
john.jacobs@clearwaterpaper.com
david.wren@clearwaterpaper.com
nathan.smith@clearwaterpaper.com

BRAD M PURDY
ATTORNEY AT LAW
2019 N 17TH ST
BOISE ID 83702
E-MAIL: bmpurdy@hotmail.com

RONALD L WILLIAMS
WILLIAMS BRADBURY
PO BOX 388
BOISE ID 83701
E-MAIL: ron@williamsbradbury.com

ELECTRONIC ONLY
DEAN J MILLER
3620 E WARM SPRINGS
BOISE ID 83716
E-MAIL: deanjmiller@cableone.net

LARRY A CROWLEY
THE ENERGY STRATEGIES INSTITUTE
5549 S CLIFFSEDGE AVENUE
BOISE ID 83716
E-MAIL: crowleyla@aol.com

EMILY MATTHEWS
E-MAIL: ematthews@idfg.com

MATTHEW A. NYKIEL
ID CONSERVATION LEAGUE
PO BOX 2308
102 S EUCLID #207
SANDPOINT ID 83864
E-MAIL: mnykiel@idahoconservation.org

BENJAMIN J OTTO
ID CONSERVATION LEAGUE
710 N. 6TH STREET
BOISE ID 83702
E-MAIL: botto@idahoconservation.org

TRAVIS RITCHIE
SIERRA CLUB
2101 WEBSTER ST., SUITE 1300
OAKLAND, CA 94612
E-MAIL: travis.ritchie@sierraclub.org

Jo Nelson
SECRETARY