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AVISTA Corp.

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IDAHO PUBLIC
UTILITIES COMMISSION

October 16, 2015

Jean D. Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington Street
Boise, ID 83702

Re: Case Nos. AVU-E-15-05 and AVU-G-15-01
Stipulation and Settlement and Joint Motion

Enclosed for filing with the Commission in the above-referenced docket are the original and seven copies of the Joint Motion for Approval of Stipulation and Settlement, and the Stipulation and Settlement, dated October 16, 2015.

Sincerely,

David J. Meyer
Vice President, Chief Counsel for Regulatory
& Governmental Affairs

Enclosures

c: Service List

Date: 12-5-17 Exh # 18
Regulatory Commission of Alaska
U-16-094 By: AOS U-17-008
Northern Lights Realtime & Reporting, Inc.
(907) 337-2221

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this 16th day of October, 2015, served the Settlement and Stipulation, and Joint Motion, upon the following parties, by mailing a copy thereof, properly addressed with postage prepaid to:

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF AVISTA CORPORATION DBA AVISTA	)	CASE NOS. AVU-E-15-05
UTILITIES FOR AUTHORITY TO	)	AVU-G-15-01
INCREASE ITS RATES AND CHARGES	)	
FOR ELECTRIC AND NATURAL GAS	)	
SERVICE IN IDAHO	)	**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"), the Community Action Partnership Association of Idaho ("CAPAI"), the Idaho Conservation League ("ICL"), and the Snake River Alliance ("Snake River"). These entities are collectively referred to as the "Parties," and represent all of the parties in the above-referenced cases. The Parties understand this Stipulation is subject to approval by the Idaho Public Utilities Commission ("IPUC" or the "Commission").

I. INTRODUCTION

1. The terms and conditions of this Stipulation are set forth herein. The 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 these cases. The 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 1, 2015, Avista filed an Application with the Commission for authority to increase revenue effective January 1, 2016 for electric and natural gas service in Idaho by 5.2% and 4.5%, respectively. If approved, the Company's 2016 revenues for electric base retail rates would have increased by $13.2 million annually, and Company revenues for natural gas service would have increased by $3.2 million annually. The Company also requested an increase to electric base retail revenue of $13.7 million (5.1%), and an increase in natural gas base retail revenue of $1.7 (2.2%), effective January 1, 2017. By Order No. 33324, dated June 15, 2015, 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, ICL, and Snake River. The Commission granted these interventions through IPUC Order Nos. 33331 and 33338.

4. A settlement conference was noticed and held in the Commission offices on September 18, 2015, and was attended by signatories to this Stipulation.[1] Based upon the discussions among the Parties, as a compromise of positions in this case, and for other consideration as set forth below, the Parties agree to the following terms:

III. TERMS OF THE STIPULATION AND SETTLEMENT

5. Overview of Settlement and Revenue Requirement. The Parties agree that Avista should be allowed to implement revised tariff schedules designed to recover $1.7 million in additional annual electric revenue, and $2.5 million in additional annual natural gas revenue, which represent a 0.69% and 3.49% increase in electric and natural gas annual base tariff revenues, respectively. New electric and natural gas rates would become effective January 1, 2016.

6. 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%	5.34%	2.67%
Common Equity	50%	9.50%	4.75%
Total	100%		**7.42%**

[1] ICL was unable to attend the Settlement Conference; however, they did provide a "Position Statement" on September 17, 2015 providing their views on issues related to the proposed Fixed Cost Adjustment mechanisms and rate design.

A. ELECTRIC

7. Overview of Electric Revenue Requirement. Below is a summary table and descriptions of the electric revenue requirement components agreed to by the Parties for January 1, 2016:

SUMMARY TABLE OF ADJUSTMENTS TO ELECTRIC REVENUE REQUIREMENT
EFFECTIVE JANUARY 1, 2016
(000s of Dollars)

		Revenue Requirement		Rate Base	
	Amount as Filed:	$	13,230	$	749,225
	Adjustments:				
a.)	Cost of Capital	$	(2,438)		
b.)	Revise 2015 Capital Additions	$	(3,345)	$	(16.125)
c.)	Remove 2016 Capital Additions	$	(548)	$	1,789
d.)	Revise Deferred Debits and Credits to Reflect 2015 Balances	$	52	$	131
e.)	Remove 2016 Expenses				
i.	Insurance Expense	$	(62)		
ii.	Information Services & Technology	$	(521)		
iii.	Non-Executive Labor	$	(385)		
iv.	O&M Offsets	$	212		
f.)	Update 2015 Employee Benefit Costs	$	481		
g.)	Adjust Injuries and Damages Expense	$	(8)		
h.)	Remove Officer Incentives and Restate Non-Officer Incentives	$	(100)		
i.)	Include Four-Year Amortization of 2015 Project Compass Deferral	$	(669)		
j.)	Include Four-Year Amortization of Lake Spokane Deferral	$	(119)		
k.)	Include Palouse Wind in PCA	$	(3,500)		
l.)	Miscellaneous A&G Adjustments: Director & Officer Insurance, Board of Director Expenses, Reallocation of Legal Expenses, Removal of Environmental Cleanup Costs, and Removal of Miscellaneous Agreed-To Expenses	$	(580)		
	Adjusted Amounts Effective January 1, 2016	$	1,700	$	735,020

a. Cost of Capital. As previously described (see Paragraph 6 above). This adjustment reduces the overall revenue requirement by $2.438 million.

b. Revise 2015 Capital Additions. Reflects adjustments to updated information related to 2015 capital additions, including the delay in completion of the Nine Mile Hydroelectric Capital Project from 2015 to 2016 and the impact on depreciation expense, as well as accumulated depreciation (A/D) and accumulated deferred federal income taxes (ADFIT). This adjustment reduces the overall revenue requirement by $3.345 million and reduces rate base by $16.125 million.

c. Remove 2016 Capital Additions. Reflects the removal of proposed 2016 capital additions) and related depreciation expense, as well as the impact on A/D and ADFIT. This adjustment reduces the overall revenue requirement by $548,000 and increases rate base by $1.789 million[2].

d. Revise Deferred Debits and Credits. Revises the deferred debits and credits regulatory balances to reflect balances as of December 2015, rather than the 2016 balances as proposed by the Company. This adjustment increases the overall revenue requirement by $52,000 and increases rate base by $131,000.

e. Remove 2016 Expenses. These adjustments remove 2016 incremental expenses or offsets as proposed by the Company, including:

    i. Insurance Expense – This adjustment reduces the overall revenue requirement by $62,000, by removing 2016 incremental expenses.

    ii. Information Services & Technology – This adjustment reduces the overall revenue requirement by $521,000, by removing 2016 incremental expenses.

    iii. Non-Executive Labor – This adjustment reduces the overall revenue requirement by $385,000, by removing 2016 incremental expenses.

    iv. O&M Offsets – This adjustment increases the overall revenue requirement by $212,000, by removing 2016 offsets related to 2016 capital additions removed in sub-paragraph c. above.

[2] Removing the impact of 2016 capital additions, as well as removing the impact on accumulated depreciation and accumulated deferred federal income taxes on total net plant during 2016, has the result of increasing overall net rate base.

f. Update 2015 Employee Benefit Costs. Reflects updated information related to 2015 incremental pension and medical costs. This adjustment increases the overall revenue requirement by $481,000.

g. Adjust Injuries and Damages Expense. Revises the six-year average of injuries and damages. This adjustment decreases the overall revenue requirement by $8,000.

h. Remove Officer Incentives and Restate Non-Officer Incentives. Reflects the removal of officer incentives and adjusts the non-officer incentive six-year average from a 102% to a 100% payout. This adjustment decreases the overall revenue requirement by $100,000.

i. Include Four-Year Amortization of 2015 Project Compass Deferral. Revises the two-year amortization of the 2015 Project Compass Deferral, as proposed by the Company, to a four-year amortization. This adjustment decreases the overall revenue requirement by $669,000.

j. Include Four-Year Amortization of Lake Spokane Deferral. Revises the two-year amortization of the Lake Spokane Deferral, as proposed by the Company, to a four-year amortization. This adjustment decreases the overall revenue requirement by $119,000.

k. Include Palouse Wind in PCA. Reflects the removal of the Palouse Wind Power Purchase Agreement net expenses from base power supply expense. This adjustment decreases the overall revenue requirement by $3.5 million. See Paragraph 8 below for further information related to Palouse Wind.

l. Miscellaneous A&G Adjustments. Reflects the removal of net administrative and general (A&G) expenses related to: 1) removing an additional 40% of Idaho electric Director and Officer insurance expense ($114,000); 2) removing legal expenses allocated to Idaho electric in error ($5,000); 3) removing 2/3 of environmental cleanup expenses incurred in 2014 ($322,000); 4) removing miscellaneous expenses as agreed to ($65,000); and removing additional Board of Director expenses included in 2014 ($74,000). This adjustment decreases the overall revenue requirement by $580,000.

8. Palouse Wind. The Parties agree that, for purposes of this case, the recovery of costs related to the Palouse Wind Power Purchase Agreement ("PPA") will continue to be included in the PCA, subject to the current sharing (90% customer, 10% Company).

B. NATURAL GAS

9. Overview of Natural Gas Revenue Requirement. Below is a summary table and descriptions of the Natural Gas revenue requirement components agreed to by the Parties:

SUMMARY TABLE OF ADJUSTMENTS TO NATURAL GAS REVENUE REQUIREMENT
EFFECTIVE JANUARY 1, 2016
(000s of Dollars)

		Revenue Requirement	Rate Base
	Amount as Filed:	$ 3,205	$ 127,498
	Adjustments:		
a.)	Cost of Capital	$ (415)	
b.)	Revise 2015 Capital Additions	$ 440	$ 3,758
c.)	Remove 2016 Capital Additions	$ (76)	$ 669
d.)	Revise Deferred Debits and Credits to Reflect 2015 Balances	$ (3)	
e.)	Remove 2016 Expenses		
i.	Insurance Expense	$ (16)	
ii.	Information Services & Technology	$ (132)	
iii.	Non-Executive Labor	$ (185)	
f.)	Update 2015 Employee Benefit Costs	$ 129	
g.)	Adjust Injuries and Damages Expense	$ (126)	
h.)	Remove Officer Incentives and Restate Non-Officer Incentives	$ (25)	
i.)	Include Four-Year Amortization of 2015 Project Compass Deferral	$ (168)	
j.)	Miscellaneous A&G Adjustments: Director & Officer Insurance, Board of Director Expenses, Reallocation of Legal Expenses, and Removal of Miscellaneous Agreed-To Expenses	$ (128)	
	Adjusted Amounts Effective January 1, 2016	$ 2,500	$ 131,925

a. Cost of Capital. As previously described (see Paragraph 6 above). This adjustment reduces the overall revenue requirement by $415,000.

b. Revise 2015 Capital Additions. Reflects adjustments to updated information related to 2015 capital additions and the impact on depreciation expense, as well as A/D and ADFIT. This adjustment increases the overall revenue requirement by $440,000 and increases rate base by $3.758 million.

c. Remove 2016 Capital Additions. Reflects the removal of proposed 2016 capital additions and related depreciation expense, as well as the impact on A/D and ADFIT. This adjustment reduces the overall revenue requirement by $76,000 and increases rate base by $669,000[3].

d. Revise Deferred Debits and Credits. Revises the deferred debits and credits regulatory amortization expense to reflect 2015 expenses, rather than 2016 expense levels as proposed by the Company. This adjustment decreases the overall revenue requirement by $3,000.

e. Remove 2016 Expenses. These adjustments remove 2016 incremental expenses as proposed by the Company, including:

    i. Insurance Expense – This adjustment reduces the overall revenue requirement by $16,000, by removing 2016 incremental expenses.

    ii. Information Services & Technology – This adjustment reduces the overall revenue requirement by $132,000, by removing 2016 incremental expenses.

    iii. Non-Executive Labor – This adjustment reduces the overall revenue requirement by $185,000, by removing 2016 incremental expenses.

[3] *id*

f. Update 2015 Employee Benefit Costs. Reflects updated information related to 2015 incremental pension and medical costs. This adjustment increases the overall revenue requirement by $129,000.

g. Adjust Injuries and Damages Expense. Revises the six-year average of injuries and damages. This adjustment decreases the overall revenue requirement by $126,000.

h. Remove Officer Incentives and Restate Non-Officer Incentives. Reflects the removal of officer incentives and adjusts the non-officer incentive six-year average from a 102% to a 100% payout. This adjustment decreases the overall revenue requirement by $25,000.

i. Include Four-Year Amortization of 2015 Project Compass Deferral. Revises the two-year amortization of the 2015 Project Compass Deferral, as proposed by the Company, to a four-year amortization. This adjustment decreases the overall revenue requirement by $168,000.

j. Miscellaneous A&G Adjustments. Reflects the removal of net administrative and general (A&G) expenses related to: 1) removing an additional 40% of Idaho Director and Officer insurance expense ($29,000); 2) removing legal expenses allocated to Idaho natural gas in error ($1,000); 3) removing miscellaneous expenses as agreed to ($79,000); and removing additional Board of Director expenses included in 2014 ($19,000). This adjustment decreases the overall revenue requirement by $128,000.

C. OTHER SETTLEMENT COMPONENTS

12. 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, 2016

settlement revenue requirement for purposes of the monthly PCA mechanism calculations are detailed in Appendix A.

13. Fixed Cost Adjustment Mechanism. The Parties agree that Avista will implement electric and natural gas Fixed Cost Adjustment mechanisms ("FCA"). The electric and natural gas FCAs are illustrated in Appendices B and C and will commence concurrently with the natural gas and electric rate changes January 1, 2016. Below are the key components of the mechanisms:

A. FCA Mechanisms Term. The Parties agree to an initial FCA term of 3 years, with a review of how the mechanisms have functioned conducted by Avista, Staff, and other interested parties following the end of the second full-year. Avista may seek to extend the term of the mechanism prior to its expiration.

B. Rate Groups. There will be two rate groups established for both the electric FCA and natural gas FCA:

Electric Customer Rate Groups:

1. Residential – Schedule 1
2. Commercial – Schedules 11, 12, 21, 22, 31, 32

Natural Gas Rate Groups:

1. Residential – Schedule 101
2. Commercial – Schedules 111 and 112

C. Existing Customers and New Customers. The Parties have agreed that revenue related to certain items discussed below would not be included in the FCA for new customers. The result is that the Fixed Cost Adjustment Revenue-Per-Customer for new customers will be less than the Fixed Cost Adjustment Revenue-Per-Customer for existing customers. For new electric customers added after the test period, recovery of incremental revenue related to fixed production and transmission costs would be excluded from the electric FCA. For new natural gas customers added after the test period, recovery of incremental revenue related to fixed production and underground storage facility costs would be excluded. These modifications are included in Appendices B and C to the Stipulation.

D. Quarterly Reporting. Avista will file, within 45 days of the end of each quarter, a report detailing the FCA activity by month. The reporting will also include information related to the deferrals by rate group, what the deferrals would have been if tracked by rate schedule, use and revenue-per-customer for existing and new customers, and other summary financial information. Avista will provide such other information as may be reasonably requested, from time to time, in the future quarterly reports.

E. Annual Filings. On or before July 1, the Company will file a proposed rate adjustment surcharge or rebate based on the amount of deferred revenue recorded for the prior January through December time period. The rate adjustment would be calculated separately for each Rate Group, with the applicable surcharge or rebate recovered from each group on a uniform cents per kWh or per therm basis. The proposed tariff (Schedule 75 for electric, Schedule 175 for natural gas) included with that filing would include a rate adjustment that recovers/rebates the appropriate deferred revenue amount over a twelve-month period effective on October 1 for electric (to match with Power Cost Adjustment and Residential Exchange annual rate adjustments time period) and November 1st for natural gas (to match with the annual Purchased Gas Cost Adjustment rate adjustment time period). The deferred revenue amount approved for recovery or rebate would be transferred to a balancing account and the revenue surcharged or rebated during the period would reduce the deferred revenue in the balancing account. After determining the amount of deferred revenue that can be recovered through a surcharge (or refunded through a rebate) by Rate Group, the proposed rates under Schedules 75 and 175 would be determined by dividing the deferred revenue to be recovered by Rate Group by the estimated kWh sales (Electric FCA) or therm sales (Natural Gas FCA) for each Rate Group during the twelve-month recovery period. Any deferred revenue remaining in the balancing account at the end of the amortization period would be added to the new revenue deferrals to determine the amount of the proposed surcharge/rebate for the following year.

F. Interest. Interest will be accrued on the unamortized balance in the FCA balancing accounts at the Customer Deposit Rate.[4]

G. Accounting. Avista will record the deferral in account 186 – Miscellaneous Deferred Debits. The amount approved for recovery or rebate would then be transferred into a Regulatory Asset or Regulatory Liability account for amortization. On the income statement, the Company would record both the deferred revenue and the amortization of the deferred revenue through Account 456 (Other Electric Revenue), or Account 495 (Other Gas Revenue), in separate sub-accounts. The Company would file quarterly reports with the Commission showing pertinent information regarding the status of the current deferral. This report would include a spreadsheet showing the monthly revenue deferral calculation for each month of the deferral period (January - December), as well as the current and historical monthly balance in the deferral account.

[4] Based on Order No. 33187 in Case No. GNR-U-14-12, the deposit rate for 2015 is 1.0%. The rate is updated annually.

H. <u>3% Rate Increase Cap</u>. An FCA surcharge, by rate group, cannot exceed a 3% annual rate adjustment, and any unrecovered balances will be carried forward to future years for recovery. There is no limit to the level of the FCA rebate.

D. COST OF SERVICE/RATE SPREAD/RATE DESIGN

14. <u>Cost of Service</u>. For electric operations, the Company prepared an analysis using a system load factor peak credit method of classifying production costs, allocating 100% of transmission costs to demand, and allocating transmission costs on a twelve-month basis. For settlement purposes, the Parties agreed to use a pro-rata allocation based on the Company's proposed 25% move towards unity for purposes of spreading the revised electric revenue requirement, while not agreeing on any particular cost of service methodology.

For natural gas operations, the Company proposed that all rate schedules be moved approximately 33% towards unity. For settlement purposes, the Parties agreed to use a pro-rata allocation of the Company's natural gas rate spread percentages from its original filing for purposes of spreading the revised revenue requirement.

15. <u>Rate Spread/Rate Design (Base Rate Changes)</u>.

(a) As indicated above, the Parties agreed that the increase in base revenues would be spread to all electric and natural gas rate schedules on a pro-rata allocation of the Company's rate spread percentages from its original filing.

(b) <u>Electric Rate Design</u>. The Parties agree that the revenue requirement for each electric service schedule will be applied as a uniform percentage increase to each volumetric energy rate as shown in Appendix D. Fixed monthly charges and fixed and variable demand charges will remain unchanged. The electric Residential Basic Charge

(Schedule 1) will remain at $5.25 per month. Finally, the street and area light codes and calculation methodology described in Mr. Ehrbar's direct testimony will be adopted.

(c) Natural Gas Rate Design. The Parties agree that the Basic Charge for Schedule 101 will increase by $1.00 per month, from $4.25 to $5.25. The revenue requirement for all other natural gas service schedules will be applied as a uniform percentage increase to each volumetric energy rate as shown in Appendix D.

(d) Appendix D provides a summary of the current and revised rates and charges (as per the Settlement) for electric and natural gas service.

16. Electric Rebate Extension. Through rate Schedule 97, customers are receiving a rebate of $0.00091 per kWh for 2015 (approximately $2.8 million). This rebate rate was first approved in the Company's 2012 general rate case, Case No. AVU-E-12-08. As a part of the settlement stipulation approved by the Commission in Case No. AVU-E-14-05, the rebate rate was extended through December 31, 2015 using the 2013 electric earnings sharing deferral. For 2014, Avista deferred approximately $5.6 million under the electric earnings sharing. The Parties agree to use the $5.6 million deferral balance from 2014 and extend the Schedule 97 rebate rate for 2016 and 2017[5]. This information is shown on Appendix E.

17. Natural Gas Rebate Extension. Through rate Schedule 197, customers are receiving a rebate of $0.01489 per therm through December 31, 2015 (approximately $1.2 million). This rebate rate was first approved in the Company's 2012 general rate case, Case No. AVU-G-12-07. As a part of the settlement stipulation approved by the Commission in Case No. AVU-G-14-01, the rebate rate was extended for 2015 using the 2013 natural gas earnings sharing deferral, as well as the Schedule 191 Natural Gas Energy Efficiency funding balance. For 2014, Avista deferred approximately $0.2 million under the natural gas earnings sharing. The Company is

[5] The electric and natural gas earnings sharing is in place for the 2013-2015 rate plan.

proposing to use the $0.2 million natural gas deferral balance from 2014 to partially offset the expiration of the $1.2 million rebate that will occur on January 1, 2016. This information is shown on Appendix E.

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

Rate Schedule	**Increase in Base Rates**	**Increase in Billing Rates**
Residential Schedule 1	0.9%	0.9%
General Service Schedules 11/12	0.5%	0.5%
Large General Service Schedules 21/22	0.6%	0.6%
Extra Large General Service Schedule 25	0.6%	0.6%
Clearwater Paper Schedule 25P	0.4%	0.4%
Pumping Service Schedules 31/32	0.7%	0.7%
Street & Area Lights Schedules 41-48	0.8%	0.8%
Overall	0.7%	0.7%

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

Rate Schedule	**Increase in Base Rates**	**Increase in Billing Rates**	**Billing Increase Net of New & Expiring Rebate**
General Service Schedule 101	7.7%	4.1%	5.3%
Large General Service Schedules 111/112	3.7%	1.5%	3.1%
Interrupt. Sales Service Schedules 131/132	7.5%	2.7%	4.8%
Transportation Service Schedule 146*	5.2%	5.2%	3.1%
Overall	6.9%	3.5%	4.8%

* *excludes commodity and interstate pipeline transportation costs*

20. Customer Service-Related Issues.

(a) Low-Income Usage Data. The Company and interested parties will meet and confer prior to the Company's next general rate case in an effort to identify low income customers served by the Company, quantify the number of customers so identified, and determine those customers' usage patterns. An initial meeting shall occur no later than June 30, 2016, with follow-up meetings to occur as the attendees may deem appropriate.

(b) Collaboration on Low-Income Weatherization. The Company and interested parties will meet and confer prior to the Company's next general rate filing in order to assess the Low Income Weatherization and Low Income Energy Conservation Education Programs and discuss appropriate levels of cost-effective, low-income weatherization funding in the future. An initial meeting shall occur no later than June 30, 2016, with follow-up meetings to occur as the attendees may deem appropriate.

IV. OTHER GENERAL PROVISIONS

21. The Parties agree that this Stipulation represents a compromise of the positions of the 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 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.

22. The Parties submit this Stipulation to the Commission and recommend approval in its entirety pursuant to RP 274. Parties shall support this Stipulation before the Commission, and no 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 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 Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

23. If the Commission rejects any part or all of this Stipulation or imposes any additional material conditions on approval of this Stipulation, each 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 Party shall be bound or prejudiced by the terms of this Stipulation, and each 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 Parties immediately will request the prompt reconvening of a prehearing conference for purposes of establishing a procedural schedule for the completion of the case. The Parties agree to cooperate in development of a schedule that concludes the proceeding on the earliest possible date, taking into account the needs of the Parties in participating in hearings and preparing testimony and briefs.

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

25. No 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 Party unless such rights are expressly waived herein. Execution of this Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory or principle of regulation or cost recovery. No 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.

26. The obligations of the 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.

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

DATED this 16th day of October, 2015.

Avista Corporation	Idaho Public Utilities Commission Staff
By: ______	By: ______
David J. Meyer Attorney for Avista Corporation	Karl Klein Brandon Karpen Deputy Attorneys General
Clearwater Paper Corporation	Idaho Forest Group
By: ______	By: ______
Peter Richardson Attorney for Clearwater Paper	Dean J. Miller Attorney for Idaho Forest Group LLC
Idaho Conservation League	Snake River Alliance
By: ______	By: ______
Benjamin J. Otto Attorney for ICL	Kelsey Nunez Attorney for Snake River Alliance

or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

26. The obligations of the 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.

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

DATED this 16th day of October, 2015.

Avista Corporation

By:________________________
David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

By: Karl Klein
Karl Klein
Brandon Karpen
Deputy Attorneys General

Clearwater Paper Corporation

By:________________________
Peter Richardson
Attorney for Clearwater Paper

Idaho Forest Group

By:________________________
Dean J. Miller
Attorney for Idaho Forest Group LLC

Idaho Conservation League

By:________________________
Benjamin J. Otto
Attorney for ICL

Snake River Alliance

By:________________________
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By:______________________________
David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

By:______________________________
Karl Klein
Brandon Karpen
Deputy Attorneys General

Clearwater Paper Corporation

By: Peter J. Richardson
Peter Richardson 10/6/05
Attorney for Clearwater Paper

Idaho Forest Group

By:______________________________
Dean J. Miller
Attorney for Idaho Forest Group LLC

Idaho Conservation League

By:______________________________
Benjamin J. Otto
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Snake River Alliance

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Karl Klein
Brandon Karpen
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Clearwater Paper Corporation

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Peter Richardson
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David J. Meyer
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Idaho Public Utilities Commission Staff

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DATED this 15 day of October, 2015.

Avista Corporation	Idaho Public Utilities Commission Staff
By:__________	By:__________
David J. Meyer Attorney for Avista Corporation	Karl Klein Brandon Karpen Deputy Attorneys General
Clearwater Paper Corporation	Idaho Forest Group
By:__________	By:__________
Peter Richardson Attorney for Clearwater Paper	Dean J. Miller Attorney for Idaho Forest Group LLC
Idaho Conservation League	Snake River Alliance
By:__________	By: Kelsey Nunez
Benjamin J. Otto Attorney for ICL	Kelsey Nunez Attorney for ICL

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Avista Corporation

By:________________________
David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

By:________________________
Karl Klein
Brandon Karpen
Deputy Attorneys General

Clearwater Paper Corporation

By:________________________
Peter Richardson
Attorney for Clearwater Paper

Idaho Forest Group

By:________________________
Dean J. Miller
Attorney for Idaho Forest Group LLC

Idaho Conservation League

By:________________________
Benjamin J. Otto
Attorney for ICL

Snake River Alliance

By:________________________
Kelsey Nunez
Attorney for Snake River Alliance

Community Action Partnership Association of Idaho

By:________________________
Brad Purdy
Attorney for CAPAI

Avista Corp
January - December
PCA Authorized Expense and Retail Sales
January 2014 - December 2014 Historic 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	$111,159,298	$12,181,272	$11,404,620	$9,963,402	$8,809,523	$6,740,588	$6,706,571	$7,374,163	$8,380,370	$7,222,858	$8,051,573	$11,904,606	$12,459,755
Account 501 - Thermal Fuel	$30,320,175	$2,775,328	$2,612,937	$2,819,359	$2,265,736	$2,033,267	$1,704,765	$2,520,233	$2,715,171	$2,695,525	$2,799,957	$2,749,116	$2,837,780
Account 547 - Natural Gas Fuel	$72,676,167	$8,051,247	$7,027,863	$6,561,435	$4,389,417	$2,748,054	$2,201,271	$4,954,115	$6,610,188	$8,780,714	$7,048,073	$7,677,634	$8,666,178
Account 447 - Sale for Resale	$69,779,554	$5,920,060	$4,854,311	$5,165,161	$8,564,608	$8,515,727	$4,972,680	$6,095,109	$4,125,900	$4,959,989	$4,807,644	$6,125,690	$6,682,687
Power Supply Expense	$147,365,088	$17,087,798	$16,191,109	$13,979,034	$8,890,069	$5,006,180	$5,639,927	$8,753,401	$13,559,807	$11,719,109	$13,091,960	$16,205,666	$17,281,025
Transmission Expense	$16,903,007	$1,462,738	$1,372,808	$1,509,572	$1,336,193	$1,509,317	$1,348,174	$1,362,491	$1,404,564	$1,467,208	$1,430,341	$1,420,003	$1,431,599
Transmission Revenue	$16,741,874	$1,405,733	$1,166,326	$1,222,888	$1,264,428	$1,579,616	$1,659,588	$1,679,720	$1,535,727	$1,376,848	$1,338,310	$1,287,827	$1,224,863
REC Revenue	$2,788,020	$236,220	$220,980	$236,220	$228,283	$236,220	$228,600	$236,220	$236,220	$228,600	$236,538	$228,600	$236,220
Exclude Palouse Wind (3)	$9,858,317	$821,526	$821,526	$821,526	$821,526	$821,526	$821,526	$821,526	$821,526	$821,526	$821,526	$821,526	$821,526
PCA Authorized System Net Expense	$134,899,183	$16,057,057	$16,356,083	$13,207,972	$7,912,026	$3,738,135	$4,276,366	$7,378,425	$12,370,898	$10,759,343	$12,125,926	$15,287,916	$16,430,015

PCA Authorized Idaho Retail Sales (2)

	Total	January	February	March	April	May	June	July	August	September	October	November	December
Total Retail Sales, MWh	3,072,989	299,392	263,781	268,236	243,401	234,951	228,959	249,355	246,161	197,872	249,356	287,858	303,659
Load Change Adjustment Rate	$22.88 /MWh												

1) Multiply system numbers by 35.29% to determine Idaho share.
2) 2014 weather normalized Idaho retail sales.
3) The purchased power and sales for resale values are as originally filed which included the impact of the Palouse Wind Contract. This system adjustment results in an Idaho revenue requirement decrease of $3,500,000 as agreed to in the Settlement Stipulation (see Page 6, paragraph 7k)

Avista Utilities
Electric Fixed Cost Adjustment Mechanism (Idaho)
Development of Fixed Cost Adjustment Revenue by Rate Schedule - Electric
AVU-E-15-05 Rates Effective 1/1/2016

			TOTAL	RESIDENTIAL SCHEDULE 1	GENERAL SVC. SCH 11,12	L.G. GEN. SVC. SCH. 21,22	PUMPING SCH. 31, 32	OTHER SERVICE SCHEDULES
1	Total Normalized Test Year Revenue		$ 244,972,000	$ 104,939,000	$ 36,296,000	$ 54,359,000	$ 5,278,000	$ 44,100,000
2	Proposed Revenue Increase		$ 1,700,000	$ 944,000	$ 172,000	$ 330,000	$ 37,000	$ 217,000
3	Total Rate Revenue (January 1, 2016)		$ 246,672,000	$ 105,883,000	$ 36,468,000	$ 54,689,000	$ 5,315,000	$ 44,317,000
4	Normalized kWhs (Test Year)		3,072,989,455	1,147,394,729	362,993,070	698,803,658	58,985,861	804,812,137
5	Load Change Adjustment Rate (Ln 14)		$ 0.02281	$ 0.02281	$ 0.02281	$ 0.02281	$ 0.02281	
6	Variable Power Supply Revenue (Ln 4 * Ln 5)		$ 70,094,889	$ 26,172,074	$ 8,279,872	$ 15,939,711	$ 1,345,467	$ 18,357,765
6A	Fixed Production and Transmission Rate per kWh	(New Customers Only)		$ 0.02421	$ 0.02998	$ 0.02487	$ 0.01764	
6B	Fixed Production and Transmission Revenue	(New Customers Only)	$ 72,964,132	$ 27,782,956	$ 10,882,867	$ 17,379,007	$ 1,040,621	$ 15,878,682
7	Subtotal (Ln 3 - Ln 6)	(Test Year Customers)	$ 150,617,875	$ 79,710,926	$ 28,188,128	$ 38,749,289	$ 3,969,533	Excluded From Fixed Cost Adjustment
7A	Subtotal (Ln 3 - Ln 6 - Ln 6B)	(New Customers)	$ 93,532,425	$ 51,927,970	$ 17,305,262	$ 21,370,282	$ 2,928,912	
8	Customer Bills (Test Year)		1,511,967	1,235,079	246,375	13,816	16,697	
9	Proposed Fixed Charges			$ 5.25	$ 10.00	$ 350.00	$ 8.00	
10	Fixed Charge Revenue (Ln 8 * Ln 9)		$ 13,917,091	$ 6,484,165	$ 2,463,750	$ 4,835,600	$ 133,576	
11	Fixed Cost Adjustment Revenue (Ln 7 - Ln 10)	(Test Year Customers)	$ 136,700,785	$ 73,226,761	$ 25,724,378	$ 33,913,689	$ 3,835,957	
11A	Fixed Cost Adjustment Revenue (Ln 7A - Ln 10)	(New Customers)	$ 79,615,335	$ 45,443,805	$ 14,841,512	$ 16,534,682	$ 2,795,336	
12	Load Change Adjustment Rate		$0.02268					
13	Gross Up Factor for Revenue Related Exp		100.58%					
14	Grossed Up Load Change Adjustment Rate		$0.02281					

		Residential	Non-Residential Group
15	Average Number of Customers (Line 8 / 12)	102,923	23,074
16	Annual kWh	1,147,394,729	1,120,782,589
17	Basic Charge Revenues	6,484,165	7,432,926
18	Customer Bills	1,235,079	276,888
19	Average Basic Charge	$5.25	$26.84

Avista Utilities
Electric Fixed Cost Adjustment Mechanism (Idaho)
Development of Annual Fixed Cost Adjustment Revenue Per Customer - Electric
AVU-E-15-05 Rates Effective 1/1/2016

Line No.		Source		Residential		Non-Residential Schedules*
	(a)	(b)		(c)		(d)
	Existing Customer FCA					
1	Fixed Cost Adjustment Revenue	Page 1	$	73,226,761	$	63,474,023
2	Test Year Number of Customers	Revenue Data		102,923		23,074
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$	711.47	$	2,750.89
	New Customer FCA					
1	Fixed Cost Adjustment Revenue	Page 1	$	45,443,805	$	34,171,529
2	Test Year Number of Customers	Revenue Data		102,923		23,074
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$	441.53	$	1,480.95

* 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-15-05 Rates Effective 1/1/2016

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	131,964,665	109,539,257	110,545,005	88,096,696	80,885,105	71,636,706	80,440,301	81,351,035	56,294,186	81,375,471	110,559,925	144,706,397	1,147,394,729
4	- % of Annual Total	% of Total	11.50%	9.55%	9.63%	7.68%	7.05%	6.24%	7.01%	7.09%	4.91%	7.09%	9.64%	12.61%	100.00%
5															
6	*Non-Residential**														
7	- Weather-Normalized kWh Sales	Monthly Test Year	98,121,978	94,055,795	92,426,541	91,556,747	88,862,061	93,706,509	100,267,497	96,269,825	79,553,868	93,095,055	99,284,871	93,586,642	1,120,782,589
8	- % of Annual Total	% of Total	8.75%	8.39%	8.25%	8.17%	7.93%	8.36%	8.95%	8.59%	7.10%	8.31%	8.86%	8.35%	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													$ 711.47
15	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(4) x (14)	$ 81.83	$ 67.92	$ 68.55	$ 54.63	$ 50.15	$ 44.42	$ 59.89	$ 50.41	$ 34.91	$ 50.66	$ 68.56	$ 92.73	$ 711.47
16															
17	*Non-Residential**														
18	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 2,750.89
19	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(8) x (18)	$ 240.40	$ 230.84	$ 226.86	$ 224.72	$ 218.11	$ 230.00	$ 246.10	$ 236.29	$ 195.26	$ 228.50	$ 243.00	$ 229.70	$ 2,750.89
20															
21															
22	*For New Customers*														
23	*Residential*														
24	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 441.52
25	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(4) x (24)	$ 50.78	$ 42.15	$ 42.54	$ 33.90	$ 31.13	$ 27.57	$ 30.95	$ 31.30	$ 21.66	$ 31.31	$ 42.54	$ 55.68	$ 441.52
26															
27	*Non-Residential**														
28	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 1,480.95
29	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(8) x (28)	$ 129.65	$ 124.27	$ 122.13	$ 120.98	$ 117.42	$ 123.82	$ 132.49	$ 127.21	$ 105.12	$ 123.02	$ 131.19	$ 123.66	$ 1,480.95

* Schedules 11, 12, 21, 22, 25 and 25P

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Normalized Test Year Usage													
Residential Schedule 001	131,964,665	109,539,257	110,545,005	88,096,696	80,885,105	71,636,706	80,440,301	81,351,035	56,294,186	81,375,471	110,559,925	144,706,397	1,147,394,729
General Svc Schedule 011/012	35,351,987	32,262,528	31,553,048	28,858,672	27,817,091	27,385,249	29,030,953	29,840,817	24,081,839	25,279,735	31,586,724	35,954,446	362,993,070
Large Gen Svc Schedule 021/022	58,575,013	58,550,694	57,441,521	59,071,831	56,830,483	59,019,058	62,553,510	57,615,436	49,823,152	59,316,421	64,367,922	54,738,637	698,903,658
Extra Large Gen Schedule 25	27,813,646	25,099,870	26,556,305	25,710,417	25,611,341	25,172,498	27,073,330	26,306,697	26,112,174	27,634,477	25,949,026	26,937,437	316,177,218
Extra Large Gen Schedule 25P	40,331,970	33,911,330	37,547,150	36,877,750	38,462,030	37,286,280	40,419,880	41,072,430	34,776,110	46,117,740	50,947,670	37,296,570	475,046,910
Pumping Schedule 31/32	3,694,978	3,337,773	3,431,972	3,626,244	4,214,487	7,102,231	8,693,034	8,813,582	5,648,877	4,998,890	2,530,225	2,893,559	58,985,861
Street and Area Lights	1,159,357	1,159,902	1,160,675	1,159,682	1,160,110	1,155,654	1,153,629	961,083	1,135,821	1,133,107	1,116,300	1,131,689	13,588,009
Total Normalized Test Year Usage	299,391,616	263,761,334	265,235,676	243,401,292	234,980,647	228,958,647	249,354,637	246,161,070	197,872,159	249,355,850	287,957,792	303,658,735	3,072,989,455

Appendix B

Sumcost | AVISTA UTILITIES | Idaho Jurisdiction
Scenario: AVU-E-15-05 Settlement Case | Revenue to Cost by Functional Component Summary | Electric Utility | 01/01/16
Load Factor Peak Credit | For the Twelve Months Ended December 31, 2014
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	116,381,261	43,834,300	15,151,702	26,940,838	11,113,743	16,942,287	2,009,519	388,872
2	Transmission	25,875,828	9,718,351	3,934,119	6,214,281	2,249,812	3,361,999	364,384	42,983
3	Distribution	61,351,755	29,831,665	10,779,769	14,076,269	1,699,164	428,169	2,077,164	2,450,555
4	Common	41,363,056	21,554,684	6,430,410	7,127,612	2,099,282	2,735,545	826,833	598,589
5	Total Current Rate Revenue	244,972,000	104,939,000	36,296,000	54,359,000	17,152,000	23,458,000	5,278,005	3,490,000
	Expressed as $/kWh								
6	Production	$0.03787	$0.03820	$0.04174	$0.03855	$0.03515	$0.03566	$0.03407	$0.02862
7	Transmission	$0.00942	$0.00847	$0.01084	$0.00889	$0.00712	$0.00706	$0.00618	$0.00316
8	Distribution	$0.01996	$0.02600	$0.02970	$0.02014	$0.00537	$0.00090	$0.03521	$0.18101
9	Common	$0.01346	$0.01879	$0.01771	$0.01020	$0.00661	$0.00576	$0.01402	$0.04405
10	Total Current Melded Rates	$0.07972	$0.09146	$0.09999	$0.07779	$0.05425	$0.04938	$0.08948	$0.25684
	Functional Cost Components at Uniform Current Return								
11	Production	115,229,071	46,239,371	14,149,565	26,039,428	10,965,434	15,396,018	1,984,232	395,025
12	Transmission	25,531,066	11,315,196	3,299,985	6,714,435	2,170,174	2,634,191	352,205	44,880
13	Distribution	62,527,167	33,650,930	9,307,333	13,023,320	1,642,916	331,779	2,015,160	2,545,729
14	Common	41,684,695	23,112,215	5,880,131	6,810,316	2,050,518	2,400,469	812,634	612,411
15	Total Uniform Current Cost	244,972,000	114,327,712	32,637,014	51,653,498	16,829,043	20,762,457	5,164,232	3,598,045
	Expressed as $/kWh								
16	Production	$0.03750	$0.04020	$0.03898	$0.03735	$0.03468	$0.03241	$0.03364	$0.02907
17	Transmission	$0.00831	$0.00980	$0.00909	$0.00818	$0.00686	$0.00555	$0.00597	$0.00330
18	Distribution	$0.02035	$0.02934	$0.02564	$0.01854	$0.00520	$0.00070	$0.03416	$0.18735
19	Common	$0.01356	$0.02014	$0.01620	$0.00975	$0.00649	$0.00505	$0.01378	$0.04507
20	Total Current Uniform Melded Rates	$0.07972	$0.09964	$0.08991	$0.07392	$0.05323	$0.04371	$0.08755	$0.26480
21	**Revenue to Cost Ratio at Current Rates**	1.00	0.92	1.11	1.05	1.02	1.13	1.02	0.97
	Functional Cost Components at Proposed Return by Schedule								
22	Production	116,679,049	44,076,173	15,198,811	27,043,470	11,161,961	16,990,473	2,017,744	390,467
23	Transmission	26,179,972	9,878,907	3,961,927	6,275,248	2,275,703	3,374,367	368,344	43,475
24	Distribution	61,998,205	30,216,691	10,848,984	14,204,700	1,717,451	431,172	2,097,329	2,481,897
25	Common	41,814,774	21,711,289	6,456,278	7,165,582	2,101,885	2,745,987	831,583	602,171
26	Total Proposed Rate Revenue	246,672,000	105,883,000	36,468,000	54,689,000	17,257,000	23,542,000	5,316,000	3,518,000
	Expressed as $/kWh								
27	**Production**	**$0.03803**	**$0.03841**	**$0.04187**	**$0.03870**	**$0.03530**	**$0.03577**	**$0.03421**	**$0.02874**
28	**Transmission**	**$0.00852**	**$0.00861**	**$0.01092**	**$0.00898**	**$0.00720**	**$0.00710**	**$0.00624**	**$0.00320**
29	Distribution	$0.02018	$0.02634	$0.02989	$0.02033	$0.00543	$0.00091	$0.03556	$0.18265
30	Common	$0.01354	$0.01892	$0.01779	$0.01025	$0.00665	$0.00578	$0.01410	$0.04432
31	Total Proposed Melded Rates	$0.08027	$0.09228	$0.10046	$0.07826	$0.05468	$0.04956	$0.09011	$0.25890
	Functional Cost Components at Uniform Requested Return								
32	Production	115,740,980	46,444,790	14,212,425	28,215,374	11,014,149	15,464,415	1,990,047	396,780
33	Transmission	25,838,799	11,451,581	3,339,761	5,783,313	2,196,331	2,665,941	356,451	45,421
34	Distribution	63,160,604	33,987,985	9,399,691	13,168,414	1,661,391	338,043	2,038,774	2,570,307
35	Common	41,931,617	23,245,244	5,914,647	6,859,212	2,063,251	2,415,291	817,618	616,354
36	Total Uniform Cost	246,672,000	115,129,600	32,866,573	52,026,313	16,935,122	20,881,690	5,203,891	3,628,861
	Expressed as $/kWh								
37	Production	$0.03766	$0.04048	$0.03915	$0.03751	$0.03484	$0.03256	$0.03379	$0.02920
38	Transmission	$0.00841	$0.00998	$0.00920	$0.00823	$0.00695	$0.00561	$0.00604	$0.00334
39	Distribution	$0.02055	$0.02962	$0.02589	$0.01884	$0.00525	$0.00071	$0.03453	$0.18916
40	Common	$0.01365	$0.02026	$0.01629	$0.00992	$0.00653	$0.00508	$0.01386	$0.04536
41	Total Uniform Melded Rates	$0.08027	$0.10034	$0.09064	$0.07445	$0.05355	$0.04396	$0.08822	$0.26706
42	**Revenue to Cost Ratio at Proposed Rates**	1.00	0.92	1.11	1.05	1.02	1.13	1.02	0.97
43	**Current Revenue to Proposed Cost Ratio**	0.99	0.91	1.10	1.04	1.01	1.12	1.01	0.96
44	**Target Revenue Increase**	1,700,000	10,190,000	(3,429,000)	(2,333,000)	(247,000)	(2,576,000)	(74,000)	139,000

Avista Utilities
Natural Gas Fixed Cost Adjustment Mechanism (Idaho)
Development of Fixed Cost Adjustment Revenue by Rate Schedule - Natural Gas
AVU-G-15-01 Rates Effective 1/1/2016

			TOTAL	GENERAL SERVICE SCHEDULE 101	LARGE GENERAL SERVICE SCH. 111/112	OTHER SERVICE SCHEDULES
1	Total Normalized Test Year Revenue		$ 36,274,000	$ 29,140,000	$ 6,625,000	$ 509,000
2	Proposed Revenue Increase		$ 2,500,000	$ 2,231,000	$ 246,000	$ 23,000
3	Total Base Rate Revenue (January 1, 2016)		$ 38,774,000	$ 31,371,000	$ 6,871,000	$ 532,000
4	Normalized Therms (Test Year)		119,606,640	55,714,011	22,947,786	40,944,843
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)		$ 0.02769	$ 0.03000	
6B	Fixed Production and Underground Storage Revenue	(New Customers Only)	$ 2,288,089	$ 1,542,686	$ 688,403	$ 57,000
7	Subtotal (Ln 3 - Ln 6)	(Test Year Customers)	$ 38,242,000	$ 31,371,000	$ 6,871,000	**Excluded From**
7A	Subtotal (Ln 3 - Ln 6 - Ln 6B)	(New Customers)	$ 36,010,911	$ 29,828,314	$ 6,182,597	**Fixed Cost**
						Adjustment
8	Customer Bills (Test Year)		925,130	908,483	16,647	
9	Proposed Fixed Charges			$ 5.25	$ 100.75	
10	Fixed Charge Revenue (Ln 8 * Ln 9)		$ 6,446,721	$ 4,769,536	$ 1,677,185	
11	Fixed Cost Adjustment Revenue (Ln 7 - Ln 10)	(Test Year Customers)	$ 31,795,279	$ 26,601,464	$ 5,193,815	
11A	Fixed Cost Adjustment Revenue (Ln 7A - Ln 10)	(New Customers)	$ 29,564,190	$ 25,058,778	$ 4,505,412	

		Residential	Non-Residential Group
12	Average Number of Customers (Line 8 / 12)	75,707	1,387
13	Annual kWh	55,714,011	22,947,786
14	Basic Charge Revenues	4,769,536	1,677,185
15	Customer Bills	908,483	16,647
16	Average Basic Charge	$5.25	$100.75

Avista Utilities
Natural Gas Fixed Cost Adjustment Mechanism (Idaho)
Development of Annual Fixed Cost Adjustment Revenue Per Customer - Natural Gas
AVU-G-15-01 Rates Effective 1/1/2016

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
	Existing Customer FCA			
1	Fixed Cost Adjustment Revenue	Page 1	$ 26,601,464	$ 5,193,815
2	Test Year Number of Customers	Revenue Data	75,707	1,387
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$ 351.37	$ 3,743.96
	New Customer FCA			
1	Fixed Cost Adjustment Revenue	Page 1	$ 25,058,778	$ 4,505,412
2	Test Year Number of Customers	Revenue Data	75,707	1,387
3	Fixed Cost Adjustment Revenue Per Customer	(1) / (2)	$ 331.00	$ 3,247.73

* 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-15-01 Rates Effective 1/1/2016

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 Therm Delivery Volume	Monthly Test Year	8,886,364	7,750,649	6,781,397	3,909,585	2,543,377	1,614,311	1,007,077	989,884	1,199,079	3,772,680	7,577,199	9,682,409	55,714,011
4	- % of Annual Total	% of Total	15.95%	13.91%	12.17%	7.02%	4.57%	2.90%	1.81%	1.78%	2.15%	6.77%	13.60%	17.38%	100.00%
5															
6	*Non-Residential Sales**														
7	- Weather-Normalized Therm Delivery Volume	Monthly Test Year	3,082,687	2,746,782	2,470,695	1,708,520	1,228,919	1,289,309	912,267	1,074,602	943,508	2,036,513	2,523,132	2,930,852	22,947,786
8	- % of Annual Total	% of Total	13.43%	11.97%	10.77%	7.45%	5.36%	5.62%	3.98%	4.68%	4.11%	8.87%	11.00%	12.77%	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													$ 351.37
15	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(4) x (14)	$ 56.04	$ 48.88	$ 42.77	$ 24.66	$ 16.06	$ 10.18	$ 6.35	$ 6.24	$ 7.55	$ 23.79	$ 47.79	$ 61.06	$ 351.37
16															
17	*Non-Residential Sales**														
18	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 3,743.96
19	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(8) x (18)	$ 502.94	$ 448.14	$ 403.10	$ 278.75	$ 200.50	$ 210.35	$ 148.84	$ 175.32	$ 153.93	$ 332.26	$ 411.65	$ 478.17	$ 3,743.96
20															
21															
22	*For New Customers*														
23	*Residential*														
24	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 331.00
25	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(4) x (24)	$ 52.79	$ 46.05	$ 40.29	$ 23.23	$ 15.11	$ 9.59	$ 5.98	$ 5.88	$ 7.12	$ 22.41	$ 45.02	$ 57.52	$ 331.00
26															
27	*Non-Residential Sales**														
28	- 2016 Fixed Cost Adj. Revenue per Customer	Page 2													$ 3,247.73
29	- 2016 Monthly Fixed Cost Adj. Revenue per Customer	(8) x (28)	$ 436.28	$ 388.74	$ 349.67	$ 241.89	$ 173.93	$ 182.47	$ 129.11	$ 152.09	$ 133.53	$ 288.22	$ 357.09	$ 414.79	$ 3,247.73

* Schedules 111 and 112.

Normalized Test Year Usage													
Small Service Schedule 101	8,886,364	7,750,649	6,781,397	3,909,585	2,543,377	1,614,311	1,007,077	989,884	1,199,079	3,772,680	7,577,199	9,682,409	55,714,011
Large Service Schedule 111/112	3,082,687	2,746,782	2,470,695	1,708,520	1,228,919	1,289,309	912,267	1,074,602	943,508	2,036,513	2,523,132	2,930,852	22,947,786
Interrupt Service Schedule 131/132	41,552	36,266	32,078	28,993	26,189	24,317	20,569	17,075	19,354	20,322	25,290	38,391	330,396
Transport Service Schedule 146	209,745	318,946	228,523	232,092	217,921	237,113	263,479	183,753	188,340	187,994	226,977	212,778	2,707,661
Special Contract Transport	4,512,199	3,771,463	3,260,898	2,822,028	3,267,902	3,261,964	2,482,523	2,694,459	2,463,229	2,553,860	2,965,846	4,050,415	37,906,786
Total Normalized Test Year Usage	16,732,547	14,624,106	12,573,591	8,701,218	7,284,308	6,427,014	4,685,915	4,959,775	4,813,510	8,571,369	13,318,444	16,914,845	119,606,640

AVISTA UTILITIES
Company Settlement Case
Summary by Function with Margin Analysis
For the Year Ended December 31, 2014

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	337,031	235,918	97,171	1,399	2,542
2	Underground Storage	1,748,119	1,135,497	561,698	5,606	43,324
3	Distribution	24,249,[illegible]	19,387,003	4,614,046	45,393	222,226
4	Common	9,840,131	8,401,406	1,352,211	14,204	72,360
5	**Total Current Rate Revenue**	**38,173,000**	**29,139,824**	**6,825,127**	**67,596**	**340,462**
6	Exclude Cost of Gas w / Revenue Exp.	0	0	0	0	0
7	**Total Margin Revenue at Current Rates**	**36,173,000**	**29,139,824**	**6,626,127**	**67,596**	**340,462**
	Margin per Therm at Current Rates					
8	Production	$0.00413	$0.00423	$0.00423	$0.00423	$0.00094
9	Underground Storage	$0.02137	$0.02036	$0.02448	$0.01896	$0.01600
10	Distribution	$0.29881	$0.34761	$0.20107	$0.14042	$0.08207
11	Common	$0.12044	$0.15080	$0.05893	$0.04209	$0.02672
12	Total Current Margin Melded Rate per Therm	**$0.44275**	**$0.62303**	**$0.28870**	**$0.20459**	**$0.12574**
	Functional Cost Components at Uniform Current Return					
13	Production	337,031	235,918	97,171	1,399	2,542
14	Underground Storage	1,689,278	1,231,419	416,370	5,255	36,235
15	Distribution	24,223,976	20,296,739	3,685,561	44,149	197,526
16	Common	9,922,715	8,625,255	1,215,502	13,913	68,045
17	Total Uniform Current Cost	**38,173,000**	**30,389,331**	**5,414,605**	**64,716**	**304,348**
18	Exclude Cost of Gas w / Revenue Exp.	0	0	0	0	0
19	Total Uniform Current Margin	**36,173,000**	**30,389,331**	**5,414,605**	**64,716**	**304,348**
	Margin per Therm at Uniform Current Return					
20	Production	$0.00413	$0.00423	$0.00423	$0.00423	$0.00094
21	Underground Storage	$0.02068	$0.02210	$0.01814	$0.01590	$0.01338
22	Distribution	$0.29650	$0.36430	$0.16061	$0.13363	$0.07295
23	Common	$0.12145	$0.15481	$0.05297	$0.04211	$0.02513
24	Total Current Uniform Margin Melded Rate per Therm	**$0.44275**	**$0.54545**	**$0.23595**	**$0.19587**	**$0.11240**
25	**Margin to Cost Ratio at Current Rates**	**1.00**	**0.96**	**1.22**	**1.04**	**1.12**
	Functional Cost Components at Proposed Rates					
26	Production	337,031	235,918	97,171	1,399	2,542
27	Underground Storage	1,951,059	1,306,768	591,232	6,200	46,859
28	Distribution	26,114,616	21,027,055	4,802,732	50,288	234,541
29	Common	10,270,295	8,801,083	1,379,092	14,709	74,511
30	**Total Proposed Rate Revenue**	**38,873,000**	**31,370,824**	**6,871,127**	**72,596**	**358,452**
31	Exclude Cost of Gas w / Revenue Exp	0	0	0	0	0
32	**Total Margin Revenue at Proposed Rates**	**38,873,000**	**31,370,824**	**6,671,127**	**72,596**	**358,462**
	Margin per Therm at Proposed Rates					
33	**Production**	**$0.00413**	**$0.00423**	**$0.00423**	**$0.00423**	**$0.00094**
34	**Underground Storage**	**$0.02388**	**$0.02346**	**$0.02578**	**$0.01876**	**$0.01731**
35	Distribution	$0.31964	$0.37741	$0.20920	$0.15221	$0.08662
36	Common	$0.12571	$0.15797	$0.06014	$0.04452	$0.02752
37	Total Proposed Margin Melded Rate per Therm	**$0.47336**	**$0.56307**	**$0.29942**	**$0.21973**	**$0.13238**
	Functional Cost Components at Uniform Proposed Return					
38	Production	337,031	235,918	97,171	1,399	2,542
39	Underground Storage	1,903,251	1,387,397	469,110	5,920	40,825
40	Distribution	26,093,052	21,808,656	4,022,507	48,472	213,517
41	Common	10,339,668	8,989,242	1,265,112	14,474	70,838
42	Total Uniform Proposed Cost	38,873,000	32,421,113	5,853,900	70,266	327,722
43	Exclude Cost of Gas w / Revenue Exp.	0	0	0	0	0
44	Total Uniform Proposed Margin	38,873,000	32,421,113	5,853,900	70,266	327,722
	Margin per Therm at Uniform Proposed Return					
45	Production	$0.00413	$0.00423	$0.00423	$0.00423	$0.00094
46	Underground Storage	$0.02330	$0.02490	$0.02044	$0.01792	$0.01508
47	Distribution	$0.31938	$0.39144	$0.17529	$0.14671	$0.07886
48	Common	$0.12658	$0.16135	$0.05513	$0.04381	$0.02616
49	Total Proposed Uniform Margin Melded Rate per Therm	**$0.47335**	**$0.58192**	**$0.25610**	**$0.21267**	**$0.12104**
50	**Margin to Cost Ratio at Proposed Rates**	**1.00**	**0.97**	**1.17**	**1.03**	**1.08**
51	**Current Margin to Proposed Cost Ratio**	**0.94**	**0.90**	**1.13**	**0.96**	**1.04**

AVISTA UTILITIES
IDAHO ELECTRIC, CASE NO. AVU-E-15-05
PROPOSED INCREASE BY SERVICE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2014
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Base Tariff Revenue Under Present Rates(1)	Settlement Pro-rata Allocation Increase	Base Tariff Revenue Under Proposed Rates (1)	Base Tariff Percent Increase	Total Billed Revenue at Present Rates(2)	Total General Increase	Total Billed Revenue at Proposed Rates(2)	Percent Increase on Billed Revenue (3)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Residential	1	$104,939	$944	$105,883	0.9%	$106,098	$944	$107,042	0.9%
2	General Service	11,12	$36,296	$172	$36,468	0.5%	$36,826	$172	$36,998	0.5%
3	Large General Service	21,22	$54,359	$330	$54,689	0.6%	$54,948	$330	$55,278	0.6%
4	Extra Large General Service	25	$17,152	$105	$17,257	0.6%	$17,212	$105	$17,317	0.6%
5	Clearwater	25P	$23,458	$84	$23,542	0.4%	$23,496	$84	$23,580	0.4%
6	Pumping Service	31,32	$5,278	$37	$5,315	0.7%	$5,345	$37	$5,382	0.7%
7	Street & Area Lights	41-49	$3,490	$28	$3,518	0.8%	$3,566	$28	$3,594	0.8%
8	Total		$244,972	$1,700	$246,672	0.7%	$247,489	$1,700	$249,189	0.7%

(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.

(3) Reflects the coninuation of the rate credit set forth in Schedule 97

Type of Service	Schedule Number	Original Proposed General Increase	Percentage of Total	Settlement Spread $1.7 Million
Residential	1	$7,349	55.55%	$944
General Service	11,12	$1,338	10.11%	$172
Large General Service	21,22	$2,563	19.37%	$330
Extra Large General Service	25	$820	6.20%	$105
Clearwater	25P	$653	4.94%	$84
Pumping Service	31,32	$288	2.18%	$37
Street & Area Lights	41-49	$219	1.66%	$28
		$13,230	100.00%	$1,700

AVISTA UTILITIES
IDAHO ELECTRIC, CASE NO. AVU-E-15-05
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

Effective January 1, 2016

(a)	Base Tariff Sch. Rate (b)	Present Other Adj.(1) (c)	Present Billing Rate (d)	General Rate Inc/(Decr) (e)	Proposed Billing Rate (f)	Proposed Base Tariff Rate (g)
Residential Service - Schedule 1						
Basic Charge	$5.25		$5.25	$0.00	$5.25	$5.25
Energy Charge:						
First 600 kWhs	$0.08146	$0.00101	$0.08247	$0.00078	$0.08325	$0.08224
All over 600 kWhs	$0.09096	$0.00101	$0.09197	$0.00087	$0.09284	$0.09183
General Services - Schedule 11						
Basic Charge	$10.00		$10.00	$0.00	$10.00	$10.00
Energy Charge.						
First 3,650 kWhs	$0.09634	$0.00148	$0.09782	$0.00052	$0.09834	$0.09686
All over 3,650 kWhs	$0.07178	$0.00148	$0.07326	$0.00038	$0.07364	$0.07216
Demand Charge:						
20 kW or less	no charge		no charge	no charge		no charge
Over 20 kW	$5.25/kW		$5.25/kW		$5 25/kW	$5.25/kW
Large General Service - Schedule 21						
Energy Charge:						
First 250,000 kWhs	$0.06297	$0 00086	$0.06383	$0.00047	$0.06430	$0.06344
All over 250,000 kWhs	$0.05373	$0.00086	$0.05459	$0.00041	$0.05500	$0.05414
Demand Charge:						
50 kW or less	$350.00		$350.00	$0.00	$350.00	$350.00
Over 50 kW	$4.75/kW		$4.75/kW		$4.75/kW	$4.75/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	$0.05212	$0.00019	$0.05231	$0.00039	$0.05270	$0.05251
All over 500,000 kWhs	$0.04414	$0.00019	$0.04433	$0.00032	$0.04465	$0.04446
Demand Charge:						
3,000 kva or less	$12,500		$12,500		$12,500	$12,500
Over 3,000 kva	$4.50/kva		$4 50/kva		$4.50/kva	$4.50/kva
Primary Volt. Discount	$0.20/kW		$0.20/kW		$0.20/kW	$0.20/kW
Annual Minimum	Present:	$683,420			$687,360	
Clearwater - Schedule 25P						
Energy Charge.						
all kWhs	$0.04254	$0.00008	$0.04262	$0.00018	$0.04280	$0.04272
Demand Charge:						
3,000 kva or less	$12,500		$12,500		$12,500	$12,500
3,000 - 55,000 kva	$4.50/kva		$4.50/kva		$4.50/kva	$4.50/kva
Over 55,000 kva	$2.00/kva		$2.00/kva		$2.00/kva	$2.00/kva
Primary Volt. Discount	$0.20/kW		$0.20/kW		$0.20/kW	$0.20/kW
Annual Minimum	Present:	$617,940			$619,920	
Pumping Service - Schedule 31						
Basic Charge	$8.00		$8.00	$0.00	$8.00	$8.00
Energy Charge:						
First 165 kW/kWh	$0.09299	$0.00117	$0.09416	$0.00066	$0.09482	$0.09365
All additional kWhs	$0.07927	$0.00117	$0.08044	$0.00056	$0.08100	$0.07983

(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 Rebate.

AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-15-01
PROPOSED INCREASE BY SERVICE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2014
(000s of Dollars)

Line No.	Type of Service (a)	Schedule Number (b)	Base Tariff Distribution Revenue Under Present Rates (1) (c)	Settlement Pro-rata Allocation of Filed (d)	Base Tariff Distribution Revenue Under Proposed Rates (e)	Base Tariff Percent Increase (f)	Total Billed Revenue at Present Rates (1) (g)	Total General Increase (h)	Percent Increase on Billed GRC Revenue (i)	Total Sch 197 - 2013 Earnings/DSM Rebate Expiration (2) (j)	Sch 197 Percent Increase on Billed GRC Revenue (k)	Total Sch 197 - 2014 Earnings Rebate (l)	Sch 197 Percent Increase on Billed GRC Revenue (m)	Total Billed Revenue at Proposed Rates (3) (n)	Percent Increase on Billed Revenue (o)
1	General Service	101	$29,140	$2,231	$31,371	7.7%	$54,067	$2,231	4.1%	$630	1.6%	-$149	-0.3%	$56,978	5.3%
2	Large General Service	111/112	$6,625	$246	$6,871	3.7%	$16,903	$246	1.5%	$342	2.0%	-$62	-0.4%	$17,430	3.1%
3	Interruptible Service	131/132	$68	$5	$73	7.6%	$190	$5	2.7%	$5	2.6%	-$1	-0.6%	$199	4.8%
4	Transportation Service	146	$340	$18	$358	5.2%	$340	$18	5.2%	$0	0.0%	-$7	-2.1%	$351	3.1%
5	Special Contracts	148	$101	$0	$101	0.0%	$101	$0	0.0%	$0	0.0%	$0	0.0%	$101	0.0%
6	Total		$36,274	$2,500	$38,774	6.9%	$71,601	$2,500	3.5%	$1,177	1.6%	-$219	-0.3%	$75,058	4.8%

(1) Includes Schedule 150 - Purchased Gas Cost Adjustment, Schedule 155 - Gas Rate Adjustment & Schedule 197 - Rebate of 2013 Earnings Test & DSM Deferrals
(2) Schedule 197 - Rebate of 2013 Natural Gas Earnings Test & DSM Deferrals expires after December 31, 2015 resulting in a rate increase to customers
(3) Includes Schedule 150 - Purchased Gas Cost Adjustment, Schedule 155 - Gas Rate Adjustment & Schedule 197 - Rebate of 2014 Earnings Test Deferrals

Type of Service	Schedule Number	Original Proposed General Increase	Percentage of Total	Settlement Spread $2.5 Million
General Service	101	$2,860	89.24%	$2,231
Large General Service	111/112	$316	9.86%	$246
Interruptible Service	131/132	$6	0.19%	$5
Transportation Service	146	$23	0.72%	$18
Special Contracts	148	$0	0.00%	$0
Total		$3,205	100.00%	$2,500

AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-15-01
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

Effective January 1, 2016

Type of Service (a)	Present Base Distribution Rate (b)	Present Billing Rate Adj.(1) (c)	Present Billing Rate (d)	General Rate Increase (e)	Sch 197 - 2013 Earnings Test & PGA Rebate Expiration (f)	Sch 197 - 2014 Earnings Test Rebate Credit (2) (g)	Proposed Billing Rate (h)	Proposed Base Distribution Rate (i)
General Service - Schedule 101								
Basic Charge	$4.25		$4.25	$1.00			$5.25	$5.25
Usage Charge:								
All therms	$0.45372	$0.44741	$0.90113	$0.02374	$0.01488	($0.00268)	$0.93708	$0.47746
Large General Service - Schedule 111								
Usage Charge								
First 200 therms	$0.47500	$0.44741	$0.92241	$0.02875	$0.01489	($0.00268)	$0.96337	$0.60375
200 - 1,000 therms	$0.31030	$0.44741	$0.75771	$0.00924	$0.01489	($0.00268)	$0.77918	$0.31954
1,000 - 10,000 therms	$0.23095	$0.44741	$0.67836	$0.00688	$0.01489	($0.00268)	$0.69745	$0.23783
All over 10,000 therms	$0.17850	$0.44741	$0.62591	$0.00531	$0.01488	($0.00268)	$0.64343	$0.18381
Minimum Charge:								
per month	$95.00		$95.00	$5.75			$100.75	$100.75
per therm	$0.00000	$0.44741	$0.44741		$0.01489	($0.00268)	$0.45962	$0.00000
Interruptible Service - Schedule 132								
Usage Charge:								
All Therms	$0.20459	$0.37021	$0.57480	$0.01513	$0.01489	($0.00268)	$0.60214	$0.21972
Transportation Service - Schedule 146								
Basic Charge	$225.00		$225.00	$0.00			$225.00	$225.00
Usage Charge:								
All Therms	$0.12075		$0.12075	$0.00665		($0.00268)	$0.12472	$0.12740

(1) Includes Schedule 150 - Purchased Gas Cost Adjustment, Schedule 155 - Gas Rate Adjustment, and Schedule 197 - PGA/DSM Rebate

(2) The 2014 Earnings Test Rebate Credit will be effective January 1, 2016 through December 31, 2016

Schedule 197

Present Rebate Expiring 12/31/2015
Rebate of 2013 Earnings Test & DSM Deferrals

	Rate Schedule	Pro Forma Therms	2013 Earnings Rebate & DSM Reduction
General Service	101	55,714,011	$ 829,582
Large General Service	111/112	22,947,786	$ 341,693
Interruptible Service	131/132	330,396	$ 4,920
	Total	78,992,193	$ 1,176,194
	Uniform Cents Reduction		$ 0.01489

Proposed Rebate Effective 1/1/16 - 12/31/16
Rebate of 2014 Earnings Test

	Rate Schedule	Pro Forma Therms	2014 Earnings Rebate Reduction
General Service	101	55,714,011	$ (149,314)
Large General Service	111/112	22,947,786	$ (61,500)
Interruptible Service	131/132	330,396	$ (885)
Transportation Service	146	2,707,661	$ (7,257)
	Total	81,699,854	$ (218,956)

2014 Earnings Test Balance	$ (219,212)
Uniform Cents Reduction	**$ (0.00268)**