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IDAHO PUBLIC UTILITIES COMMISSION

February 22, 2013

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

Re: Case Nos. AVU-E-12-08 and AVU-G-12-07
Direct Testimony of Kelly O. Norwood in Support of the Stipulation and Settlement

Enclosed for filing with the Commission in the above-referenced dockets are the original and nine copies of the Direct Testimony of Kelly O. Norwood in Support of the Stipulation and Settlement, dated February 22, 2013.

Sincerely,

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

Enclosures

c: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this 22nd day of February, 2013, served the Direct Testimony of Kelly O. Norwood in support of the Stipulation and Settlement in Docket No. AVU-E-12-08 and AVU-G-12-07, 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 FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-12-08 CASE NO. AVU-G-12-07 DIRECT TESTIMONY OF KELLY O. NORWOOD IN SUPPORT OF THE STIPULATION AND SETTLEMENT

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

<u>I.INTRODUCTION</u>

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

A. My name is Kelly O. Norwood and I am employed as the Vice-President of State and Federal Regulation for Avista Utilities ("Company" or "Avista"), at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you briefly describe your educational background and professional experience?

A. Yes. I am a graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. I joined the Company in June of 1981. Over the past 31 years, I have spent approximately 20 years in the Rates Department with involvement in cost of service, rate design, revenue requirements and other aspects of ratemaking. I spent approximately 11 years in the Energy Resources Department (power supply and natural gas supply) in a variety of roles, with involvement in resource planning, system operations, resource analysis, negotiation of power contracts, and risk management. I was appointed Vice-President of State & Federal Regulation in March 2002.

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

A. The purpose of my testimony is to describe and support the Stipulation and Settlement ("Stipulation"), filed on February 6, 2013 between the Staff of the Idaho Public Utilities Commission ("Staff'), Clearwater Paper Corporation ("Clearwater"), Idaho Forest Group, LLC ("Idaho Forest"), the Idaho Conservation League ("Conservation League"), and the Company, which, if approved by the Commission, would resolve all of the issues in the Company's filing. These entities are collectively referred to as the "Parties," and represent several parties in the above-referenced cases.[1]

The Stipulation is the product of settlement discussions held in the Commission offices on January 17 and 24, 2013. The Stipulation between the Parties resolved all issues associated with the calculation of the Company's requested cost of capital, including capital structure and

[1] The Community Action Partnership Association of Idaho ("CAPAI") participated in settlement discussions and is continuing to review its position with regard to the Stipulation, as proposed, and will be filing separate comments and/or testimony in that regard. The Snake River Alliance, as an intervenor, was provided notice of the settlement discussions, but did not participate. However, on February 20, 2013, The Snake River Alliance, through separate communication filed notice with the Commission indicating that, although not a signatory to the Settlement agreement, they do support the Stipulation agreed to by the Parties.

cost components, and resolved all revenue requirement, rate spread and rate design issues.

The Stipulation represents a compromise among differing points of view. Concessions were made by all Parties to reach a balancing of interests. As will be explained in the following testimony, the Stipulation represents a fair, just and reasonable compromise of the issues and is in the public interest.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit No. 1, which is a copy of the Stipulation and Settlement filed on February 6, 2013, with the Commission.

Q. Please explain how the Parties arrived at the Stipulation in this proceeding.

A. The Stipulation is the end result of extensive audit work conducted through the discovery process[2], including a week-long on-site audit by Commission Staff, and hard bargaining by all Parties in this proceeding. I would like to express my appreciation to all Parties involved in this proceeding for their efforts in arriving at this Stipulation and to this Commission for your

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[2] For its part, Avista responded to over 270 production requests (including sub-parts) from IPUC Staff and other intervening parties.

willingness to hear this matter promptly, in light of the proposed April 1 effective date.

Q. Why is the Stipulation in the public interest?

A. The Stipulation is in the "public interest" for several reasons, which include:

- It was the product of the give-and-take of negotiation that produced an "end result" that is just and reasonable.
- It is supported by the evidence, demonstrating the need for rate adjustments to provide recovery of necessary expenditures and investment, the costs of which are not offset by a growth in sales margins.
- The Settlement enjoys broad-based support from a variety of constituencies, including Clearwater, Idaho Forest, the Conservation League, and the Snake River Alliance, serving to address their specific needs, and the Staff of the Commission representing all customers.
- The Settlement provides base rate certainty over the next two years (2013/2014), which would benefit all customers, as they plan and budget for their needs.
- It would prohibit Avista from making further changes in base rates prior to January 1, 2015, thereby breaking the yearly cycle of rate filings.
- The impact of the base rate increases in Step 2, effective October 1, 2013, would be mitigated, in part, by the amortization of the BPA settlement payment for electric and the PGA deferral credit balance for natural gas.
- The "stay-out" provision preventing a further change in base rates until 2015 would challenge Avista to manage its costs in order to have the opportunity to earn the agreed-upon return on equity; indeed, the Company has already put in place cost saving measures, such as the voluntary severance program reducing Avista's work force by 55 individuals, executed at year-end 2012.
- Finally, as I will discuss later in my testimony, in order to allay any concerns that Avista might somehow "over-earn" during the 2013/2014 rate-

effective period, Avista would agree to refund back to customers 50% of any earnings that exceed the 9.8% agreed-upon ROE during the 2013 and 2014 rate-effective periods, based on actual, consolidated results for its Idaho electric and natural gas operations.

Q. Would you briefly summarize the Stipulation?

A. Yes. Under the terms of the Stipulation, Avista would implement revised tariff schedules designed to recover additional annual electric and natural gas revenue in two steps, effective April 1 and October 1, 2013. This represents a two-year rate plan for the period 2013 and 2014, designed to provide retail revenues necessary to allow the Company the opportunity to earn the return agreed to in the Stipulation.

For electric operations, there is no electric base rate increase in the first step (April 1, 2013), however, effective October 1, 2013 (Step 2), the Parties agree to an overall base rate increase of 3.1% (3.2% on a billed basis) or $7.825 million in electric annual base tariff revenues. Partially offsetting the October 1, 2013 electric increase is $3.865 million of revenues resulting from a payment to be made to Avista by the Bonneville Power Administration (BPA)[3]. This payment to Avista is for the Parallel Operation

[3] The agreement between Avista and BPA was approved by FERC on February 5, 2013.

Settlement agreement, pertaining to BPA's prior use of Avista's transmission system (discussed later in my testimony), and amortized over 15 months, from October 1, 2013 to December 31, 2014, resulting in a decrease to billed customer rates of 1.3%. As a result of the two October 1, 2013 adjustments, the overall net increase on a billed basis is 1.9%. A residential customer using an average of 930 kilowatt hours per month would see a $2.04, or 2.6%, increase per month for a revised monthly bill of $80.73. (See Exhibit No. 1, Paragraph 21, for the October 1, 2013 percentage change in rates by rate schedule.)

The table below summarizes the April 1 and October 1, 2013 electric rate changes:

Summary of Electric Rate Changes (millions)

	Revenue Requirement	Base Rate Change	Billing Rate Change	Offset	Net Billing Rate Change
April 1, 2013	$0.00	0.0%	0.0%	0.0%	0.0%
October 1, 2013	$7.825	3.1%	3.2%	-1.3%	1.9%

For natural gas, under <u>Step 1</u>, effective April 1, 2013, Avista would implement revised tariff schedules designed to recover $3.115 million in additional annual natural gas revenue, representing an overall 4.9% (5.0% on a billed basis) increase. As a result of the April 1, 2013 rate adjustment, a residential customer using an average of 60 therms per month would see a $2.82, or 5.4%, increase per month for a revised monthly bill of $55.37.

Under Step 2, effective October 1, 2013, Avista would implement revised tariff schedules designed to recover an additional $1.330 million in annual natural gas revenue, representing an overall 2.0% increase (on both a base and billed basis). Partially offsetting the natural gas rate increase would be a $1.550 million Purchase Gas Adjustment (PGA) deferral credit balance from the 2012 PGA. This credit would be amortized over 15 months, October 1, 2013 to December 31, 2014, resulting in a decrease to billed customer rates of 1.7%. The result of the two October 1, 2013 adjustments is an overall net increase on a billed basis of 0.3%. A residential customer using an average of 60 therms per month would see a $0.31, or 0.6%, increase per month for a revised monthly bill of $55.68. Other customer classes, except transportation customers, would see an overall net rate decrease October 1, 2013. (See Exhibit No. 1, Paragraph 22, for the April 1 and October 1, 2013 change in rates by rate schedule.)

The table below summarizes the April 1 and October 1, 2013 proposed natural gas rate changes:

Summary of Natural Gas Rate Changes (millions)					
	Revenue Requirement	Base Rate Change	Billing Rate Change	Offset	Net Billing Rate Change
April 1, 2013	$3.115	4.9%	5.0%	0.0%	5.0%
October 1, 2013	$1.330	2.0%	2.0%	-1.7%	0.3%

Avista would not file another electric or natural gas general rate case before May 31, 2014, and while it may request an effective date earlier than January 1, 2015, final approved new rates would not go into effect prior to January 1, 2015. This does not apply to tariff filings authorized by or contemplated by the terms of the Power Cost Adjustment (PCA), or the Purchased Gas Adjustment tariff (PGA), or other miscellaneous filings.

In determining these revenue increases, the Parties have agreed to various adjustments to the Company's original filing, which are summarized in the Stipulation, and described further below.

The Stipulation calls for an overall rate of return of 7.91%, determined using a capital structure consisting of 50% common stock equity and 50% long-term debt, an authorized return on equity of 9.8% and cost of debt of 6.01%.

II. HISTORY OF FILING

Q. Please describe the Company's general rate case request, as filed.

A. On October 11, 2012, Avista filed an Application with the Commission for authority to increase revenue from electric and natural gas service in Idaho by 4.6% and 7.2%, respectively. If approved, the Company's revenues for electric base retail rates would have increased by $11.4 million annually; Company revenues for natural gas service would have increased by $4.6 million annually. The Company requested an effective date of April 1, 2013 for its proposed electric and natural gas rate increases. By Order No. 32689, dated December 4, 2012, the Commission suspended the proposed schedules of rates and charges for electric and natural gas service.

The Company proposed utilizing the results of its electric and natural gas service studies, sponsored by Company witness Knox, as a guide to spread the overall requested electric and natural gas revenue increases by rate schedule on a basis which: 1) moved the rates for nearly all the schedules closer to the cost of providing service, and 2) resulted in a reasonable range in the (net) proposed percentage increase across the schedules. The spread of the proposed electric increase generally resulted in the rates of return for the various electric service schedules moving approximately 15% closer to the overall rate of return (unity); whereas the proposed increases for the various natural gas service schedules would move the return approximately 25% closer to the overall rate of return (unity). The Company did not request a change in its electric or natural gas residential basic charges.

Q. What are the primary factors driving the Company's need for electric and natural gas increases?

A. Approximately 70% of the Company's electric revenue requirement, and 48% for natural gas, is due to an increase in net plant investment (including return on investment, depreciation and taxes, and offset by the tax benefit of interest).

The remaining revenue requirement request is due to increases in distribution, operation and maintenance (O&M), and administrative and general (A&G) expenses for both electric and natural gas operations. However, the increased costs for electric operations are partially offset by a reduction in net power supply and transmission expenditures.

III. REVENUE REQUIREMENT ELEMENTS OF THE STIPULATION

Q. Please explain the derivation of the Electric and Natural Gas Revenue Requirements outlined in the Stipulation.

A. The Parties agreed that Avista would implement revised tariff schedules designed to recover additional annual electric and natural gas revenue in two steps, effective April 1 and October 1, 2013. This represents a two-year rate plan designed to provide sufficient retail revenues for the period 2013 and 2014, which together with management of costs, would provide the Company with the opportunity to earn the return agreed to in the Stipulation.

While Avista's filing requested an electric revenue requirement increase of $11.393 million effective April 1, 2013, agreed-upon adjustments, including the agreed-upon rate of return, result in a recommended electric revenue requirement increase of $0.0 as of April 1, 2013 and $7.825 million as of October 1, 2013.

Similarly, while the Company requested a natural gas revenue requirement increase of $4.561 million effective April 1, 2013, agreed-upon adjustments result in a recommended natural gas revenue requirement increase of $3.115 million as of April 1, 2013 and $1.330 million as of October 1, 2013.

Q. Please explain the Parties' agreement with regard to an Authorized Rate of Return, including the Return on Equity.

A. The Parties have agreed to a revenue requirement which produces an overall rate of return of 7.91%, based on a return on equity of 9.8%, an equity component at 50% and cost of debt of 6.01%. By comparison, the Company's original filing requested an overall rate of return of 8.46%, a return on equity of 10.9%, an equity component of 50% and cost of debt of 6.02%.

Q. What is the proposed effective date of new rates from the Stipulation?

A. The Parties have requested implementation of new retail rates from the Stipulation on April 1, 2013, with further tariff changes on October 1, 2013. These proposed effective dates are an integral part of the Stipulation that includes a negotiated resolution of all of the issues.

Q. Please provide an overview of the revenue requirement adjustments agreed to by the Parties resulting in the April 1 and October 1, 2013 revenue requirements.

A. A number of the adjustments, agreed to by the Parties, resulted in delaying recovery of 2013 increased costs until October 1, 2013, as well as reducing certain expenditures to the agreed-upon levels by the Parties. The Parties agreed to revenue requirements that reflect the adjustments shown below in the excerpted tables from the Stipulation:

Table 1: April 1, 2013 Electric Revenue Requirement

SUMMARY TABLE OF ADJUSTMENTS TO ELECTRIC REVENUE REQUIREMENT
EFFECTIVE APRIL 1, 2013
000s of Dollars

		Revenue Requirement		Rate Base	
	Amount as Filed:	**$**	**11,393**	**$**	**639,030**
	Adjustments:				
a.)	Cost of Capital	$	(5,517)		
b.)	Remove 2013 Capital Additions (Delay to October 1, 2013)	$	(1,117)	$	(1,582)
c.)	Remove 2013 Expenses: Delay Recovery to October 1, 2013 Rate Change				
i.	Major Generation O&M	$	(926)		
ii.	Information Services & Technology	$	(318)		
iii.	CS2 Levelized Return	$	(38)		
iv.	Non-Exec Labor	$	(426)		
d.)	Remove 2013 Property Tax Expense	$	(428)		
e.)	Remove Officer Incentive and CPI escalation	$	(187)		
f)	Two-Year Amortization of Reardan	$	878		
g.)	Include Palouse Wind in PCA until in base rates in 2015 (90%/10% sharing)	$	(3,139)		
h.)	Miscellaneouse Adjustments: Two-Year Amortization of Booz Consulting costs, Oasis Training, Abandoned Projects & Depreciation Study expense	$	(175)		
	Adjusted Amounts Effective April 1, 2013	**$**	**-**	**$**	**637,448**

Table 2: October 1, 2013 Electric Revenue Requirement

	SUMMARY TABLE OF ELECTRIC REVENUE REQUIREMENT EFFECTIVE OCTOBER 1, 2013 000s of Dollars	Revenue Requirement	Rate Base
	Amounts Effective April 1, 2013	$ -	$ 637,448
	Adjustments to October 1, 2013 Rate Change:		
a.)	2013 Capital Additions	$ 5,488	$ 20,705
b.)	2014 Capital Additions	$ 629	$ 888
c.)	Add 2013 Expenses		
i.	Major Generation O&M	$ 926	
ii.	Information Services & Technology	$ 318	
iii.	CS2 Levelized Return	$ 38	
iv.	Non-Exec Labor	$ 426	
	Adjusted Amounts Effective October 1, 2013	**$ 7,825**	**$ 659,041**

Table 3: April 1, 2013 Natural Gas Revenue Requirement

	SUMMARY TABLE OF ADJUSTMENTS TO NATURAL GAS REVENUE REQUIREMENT EFFECTIVE APRIL 1, 2013 000s of Dollars	Revenue Requirement	Rate Base
	Amount as Filed:	**$ 4,561**	**$ 110,930**
	Adjustments:		
a.)	Cost of Capital	$ (957)	
b.)	Remove 2013 Capital Additions (Delay to October 1, 2013)	$ (22)	$ 1,309
c.)	Remove 2013 Expenses: Delay Recovery to October 1, 2013 Rate Change		
i.	Information Services & Technology	$ (42)	
ii.	Non-Exec Labor	$ (215)	
d.)	Remove 2013 Property Tax Expense	$ (84)	
e.)	Remove Officer Incentive and CPI escalation	$ (50)	
f.)	Miscellaneouse Adjustments: Two-Year Amortization of Booz Consulting costs, Injuries & Damages, Abandoned Projects & Depreciation Study expense	$ (76)	
	Adjusted Amounts Effective April 1, 2013	**$ 3,115**	**$ 112,239**

Table 4: October 1, 2013 Natural Gas Revenue Requirement

SUMMARY TABLE OF ADJUSTMENTS TO NATURAL GAS REVENUE REQUIREMENT
EFFECTIVE OCTOBER 1, 2013
000s of Dollars

		Revenue Requirement	Rate Base
	Amounts Effective April 1, 2013	$ -	$ 112,239
	Adjustments to October 1, 2013 Rate Change:		
a.)	2013 Capital Additions	$ 1,073	$ 3,831
b.)	Add 2013 Expenses		
i.	Information Services & Technology	$ 42	
ii.	Non-Exec Labor	$ 215	
	Adjusted Amounts Effective October 1, 2013	**$ 1,330**	**$ 116,070**

As can be seen by a quick review of the individual line descriptions provided within the summary tables excerpted from the Stipulation, the adjustments accepted for settlement purposes cover a broad range of revenue and cost categories, including the authorized rate of return. The individual adjustments should not be viewed in isolation; rather, they should be viewed in total as part of the entire Stipulation, and are the result of hard bargaining and compromise.

Q. Would you please elaborate on the individual line items contained within the excerpted tables?

A. Yes. A description of these adjustments resulting in the Step 1 revenue requirement, effective April 1, 2013 and the Step 2 revenue requirement, effective October 1, 2013, follows.

Step 1: April 1, 2013 Rate Change: Electric $0.0; Natural Gas $3.115 million:

Remove 2013 Capital additions - (Table 1, Line b. and Table 3, Line b.) The 2013 electric and natural gas capital additions adjustments, as proposed by the Company in its original filings, were removed, delaying recovery of the associated revenue requirement until the October 1, 2013 rate increase. April 1, 2013, therefore, reflected total depreciation expenses and rate base, net of accumulated depreciation and accumulated deferred income tax, as of year-end December 31, 2012.

Remove 2013 Expenses - (Table 1, Line c. and Table 3, Line c.) The following adjustments remove 2013 expenses pro formed in the Company's original filing, delaying recovery of those expenditures until the October 1, 2013 rate change:

Major Generation O&M - (Table 1, Line c.i.) 2013 incremental non-labor generation plant operation and maintenance (O&M) expenses related to the Company's thermal generation plant at Kettle Falls, and its hydro generation plants (electric only).

Information Services & Technology - (Table 1, Line c.ii. and Table 3, Line c.i.) 2013 incremental information service and technology expenses, related to the Company's replacement of the Company's Customer

Service Information System, and increased costs to support various business processes, application support, additional security requirements, annual contractual agreements and maintenance and license fees.

CS2 Levelized Return - (Table 1, Line c.iii.) 2013 incremental amortization of the deferred levelized return related to the 10-year deferral of return on the Coyote Springs 2 (CS2) investment(electric only).

Non-Exec Labor - (Table 1, Line c.iv. and Table 3, Line c.ii.) 2013 incremental non-executive labor increases, includes increases approved by the Board of Directors for 2013 for its non-union, non-executive employees, as well as the 2013 union contract increases for union employees.

Remove 2013 Property Tax Expense - (Table 1, Line d. and Table 3, Line d.) This adjustment removes the 2013 incremental pro forma property tax expense. In its original filing, the Company adjusted test period accrued property tax expense to the expected 2013 rate period expense level based on property values as of December 31, 2012. This adjustment reduces recovery of property tax to 2012 expense levels.

Remove Officer Incentive and CPI Escalation - (Table 1, Line e. and Table 3, Line e.) This adjustment removes the officer portion of the employee incentive expense included in the Company's original filing. Included in the Company's original filing was a six-year average (2006-2011) of actual incentive expense adjusted by the Consumer Price Index (CPI). This adjustment in the Settlement also removes the CPI escalation.

Miscellaneous Adjustments - (Table 1, Line h. and Table 3, Line f.) The Company adopted, for settlement purposes, Staff's proposal to adjust or remove various administrative and general (A&G) and O&M-related costs, including a two-year amortization of Booz & Co. consulting fees, thereby reducing test period expenses, as well as removal of certain other amounts related to OASIS[4] training, abandoned projects, injuries and damages (natural gas only) and depreciation study expenses.

Reardan Wind Site - (Table 1, Line f.) In May 2008, Avista purchased the Reardan Wind Project Site from Energy Northwest after it was demonstrated as the Company's least-cost option for securing a renewable resource for its customers, consistent with its 2007 Integrated Resource

[4] Open Access Same-Time Information System (OASIS).

Plan. Avista later chose to delay the construction of the Reardan project and take advantage of much-lower costs for wind projects that emerged in 2011 (Palouse Wind). Avista recorded $4.0 million of site acquisition and preparation costs, of which approximately $1.7 million is Idaho's share. This includes approximately $0.4 million in AFUDC in accordance with Order No. 30611 (Case No. AVU-E-08-04). As a part of the agreed-upon Settlement, Avista would amortize Idaho's portion of the Reardan Wind Project deferred balance of approximately $1.7 million over a two-year period beginning April 1, 2013.

Palouse Wind - (Table 1, Line g.) The Parties agree that recovery of costs related to the Palouse Wind Power Purchase Agreement ("PPA") would be included in the PCA, subject to the current sharing (90% customer, 10% Company) until it is included in base rates as part of the implementation of new rates from the Company's next general rate case, anticipated in 2015. This adjustment removes the Palouse Wind PPA expenses from the pro forma power supply adjustment included in the Company's original filing.

Q. Please summarize the impact of these adjustments on Step 1, effective April 1, 2013.

A. Consolidation of the adjustments discussed above for the Step 1 base rate change, effective April 1, 2013, reduces Avista's electric revenue requirement request of $11.393 million to $0.0, and its natural gas revenue requirement request of $4.561 million to $3.115 million, resulting in a 0.0% electric and 3.1% natural gas base rate increase. Net rate base for electric and natural gas is $637.45 million and $112.24 million, respectively, effective April 1, 2013.

Q. Please continue your explanation of the revenue requirement adjustments agreed to by the Parties resulting in the electric and natural gas Step 2, October 1, 2013, rate changes.

A. As discussed above, a number of capital and expense related adjustments proposed in the Company's original filing were removed from the electric and natural gas revenue requirements for purposes of the Step 1, rate changes effective April 1, 2013, delaying the recovery of those incremental 2013 increased costs to the Step 2, October 1, 2013 rate changes. A description of these adjustments resulting in the Step 2 increases, effective October 1, 2013, follows.

<u>Step 2: October 1, 2013 Rate Changes: Electric $7.825 million; Natural Gas $1.330 million:</u>

<u>2013 Capital additions</u> - (Table 2, Line a. and Table 4, Line a.) This adjustment includes 2013 capital additions, reflecting total depreciation expense and rate base, net of accumulated depreciation and accumulated deferred income tax, as of year-end December 31, 2013 for electric operations, and an agreed-upon level of rate base for natural gas operations.

<u>2013 Expenses</u> - (Table 2, Line c. and Table 4, Line b.) The following adjustments include the 2013 expenses removed from the Step 1 increases, effective April 1, 2013, <u>described above</u>, for recovery in Step 2, effective October 1, 2013:

<u>Major Generation O&M</u> - (Table 2, Line c.i.) 2013 incremental non-labor generation plant operation and maintenance (O&M) expenses (electric only).

<u>Information Services & Technology</u> - (Table 2, Line c.ii. and Table 4, Line b.i.) 2013 incremental information service and technology expenses.

<u>CS2 Levelized Return</u> - (Table 2, Line c.iii.) 2013 incremental amortization of the CS2 deferred levelized return (electric only).

Non-Exec Labor - (Table 2, Line c.iv. and Table 4, Line b.ii.) 2013 incremental non-executive labor increases.

2014 Capital additions - (Table 2, Line b.) This adjustment includes certain 2014 capital additions, including depreciation expense and rate base, net of accumulated depreciation and accumulated deferred income tax, to represent an agreed-upon level of rate base (electric only).

Amortization of 2013 Coyote Springs 2/Colstrip Maintenance Deferral - Per Order No. 32371 in Case No. AVU-E-11-01, in order to address the large variability in year-to-year O&M costs, beginning in 2011, the Company was allowed to defer changes in O&M costs related to its Coyote Springs 2 (CS2) natural gas-fired generating plant located near Boardman, Oregon, and its fifteen (15) percent ownership share of the Colstrip 3 & 4 coal-fired generating plants located in southeastern Montana. The Company compares actual, non-fuel, O&M expenses for the Coyote Springs 2 and Colstrip 3 & 4 plants in the applicable deferral year with the amount of expenses authorized for recovery in base rates, and defers the difference from that currently authorized. The deferral occurs annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in January of the year following the period costs are deferred.

As a part of this Settlement agreement, the Parties agree that the amount deferred in 2013 related to the Company's O&M costs of its CS2 and Colstrip 3 & 4 generating plants would be amortized over three years, beginning with the implementation of new base rates resulting from the Company's next general rate case filing, anticipated in 2015.

Q. Please summarize the impact of these adjustments on the Step 2 rate adjustments, effective October 1, 2013.

A. Consolidation of the adjustments discussed above for the Step 2 base rate changes, effective October 1, 2013, results in an electric revenue requirement of \$7.825 million, or a 3.1% increase, and a natural gas revenue requirement of \$1.330 million, or a 2.0% rate increase. Net rate base for electric and natural gas is \$659.04 million and \$116.07 million, respectively, effective October 1, 2013.

Q. Please explain the offset agreed to by the Parties to mitigate the overall impact of the electric October 1, 2013 base rate increase.

A. Effective October 1, 2013, coincident with the electric base rate change described above, for rate mitigation purposes, the Company would amortize a $3.865 million credit resulting from a payment to be made to Avista by the Bonneville Power Administration (BPA) relating to the prior use of Avista's transmission system.

In December 2012, Avista and Bonneville reached a settlement pertaining to the prior and future use of Avista's transmission system by Bonneville. BPA Settlement Revenue of $3.865 million represents Idaho customers' share of the $12.224 million (system) to be paid by BPA for its prior use of Avista's transmission system[5]. The settlement was intended to resolve the issue of compensation to Avista for the prior use of its transmission system by BPA, as well as provide Bonneville with continuing access to transmission in lieu of it constructing additional transmission facilities at this point in time.

On February 5, 2013, Avista received approval from the Federal Energy Regulatory Commission (FERC)(Docket No. ER13-689-000) for the settlement filed on December 31, 2012.

Avista would amortize the BPA settlement revenue over 15-months from October 1, 2013 to December 31, 2014, which reduces the overall bill increase to customers on October 1, 2013 from 3.2% to 1.9%.

[5] For prior periods up through February 28, 2013.

Q. Please explain the offset agreed to by the Parties to mitigate the overall impact of the natural gas October 1, 2013 base rate increase.

A. Effective October 1, 2013, coincident with the natural gas base rate change described above, to partially offset the base rate increase, the Company would amortize the $1.55 million PGA deferral credit balance resulting from the 2012 PGA, over 15-months, October 1, 2013 to December 31, 2014. This PGA deferral credit balance results from Docket AVU-G-12-05, in which the Commission approved Staff's proposal that approximately $1.55 million in un-refunded credit balances be held back due to the Company's filing of a "Notice of Intent to File a General Rate Case." The Commission stated in Order 32651, on page 6, that "the resulting $1.55 million un-refunded credit balance will help mitigate potential rate increases and provide rate stability for customers." This credit would reduce the overall bill increase to customers effective October 1, 2013 from 2.0% to 0.3%.

IV. OTHER ELEMENTS OF THE STIPULATION

Q. Please explain the settlement terms relating to the PCA authorized level of expenses.

A. The new level of power supply expense, retail load and Clearwater Paper generation, for purposes of monthly PCA calculations, are detailed in Attachment B of the Stipulation and Settlement provided as Exhibit No. 1. The Parties agree for settlement purposes to accept the Company's normalized load forecast without specifically accepting the weather normalization methodology or the proposed Energy Efficiency Load Adjustment.

Q. Please explain the settlement terms relating to Depreciation Rates.

A. The Parties have agreed to the updated electric and natural gas depreciation rates as filed by the Company, with all common/allocated plant depreciation rates, including the new depreciation rates for transportation equipment, effective January 1, 2013 to coincide with the Company's Washington and Oregon jurisdictions; the remaining direct Idaho plant depreciation rate changes would be effective April 1, 2013.

Q. Please explain the settlement terms relating to the after-the-fact earnings test for 2013 and 2014.

A. The Company agrees to an after-the-fact earnings test, where it would refund to customers one-half of any earnings in excess of the agreed-upon 9.8% ROE for each of the years 2013 and 2014, to allay any concerns that the base rate relief in April 1, 2013 and October 1, 2013 may allow the Company to exceed its authorized return. The earnings test would be based on actual, consolidated results for Idaho electric and natural gas operations.

Q. Please explain the settlement terms relating to the rate freeze / stay-out agreed to by the Parties.

A. The Parties agree that, in recognition of the two-year rate plan covered by this Stipulation, Avista would not file another electric or natural gas general rate case before May 31, 2014, and while it may request an effective date earlier than January 1, 2015, final approved new rates would not go into effect prior to January 1, 2015. This does not apply to tariff filings authorized by or contemplated by the terms of the Power Cost Adjustment (PCA), or the Purchased Gas Adjustment tariff (PGA), or other miscellaneous filings.

Q. How does the Stipulation's two-year rate plan, including the rate freeze / stay-out element, agreed to by the Parties challenge Avista to manage its costs?

A. The two-year rate plan for the period 2013 and 2014 would only provide retail revenues sufficient to provide Avista the opportunity to earn the return agreed to by the Parties, if the Company undertakes aggressive cost management measures now and going forward.

As explained in Avista's direct testimony, the Company is experiencing significant increases in plant investment and non-fuel O&M expenses required to serve its customers, both of which are growing at a much faster pace than its retail sales. Although we continue to take extensive measures to ensure that the costs that we are incurring represent the most cost-effective and reliable way to continue to serve our customers, while preserving a high level of customer satisfaction, we continue to experience significant increases in annual operating expenses.

Avista has put into place additional cost-management measures, which combined with the rate adjustments in the Settlement, will provide the Company a reasonable opportunity to earn the return agreed to in the Stipulation. As an example, in October 2012, Avista's Board of Directors approved the Company's Voluntary Severance Incentive Plan (VSIP), which was implemented in December 2012. Through this program, effective January 1, 2013 Avista reduced its number of employees by 55.

V. RATE SPREAD & RATE DESIGN

Q. Please explain the settlement terms relating to cost of service.

A. For electric operations, the Company prepared a cost of service analysis using a 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 15% 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 25% 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, without agreement on any particular cost of service methodology.

Q. How did the Stipulation address rate design?

A. For settlement purposes, the Parties have agreed that the revenue requirement for each electric and natural gas service schedule would be applied as a uniform percentage increase to each volumetric energy rate, as shown in Attachment C of the Stipulation and Settlement provided as Exhibit No. 1, and there would be no change to the residential electric Schedule 1 and natural gas Schedule 101 basic charges.

Attachment C of the Stipulation provides a summary of the current and proposed rates and charges for electric and natural gas service.

Q. Please explain how the Stipulation addresses rate spread/rate design related to the electric and natural gas base rate offsets effective October 1, 2013.

A. The Parties have agreed that the electric base rate offset related to the BPA Settlement Revenues would be spread to electric rate schedules on a uniform cents per kWh basis, and the natural gas base rate offset related to the 2012 PGA deferral credit balance of $1.55 million would be spread to natural gas rate schedules on a uniform cents per therm basis.

Attachment D of the Stipulation contains the form of tariff related to the electric and natural gas offsets agreed to by the Parties. A new electric rate schedule, Schedule 97, would be used for purposes of passing through to customers the electric offset. A new natural gas rate schedule, Schedule 197, would be used for purposes of passing through to customers the natural gas offset. Both tariffs would expire on December 31, 2014.

Any under- or over-refunded amounts relating to the electric or natural gas offsets would be trued up in the following year's Power Cost Adjustment (electric) or Purchased Gas Cost Adjustment (natural gas) filings.

VI. CUSTOMER SERVICE PROGRAMS

Q. Does the Company have programs in place to mitigate the impacts on customers of the proposed rate increases?

A. Yes. We have a history of making it a priority within our Company to maintain meaningful programs to assist our customers that are least able to pay their energy bills. We also have programs to assist our entire customer base, i.e., not just our low-income customers. Some of the key programs that we offer or support are as follows:

- **DSM Energy Efficiency Programs and Funding.** The Company offers a broad array of energy efficiency program measures that provide customers with increased opportunity to manage their energy bills. In 2012, Avista hosted two Energy Fairs, one in Lewiston, and the other in Coeur d'Alene. Over 280 customers were in attendance and received energy efficiency tips and kits that included low cost/no cost ways to reduce energy consumption.

- **Project Share.** Project Share is a voluntary program allowing customers to donate funds that are distributed through community action agencies to customers in need. In addition to the Idaho customer contributions during the 2011/2012 program year of $66,490, the Company also contributed $69,421 (Idaho's share) to the program.

- **Comfort Level Billing.** The Company offers the option for all customers to pay the same bill amount each month of the year by averaging their annual usage. Under this program, customers can avoid unpredictable winter heating bills.

- **Payment Arrangements.** The Company's Contact Center Representatives work with customers to set up payment arrangements to pay energy bills.
- **CARES Program.** Customer Assistance Referral and Evaluation Services provides assistance to special-needs customers through access to specially trained (CARES) representatives who provide referrals to area agencies and churches for help with housing, utilities, medical assistance, etc.

- **Senior Energy Outreach:** Avista has developed specific strategic outreach efforts to reach our more vulnerable customers (seniors and disabled customers) with bill paying assistance and energy efficiency information that emphasizes comfort and safety. Some examples of this effort are as follows:

    - **Senior Publications:** Avista has created a one-page advertisement that has been placed in senior resource directories and targeted senior publications to reach seniors with information about energy efficiency, Comfort Level Billing, Avista CARES and energy assistance. A brochure with the same information has also been created for distribution through senior meal delivery programs and other senior home-care programs.

    - **Senior Energy Workshops:** With the help of additional workshop presenters, 9 Senior Energy Workshops were held during 2012 in Idaho. Over 393 seniors were reached and were given Senior Energy Efficiency kits along with learning about low-cost/no-cost ways to reduce energy use.

VI. CONCLUSION

Q. In conclusion, why is this Stipulation in the public interest?

A. This Stipulation strikes a reasonable balance between the interests of the Company and its customers, including its low-income customers. As such, it represents a reasonable compromise among differing interests and points of view.

The terms of the Settlement agreement represent a two-year rate plan designed to provide necessary retail revenues. For its part, the Company will continue to closely manage its costs during this two-year period. The Parties have agreed that the Company has demonstrated the need for revenue requirement increases for both its electric and natural gas operations, thus providing recovery of its costs over the two-year rate period.

Therefore, the Stipulation is designed to address the multiple purposes of addressing the Company's revenue requirement needs; minimizing the impact to customers from changes in retail rates; providing rate certainty over the two year period 2013-2014; and reducing the administrative burden to all parties and the Commission associated with this general rate case, as well as avoiding another rate filing in 2013 for new rates in 2014. It also provides a form of price cap regulation under which the Company is expected to manage its costs under the given rates to earn a fair return.

In the final analysis, however, any settlement reflects a compromise in the give-and-take of negotiations. The Commission, therefore, has before it a Stipulation that is supported by sound analysis and supporting evidence, the approval of which is in the public interest.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

DIRECT TESTIMONY OF
KELLY O. NORWOOD
IN SUPPORT OF THE
STIPULATION AND SETTLEMENT
Case Nos. AVU-E-12-08 & AVU-G-12-07

EXHIBIT 1

REVISED – March 1, 2013

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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 NOS. AVU-E-12-08 AVU-G-12-07 **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 Idaho Conservation League ("Conservation League")[1]. These entities are collectively referred to as the "Parties," and represent several parties in the above-referenced cases that participated in settlement discussions. The Parties understand this Stipulation is subject to approval by the Idaho Public Utilities Commission ("IPUC" or the "Commission").

[1] The Community Action Partnership Association of Idaho ("CAPAI") participated in settlement discussions and is continuing to review its position with regard to the Settlement, as proposed, and will be filing separate comments and/or testimony in that regard. The Snake River Alliance, as an intervenor, was provided notice of the settlement discussions, but did not participate.

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 and that this Stipulation 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 October 11, 2012, Avista filed an Application with the Commission for authority to increase revenue from electric and natural gas service in Idaho by 4.6% and 7.2%, respectively. If approved, the Company's revenues for electric base retail rates would have increased by $11.4 million annually; Company revenues for natural gas service would have increased by $4.6 million annually. The Company requested an effective date of April 1, 2013 for its proposed electric and natural gas rate increases. By Order No. 32689, dated December 4, 2012, 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, the Idaho Conservation League, and the Snake River Alliance. By various orders, the Commission granted these interventions. *See*, IPUC Order Nos. 32678, 32680 and 32687.

4. Settlement conferences were noticed and held in the Commission offices on January 17 and 24, 2013, and were attended by signatories to this Stipulation; further discussions ensued. Based upon the settlement 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 the following revenue requirement in two steps, as summarized in Attachment A, and below:

Electric

Step 1: April 1, 2013

a. No electric base rate change effective April 1, 2013, instead of the proposed 4.6%, or $11.393 million.

Step 2: October 1, 2013

a. Overall electric base rate increase of 3.1% (3.2% in billed rates) or $7.825 million effective October 1, 2013.

b. Offsets – Apply $3.865 million for rate mitigation purposes (the BPA Parallel Operation Settlement[2]), and amortize that offset over 15 months, from October 1, 2013 to December 31, 2014.

c. Net overall bill increase to customers of 1.9% effective October 1, 2013.

Summary of Electric Rate Changes			
	Billing Rate Change	Offset	Net Billing Rate Change
April 1, 2013	0.0%	0.0%	0.0%
October 1, 2013	3.2%	-1.3%	1.9%

[2] The BPA Settlement Revenue of $3.865 million represents the Idaho customers' share of $12.224 million (system) for the past use of Avista's transmission system for the period January 2005 through February 2013. In December 2012, Avista and Bonneville reached a settlement that pertains to the use of Avista's transmission system by Bonneville. Avista and Bonneville each own and operate transmission systems that are interconnected at various points. Between June 1998 and December 2009, Bonneville integrated four generation projects onto its 115 kV transmission system in the Walla Walla, Washington area. Bonneville sold transmission capacity to wind projects totaling 336 MW. The transmission path for these four projects follows a single Bonneville line that has a rated capacity of only 203 MW. Upon Avista's discovery of this situation, Avista asserted that Bonneville requires the use of up to 133 MW of parallel capacity support through the Avista system in order to fulfill Bonneville's transmission service obligations for these wind projects. The Settlement Agreement was intended to resolve the issue of compensation to Avista for the prior use of its transmission system, as well as provide Bonneville with continuing cost-effective parallel capacity support in lieu of constructing additional transmission facilities at this point in time. Avista anticipates FERC approval of the Settlement in February 2013, after which Avista will bill Bonneville.

Natural Gas

Step 1: April 1, 2013

a. Overall natural gas base rate increase of 4.9% (5.0% in billed rates) or $3.115 million, instead of the proposed 7.2%, or $4.561 million, effective April 1, 2013.

Step 2: October 1, 2013

a. Overall natural gas base rate increase of 2.0% (2.0% in billed rates) or $1.330 million effective October 1, 2013.

b. Offsets – Apply $1.550 million PGA deferral credit balance from 2012 PGA[3] to partially offset the base rate increase, amortized over 15 months, October 1, 2013 to December 31, 2014.

c. Net overall bill impact to customers of 0.3% effective October 1, 2013.

Summary of Natural Gas Rate Changes			
	Billing Rate Change	Offset	Net Billing Rate Change
April 1, 2013	5.0%	0.0%	5.0%
October 1, 2013	2.0%	-1.7%	0.3%

6. Cost of Capital. The Settling Parties agree to a 9.8 percent return on equity, with a 50.0 percent common equity ratio, and adopt the capital structure and resulting rate of return as set forth below:

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
Total Debt	50.00%	6.01%	3.01%
Common Equity	50.00%	9.80%	4.90%
Total	100.00%		**7.91%**

[3] In Docket AVU-G-12-05, the Commission approved Staff's proposal that approximately $1.55 million in un-refunded credit balances be held back due to the Company's filing of a "Notice of Intent to File a General Rate Case." The Commission stated in Order 32651, on page 6, that "the resulting $1.55 million un-refunded credit balance will help mitigate potential rate increases and provide rate stability for customers."

A. ELECTRIC

7. Overview of Electric Revenue Requirement (April 1, 2013). Below is a summary table and descriptions of the electric revenue requirement components agreed to by the Parties for April 1, 2013:

SUMMARY TABLE OF ADJUSTMENTS TO ELECTRIC REVENUE REQUIREMENT
EFFECTIVE APRIL 1, 2013
000s of Dollars

		Revenue Requirement		Rate Base	
	Amount as Filed:	**$**	**11,393**	**$**	**639,030**
	Adjustments:				
a.)	Cost of Capital	$	(5,517)		
b.)	Remove 2013 Capital Additions (Delay to October 1, 2013)	$	(1,117)	$	(1,582)
c.)	Remove 2013 Expenses: Delay Recovery to October 1, 2013 Rate Change				
i.	Major Generation O&M	$	(926)		
ii.	Information Services & Technology	$	(318)		
iii.	CS2 Levelized Return	$	(38)		
iv.	Non-Exec Labor	$	(426)		
d.)	Remove 2013 Property Tax Expense	$	(428)		
e.)	Remove Officer Incentive and CPI escalation	$	(187)		
f.)	Two-Year Amortization of Reardan	$	878		
g.)	Include Palouse Wind in PCA until in base rates in 2015 (90%/10% sharing)	$	(3,139)		
h.)	Miscellaneous Adjustments: Two-Year Amortization of Booz Consulting costs, Oasis Training, Abandoned Projects & Depreciation Study expense	$	(175)		
	Adjusted Amounts Effective April 1, 2013	**$**	**-**	**$**	**637,448**

a. Cost of Capital. As previously described (see Paragraph 6 above).

b. Remove 2013 Capital Additions. Reflects total depreciation expense and rate base, net of accumulated depreciation and accumulated deferred income tax, as of year-end December 31, 2012. Moves 2013 capital additions to October 1, 2013 rate change.

c. Remove 2013 Expenses: Delay Recovery to October 1, 2013 Rate Change.

   i. Major Generation O&M. Removes the 2013 incremental non-labor generation plant operation and maintenance (O&M) expense related to the Company's thermal generation plant at Kettle Falls, and its hydro generation plants, to be included in the October 1, 2013 rate change.

ii. Information Services & Technology. Removes the 2013 incremental information service and technology expenses, related mainly to the Company's replacement of the Company's Customer Service Information System, and increased costs to support various business processes, application support, additional security requirements, annual contractual agreements and maintenance and license fees, to be included in the October 1, 2013 rate change.

iii. CS2 Levelized Return. Removes the 2013 incremental amortization of the deferred levelized return related to the 10-year deferral of return on the Coyote Springs 2 (CS2) investment, to be included in the October 1, 2013 rate change.

iv. Non-Exec Labor. Removes the 2013 incremental non-executive labor increases, to be included in the October 1, 2013 rate change.

d. 2013 Property Tax. Removes the 2013 incremental property tax expense, adjusting property tax expense to December 31, 2012 levels.

e. Remove Officer Incentive and CPI Escalation. Removes officer portion of incentives and removes the Consumer Price Index adjustment on incentives included in the Company's original filing.

f. Two-Year Amortization of Reardan. See Paragraph 10 below for further information.

g. Include Palouse Wind in PCA until Reflected in Base Rates in 2015. See Paragraph 9 below for further information.

h. Miscellaneous Adjustments. Includes a two-year amortization of Booz & Co. consulting fees, thereby reducing test period expenses, and removes certain other amounts related to OASIS training, abandoned projects and depreciation study expenses.

8. Overview of Electric Revenue Requirement (October 1, 2013). Below is a summary table and descriptions of the Electric revenue requirement components agreed to by the Parties for October 1, 2013:

SUMMARY TABLE OF ELECTRIC REVENUE REQUIREMENT
EFFECTIVE OCTOBER 1, 2013
000s of Dollars

		Revenue Requirement	Rate Base
	Amounts Effective April 1, 2013	**$ -**	**$ 637,448**
	Adjustments to October 1, 2013 Rate Change:		
a.)	2013 Capital Additions	$ 5,488	$ 20,705
b.)	2014 Capital Additions	$ 629	$ 888
c.)	Add 2013 Expenses		
i.	Major Generation O&M	$ 926	
ii.	Information Services & Technology	$ 318	
iii.	CS2 Levelized Return	$ 38	
iv.	Non-Exec Labor	$ 426	
	Adjusted Amounts Effective October 1, 2013	**$ 7,825**	**$ 659,041**

a. 2013 Capital Additions. Includes 2013 capital additions, reflecting total depreciation expense and rate base, net of accumulated depreciation and accumulated deferred income tax, as of year-end December 31, 2013.

b. 2014 Capital Additions. Includes certain 2014 capital additions, including depreciation expense and rate base, net of accumulated depreciation and accumulated deferred income tax, to represent an agreed-upon level of rate base.

c. 2013 Expenses:

i. Major Generation O&M. Includes the 2013 incremental non-labor generation plant O&M expense discussed above in Paragraph 7(c)(i).

ii. Information Services & Technology. Includes the 2013 incremental information service and technology expenses discussed above in Paragraph 7(c)(ii).

iii. CS2 Levelized Return. Includes the 2013 incremental amortization of the deferred CS2 levelized return discussed above in Paragraph 7(c)(iii).

iv. Non-Exec Labor. Includes the 2013 incremental non-executive labor increases discussed above in Paragraph 7(c)(iv).

9. Palouse Wind. The Parties agree that recovery of costs related to the Palouse Wind Power Purchase Agreement ("PPA") will be included in the PCA, subject to the current sharing (90% customer, 10% Company) until it is included in base rates as part of the implementation of new rates from the Company's next general rate case anticipated in 2015.

10. Reardan Wind Site Deferral. The Parties agree to amortize the Reardan Wind Project deferred balance of $1.747 million over a two-year period beginning April 1, 2013.[4]

11. Amortization of 2013 Coyote Springs 2/Colstrip Maintenance Deferral. The Parties agree that the amount deferred in 2013 related to the Company's O&M costs of its Coyote Springs 2 (CS2) natural gas-fired generating plant and its fifteen (15) percent ownership

[4] In May 2008, Avista purchased the Reardan Wind Project Site from Energy Northwest, the then-current developer, after it was demonstrated as the Company's least-cost option for securing a renewable resource for its customers, consistent with its 2007 Integrated Resource Plan. Avista later chose to delay the construction of the Reardan project and take advantage of much-lower costs for wind projects that emerged in 2011 (Palouse Wind). Avista recorded $4.0 million of site acquisition and preparation costs, of which approximately $1.7 million is Idaho's share. This includes approx. $0.37 million in AFUDC in accordance with Order No. 30611 (Case No. AVU-E-08-04)

share of the Colstrip 3 & 4 coal-fired generating plants will be amortized over three years, beginning with the implementation of new base rates resulting from the Company's next general rate case filing.[5]

B. NATURAL GAS

12. Overview of Natural Gas Revenue Requirement (April 1, 2013). 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 APRIL 1, 2013
000s of Dollars

		Revenue Requirement		Rate Base
	Amount as Filed:	**$**	**4,561**	**$ 110,930**
	Adjustments:			
a.)	Cost of Capital	$	(957)	
b.)	Remove 2013 Capital Additions (Delay to October 1, 2013)	$	(22)	$ 1,309
c.)	Remove 2013 Expenses: Delay Recovery to October 1, 2013 Rate Change			
i.	Information Services & Technology	$	(42)	
ii.	Non-Exec Labor	$	(215)	
d.)	Remove 2013 Property Tax Expense	$	(84)	
e.)	Remove Officer Incentive and CPI escalation	$	(50)	
f.)	Miscellaneouse Adjustments: Two-Year Amortization of Booz Consulting costs, Injuries & Damages, Abandoned Projects & Depreciation Study expense	$	(76)	
	Adjusted Amounts Effective April 1, 2013	**$**	**3,115**	**$ 112,239**

a. Cost of Capital. As previously described (see Paragraph 6 above).

b. Remove 2013 Capital Additions. Reflects total depreciation expense and rate base, net of accumulated depreciation and accumulated deferred income tax,

[5] Per Order No. 32371 in Case No. AVU-E-11-01, in order to address the large variability in year-to-year O&M costs, beginning in 2011, the Company was allowed to defer changes in O&M costs related to its Coyote Springs 2 (CS2) natural gas-fired generating plant located near Boardman, Oregon, and its fifteen (15) percent ownership share of the Colstrip 3 & 4 coal-fired generating plants located in southeastern Montana. The Company compares actual, non-fuel, O&M expenses for the Coyote Springs 2 and Colstrip 3 & 4 plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defers the difference from that currently authorized. The deferral occurs annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in January of the year following the period costs are deferred.

as of year-end December 31, 2012. Moves certain 2013 capital additions to the October 1, 2013 rate change.[6]

c. Remove 2013 Expenses: Delay Recovery to October 1, 2013 Rate Change.

   i. Information Services & Technology. Removes the 2013 incremental information service and technology expenses as discussed above, to be included in the October 1, 2013 rate change.

   ii. Non-Exec Labor. Removes the 2013 incremental non-executive labor increases as discussed above, to be included in the October 1, 2013 rate change.

d. 2013 Property Tax. Removes the 2013 incremental property tax expense, adjusting property tax expense to December 31, 2012 levels.

e. Remove Officer Incentive and CPI Escalation. Removes officer portion of incentives and removes the Consumer Price Index adjustment on incentives included in the Company's original filing.

f. Miscellaneous Adjustments. Includes a two-year amortization of Booz & Co. consulting fees, thereby reducing test period expenses, and removes certain other amounts related to injuries and damages, abandoned projects and depreciation study expenses.

[6] In the Company's filed case, inclusion of total net plant, including accumulated depreciation and accumulated deferred income tax on an average-of-monthly-average basis for 2013, had the effect of reducing rate base by $1.309 million and increasing revenue requirement associated with a net increase in depreciation expense by $22,000. This is due to the original filed adjustment that depreciated all plant, including the plant in service balance at December 31, 2012, to the AMA balance at December 31, 2013. The additional accumulated depreciation on plant in service at December 31, 2012 was greater than the net plant additions in 2013 on an AMA basis, which had an overall impact of reducing net rate base.

13. Overview of Natural Gas Revenue Requirement (October 1, 2013). 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 OCTOBER 1, 2013
000s of Dollars

		Revenue Requirement	Rate Base
	Amounts Effective April 1, 2013	$ -	$ 112,239
	Adjustments to October 1, 2013 Rate Change:		
a.)	2013 Capital Additions	$ 1,073	$ 3,831
b.)	Add 2013 Expenses		
i.	Information Services & Technology	$ 42	
ii.	Non-Exec Labor	$ 215	
	Adjusted Amounts Effective October 1, 2013	$ 1,330	$ 116,070

a. 2013 Capital Additions. Includes certain 2013 capital additions, including depreciation expense and rate base, net of accumulated depreciation and accumulated deferred income tax, to represent an agreed-upon level of rate base.

b. 2013 Expenses:

i. Information Services & Technology. Includes the 2013 incremental information service and technology expenses discussed above in Paragraph 12(c)(i).

ii. Non-Exec Labor. Includes the 2013 incremental non-executive labor increases discussed above in Paragraph 12(c)(ii).

C. OTHER SETTLEMENT COMPONENTS

14. PCA Authorized Level of Expense. The new level of power supply expense, retail load and Clearwater Paper generation, and the April 1, 2013 and October 1, 2013 Load Change Adjustment Rates resulting from the April 1, 2013 and October 1, 2013 settlement revenue requirements for purposes of the monthly PCA mechanism calculations, are detailed in Attachment B. The parties agree for the purpose of Settlement in this case to accept the Company's normalized load forecast without specifically accepting the weather normalization methodology or the proposed Energy Efficiency Load Adjustment.

15. Depreciation Rates. The Parties have agreed to the updated electric and natural gas depreciation rates as filed by the Company, with all common/allocated plant depreciation rates, including the new depreciation rates for transportation equipment, effective January 1, 2013 to coincide with the Company's Washington and Oregon jurisdictions, with the remaining direct Idaho plant depreciation rate changes effective April 1, 2013.

16. Earnings Test. The Company agrees to an after-the-fact earnings test, where it would refund to customers one-half of any earnings in excess of the 9.8% ROE for each of the years 2013 and 2014, to allay any concerns that the base rate relief in April 1, 2013 and October 1, 2013 may allow the Company to exceed its authorized return. The earnings test would be based on actual, consolidated results for Idaho electric and natural gas operations.

17. Rate Freeze/Stay Out. The Parties agree that, in recognition of the two-year rate plan covered by this Stipulation, Avista will not file another electric or natural gas general rate case before May 31, 2014, and while it may request an effective date earlier than January 1, 2015, final approved new rates will not go into effect prior to January 1, 2015. This does not apply to tariff filings authorized by or contemplated by the terms of the Power Cost Adjustment (PCA), or the Purchased Gas Adjustment tariff (PGA), or other miscellaneous filings.

D. COST OF SERVICE/RATE SPREAD/RATE DESIGN

18. Cost of Service. For electric operations, the Company prepared an analysis using a 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 15% 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 25% 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.

19. Rate Spread/Rate Design (Base Rate Changes).

(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) The Parties agree that the revenue requirement for each electric and natural gas service schedule will be applied as a uniform percentage increase to each volumetric energy rate as shown in Attachment C. The Parties agree that there will be no change to Schedule 1 and Schedule 101 basic charges.

(c) Attachment C provides a summary of the current and revised rates and charges (as per the Settlement) for electric and natural gas service.

20. Rate Spread/Rate Design (Offsets).

(a) The Parties have agreed that the electric base rate offset related to the BPA Settlement Revenues will be spread to electric rate schedules on a uniform cents per kWh basis.

(b) The Parties have agreed that the natural gas base rate offset related to the 2012 PGA deferral credit balance of $1.55 million will be spread to natural gas rate schedules on a uniform cents per therm basis.

(c) Attachment D contains the form of tariff related to the electric and natural gas offsets agreed to by the Parties. A new electric rate schedule, Schedule 97, will be used for purposes of passing through to customers the electric offset. A new natural gas rate schedule, Schedule 197, will be used for purposes of passing through to customers the natural gas offset. Both tariffs would expire on December 31, 2014.

(d) Any under- or over-refunded amounts relating to the Electric or Natural Gas offsets will be trued up in the following year's Power Cost Adjustment (electric) or Purchased Gas Cost Adjustment (natural gas).

21. <u>Resulting Percentage Increase by Electric Service Schedule</u>. The following tables reflect the agreed-upon percentage increase by schedule for electric service[7]:

Electric Increase Percentage by Schedule - April 1, 2013		
Rate Schedule	**Increase in Base Rates**	**Net Increase in Billing Rates**
Residential Schedule 1	0.0%	0.0%
General Service Schedule 11/12	0.0%	0.0%
Large General Service Schedule 21/22	0.0%	0.0%
Extra Large General Service Schedule 25	0.0%	0.0%
Clearwater Paper Schedule 25P	0.0%	0.0%
Pumping Service Schedule 31/32	0.0%	0.0%
Street & Area Lights Schedules	0.0%	0.0%
Overall	**0.0%**	**0.0%**

[7] Avista will file both electric and natural gas conforming tariffs related to the October 1, 2013 rate changes with the Commission on or before August 30, 2013 for the Commission's review and approval.

Electric Increase Percentage by Schedule - October 1, 2013		
Rate Schedule	**Increase in Base Rates**	**Net Increase in Billing Rates***
Residential Schedule 1	3.5%	2.6%
General Service Schedule 11/12	2.8%	1.9%
Large General Service Schedule 21/22	3.3%	2.1%
Extra Large General Service Schedule 25	2.7%	1.0%
Clearwater Paper Schedule 25P	2.3%	0.4%
Pumping Service Schedule 31/32	3.9%	2.9%
Street & Area Lights Schedules	3.1%	2.7%
Overall	**3.1%**	**1.9%**
* Net Increase includes the effects of the proposed changes in Schedule 97 (BPA Adjustment) and the General Rate Increase, all effective on October 1, 2013.		

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

Natural Gas Increase Percentage by Schedule - April 1, 2013		
Rate Schedule	**Increase in Base Rates**	**Net Increase in Billing Rates**
General Service Schedule 101	5.3%	5.4%
Large General Service Schedule 111/112	3.8%	3.9%
Interruptible Sales Service Schedule 131/132	4.0%	4.0%
Transportation Service Schedule 146	8.7%	8.7%
Overall	**4.9%**	**5.0%**

Natural Gas Increase Percentage by Schedule - October 1, 2013		
Rate Schedule	**Increase in Base Rates**	**Net Increase in Billing Rates****
General Service Schedule 101	2.1%	0.6%
Large General Service Schedule 111/112	1.6%	-0.5%
Interruptible Sales Service Schedule 131/132	1.4%	-1.4%
Transportation Service Schedule 146	3.5%	3.5%
Overall	**2.0%**	**0.3%**
** Net Increase includes the effects of the proposed changes in Schedule 197 (PGA) and the General Rate Increase, all effective on October 1, 2013.		

IV. OTHER GENERAL PROVISIONS

23. 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.

24. 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.

25. 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.

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

27. 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.

28. 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.

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

DATED this 6th day of February, 2013.

Avista Corporation

By: ______________________

David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

By: ______________________

Karl Klein
Weldon Stutzman
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

DATED this 6th day of February, 2013.

Avista Corporation

By:______________________________
David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

By:______________________________
Karl Klein
Weldon Stutzman
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

DATED this ____ day of February, 2013.

Avista Corporation

By:______________________________

David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

By:______________________________

Karl Klein
Weldon Stutzman
Deputy Attorneys General

Clearwater Paper Corporation

By: Peter J. Richardson

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

DATED this 6 day of February, 2013.

Avista Corporation

By:______________________________
David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

By:______________________________
Karl Klein
Weldon Stutzman
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

DATED this 5th day of February, 2013.

Avista Corporation

By:______________________________
David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

By:______________________________
Karl Klein
Weldon Stutzman
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: [signature]
Benjamin J. Otto
Attorney for ICL

STIPULATION AND SETTLEMENT
Case Nos. AVU-E-12-08 & AVU-G-12-07

ATTACHMENT A

Avista Utilities

Idaho Rate Adjustments

Electric

Line		TOTAL	RESIDENTIAL SCHEDULE 1	GENERAL SVC. SCH. 11,12	LG. GEN. SVC. SCH. 21,22	EX LG GEN SVC SCHEDULE 25	CLEARWATER SCHEDULE 25P	PUMPING SCH. 31, 32	ST & AREA LTG SCH. 41-49
	Effective April 1, 2013								
1	Total Billed Revenue	$ 245,924,000	$ 96,390,000	$ 32,597,000	$ 51,597,000	$ 16,024,000	$ 41,005,000	$ 4,867,000	$ 3,444,000
2	**Revenue Changes**								
3	GRC Increase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	**Total Revenue Change**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
5									
6	**Percentage Changes**								
7	GRC Increase	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
8	**Total Billed Percentage Change**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
9									
10									
11									
12									
13									
14									
15									
16	**Effective October 1, 2013**								
17	Total Billed Revenue	$ 245,924,000	$ 96,390,000	$ 32,597,000	$ 51,597,000	$ 16,024,000	$ 41,005,000	$ 4,867,000	$ 3,444,000
18	**Revenue Changes**								
19	GRC Increase *	$ 7,825,000	$ 3,532,000	$ 920,000	$ 1,714,000	$ 434,000	$ 928,000	$ 190,000	$ 107,000
20	BPA Reduction (15 Month Amortization) **	$ (3,058,000)	$ (1,024,000)	$ (301,000)	$ (614,000)	$ (273,000)	$ (782,000)	$ (51,000)	$ (13,000)
21	**Total Revenue Change**	**$ 4,767,000**	**$ 2,508,000**	**$ 619,000**	**$ 1,100,000**	**$ 161,000**	**$ 146,000**	**$ 139,000**	**$ 94,000**
22									
23	**Percentage Changes**								
24	GRC Increase	3.2%	3.7%	2.8%	3.3%	2.7%	2.3%	3.9%	3.1%
25	BPA Reduction	-1.3%	-1.1%	-0.9%	-1.2%	-1.7%	-1.9%	-1.0%	-0.4%
26	**Total Billed Percentage Change**	**1.9%**	**2.6%**	**1.9%**	**2.1%**	**1.0%**	**0.4%**	**2.9%**	**2.7%**
27									
28									

29 * Utilizes a pro-rata allocation of the Company's electric rate spread percentage from its original filing for purposes of spreading the revised revenue requirement.

30 ** The BPA settlement benefit of $3.865 million amortized over 15 months is equal to $3.058 million annually. It will expire @ 12/31/14.

Avista Utilities
Idaho Rate Adjustments

Natural Gas

Effective April 1, 2013	TOTAL	GEN SERVICE SCHEDULE 101	LRG GEN SVC SCH. 111&112	INTERRUPTIBLE SCH. 131&132	TRANSPORT SCHEDULE 146	SPECIAL CONTRACTS
Total Billed Revenue	$ 62,090,000	$46,896,000	$14,607,000	$201,000	$289,000	$97,000
Revenue Changes						
GRC Increase *	$ 3,114,740	$ 2,512,740	$ 569,000	$ 8,000	$ 25,000	$ -
Total Revenue Change	**$ 3,114,740**	**$ 2,512,740**	**$ 569,000**	**$ 8,000**	**$ 25,000**	**$ -**
Percentage Changes						
GRC Increase	5.0%	5.4%	3.9%	4.0%	8.7%	0.0%
Total Billed Percentage Change	**5.0%**	**5.4%**	**3.9%**	**4.0%**	**8.7%**	**0.0%**

Effective October 1, 2013	TOTAL	GEN SERVICE SCHEDULE 101	LRG GEN SVC SCH. 111&112	INTERRUPTIBLE SCH. 131&132	TRANSPORT SCHEDULE 146	SPECIAL CONTRACTS
Total Billed Revenue	$ 65,204,740	$ 49,408,740	$ 15,176,000	$ 209,000	$ 314,000	$ 97,000
Revenue Changes						
GRC Increase *	$ 1,330,000	$ 1,073,000	$ 243,000	$ 3,000	$ 11,000	$ -
PGA Reduction (15 Month Amortization) **	$ (1,131,000)	$ (799,000)	$ (326,000)	$ (6,000)	$ -	$ -
Total Revenue Change	**$ 199,000**	**$ 274,000**	**$ (83,000)**	**$ (3,000)**	**$ 11,000**	**$ -**
Percentage Changes						
GRC Increase	2.0%	2.2%	1.6%	1.4%	3.5%	0.0%
PGA Reduction	-1.7%	-1.6%	-2.1%	-2.9%	0.0%	0.0%
Total Billed Percentage Change	**0.3%**	**0.6%**	**-0.5%**	**-1.4%**	**3.5%**	**0.0%**

* Utilizes 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.

** The PGA deferral of $1.55 million amortized over 15 months is equal to $1.31 million annually. It will expire @ 12/31/14.

STIPULATION AND SETTLEMENT
Case Nos. AVU-E-12-08 & AVU-G-12-07

ATTACHMENT B

REVISED - March 1, 2013

Avista Corp
Pro forma January - December
PCA Authorized Expense and Retail Sales

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 (2)	$88,182,972	$10,717,432	$9,359,487	$8,546,885	$6,841,564	$5,337,699	$5,287,042	$5,648,618	$7,939,502	$5,551,282	$5,789,904	$8,437,276	$8,726,282
Account 501 - Thermal Fuel	$30,916,732	$2,789,917	$2,632,215	$2,785,057	$2,031,330	$1,718,372	$1,405,767	$2,715,972	$2,948,383	$2,925,528	$3,051,784	$2,909,636	$3,002,771
Account 547 - Natural Gas Fuel	$86,631,151	$8,264,229	$7,537,533	$7,376,233	$4,927,841	$2,851,219	$2,201,285	$6,893,937	$8,303,984	$8,561,441	$9,099,171	$9,713,701	$10,900,577
Account 447 - Sale for Resale	$57,620,639	$4,641,568	$4,386,361	$4,792,538	$5,372,207	$5,022,215	$3,271,701	$6,033,100	$3,115,032	$4,649,875	$4,672,288	$5,573,841	$6,089,913
Power Supply Expense	$148,110,215	$17,130,010	$15,142,875	$13,915,637	$8,428,528	$4,885,076	$5,622,392	$9,225,427	$16,076,838	$12,388,375	$13,268,571	$15,486,772	$16,539,716
Transmission Expense	$17,970,479	$1,495,284	$1,530,877	$1,480,538	$1,427,248	$1,371,518	$1,420,882	$1,432,251	$1,480,124	$1,483,239	$1,547,809	$1,665,262	$1,635,447
Transmission Revenue	$15,910,828	$1,324,260	$1,118,308	$1,231,356	$1,159,556	$1,231,179	$1,409,821	$1,563,830	$1,439,516	$1,361,638	$1,498,286	$1,294,553	$1,278,524

PCA Authorized Idaho Retail Sales (3)

	Total	January	February	March	April	May	June	July	August	September	October	November	December
Total Retail Sales, MWh	2,920,315	288,554	259,942	251,709	220,890	215,126	211,354	242,247	239,641	218,705	210,034	262,809	299,304
Clearwater Paper Retail Load = Generation, MWh	444,563	39,257	35,848	26,604	38,658	38,512	33,557	38,814	38,992	35,735	38,447	38,899	41,240

April 1, 2013 Approved Rates
Load Change Adjustment Rate $26.63 /MWh
October 1, 2013 Approved Rates
Load Change Adjustment Rate $26.97 /MWh

PCA Authorized Clearwater Paper Directly Assigned Values

	Total	January	February	March	April	May	June	July	August	September	October	November	December
Purchased Power	$19,080,644	$1,684,910	$1,538,596	$1,141,844	$1,659,201	$1,652,935	$1,440,266	$1,665,897	$1,673,537	$1,533,746	$1,650,145	$1,669,545	$1,770,021
April 1, 2013 Approved Rates													
Retail Revenue from Load = Generation (4)	$21,043,428	$1,854,485	$1,707,734	$1,256,968	$1,833,636	$1,819,288	$1,591,683	$1,833,555	$1,841,967	$1,694,991	$1,816,219	$1,844,742	$1,948,159
October 1, 2013 Approved Rates													
Retail Revenue from Load = Generation (4)	$21,523,556	$1,896,882	$1,746,450	$1,285,700	$1,875,387	$1,860,881	$1,627,925	$1,875,474	$1,884,078	$1,733,585	$1,857,742	$1,886,753	$1,992,699

1) Multiply system numbers by 34.76% to determine Idaho share.
2) Purchased Power Expense includes reduction for Pro Forma Billing Determinants at system cost.
3) 12 months ended June 2012 weather normalized Idaho retail sales (utilizes Company's Pro Forma Billing Determinants).
4) Calculated at approved marginal Schedule 25P rates assuming 100% load factor for demand charge.

STIPULATION AND SETTLEMENT

Case Nos. AVU-E-12-08 & AVU-G-12-07

ATTACHMENT C

AVISTA UTILITIES
IDAHO ELECTRIC, CASE NO. AVU-E-12-08
PROPOSED INCREASE BY SERVICE SCHEDULE
12 MONTHS ENDED JUNE 30, 2012
(000s of Dollars)

Effective October 1st, 2013

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	Total Sch. 97 - BPA Decrease	Total Billed Revenue at Proposed Rates(2)	Gen. Incr. as a % of Billed Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Residential	1	$99,497	$3,532	$103,029	3.5%	$96,390	$3,532	($1,024)	$98,898	2.6%
2	General Service	11,12	$32,432	$920	$33,352	2.8%	$32,597	$920	($301)	$33,216	1.9%
3	Large General Service	21,22	$51,400	$1,714	$53,114	3.3%	$51,597	$1,714	($614)	$52,698	2.1%
4	Extra Large General Service	25	$16,036	$434	$16,470	2.7%	$16,024	$434	($273)	$16,185	1.0%
5	Clearwater	25P	$41,091	$928	$42,019	2.3%	$41,005	$928	($782)	$41,151	0.4%
6	Pumping Service	31,32	$4,859	$190	$5,049	3.9%	$4,867	$190	($51)	$5,006	2.9%
7	Street & Area Lights	41-49	$3,405	$107	$3,512	3.1%	$3,444	$107	($13)	$3,539	2.7%
8	Total		$248,720	$7,825	$256,545	3.1%	$245,924	$7,825	($3,058)	$250,691	1.9%

(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 - BPA Rate Adjustment.

AVISTA UTILITIES
IDAHO ELECTRIC, CASE NO. AVU-E-12-08
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

Effective October 1st, 2013

(a)	Base Tariff Sch. Rate (b)	Present Other Adj.(1) (c)	Present Billing Rate (d)	General Rate Inc/(Decr) (e)	Sch. 97-BPA Decrease (f)	Proposed Billing Rate (g)	Proposed Base Tariff Rate (h)
Residential Service - Schedule 1							
Basic Charge	$5.25		$5.25	$0.00		$5.25	$5.25
Energy Charge:							
First 600 kWhs	$0.07848	($0.00276)	$0.07572	$0.00298	($0.00091)	$0.07779	$0.08146
All over 600 kWhs	$0.08764	($0.00276)	$0.08488	$0.00332	($0.00091)	$0.08729	$0.09096
General Services - Schedule 11							
Basic Charge	$10.00		$10.00	$0.00		$10.00	$10.00
Energy Charge:							
First 3,650 kWhs	$0.09338	$0.00072	$0.09410	$0.00296	($0.00091)	$0.09615	$0.09634
All over 3,650 kWhs	$0.06958	$0.00072	$0.07030	$0.00220	($0.00091)	$0.07159	$0.07178
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	$0.06039	$0.00035	$0.06074	$0.00258	($0.00091)	$0.06241	$0.06297
All over 2(2) Includes all preser	$0.05154	$0.00035	$0.05189	$0.00219	($0.00091)	$0.05317	$0.05373
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	$0.05047	($0.00004)	$0.05043	$0.00165	($0.00091)	$0.05117	$0.05212
All over 500,000 kWhs	$0.04275	($0.00004)	$0.04271	$0.00139	($0.00091)	$0.04319	$0.04414
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:	$666,570			Proposed:	$683,420	
Clearwater - Schedule 25P							
Energy Charge:							
all kWhs	$0.04146	($0.00010)	$0.04136	$0.00108	($0.00091)	$0.04153	$0.04254
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:	$606,060			Proposed:	$617,940	
Pumping Service - Schedule 31							
Basic Charge	$8.00		$8.00	$0.00		$8.00	$8.00
Energy Charge:							
First 165 kW/kWh	$0.08939	$0.00052	$0.08991	$0.00360	($0.00091)	$0.09260	$0.09299
All additional kWhs	$0.07620	$0.00052	$0.07672	$0.00307	($0.00091)	$0.07888	$0.07927

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

AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-12-07
PROPOSED INCREASE BY SERVICE SCHEDULE
12 MONTHS ENDED JUNE 30, 2012
(000s of Dollars)

Effective April 1st, 2013

Line No.	Type of Service (a)	Schedule Number (b)	Base Tariff Revenue Under Present Rates (1) (c)	Proposed General Increase (d)	Base Tariff Revenue Under Proposed Rates (1) (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 Revenue (j)**
1	General Service	101	$47,852	$2,513	$50,365	**5.3%**	$46,896	$2,513	$49,409	**5.4%**
2	Large General Service	111/112	$14,997	$569	$15,566	**3.8%**	$14,607	$569	$15,175	**3.9%**
3	Interruptible Service	131/132	$201	$8	$209	**4.0%**	$201	$8	$209	**4.0%**
4	Transportation Service	146	$289	$25	$314	**8.7%**	$289	$25	$315	**8.7%**
5	Special Contracts	148	$97	$0	$97	**0.0%**	$97	$0	$97	**0.0%**
6	Total		$63,436	$3,115	$66,551	**4.9%**	$62,090	$3,115	$65,205	**5.0%**

(1) Includes Schedule 150 - Purchased Gas Cost Adjustment

(2) Includes Schedule 155 - Gas Rate Adjustment

AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-12-07
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

Effective April 1st, 2013

(a)	Base Rate (1) (b)	Present Rate Adj.(2) (c)	Present Billing Rate (d)	General Rate Increase (e)	Proposed Billing Rate (f)	Proposed Base Rate (1) (g)
General Service - Schedule 101						
Basic Charge	$4.25		$4.25	**$0.00**	**$4.25**	**$4.25**
Usage Charge:						
All therms	$0.82291	($0.01785)	$0.80506	**$0.04690**	**$0.85196**	**$0.86981**
Large General Service - Schedule 111						
Usage Charge:						
First 200 therms	$0.84418	($0.01785)	$0.82633	**$0.04689**	**$0.87322**	**$0.89107**
200 - 1,000 therms	$0.71203	($0.01785)	$0.69418	**$0.02413**	**$0.71831**	**$0.73616**
1,000 - 10,000 therms	$0.63624	($0.01785)	$0.61839	**$0.02156**	**$0.63995**	**$0.65780**
All over 10,000 therms	$0.58630	($0.01785)	$0.56845	**$0.01987**	**$0.58832**	**$0.60617**
Minimum Charge:						
per month	$81.61		$81.61	**$9.38**	**$90.99**	**$90.99**
per therm	$0.43612	($0.01785)	$0.41827		**$0.41827**	**$0.43612**
Interruptible Service - Schedule 132						
Usage Charge:						
All Therms	$0.50911		$0.50911	**$0.02074**	**$0.52985**	**$0.52985**
Transportation Service - Schedule 146						
Basic Charge	$225.00		$225.00	**$0.00**	**$225.00**	**$225.00**
Usage Charge:						
All Therms	$0.10671		$0.10671	**$0.00978**	**$0.11649**	**$0.11649**

(1) Includes Schedule 150 - Purchased Gas Cost Adjustment
(2) Includes Schedule 155 - Gas Rate Adjustment

AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-12-07
PROPOSED INCREASE BY SERVICE SCHEDULE
12 MONTHS ENDED JUNE 30, 2012
(000s of Dollars)

Effective October 1st, 2013

Line No.	Type of Service (a)	Schedule Number (b)	Base Tariff Revenue Under Present Rates (1) (c)	Proposed General Increase (d)	Base Tariff Revenue Under Proposed Rates (1) (e)	**Base Tariff Percent Increase (f)**	Total Billed Revenue at Present Rates (2) (g)	Total General Increase (h)	Total Sch 197 - PGA Increase (i)	Total Billed Revenue at Proposed Rates (3) (j)	**Percent Increase on Billed Revenue (k)**
1	General Service	101	$50,365	$1,073	$51,438	**2.1%**	$49,408	$1,073	-$799	$49,682	**0.6%**
2	Large General Service	111/112	$15,566	$243	$15,809	**1.6%**	$15,175	$243	-$326	$15,092	**-0.5%**
3	Interruptible Service	131/132	$209	$3	$212	**1.4%**	$209	$3	-$6	$206	**-1.4%**
4	Transportation Service	146	$314	$11	$325	**3.5%**	$315	$11	$0	$326	**3.5%**
5	Special Contracts	148	$97	$0	$97	**0.0%**	$97	$0	$0	$97	**0.0%**
6	Total		$66,551	$1,330	$67,881	**2.0%**	$65,204	$1,330	-$1,131	$65,403	**0.3%**

(1) Includes Schedule 150 - Purchased Gas Cost Adjustment

(2) Includes Schedule 155 - Gas Rate Adjustment

(3) Includes Schedule 155 - Gas Rate Adjustment and Schedule 197 - PGA Rate Adjustment

AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-12-07
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

Effective October 1st, 2013

(a)	Base Rate (1) (b)	Present Rate Adj.(2) (c)	Present Billing Rate (d)	General Rate Increase (e)	Proposed Sch. 197 PGA Adj. Rate (f)	Proposed Billing Rate (g)	Proposed Base Rate (1) (h)
General Service - Schedule 101							
Basic Charge	$4.25		$4.25	**$0.00**		**$4.25**	**$4.25**
Usage Charge:							
All therms	$0.86981	($0.01785)	$0.85196	**$0.02003**	**($0.01489)**	**$0.85710**	**$0.88984**
Large General Service - Schedule 111							
Usage Charge:							
First 200 therms	$0.89107	($0.01785)	$0.87322	**$0.02005**	**($0.01489)**	**$0.87838**	**$0.91112**
200 - 1,000 therms	$0.73616	($0.01785)	$0.71831	**$0.01026**	**($0.01489)**	**$0.71368**	**$0.74642**
1,000 - 10,000 therms	$0.65780	($0.01785)	$0.63995	**$0.00927**	**($0.01489)**	**$0.63433**	**$0.66707**
All over 10,000 therms	$0.60617	($0.01785)	$0.58832	**$0.00845**	**($0.01489)**	**$0.58188**	**$0.61462**
Minimum Charge:							
per month	$90.99		$90.99	**$4.01**		**$95.00**	**$95.00**
per therm	$0.43612	($0.01785)	$0.41827		**($0.01489)**	**$0.40338**	**$0.43612**
Interruptible Service - Schedule 132							
Usage Charge:							
All Therms	$0.52985		$0.52985	**$0.00759**	**($0.01489)**	**$0.52255**	**$0.53744**
Transportation Service - Schedule 146							
Basic Charge	$225.00		$225.00	**$0.00**		**$225.00**	**$225.00**
Usage Charge:							
All Therms	$0.11649		$0.11649	**$0.00426**		**$0.12075**	**$0.12075**

(1) Includes Schedule 150 - Purchased Gas Cost Adjustment
(2) Includes Schedule 155 - Gas Rate Adjustment

STIPULATION AND SETTLEMENT
Case Nos. AVU-E-12-08 & AVU-G-12-07

ATTACHMENT D

Avista Corporation
State of Idaho
BPA Rate Adjustment Offset

ID portion of BPA Settlement	-$3,846,000
Conversion Factor	0.995010
Revenue Requirement	-$3,865,288

15 Month Amortization

Rate Sch	Pro Forma kWh	BPA Reduction
1	1,454,376,696	($1,320,981)
11&12	418,029,209	($379,688)
21&22	847,204,858	($769,499)
25	373,474,024	($339,219)
25P	1,079,930,838	($980,879)
31&32	65,224,871	($59,242)
41-49	17,372,742	($15,779)
Total	4,255,613,238	($3,865,288)

Uniform cents reduction ($0.00091)

* Effective October 1st, 2013 through December 31st, 2014

** Any residual balance will be trued up in a future PCA filed by the Company.

AVISTA CORPORATION
d/b/a Avista Utilities

SCHEDULE 97
BONNEVILLE POWER ADMINISTRATION SETTLEMENT - IDAHO

AVAILABLE:

To Customers in the State of Idaho where Company has electric service available.

PURPOSE:

To adjust electric rates for revenues related to the Bonneville Power Administration settlement.

MONTHLY RATE:

The energy charges of electric Schedules 1, 11, 12, 21, 22, 25, 25P, 31, 32 and 41-49 are to be decreased by 0.091¢ per kilowatt-hour in all blocks of these rate schedules.

TERM:

The energy charges will be reduced for a fifteen month period, from October 1, 2013 through December 31, 2014. Any residual balance will be trued up in a future PCA filed by the Company.

SPECIAL TERMS AND CONDITIONS:

Service under this schedule is subject to the Rules and Regulations contained in this tariff. The above Rate is subject to increases as set forth in Tax Adjustment Schedule 58.

Issued September XX, 2013 Effective October 1, 2013

Issued by Avista Utilities
By Kelly Norwood, Vice President, State & Federal Regulation

Avista Corporation
State of Idaho
PGA Rate Adjustment Offset

Refund of Deferred Gas Costs	-$1,542,264
Conversion Factor	0.995009
Revenue Requirement	-$1,550,000

15 Month Amortization	Rate Sch	Pro Forma Therms	PGA Reduction
	101	74,508,535	($1,109,559)
	111&112	29,081,957	($433,080)
	131&132	494,346	($7,362)
	Total	104,084,838	($1,550,000)
	Uniform cents reduction		($0.01489)

* Effective October 1st, 2013 through December 31st, 2014
** Any residual balance will be trued up in a future PGA filed by the Company.

AVISTA CORPORATION
d/b/a Avista Utilities

SCHEDULE 197
REFUND OF DEFERRED GAS COSTS - IDAHO

AVAILABLE:

To Customers in the State of Idaho where Company has natural gas service available.

PURPOSE:

To adjust natural gas rates for the refund of prior deferred gas costs.

MONTHLY RATE:

The energy charges of natural gas Schedules 101, 111, 112, 131, and 132 are to be decreased by 1.489¢ per therm in all blocks of these rate schedules.

TERM:

The energy charges will be reduced for a fifteen month period, from October 1, 2013 through December 31, 2014. Any residual balance will be trued up in a future PGA filed by the Company.

SPECIAL TERMS AND CONDITIONS:

Service under this schedule is subject to the Rules and Regulations contained in this tariff. The above Rate is subject to increases as set forth in Tax Adjustment Schedule 158.

Issued September XX, 2013 Effective October 1, 2013

Issued by Avista Utilities
By Kelly Norwood, Vice President, State & Federal Regulation