BEFORE THE

RECEIVED
2013 FEB 25 PM 4:09
IDAHO PUBLIC
UTILITIES COMMISSION

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION DBA AVISTA UTILITIES FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE IN IDAHO.	)))))))	CASE NO. AVU-E-12-08/ AVU-G-12-07

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

IDAHO PUBLIC UTILITIES COMMISSION

FEBRUARY 25, 2013

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

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

Q. By whom are you employed?

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

Q. What is your educational and professional background?

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

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

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

Q. Please summarize your testimony.

A. After thorough review of the Company's application, detailed identification of adjustments, two settlement workshops and thoughtful assessment of settlement alternatives, Staff believes that the proposed multi-phase, two-year Settlement is in the public interest, is fair, just and reasonable and should be approved by the Commission.

Q. How is your testimony organized?

A. My testimony is subdivided under the following headings:

Stipulation Overview

Q. Please summarize the Stipulation and Settlement.

A. The Stipulation filed with the Commission provides for a two-phase rate plan for both electric and natural gas service, with a further base rate increase stay-out provision through January 1, 2015. The first phase of the plan would take effect on April 1, 2013 and provide for no increase in electric base revenue and an annual increase in natural gas revenue of $3.12 million or 4.92%. The second phase of the plan, proposed to take effect on October 1, 2013, specifies an annual electric base revenue increase of $7.825 million or 3.2%. Annual natural gas revenues would increase by $1.33 million or 2.0%. There would be no base rate increase in 2014.

When these proposed base rate increases are combined with Bonneville Power Administration transmission revenue credits and Purchased Gas Adjustment credits, the net increase over two years is about $4.77 million (1.9%) for electric and $3.31 million (5.2%) for natural gas service, respectively.

The Stipulation specifies a 9.8% return on equity and a 7.91% overall rate of return, annual power supply cost levels, non executive salary levels, end of period rate base levels and treatment of Palouse Wind expenses and benefits. The Stipulation also specifies a cost of service based revenue spread to the various customer classes with a uniform increase in the energy portion of the rate. The Stipulation was signed by all parties to the case expect the Consumer Action Partnership of Idaho (CAPAI). The Settlement document is attached as Staff Exhibit No. 101.

Q. How does the stipulated annual revenue requirement increase for electric and natural gas service compare to the increases originally requested by Avista?

A. Avista originally proposed to increase annual electric revenue by $11.393 million (or 4.6%) and annual natural gas revenue by $4.561 million (or 7.2%) effective April 1, 2013. The Company requested a 10.9% return on equity with an 8.46% overall rate of return.

The Stipulation provides for no increase in electrical rates on April 1, 2013 and a $7.825 million, 3.2% annual revenue increase October 1, 2013. Annual natural gas revenues would increase by $3.12 million or 4.92% on April 1, 2013 and $1.33 million or 2.0% on October 1, 2013. A key difference between the Company's original proposal in this case and the Stipulation is the prohibition on any additional base rate increases through January 1, 2015.

The stipulated electric increase is about 68% of the Company's original proposal and delays implementation of the rate increase for six months. The proposed increase in natural gas revenue on April 1, 2013 is also about 68% of the Company's original proposal. However, combined with the second phase of the natural gas increase on October 1, 2013, the Settlement represents about 98% of the Company's original application for natural gas. Under the Company's original proposal, the rate increases would have all taken effect on April 1, 2013 and the Company could have realistically filed three more general rate cases before the January 1, 2015 stay-out date stipulated in the Settlement.

Staff Investigation

Q. What type of investigation did Staff conduct to evaluate the Company's rate increase request?

A. Staff began analyzing the Company's filing on August 29, 2012, with 21 Commission Staff members assigned to the case. Staff submitted 199 formal production requests to the Company and numerous formal and informal audit requests. Staff also reviewed the latest Avista electric and natural gas rate case filings in the State of Washington, including over 300 data requests and responses. Three Staff accountants each conducted a week long on-site audit of Company books and reviewed external auditor workpapers.

Q. What areas and issues were specifically identified and assigned for review?

A. Capital expenditures and plant investment in generation, transmission, distribution and information technology were specifically identified for both gas and electric service and were separately evaluated. Return on equity, capital structure and cost of debt were evaluated and determined. Staff examined and verified operation and maintenance expenses including electric power supply costs, natural gas purchase costs, taxes, depreciation, salaries, level of workforce, consultant costs, incentive pay and vegetation management costs.

Staff also evaluated the Company's proposed Energy Efficiency Load Growth Adjustment, Jurisdictional allocation methodology, class cost of service methodology and rate design options.

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

A. Staff particularly focused on possible adjustments in five primary areas: 1) rate of return, 2) power supply expenses, 3) 2012/2013 capital investment and O&M expenses, 4) salaries, and 5) miscellaneous test year expenses. Staff developed positions on individual adjustments in each of these five categories then refined and quantified the revenue requirement impact of each in preparation for pre-filed direct testimony.

With respect to rate of return, Staff believed that 9.8% return on equity was reasonable, calculated a debt cost of 5.98% and identified a capital structure of 53% debt and 47% equity. The resulting overall return of 7.84% reduced the Company's proposed annual revenue requirement by an estimated $6 million.

Power supply adjustments included removing expenses and benefits associated with the Company's Palouse Wind power purchase agreement, reducing forced outage rates for the Company's coal fired power plants and modifying load forecasts by improving weather normalization methodology and removing the proposed Energy Efficiency Load Adjustment. Eliminating the effect of Palouse Wind from power supply reduced annual expenses by an estimated $2.9 million on a normalized basis.

Staff proposed to remove 2013 Capital additions, O&M expenses and Information Technology (IT) investments to limit test year proforma through December 31, 2012. In addition to adjustment for 2013 salary increases, Staff identified adjustments for prior year salary increases for nonexecutive labor starting in 2011. Staff also identified adjustments for executive officer incentives and the effects of the Company's announced workforce reduction.

Finally, Staff identified 10 other individual miscellaneous annual adjustments ranging from $400,000 for unspent vegetation management to $1,000 for transmission training and travel. The combined impact of this category of adjustments was estimated at approximately $1 million.

Q. What type of adjustments did Staff identify for natural gas revenue requirement and what was the impact?

A. Most of the adjustments identified by Staff on the electric side were applied to the natural gas revenue requirement as well. These adjustments included rate of return, 2013 capital additions and O&M, salary/workforce expenses and many of the miscellaneous items. These adjustments totaled approximately $1.6 million on an annual basis.

Staff's investigation of the Company's application was essentially complete and all of the adjustments were identified prior to settlement discussions. Staff was in the process of refining its position on the various issues in preparation for presentation at hearing.

The Settlement Process

Q. Would you please describe the process leading to the Stipulated Settlement?

A. Yes. The Company filed its rate application with the Commission on August 29, 2012 and Staff immediately began its investigation. The first settlement conference was held on January 17, 2012 in the Commission hearing room with all parties of record in the case invited to participate. Workshop participants included Commission Staff, Avista, Clearwater Paper Company, Idaho Forest Group, the Community Action Partnership of Idaho (CAPAI) and the Idaho Conservation League. The Snake River Alliance (SRA) was a party to the case but did not participate in the Conference.

Settlement discussions focused on revenue requirement issues such as capital budget requirements, appropriate return on equity, Capital Structure, Company salaries, O&M expenses, load adjustments, acceptable test period and the acquisition costs associated with the Palouse Wind project. Given the wide disparity in the revenue requirement position of the various parties, the possibility of a multi-year rate agreement was also discussed as an avenue to settlement.

Q. Was settlement reached at that time?

A. No. The parties could not reach agreement and convened a second settlement conference on January 24, 2013. Again, all parties participated except the SRA. The second conference focused primarily on needed capital additions over the next two years, the costs and benefits of the Palouse Wind project and how a two-year rate plan might be structured. After numerous proposals and counter proposals, with give and take by all parties, a two-year rate agreement was ultimately reached. The Stipulation and Settlement was filed with the Commission on February 6, 2013.

Settlement Evaluation

Q. How did Commission Staff evaluate the Stipulated Settlement to determine that it was reasonable?

A. Staff evaluated the merits of the Settlement in this case for both electric and gas service by looking closely at each of the Staff identified revenue requirement adjustments to assess how they might hold up at hearing.

Staff also evaluated the potential for and the likely impact of additional Avista general rate case filings during the proposed Settlement stay-out period. The overall objective of Staff's assessment was to achieve the best outcome for customers with respect to base rates in this case and with respect to base rate increases that might otherwise occur due to additional general rate filings during the Settlement stay-out period.

Q. Why did Staff conclude that the Settlement was better than the alternative?

A. Although Staff identified significant adjustments to propose at hearing it is unlikely Staff would have prevailed on all or most of them. Many proposed adjustments were to costs and expenses the Company already incurred or will incur in 2013. For example, Staff proposed to eliminate recovery of worker salary increases starting in 2011, but Avista certainly could make a case at hearing that these wage increases were fair and prudent, and they were actually paid by the Company. Some of Staff's proposed adjustments were to capital costs in 2012 and 2013. Staff did not conclude from its investigation that these costs were imprudent, so even if Staff had prevailed on these adjustments in this case, it would only delay Avista's recovery until the next rate case. This would likely make certain that Avista would immediately file another case and perhaps another after that.

Q. Could you please describe Staff's position regarding other issues specified in the Settlement?

A. Yes. The Settlement specifies a 9.8% return on equity, a 6.1% cost of debt and a capital structure of 50% equity and 50% debt for an overall 7.91% rate of return. Staff believes the resulting overall rate of return is justified and a reasonable compromise in this case. It reflects the same return on equity recently approved for Avista by the Washington Commission. It also reflects a current actual cost of debt that is slightly higher than previously calculated by Staff and an imputed rather than actual capital structure. The imputed Capital Structure is consistent with past cases and representative of the estimated December 2013 Capital Structure.

The Settlement also specifies annual power supply expenses for use in the Power Cost Adjustment mechanism. Staff adjustments reflecting forced outage rates, weather normalization and the energy efficiency load adjustment are not captured in stipulated power supply expenses. Staff recognizes that actual expenses associated with these adjustments will effectively flow through the Power Cost Adjustment mechanism whether they are included in base rates or not.

Staff will further evaluate the Company's weather normalization methodology and the affects of energy efficiency programs on load forecasts in subsequent rate cases.

Q. How did Staff incorporate reduction in expenses associated with the Company's announced voluntary reduction in workforce?

A. Staff originally identified the test year costs and benefits of the workforce reduction program to determine the net effect on annual revenue requirement. The workforce reduction benefits or costs were not included in the Company's Application. Staff analysis showed that actual test year expenses to implement the program exceeded test year benefits (due to expensing in a single year). However, in subsequent years, benefits of the program will continue while program expense will not. Staff therefore, amortized the expense over several years to assure a test year benefit.

Staff ultimately determined that if reasonable settlement on revenue requirement is achieved in this case, the full benefit of workforce reduction can still be captured in future test years without any expense offset. Staff therefore, conceded the issue as part of the Settlement.

Q. Could you please address Staff's position regarding the Settlement's treatment of Palouse Wind project costs?

A. Yes. For purpose of settlement in this case, the costs and benefits associated with the Palouse Wind power purchase agreement are not included as normal power supply expenses in base rates. Rather, the net costs/benefits are tracked and recovered through the Power Cost Adjustment mechanism at 90%. This represents a compromise from Staff's original position that would have excluded Palouse project costs from any rate recovery until it was shown to be needed to serve Idaho load.

Staff objected to the project because the Company acquired it to satisfy a Washington State Renewable Portfolio Standard without any immediate need to serve load. Moreover, Staff determined that the project power supply expenses would exceed project benefits under near term normalized load and power supply conditions.

However, Staff recognized that the project will likely be economical for Idaho customers over the 20-year contract life and could be economical over the next two years under a variety of load and resource conditions. Staff also recognized that the project could provide additional value through the sale of renewable energy credits and could likely be justified to meet load by 2015. Consequently, Staff deemed that treatment through the Power Cost Adjustment mechanism, with partial contribution of net project expense by the Company, reasonably resolved this issue.

Q. What types of capital costs are included in this case and how are they treated in the two-year Settlement?

A. Capital investment included in this case makes up about 70% of the Company's electric revenue increase request and 48% of the natural gas increase request. Staff's investigation shows that 94% of the 2012 investments were to replace aging infrastructure or upgrade existing plant. In 2013, over 96% of the capital investment was to replace or upgrade existing plant. Staff identified reasonable expenditures for distribution plant replacement on the gas and electric side as well as radio and customer service software used to serve all utility customers.

While Staff supports maintaining service quality and assuring safety by replacing aging infrastructure such as distribution poles and conductors and Adyl-A natural gas pipeline, Staff questions the timing for inclusion in rates. Staff limited proforma test year plant additions to December 31, 2012. Consequently, 2012 investment was included for base rate recovery on April 1, 2013. But 2013 investment was not allowed in base rates until October 1, 2013. The attached Settlement shows how 2013 capital additions were removed from the April increase and added back for the October increase.

With respect to vegetative management expenses, Staff originally proposed an adjustment to reduce the amount requested in the Application to reflect expenses actually incurred. As part of the Settlement, Staff agreed that customers would be better served if the requested vegetative management expenses were maintained and actually put toward the intended purpose.

Cost of Service/Rate Design

Q. Please describe the Stipulated Settlement with respect to customer class cost of service and rate design.

A. The Settlement spreads the Idaho jurisdictionally allocated revenue requirement to customer classes based on the Company's proposed gas and electric cost of service studies. The studies showed that residential customers were paying a smaller than necessary part of the cost while larger customers were paying more than necessary.

Staff evaluated the results of the cost of service studies by first ensuring that the underlying jurisdictional allocation methodology assigned a reasonable portion of electric and natural gas system costs to Idaho. Staff then evaluated various cost of service methodologies on the electric side to determine how customer classes were affected by the differences. While not adopting a specific methodology, Staff agrees that the cost of service move for the various gas and electric customer classes as proposed by the Company is reasonable in this case (25% move toward cost of service for gas customer classes and 15% move for electric customer classes). Consequently, Staff supports the prorated application of the Company's cost of service studies based on the stipulated gas and electric revenue requirement increases.

Q. Does the Settlement provide for changes in rate design?

A. No. Existing rate design will not change for either electric or gas customers, and the monthly residential customer charges will not increase. All of the proposed revenue increase will be applied uniformly to the energy component of rates. Staff maintains that these rate changes are reasonable given the limited change in overall revenue requirement.

Q. What rate offsets are available to mitigate the base rate increases?

A. The parties have agreed to use $3.865 million in Bonneville Power Administration Settlement Revenue beginning October 1, 2013 to partially offset the electric base rate increase. The revenue represents Idaho's share of money that the Bonneville Power Administration must pay Avista for having used Avista's transmission system. It will be used to reduce the billed energy rate over the period of October 1, 2013 through December 31, 2014.

The natural gas base rate increase will be partially offset by a $1.55 million un-refunded credit balance held back by the Commission in the most recent purchased gas adjustment case, Case No. AVU-G-12-05. The Commission held the credit refund plus interest in anticipation of Avista filing a natural gas general rate case. The Parties agreed to refund the credit balance over the period October 1, 2013 through December 31, 2014. Staff believes returning the credit during the 15-month period beginning in October provides the greatest benefit to residential gas and electric customers.

Q. How does the proposed base rate Settlement impact residential customer bills?

A. The net effect of the electric base rate increase and partially offsetting credit is about a $2.21 per month increase for a residential customer using 1000 kWh. This increase will not take effect until October 1, 2013 with the credit lasting through December of 2014.

The net effect of the gas base rate increase beginning April 1, 2013 will be $4.69 per month for a residential customer using 100 therms. The net effect of the gas base rate change and partially offsetting credit on October 1, 2013 will be $0.51 per month increase for a residential customer using 100 therms.

Q. Does this conclude your testimony in this case?

A. Yes, it does.

RECEIVED
2013 FEB -7 PM 2:17
IDAHO PUBLIC UTILITIES COMMISSION

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

Karl Klein
Weldon Stutzman
Deputy Attorneys General
Idaho Public Utilities Commission Staff
P.O. Box 83720
Boise, ID 83720-0074
Phone: (208) 334-0312, Fax: (208) 334-3762

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION DBA AVISTA UTILITIES FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE IN IDAHO	)	CASE 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.

Exhibit No. 101
Case Nos. AVU-E-12-08/
AVU-G-12-07
R. Lobb, Staff
02/25/13 Page 1 of 39

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:

		Revenue Requirement	Rate Base
	SUMMARY TABLE OF ADJUSTMENTS TO ELECTRIC REVENUE REQUIREMENT EFFECTIVE APRIL 1, 2013 000s of Dollars		
	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. Resulting Percentage Increase by Electric Service Schedule. 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

Exhibit No. 101
Case Nos. AVU-E-12-08/
AVU-G-12-07
R. Lobb, Staff
02/25/13 Page 18 of 39

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
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

Exhibit No. 101
Case Nos. AVU-E-12-08/
AVU-G-12-07
R. Lobb, Staff
02/25/13 Page 19 of 39

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 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

Exhibit No. 101
Case Nos. AVU-E-12-08/
AVU-G-12-07
R. Lobb, Staff
02/25/13 Page 21 of 39

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: Ben Otto

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

		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.

Exhibit No. 101
Case Nos. AVU-E-12-08/
AVU-G-12-07
R. Lobb, Staff
02/25/13 Page 24 of 39

Avista Utilities
Idaho Rate Adjustments

Natural Gas

Line		TOTAL	GEN SERVICE SCHEDULE 101	LRG GEN SVC SCH. 111&112	INTERRUPTIBLE SCH. 131&132	TRANSPORT SCHEDULE 146	SPECIAL CONTRACTS
	Effective April 1, 2013						
1	Total Billed Revenue	$ 62,090,000	$46,896,000	$14,607,000	$201,000	$289,000	$97,000
2	**Revenue Changes**						
3	GRC Increase *	$ 3,114,740	$ 2,512,740	$ 569,000	$ 8,000	$ 25,000	$ -
4	**Total Revenue Change**	**$ 3,114,740**	**$ 2,512,740**	**$ 569,000**	**$ 8,000**	**$ 25,000**	**$ -**
5							
6	**Percentage Changes**						
7	GRC Increase	5.0%	5.4%	3.9%	4.0%	8.7%	0.0%
8	**Total Billed Percentage Change**	**5.0%**	**5.4%**	**3.9%**	**4.0%**	**8.7%**	**0.0%**
9							
10							
11							
12							
13							
14	**Effective October 1, 2013**						
15	Total Billed Revenue	$ 65,204,740	$ 49,408,740	$ 15,176,000	$ 209,000	$ 314,000	$ 97,000
16	**Revenue Changes**						
17	GRC Increase *	$ 1,330,000	$ 1,073,000	$ 243,000	$ 3,000	$ 11,000	$ -
18	PGA Reduction (15 Month Amortization) **	$ (1,131,000)	$ (799,000)	$ (326,000)	$ (6,000)	$ -	$ -
19	**Total Revenue Change**	**$ 199,000**	**$ 274,000**	**$ (83,000)**	**$ (3,000)**	**$ 11,000**	**$ -**
20							
21	**Percentage Changes**						
22	GRC Increase	2.0%	2.2%	1.6%	1.4%	3.5%	0.0%
23	PGA Reduction	-1.7%	-1.6%	-2.1%	-2.9%	0.0%	0.0%
24	**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.

Exhibit No. 101
Case Nos. AVU-E-12-08/
AVU-G-12-07
R. Lobb, Staff
02/25/13 Page 25 of 39

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.

Exhibit No. 101
Case Nos. AVU-E-12-08/AVU-G-12-07
R. Lobb, Staff
03/01/13 Page 27 of 39

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 (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. 97 - BPA Decrease (i)	Total Billed Revenue at Proposed Rates(2) (j)	Gen. Incr. as a % of Billed Revenue (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.

Exhibit No. 101
Case Nos. AVU-E-12-08/
AVU-G-12-07
R. Lobb, Staff
02/25/13 Page 29 of 39

Attachment C

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

Exhibit No. 101
Case Nos. AVU-E-12-08/
AVU-G-12-07
R. Lobb, Staff
02/25/13 Page 32 of 39

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

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

Exhibit No. 101
Case Nos. AVU-E-12-08/
AVU-G-12-07
R. Lobb, Staff
02/25/13 Page 34 of 39

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.

Exhibit No. 101
Case Nos. AVU-E-12-08/
AVU-G-12-07
R. Lobb, Staff
02/25/13 Page 38 of 39

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

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 25TH DAY OF FEBRUARY 2013, SERVED THE FOREGOING **DIRECT TESTIMONY OF RANDY LOBB IN SUPPORT OF THE STIPULATION AND SETTLEMENT,** IN CASE NOS. AVU-E-12-08 & AVU-G-12-07, BY E-MAILING, MAILING VIA FED EX OR HAND CARRY A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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

ELECTRONIC SERVICE ONLY:
PAUL KIMBALL
AVISTA CORPORATION
E-MAIL: Paul.Kimball@avistacorp.com

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

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

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

KEN MILLER
SNAKE RIVER ALLIANCE
BOX 1731
BOISE ID 83701
E-MAIL: kmiller@snakeriveralliance.org

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

DEAN J MILLER
McDEVITT & MILLER LLP
PO BOX 2564
BOISE ID 83702
E-MAIL: joe@mcdevitt-miller.com

PETER J RICHARDSON
GREGORY M ADAMS
RICHARDSON & O'LEARY
515 N 27TH STREET
BOISE ID 83702
E-MAIL: peter@richardsonandoleary.com
greg@richardsonandoleary.com

ELECTRONIC SERVICE ONLY:
HOWARD RAY
CLEARWATER PAPER CORPORATION
E-MAIL: Howard.Ray@clearwaterpaper.com

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

Jo Nelson
SECRETARY