Avista Corp.
1411 East Mission P.O. Box 3727
Spokane. Washington 99220-0500
Telephone 509-489-0500
Toll Free 800-727-9170

RECEIVED

2011 SEP -9 AM 10: 26

IDAHO PUBLIC
UTILITIES COMMISSION

AVISTA Corp.

September 8, 2011

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

RE: Docket Nos. AVU-E-11-01 and AVU-G-11-01

Avista hereby encloses for filing an original and nine copies of the Testimony of Kelly Norwood in support of the Stipulation and Settlement in the above referenced cases. Questions regarding this filing should be directed to Patrick Ehrbar at (509) 495-8620.

Sincerely,

Kelly Norwood

Kelly Norwood
Vice President, State & Federal Regulation

Enclosures

cc: Service list

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this 8th day of September, 2011, served the Testimony of Kelly O. Norwood in support of the Stipulation and Settlement in Case Nos. AVU-E-11-01 and AVU-G-11-01, upon the following parties, by mailing a copy thereof, properly addressed with postage prepaid to:

Jean D Jewell, Secretary
Idaho Public Utilities Commission
Statehouse
Boise, ID 83720-5983
Jean.jewell@puc.idaho.gov

Donald Howell
Deputy Attorneys General
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702-0659
kristine.sasser@puc.idaho.gov
donald.howell@puc.idaho.gov

Marv Lewallen
Clearwater Paper
601 W. Riverside Avenue
Suite 1100
Spokane, WA 99201
marv.lewallen@clearwaterpaper.com

Scott Atkison
Idaho Forest Products
171 Highway 95 N.
Grangeville, ID 83530
scotta@idahoforestgroup.com

Benjamin J. Otto
Idaho Conservation League
710 N. 6th Street, P. O. Box 844
Boise, ID 83702
botto@idahoconservation.org

Brad M. Purdy
Attorney at Law
2019 N 17th Street
Boise, ID 83720
bmpurdy@hotmail.com

Peter J. Richardson
Greg M. Adams
Richardson & O'Leary PLLC
515 N. 27th Street
PO Box 7218
Boise, ID 83702
peter@richardsonandoleary.com
greg@richardsondoleary.com

Dean J. Miller
McDevitt & Miller, LLP
420 W. Bannock St.
PO Box 2564-83701
Boise, ID 83701-2564
joe@mcdevitt-miller.com

Dr. Don Reading
6070 Hill Road
Boise, ID 73703
dreading@mindspring.com

Patrick Ehrbar
Manager, Rates and Tariffs

DAVID J. MEYER
VICE PRESIDENT, CHIEF COUNSEL FOR REGULATORY &
GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851

RECEIVED
2011 SEP -9 AM 10:27
IDAHO PUBLIC
UTILITIES COMMISSION

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-11-01 CASE NO. AVU-G-11-01 DIRECT TESTIMONY OF KELLY O. NORWOOD IN SUPPORT OF THE STIPULATION AND SETTLEMENT

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

I. INTRODUCTION

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 30 years, I have spent approximately 19 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. Are you sponsoring any Exhibits that accompany

your testimony?

A. Yes. I am sponsoring Exhibit No. 1 which is a copy of the Stipulation and Settlement filed on August 26, 2011 with the Commission.

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" or "Settlement"), filed on August 26, 2011 between the Staff of the Idaho Public Utilities Commission ("Staff"), Clearwater Paper Corporation ("Clearwater"), Idaho Forest Group, LLC ("Idaho Forest"), the Community Action Partnership Association of Idaho ("CAPAI"), the Idaho Conservation League ("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 all parties in these cases (AVU-E-11-01 and AVU-G-11-01) that participated in settlement discussions.

The Stipulation is the product of settlement discussions that began in the Commission offices on August 17, 2011, and concluded on August 26th with agreement among all parties. The Stipulation between the Parties resolved all issues associated with the calculation of the Company's requested revenue requirement, all issues related to rate spread and rate design, and provides additional funding for low income energy efficiency education.

The Parties agree that this Settlement is not contingent upon any specific methodology for individual components of the revenue requirement determination, but all Parties support the overall increase to the Company's revenue requirement, and agree that the overall increase represents a fair, just and reasonable compromise of the issues in this proceeding and that this Stipulation is in the public interest.

The Parties understand that the Stipulation is subject to approval by the Idaho Public Utilities Commission (IPUC).

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

A. The Stipulation is the end result of audit work conducted through the discovery process 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 its willingness to hear this matter promptly, in light of the proposed October 1 effective date.

Q. Would you briefly summarize the Stipulation?

A. Yes. Under the terms of the Settlement, Avista would be allowed to implement revised tariff schedules effective October 1, 2011 designed to recover $2.8 million in additional annual electric revenue, which represents a 1.1% increase in electric annual base tariff revenues. Avista would also be allowed to implement revised tariff schedules on October 1, 2011 designed to recover $1.1 million in additional annual natural gas revenue, which represents a 1.6% increase in natural gas annual base tariff revenues. As discussed in more detail later in my testimony, and in the Stipulation, several other proposed rate adjustments will serve to more than offset the proposed base rate increases on October 1, 2011.

In addition, the Company agrees that it will not seek to make effective a change in base electric or natural gas rates prior to April 1, 2013, by means of a general rate filing. This will not prevent the Company, however, from otherwise seeking to implement other rate changes affecting the rates billed to customers, including, but not limited to, adjustments under the power cost adjustment (PCA) mechanism, purchased gas cost adjustments (PGA); DSM tariff rider adjustments; etc.

Q. Would you briefly summarize the net impact on customers of all rates proposed to take effect on October 1, 2011?

A. Yes. By means of separate filings, several other rate adjustments are proposed to also take effect on October 1, 2011. With respect to electric service, these adjustments include the following: a decrease of $2.2 million in Schedule 59 for Residential Exchange benefits for residential and small farm customers; a decrease of $15.6 million in Schedule 66 Power Cost Adjustment (PCA) rates; and an increase of $8.7 million for the previously-approved adjustment for Deferred State Income taxes (DSIT) in Schedule 99, as part of the Settlement approved in Case No.(s) AVU-E-10-01 and AVU-G-10-01. After taking into account the agreed-upon increase of $2.8 million in electric general rate increase revenues in this case, the net overall reduction resulting from all of the proposed aforementioned adjustments would total approximately $6.2 million.[1] Attachment A to the Stipulation sets forth these proposed October 1 adjustments in more detail, and by

[1] As part of this Settlement, Avista has also agreed to withdraw its filed-for decrease of $0.74 million in electric Demand-Side Management (DSM) Tariff Schedule 91, and did so by means of a separate filing made on August 29, 2011.

service schedule. The following table summarizes these proposed revenue adjustments:

Electric - Proposed October 1, 2011 Revenue Change		
Schedule 99 - DSIT Increase	$	8,698,844
Schedule 59 - Residential Exchange	$	(2,207,088)
Schedule 66 - PCA Decrease	$	(15,517,483)
GRC Rate Increase	$	2,800,000
Total Revenue Change	**$**	**(6,225,727)**

With respect to natural gas service, the following rate adjustments, by means of separate filings, are proposed to take effect on October 1, 2011: an increase of $0.8 million in Schedules 150/155 for Purchased Gas Costs (PGA)[2]; a decrease of $2.9 million in Demand-Side Management (DSM) tariff rider Schedule 191; and an increase of $0.5 million for the previously-approved adjustment for Deferred State Income Taxes (DSIT) in Schedule 199, as part of the Settlement approved in Case No.(s) AVU-E-10-01 and AVU-G-10-01. After taking into account the agreed-upon increase of $1.1 million in natural gas general rate revenues, the net overall decrease resulting from all of the proposed aforementioned adjustments would be $0.525 million. Attachment A to the

[2] On August 25, 2011, Avista updated its pending PGA (Case No. AVU-G-11-04) to reflect a decline in forward natural gas prices since the August 15, 2011 PGA filing which, if approved by the Commission, would result in a 0.98% overall increase versus the previously-filed 1.53% increase.

Stipulation sets forth these proposed October 1, 2011 adjustments in more detail, and by service schedule. The following table summarizes these proposed revenue adjustments:

Natural Gas - Proposed October 1, 2011 Revenue Change		
Schedule 199 - DSIT Increase	$	470,423
Schedule 150/155 - PGA Increase	$	776,190
Schedule 191 - DSM Decrease	$	(2,871,236)
GRC Rate Increase	$	1,100,000
Total Revenue Change	**$**	**(524,623)**

II. HISTORY OF FILING

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

A. On July 5, 2011, Avista filed an Application with the Commission for authority to increase revenue for electric and natural gas service in Idaho by 3.7% and 2.7%, respectively. If approved, the Company's revenues for electric base retail rates would have increased by $9.0 million annually; Company revenues for natural gas service would have increased by $1.9 million annually.

The Company proposed to spread the electric revenue increase by rate schedule on a uniform percentage basis. The Company also proposed to raise the monthly electric residential basic charge to $5.50 from the current $5.00 charge.

The Company proposed utilizing the results of the natural gas cost of service study as a guide in spreading the overall revenue increase to its natural gas service schedules and proposed to raise the natural gas residential basic charge to $4.50 from the current $4.00.

Q. What are the primary factors causing the Company's request for an electric rate increase in this filing?

A. Approximately 90% of the Company's revenue requirement requested in this case is due to an increase in Net Plant Investment (including return on investment, depreciation and taxes, and offset by the tax benefit of interest). This increase is due in part to an increase of approximately $21.0 million in net plant rate base for the Idaho jurisdiction. The remaining 10% of our request is due to increases in distribution, operation and maintenance (O&M), and administrative and general (A&G) expenses, offset by a reduction in net power supply and transmission expenditures.

Q. What are the primary factors driving the Company's request for a natural gas rate increase?

A. The Company's natural gas request is driven by changes in various operating cost components, approximately two-thirds of which are distribution O&M and A&G expenditures, such as increased costs in employee benefits, i.e. wages and medical insurance expenses, and one-third represent increased net plant investment, due to additional Company investment in underground storage facilities, distribution and general plant.

III. ELEMENTS OF THE STIPULATION

Q. Please describe the remaining terms of the Stipulation entered into by the Parties.

A. The Parties to the stipulation agreed that under the terms of the Settlement no party has accepted a specific methodology for certain elements of the revenue requirement determination. The Stipulation does, however, specify an agreed-upon level of power supply costs upon which to set the new base power supply costs for the monthly Power Cost Adjustment (PCA) calculation purposes, and it identifies other specific items that I will address in my testimony below.

Q. Where is the new level of power supply costs for the PCA calculation found in the agreement?

A. The power supply costs for the monthly PCA calculation are provided in Attachment B to the Stipulation.

Q. What is the proposed effective date of the Stipulation?

A. The Parties have requested implementation of new rates from the Stipulation on October 1, 2011. This proposed effective date is an integral part of the Stipulation that was part of the negotiated resolution of all of the issues. As discussed above, this October 1 date will synchronize with the several other rate adjustments also proposed to take effect on October 1, and by doing so, will avoid multiple rate changes over a short period of time that may cause customer confusion.

Q. Please explain the Settlement terms relating to cost of service and rate spread.

A. As part of this rate case, the Company prepared an analysis of using a peak credit method of classifying production costs, allocating 100% of transmission costs to demand, and allocating transmission costs to reflect any peak and off-peak seasonal cost differences on a weighted twelve month basis. The Parties have agreed to exchange information and convene a public workshop prior to the Company's next general rate case, with respect to the possible use of a revised peak credit method for classifying production costs, as well as consideration of the use of a 12 Coincident Peak (CP) (whether "weighted" or not) versus a 7 CP or other method for allocating transmission costs. This workshop will also address the merits of inclining or declining block rates for all service schedules. The Parties agreed, however, to spread the electric rate increase on a uniform percentage basis for purposes of this Settlement.

As for natural gas, the Company prepared a cost of service study and proposed that all rate schedules be moved to unity. For settlement purposes, the Parties agreed to spread the natural gas rate increase on a uniform percentage basis.

The table on Page 2 of Attachment C of the Stipulation shows the impact on the energy rates under each service schedule of the agreed-upon electric increase. The proposed electric revenue increase of $2.8 million represents an overall increase of 1.1% in base rates. As was discussed earlier, after the application of the other rate adjustments proposed to also be effective on October 1, the Company would have an overall revenue reduction of $6.2 million or 2.4%.

Page 4 of of Attachment C shows the impact on each service schedule of the agreed-upon natural gas increases. The increased natural gas revenue requirement of $1.1 million represents an overall increase of 1.6% in base rates. After the application of the other rate adjustments proposed to be effective also on October 1, the Company would have an overall revenue reduction of $0.525 million or 0.8%.

Q. What is the basis of the Stipulation relating to the rate design?

A. The Stipulation provides for increases in the basic charges, monthly minimum charges, and demand charges in Schedules 11, 21, 25, and 31, as shown in Attachment C, page 2 of the Stipulation. Otherwise, a uniform percentage increase is applied to each energy rate within each electric service schedule excluding Schedule 1, residential service where block differentials remain constant. In addition, the second block in Schedule 11 would be reduced by $0.00773 as contemplated in the Company's original filing, and the remaining revenue requirement, after accounting for the changes in the basic charge and demand charge, would be applied to the first energy block.

The Parties also agreed that the current residential electric basic charge of $5.00 would be increased to $5.25 per month, and the residential natural gas basic charge of $4.00 per month would be increased to $4.25.

Q. Please describe the customer service-related portion of the Stipulation.

A. There are two areas that were addressed in the Stipulation, as follows:

(a) Funding for Outreach for Low-Income Conservation. The Parties agree to annual funding of $50,000 to CAPAI for purposes of providing low-income outreach and education concerning conservation (representing an increase of $10,000 from previous funding levels). This amount will be funded through the Energy Efficiency Tariff Rider (Schedules 91 and 191), and will be in addition to the $700,000 of Low-Income Weatherization funding currently in place.

(b) Collaboration on Low-Income Weatherization. The Company and interested parties will meet and confer prior to the Company's next general rate filing in order to assess the Low Income Weatherization and Low Income Energy Conservation Education Programs and discuss appropriate levels of low-income weatherization funding in the future.

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

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:

Programs designed to assist customers include:

- **DSM Energy Efficiency Programs and Funding.** The Company offers a broad array of energy efficiency program measures that provides customers with increased opportunity to manage their energy bills.

- **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 customer contributions in 2010 of $316,600 (system), the Company also contributed $126,227 (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 specialneeds 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, 22 Senior Energy Workshops were held during the 2010/2011 heating season in Idaho and Washington. Over 1600 seniors were reached and were given Senior Energy Efficiency kits along with learning about low-cost/no-cost ways to reduce energy use.

Q. Please describe the accounting treatment agreed to by the Parties for two specific issues.

A. The Parties agree to the following accounting treatment for certain items:

(a) Costs Associated With Acquisition From Palouse Wind, LLC - The Company has signed a 30-year power purchase agreement with Palouse Wind, LLC, to acquire all of the power produced by a wind project that is expected to produce approximately 40 aMW. Deliveries are expected to begin in the second half of 2012. The annual cost of the Idaho share of the purchased power under the contract is expected to be approximately $6.5 million. Under terms of this Settlement, the Company would include 100% of the costs associated with power purchases from the wind project through the Power Cost Adjustment (PCA) until such costs, subject to prudence review, are reflected in general rates.

(b) - The Parties agree beginning in 2011 the Company would be allowed to defer changes in O&M costs related to its Coyote Springs 2 (CS 2) 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, and, as explained below, amortize the deferred amount over a three-year period.

Q. Please explain the need for the deferred accounting treatment for the Coyote Springs 2 and Colstrip 3 & 4 plants.

A. The Company experiences large variability in year-to-year O&M costs for these two plants specifically (CS2 and Colstrip) because major maintenance is scheduled every third or fourth year, resulting in large cost swings for these plants in any given year. This fluctuation in maintenance costs is typically not experienced by the Company's other hydro operating facilities or its Kettle Falls generating plant. For example, each unit at Colstrip has a regularly scheduled overhaul every third year. Since we have two units, this means that two out of every three years will have a scheduled major maintenance outage and its associated costs. Whereas the maintenance interval at Coyote Springs 2 is based on hours of operation. These major outages are scheduled in accordance with Original Equipment Manufacturer (OEM) guidelines on wear patterns and cycles for key plant equipment, and we expect major maintenance to occur approximately every four-years.

Therefore, depending on when the outages for each of these plants fall, we can have as much as two scheduled outages in one year or no scheduled outages, providing the potential for large cost fluctuations on a year-to-year basis. Unexpected outages also cause costs to fluctuate as more costs are incurred to repair the plant. The use of deferred accounting would smooth out these costs.

Q. What is the amount of actual, non-fuel, operations and maintenance costs for the Coyote Springs 2 and Colstrip 3 & 4 plants included in the 2010 test period compared to that expected in 2011 and beyond?

A. The system amount of actual, non-fuel, operations and maintenance costs for the 2010 test period for the indicated plants is shown below (millions):

Coyote Springs 2	$ 4.5
Colstrip 3 & 4	$11.0
Total (System)	$15.5

The following illustration shows the system forecast of non-fuel, operations and maintenance costs for the plants separately, and in total, for the five-year period of 2011 through 2015, as well as the actual costs for the 2010 test period. The system forecast shows major maintenance occurring for Coyote Springs 2 in 2012 and 2015, and for Colstrip 3 & 4 occurring in 2013 and 2014.