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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-12-08
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-12-07
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	DIRECT TESTIMONY
AND NATURAL GAS CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	ELIZABETH M. ANDREWS
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

CONTENTS

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corporation.

A. My name is Elizabeth M. Andrews. I am employed by Avista Corporation as Manager of Revenue Requirements in the State and Federal Regulation Department. My business address is 1411 East Mission, Spokane, Washington.

Q. Would you please describe your education and business experience?

A. I am a 1990 graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. That same year, I passed the November Certified Public Accountant exam, earning my CPA License in August 1991[1]. I worked for Lemaster & Daniels, CPAs from 1990 to 1993, before joining the Company in August 1993. I served in various positions within the sections of the Finance Department, including General Ledger Accountant and Systems Support Analyst until 2000. In 2000, I was hired into the State and Federal Regulation Department as a Regulatory Analyst until my promotion to Manager of Revenue Requirements in early 2007. I have also attended several utility accounting, ratemaking and leadership courses.

[1] Currently I keep a CPA-Inactive status with regards to my CPA license.

Q. Would you briefly describe your responsibilities?

A. Yes. As Manager of Revenue Requirements, I am responsible for the preparation of normalized revenue requirement and pro forma studies for the various jurisdictions in which the Company provides utility services. During the last twelve years, I have assisted or led the Company’s electric and/or natural gas general rate filings in Idaho, Washington and Oregon.

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

A. My testimony and exhibits in this proceeding will cover accounting and financial data in support of the Company's need for the proposed increase in rates. I will explain pro formed operating results, including expense and rate base adjustments made to actual operating results and rate base. In addition, I incorporate the Idaho share of the proposed adjustments of other witnesses in this case.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exhibit No. 10, Schedule 1 (Electric) and Schedule 2 (Natural Gas), which were prepared under my direction. These exhibits consist of worksheets, which show actual twelve months ended June 30, 2012 operating results, pro forma, and proposed electric and natural gas operating results and rate base for the State of

Idaho. The exhibits also show the calculation of the general revenue requirement, the derivation of the Company's overall proposed rate of return, the derivation of the net-operating-income-to-gross-revenue-conversion factor, and the specific pro forma adjustments proposed in this filing.

II. COMBINED REVENUE REQUIREMENT SUMMARY

Q. Would you please summarize the results of the Company's pro forma study for both the electric and natural gas operating systems for the Idaho jurisdiction?

A. Yes. After taking into account all standard Commission Basis adjustments, as well as additional pro forma and normalizing adjustments, the pro forma electric and natural gas rates of return ("ROR") for the Company's Idaho jurisdictional operations are 7.32% and 5.84%, respectively. Both return levels are below the Company's requested rate of return of 8.46%. The incremental revenue requirement necessary to give the Company an opportunity to earn its requested ROR is $11,393,000 for the electric operations and $4,561,000 for the natural gas operations. The overall base electric increase associated with this request is 4.58%. The base natural gas increase is 7.20%.

Q. What are the Company's rates of return that were last authorized by this Commission for its electric and gas operations in Idaho?

A. The Company's last authorized rate of return for its Idaho operations was 8.55%, effective October 1, 2010 for both our electric and natural gas systems.[2]

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

A. Approximately 70% of the Company's electric revenue requirement, and 48% for natural gas, is due to an increase in Net Plant Investment (including return on investment, depreciation and taxes, and offset by the tax benefit of interest).[3]

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

Also impacting the Company's electric request, the Company has included an Energy Efficiency Load Adjustment (EELA) increasing the Company's revenue requirement by approximately $1.6 million. As explained by Company Witness

[2] For the 2011 cases (AVU-E-10-01 & AVU-G-10-01), which had rates effective October 1, 2011, the Parties to the cases agreed to black box settlements, therefore, the ROR was not specified.

[3] These figures represent an approximate breakdown of amounts between the Company's request in this case compared to that approved in the Company's prior general rate case proceeding (Case Nos. AVU-E-11-01 and AVU-G-11-01). Due to the black-box nature of the Company's prior settlement approved by the IPUC in Case Nos. AVU-E-11-01 and AVU-G-11-01, the Company made certain assumptions as to the amounts approved for various rate base and expense items in order to create the estimate of the breakdown of the rate increase request.

Mr. Ehrbar, the reduced load from the EELA causes an increase in revenue requirement in each of the major cost categories, because the foregone retail revenue from the load reduction is designed to recover costs in each of the categories.

Q. What were the major components of the increased net plant investment included in the Company's electric and natural gas filings?

A. Looking at the changes to "gross" plant in service, Idaho "gross" plant increased by approximately $37.2 million electric and $12.3 million natural gas, as compared to what was included in the last rate case. In order to meet the energy and reliability needs of our customers, $15.4 million of the electric "gross" plant increase is due to the Company's investment in thermal and hydro generating facilities, as well as additional transmission investment. Electric distribution "gross" plant increased $10.0 million above that included in the last rate case, while the electric portion of general and intangible "gross" plant increased $11.8 million.

Related to gas, $8.2 million of the natural gas "gross" plant increase is due to the Company's investment in natural gas distribution plant above that included in the last rate case, while the natural gas portion of general "gross" plant increased $4.1 million.

The specific 2012 and 2013 pro forma capital expenditures undertaken by the Company to expand and replace its generation, transmission and distribution facilities are discussed further by Company witnesses Mr. Lafferty regarding production assets, and Mr. Kinney regarding transmission and distribution assets. In addition to discussing the actual restating and pro forma adjustments regarding net plant investment, Company witness Mr. DeFelice also describes all remaining 2012 and 2013 plant additions not described by Mr. Lafferty and Mr. Kinney.

Q. Mr. DeFelice explains the restating pro forma capital adjustments included in this case. Could you please briefly describe the conclusions drawn by Mr. DeFelice regarding the increased capital investment?

A. Yes. As described in Mr. DeFelice's testimony, the Company is making substantial new investment in its electric and natural gas system infrastructure to address the replacement and maintenance of Avista's aging system, and to sustain reliability and safety. As soon as this new plant is placed in service, the Company must start depreciating the new plant and incur other costs related to the investment. Unless this new investment is reflected in retail rates in a timely manner, it has a negative impact on Avista's earnings, particularly because the new plant is typically far more costly to install than the cost of the plant that was embedded in rates decades earlier. As plant is completed and is providing service to customers, it is appropriate for the Company to receive timely recovery of the costs associated with that plant.

Q. Could you please provide additional details related to the changes in electric production and transmission expense?

A. Yes. As discussed in Company witness Mr. Johnson's testimony, the level of Idaho's share of power supply expense has decreased by approximately $4.7 million ($13.56 million on a system basis) from the level included in the last rate case.

This decrease in pro forma power supply expense over the expense included in the last rate case is primarily a result of lower natural gas and power prices. For example, the natural gas price included in the Company's AURORA model has decreased from an annual average of $4.62/dth to $3.44/dth. The average modeled power purchase price has decreased from $40.45/MWh to $28.33/MWh. In addition, pro forma system loads are lower by 3.2 average megawatts (aMW) than the load included in the last rate case. Mr. Johnson discusses in further detail the changes in power supply expenses.

The reduction in power supply expense is partially offset by increased generation expense of approximately $2.2

million, including one-third of the three-year amortization of deferred Colstrip & Coyote Springs 2 (CS2) operation and maintenance (O&M) expense[4] of $1.3 million, (Idaho share) and increased hydro generation major maintenance expense of $907,000 (Idaho share) planned in 2013.

Lastly, pro forma net transmission expenditures decreased, mainly due to approximately $3.8 million (System) of increased electric revenues from various contracts, including the BPA Parallel Capacity support contract and a reduction in expenses from that included in the last rate case of $1.9 million (System) associated with the Transmission Line Ratings Confirmation Plan to be completed in 2013, as discussed by Mr. Kinney.

Q. Could you please identify the main components of the distribution, O&M and A&G expense changes included in the Company's filing?

A. Yes. A number of expense items have increased since the 2010 test year pro forma used in the last rate case. For example, employee benefits such as wages, pension and post-retirement medical expenses have increased.

We are utilizing a June 30, 2012 twelve-months-ended test year. The Company has included a number of pro forma

[4] As approved in Case No. AVU-E-11-01, the Company is amortizing prior year's deferred operation and maintenance (O&M) expense (the amount of actual costs in excess of costs included in base rates for 2011 and 2012) related to the Company's Coyote Springs 2 (CS2) natural gas-fired generating plant and Avista's 15 percent ownership share of the Colstrip 3 & 4 coal-fired generating plants, over a three-year period.

adjustments to capture some of the cost changes that the Company will experience from the test year. In particular, the Company has pro formed in the increased costs associated with compensation, including labor, pension and medical expense increases of approximately $2.4 million electric and $700,000 natural gas, and increases in Information Systems and Technology expenses of approximately $345,000 electric and $74,000 natural gas, which equates to approximately 45% of the electric and 30% of the natural gas additional increases in distribution, O&M and A&G expense included in the Company's filing. The majority of the remaining increases reflect net increases in costs over the 18-month period since the Company's last general rate case filing.

III. DERIVATION OF REVENUE REQUIREMENT

Test Period for Ratemaking Purposes

Q. On what test period is the Company basing its need for additional electric and natural gas revenue?

A. The test period being used by the Company is the twelve-month period ending June 30, 2012, presented on a pro forma basis. Currently authorized rates, effective October 1, 2011, were based upon the twelve-months ending December 31, 2010 test year utilized in cases AVU-E-11-01 and AVU-G-11-01, adjusted on a pro forma basis.

Revenue Requirement

Q. Would you please explain what is shown in Exhibit No. 10, Schedules 1 and 2?

A. Yes. Exhibit No. 10, Schedules 1 and 2, show actual and pro forma electric and natural gas operating results and rate base for the test period for the State of Idaho. Column (b) of page 1 of Exhibit No. 10, Schedules 1 and 2, show June 30, 2012 actual operating results and components of the average-of-monthly-average rate base as recorded[5]; column (c) is the total of all adjustments to net operating income and rate base; and column (d) is pro forma results of operations, all under existing rates. Column (e) shows the revenue increase required which would allow the Company to earn an 8.46% rate of return. Column (f) reflects pro forma operating results with the requested increase of $11,393,000 for electric and $4,561,000 for natural gas. The restating adjustments shown in columns *(1.01)* through *(2.13)*, of pages 6 through 10 of Exhibit No. 10, Schedule 1 (electric), and columns *(1.01)* through *(2.09)*, of pages 6 through 10 of Exhibit No. 10, Schedule 2 (natural gas) are consistent with current regulatory principles and the manner in which they have been addressed in recent cases.

[5] Actual plant rate base (cost, accumulated depreciation and associated DFIT) uses the AMA December 31, 2011 balances. Plant rate base is adjusted to a 2013 AMA basis with restating and pro forma adjustments.

Q. Would you please explain page 2 of Exhibit No. 10, Schedules 1 and 2?

A. Yes. Page 2 of Schedule 1 shows the calculation of the $11,393,000 revenue requirement for electric and Page 2 of Schedule 2 shows the calculation of the $4,561,000 revenue requirement for natural gas at the requested 8.46% rate of return.

Q. What does page 3 of Exhibit No. 10, Schedules 1 and 2 show?

A. Page 3 shows the proposed Cost of Capital and Capital Structure utilized by the Company in this case, and the weighted average cost of capital of 8.46%. Company witness Mr. Thies discusses the Company's proposed rate of return and the pro forma capital structure utilized in this case, while Company witness Dr. Avera provides additional testimony related to the appropriate return on equity for Avista.

Q. Would you now please explain page 4 of Exhibit No. 10, Schedules 1 and 2?

A. Yes. Page 4 shows the derivation of the net-operating-income-to-gross-revenue-conversion factor. The conversion factor takes into account uncollectible accounts receivable, Commission fees and Idaho State income taxes. Federal income taxes are reflected at 35%.

Q. Now turning to pages 5 through 9 of your Exhibit No. 10, Schedules 1 and 2, would you please explain what those pages show?

A. Yes. Page 5 begins with actual operating results and rate base for the test period in column (b). Individual normalizing and restating adjustments that are standard components of Commission Basis reporting or general rate case filings begin in column (1.01). Individual pro forma adjustments begin in column (3.01) on page 8 and continue through page 9. The final column on page 9 is the total pro forma operating results and net rate base for the test period.

<u>Standard Commission Basis and Restating Adjustments</u>

Q. Would you please explain each of these adjustments?

A. Yes, but before I begin, I will note that the following adjustments are consistent with the adjustments made in the Company's previous filed cases (AVU-E-11-01 and AVU-G-11-01), utilizing the same methodology to determine the adjustments. Rate base adjustments primarily adjust the June 30, 2012 test period amounts to a 2013 AMA amount.

I will note a few changes made to the **Results of Operations** column (1.00), reflecting the Company's actual electric operating results and rate base.

In past general rate case filings based on past Commission orders, this column represented actual net operating income and net utility plant, which included balances after accumulated depreciation and amortization, but before accumulated deferred income taxes (DFIT) and other rate base adjustments impacting the Company's actual net rate base results. Accumulated DFIT and other rate base adjustments were included as "Standard Commission Basis and Restating Adjustments" to be consistent with prior Commission orders, resulting in a "Restated Total" provided within the Company's filing.

In this filing however, column (1.00) Results of Operations reflects the actual operating results and total net rate base experienced by the Company on an average-of-monthly-average (AMA) basis, including Accumulated DFIT and other rate base adjustments previously shown as restating adjustments.[6] Columns following the Results of Operations column (1.00) reflect restating adjustments necessary to: restate the actual results based on prior Commission orders; reflect appropriate annualized expenses; correct for errors; or remove prior period amounts reflected in the actual results of operations.

[6] As noted above, actual plant rate base (cost, accumulated depreciation and associated DFIT) uses the AMA December 31, 2011 balances. Plant rate base is adjusted to a 2013 AMA basis with restating and pro forma adjustments. All other rate base amounts are included in column 1.00 on a June 30, 2012 AMA basis.

In addition to the explanation of adjustments provided herein, the Company has also provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the adjustments.

A summary of the adjustments follows:

Electric Adjustment (1.01) and Natural Gas Adjustment (1.01) - **Deferred FIT Rate Base**, adjusts the electric and natural gas DFIT rate base balances to the corrected DFIT balances, as shown within my workpapers provided with the Company's filing. Accumulated DFIT reflects the deferred tax balances arising from accelerated tax depreciation (Accelerated Cost Recovery System, or ACRS, and Modified Accelerated Cost Recovery, or MACRS) and bond refinancing premiums. The effect on Idaho rate base is a reduction of $285,000 electric and an increase of $297,000 natural gas. The effect on Idaho net operating income (NOI) is a reduction of $3,000 electric and an increase of $3,000 natural gas.

Electric Adjustment (1.02) and Natural Gas Adjustment (1.02) - **Deferred Debits and Credits**, is a consolidation of previous Commission Basis or other restating rate base adjustments and their NOI impact. The net impact on a consolidated basis of this adjustment decreases Idaho electric rate base by $409,000 and increases natural gas rate base by $2,000. Idaho electric NOI increases by a total of $16,000, while natural gas NOI decreases by $8,000.

As noted above, the June 2012 AMA actual rate base amounts of other rate base adjustments are included in the Results of Operations column (1.00). Adjustments included in the Deferred Debits and Credits consolidated adjustment are those necessary to reflect restatements from actual results based on prior Commission orders, and are explained below. For consistency with prior rate case filings, a description of each previously separated adjustment is included below.

The following items are included in the consolidation:

- **Gain on Office Building** reflects the removal of the amortization expense and AMA rate base balance included in the Company's test period related to Idaho's portion of the amortized gain on the sale of the Company's general office facility. The facility was sold in December 1986 and leased back by the Company. Although the Company repurchased the building in November 2005, the Company opted to continue to amortize the deferred gain over the remaining amortization period ending in 2011.
- **Colstrip 3 AFUDC Elimination** is a reallocation of rate base and depreciation expense between jurisdictions. In Cause Nos. U-81-15 and U-82-10, the Washington Utilities and Transportation Commission (WUTC) allowed the Company a return on a portion of Colstrip Unit 3 construction work in progress (CWIP). A much smaller amount of Colstrip Unit 3 CWIP was allowed in rate base in Case No. U-1008-144 by the Idaho Public Utility Commission (IPUC). The Company eliminated the AFUDC associated with the portion of CWIP allowed in rate base in each jurisdiction. Since production facilities are allocated on the Production/Transmission formula, the allocation of AFUDC is reversed and a direct assignment is made.
- **Colstrip Common AFUDC** is also associated with the Colstrip plants in Montana, and increases rate base.

Differing amounts of Colstrip common facilities were excluded from rate base by this Commission and the WUTC until Colstrip Unit 4 was placed in service. The Company was allowed to accrue AFUDC on the Colstrip common facilities during the time that they were excluded from rate base. It is necessary to directly assign the AFUDC because of the differing amounts of common facilities excluded from rate base by this Commission and the WUTC. In September 1988, an entry was made to comply with a Federal Energy Regulatory Commission (FERC) Audit Exception, which transferred Colstrip common AFUDC from the plant accounts to Account 186. These amounts reflect a direct assignment of rate base for the appropriate average-of-monthly-averages amounts of Colstrip common AFUDC to the Washington and Idaho jurisdictions. Amortization expense associated with the Colstrip common AFUDC is charged directly to the Washington and Idaho jurisdictions through Account 406 and is a component of the actual results of operations.

- **Kettle Falls & Boulder Park Disallowances** reflects the Kettle Falls generating plant disallowance ordered by this Commission in Case No. U-1008-185 and the Boulder Park plant disallowance ordered by the IPUC in Case No. AVU-E-04-1. The IPUC disallowed a rate of return on $3,009,445 of investment in Kettle Falls, and $2,600,000 million of investment in Boulder Park. The disallowed investment, and related accumulated depreciation and accumulated deferred taxes are removed. These amounts are a component of actual results of operations.
- **Restating CDA Settlement Deferral** adjusts the net assets and DFIT balances associated with the 2008/2009 past storage and §10(e) charges deferred for future recovery to a 2013 AMA basis, and records the annual amortization expense based on a ten-year amortization, as approved in Docket No. AVU-E-10-01.
- **Restating Spokane River Deferral** adjusts the net asset and DFIT balances related to the Spokane River deferred relicensing costs to a 2013 AMA basis, and records the annual amortization expense based on a ten-year amortization as approved in Case No. AVU-E-10-01.
- **Restating Spokane River PM&E Deferral** adjusts the net asset and DFIT balances related to the Spokane River deferred PM&E costs to a 2013 AMA basis, and records the annual amortization expense based on a ten-year amortization as approved in Case No. AVU-E-10-01.
- **Restating Montana Riverbed Lease** reflects the costs associated with the Montana Riverbed lease

settlement. In this settlement, the Company agreed to pay the State of Montana $4.0 million annually beginning in 2007, with annual inflation adjustments, for a 10-year period for leasing the riverbed under the Noxon Rapids Project and the Montana portion of the Cabinet Gorge Project. The first two annual payments were deferred by Avista as approved in Case No. AVU-E-07-10. In Case No. AVU-E-08-01 (see Order No. 30647), the Commission approved the Company's accounting treatment of the deferred payments, including accrued interest, to be amortized over the remaining eight years of the agreement starting October 1, 2008. This adjustment includes amortization of one-eighth of the deferred balance and the adjustment to lease payment expense for the additional annual inflation.

- **Weatherization and DSM Investment** includes in rate base the Sandpoint weatherization grant balance (FERC account 124.350), and removes the 1994 DSM Program amortization expense included in the test period. Beginning in July 1994 accumulation of AFUCE[7] ceased on Electric DSM and full amortization began on the balance based on the measure lives of the investment. Beginning in 1995 the amortization rates were accelerated to achieve a 14 year weighted average amortization period, which was completed in 2010. As no expense will be incurred during the 2013 rate year the portion of the 2010 amortization included in the test period is being eliminated.
- **Customer Advances** decreases rate base for moneys advanced by customers for line extensions, as they will be recorded as contributions in aid of construction at some future time.

Electric Adjustment (1.03) and Natural Gas Adjustment (1.03) - **Working Capital**, maintains the working capital rate base amount at the June 30, 2012 AMA test period amount included in the Results of Operations column (1.00), and therefore there is no additional adjustment to rate base needed. The Company has calculated its working capital in this proceeding by including Idaho's portion of the June 30,

[7] Allowance for funds used to conserve energy.

2012 average-monthly-average balances of FERC accounts 151 (Fuel Stock Inventory) and 154 (Plant Materials and Supplies).

Electric Adjustment (1.04) and Natural Gas Adjustment (1.04) - **Restate 2011 Capital**, restates the capital cost and expenses associated with adjusting the 2011 average-of-monthly-average (AMA) plant related balances to end-of-period (EOP) balances for plant in service at December 31, 2011.[8] The effect on Idaho rate base is an increase of $9,464,000 to electric and a reduction of $242,000 to natural gas rate base. The effect on Idaho net operating income (NOI) is a reduction of $327,000 electric and $73,000 natural gas.

Electric Adjustment (2.01) and Natural Gas Adjustment (2.02) - **Eliminate B & O Taxes**, eliminates the revenues and expenses associated with local business and occupation (B & O) taxes, which the Company passes through to its Idaho customers. The effect of this adjustment decreases electric NOI by $5,000, while natural gas nets to a $0 NOI change.

Electric Adjustment (2.02) and Natural Gas Adjustment (2.03) - **Uncollectible Expense**, restates the accrued expense to the actual level of net write-offs for the test period.

[8] Separate Pro Forma adjustments revise the total plant in service at December 31, 2011 to end-of-period December 31, 2012 and then to AMA 2013 in adjustments "Planned Capital Additions 2012" and "Planned Capital Additions 2013 AMA." See Electric Adjustments (3.09) and (3.10) and Natural Gas Adjustments (3.08) and (3.09) described below.

The effect of this adjustment increases electric NOI by $106,000 and natural gas NOI by $211,000.

Electric Adjustment (2.03) and Natural Gas Adjustment (2.04) - **Regulatory Expense**, restates recorded test period regulatory expense to reflect the IPUC assessment rates applied to expected revenues for the test period and the actual levels of FERC fees paid during the test period. The effect of this adjustment increases electric NOI by $23,000, while natural gas NOI decreases by $1,000.

Electric Adjustment (2.04) and Natural Gas Adjustment (2.05) - **Injuries and Damages**, is a restating adjustment that replaces the accrual with the six-year rolling average of actual injuries and damages payments not covered by insurance. This methodology was accepted by the Idaho Commission in Case No. WWP-E-98-11, and has been used since that time. The effect of this adjustment decreases electric NOI by $234,000 and natural gas NOI by $13,000.

Electric Adjustment (2.05) and Natural Gas Adjustment (2.06) - **FIT/DFIT/ITC/PTC Expenses**, adjusts the FIT and DFIT expenses calculated at 35% within Results of Operations by removing the effect of certain Schedule M items, matching the jurisdictional allocation of other Schedule M items to related Results of Operations allocations and adjusts the appropriate level of production tax credits and income tax credits on qualified electric generation.

For the electric adjustment, the net FIT and production tax credit adjustments increase Idaho electric NOI by $188,000, while adjusting for the proper level of deferred federal income tax (DFIT) expense for the test period, decreases Idaho NOI by $180,000, resulting in a net NOI reduction of $8,000. For the natural gas adjustment, the net effect of the FIT and DFIT adjustments results in a $0 impact to NOI.

Electric Adjustment (2.06) - **Idaho PCA**, removes the effects of the financial accounting for the Power Cost Adjustment (PCA). The PCA normalizes and defers certain power supply costs on an ongoing basis between general rate filings. Certain differences in actual power supply costs, compared to those included in base retail rates are deferred and then surcharged or rebated to customers in a future period. Revenue adjustments due to the PCA and the power cost deferrals affect actual results of operations and need to be eliminated to produce a normal period. Actual revenues and power supply costs are normalized in adjustments (2.09) Revenue Normalization and (3.01) Power Supply, respectively. The effect of this adjustment increases Idaho NOI by $2,060,000.

Electric Adjustment (2.07) - **Nez Perce Settlement Adjustment**, reflects a decrease in production operating expenses. An agreement was entered into between the Company and the Nez Perce Tribe to settle certain issues regarding earlier owned and operated hydroelectric generating facilities of the Company. This adjustment directly assigns the Nez Perce Settlement expenses to the Washington and Idaho jurisdictions. This is necessary due to differing regulatory treatment in Idaho Case No. WWP-E-98-11 and Washington Docket No. UE-991606. The effect of this adjustment increases Idaho NOI by $12,000.

Electric Adjustment (2.08) - **Restating CS2 Levelized Adjustment**, adjusts the deferred return amounts related to Coyote Springs 2 (CS2) to the amounts that will be recorded during the rate year. In the Company's electric general rate case, Case No. AVU-E-04-1, Order No. 29602, dated October 8, 2004, the Commission approved the deferral of return on CS2 investment in early years for recovery in later years in order to levelize the revenue requirement on CS2 plant investment for the first ten years of operation of the plant. The ten-year period runs from September 1, 2004 through August 31, 2014. This adjustment restates the test period amount of amortization expense, inclusive of the carrying charge on the deferred return, to the amount that will be recorded in the rate year. The change in deferred income tax expense from the test period to the rate period is also reflected. This adjustment reduces NOI by $150,000.

Electric Adjustment (2.09) and Natural Gas Adjustment (2.01) - **Revenue Normalization**, is an adjustment taking into account known and measurable changes that include 1) revenue normalization (which reprices customer usage using the current authorized rates, which were approved in the current cases, Case Nos. AVU-E-11-01 and AVU-G-11-01, that were effective October 1, 2011), 2) weather normalization, and 3) an unbilled revenue calculation. For the electric adjustment, Schedule 91 Tariff Rider and Schedule 59 Residential Exchange are excluded from pro forma revenues, and the related amortization expense is eliminated as well. For the natural gas adjustment, associated natural gas costs are replaced with natural gas costs computed using normalized volumes at the currently effective weighted-average-cost-of-gas, or WACOG rates in Schedule 150. Revenues associated with the temporary Gas Rate Adjustment Schedule 155, Schedule 191 Tariff Rider, and Schedule 199 Deferred SIT Adjustment are excluded from pro forma revenues, and the related amortization expenses are eliminated as well. Company witness Ms. Knox sponsors these adjustments. The effect of this adjustment increases electric NOI by $1,724,000 and natural gas NOI by $275,000.

Electric Adjustment (2.10) and Natural Gas Adjustment (2.07) - **Miscellaneous Restating Adjustment** removes a number of non-operating or non-utility expenses associated with advertising, dues and donations, etc., included in error, and removes or restates other expenses incorrectly charged between service and or jurisdiction. The effect of this adjustment increases electric NOI by $16,000 and natural gas NOI by $5,000.

Electric Adjustment (2.11) and Natural Gas Adjustment (2.08) - **Restating Incentives**, restates the actual employee payroll incentives included in the Company's test period using a six-year average adjusted by the Consumer Price Index.

Q. Please briefly explain the Company's incentive plan.

A. Avista's current incentive plan was first implemented in 2002, with a goal of focusing employees on controlling O & M costs per customer by improving our processes and driving efficiencies to better manage our business (O & M cost per customer and capital spending) while paying close attention to our customers' voices regarding the products and services we provide. Since that time, we have maintained the basic framework of the plan incorporating additional measures to create a more balanced approach to electric and natural gas reliability, as well as continuous improvement through our Performance Excellence measure.

The Employee Incentive Plan is a pay-at-risk plan whereby employees are eligible to receive cash incentive pay if the stated targets are achieved. The plan encourages employees at all levels to focus on common objectives that are designed to align the interests of all employees with the interests of our customers. Establishing specific targets for each element, measuring progress toward meeting the targets, and paying an incentive for achieving them motivates employees to focus on the key elements each year.

Q. How is the pay-at-risk component incorporated into Avista's total compensation package for employees?

A. Avista is committed to providing a total compensation program that provides base salaries, performance-based award programs and benefits that are competitive in the marketplace. Market data shows that pay-at-risk or variable pay plans are prevalent in over 80% of organizations, and most utilities, including Avista, have some kind of pay-at-risk plan.

The Company views the Plan as a competitive necessity, and a driver of desired behavior among employees, as well as a means to achieve cost-control. For example, if the existing incentive plan were to be eliminated, base salaries would need to be adjusted upward in order for Avista's total compensation to remain competitive with other utilities.

A pay-at-risk component of compensation is not designed to pay out the full incentive opportunity every year, nor is it designed to have no payout for an extended period of time. Pay-at-risk plans are designed to help focus employees on making decisions that benefit the Company and its customers, while at the same time functioning as an integrated component of total compensation.

Q. Please describe the specific targets included in the Company's 2011 incentive plan?

A. The targets included in the Company's 2011 plan included: 1) an O&M Cost-Per-Customer target metric to focus the business on controlling costs and driving efficiencies in order to keep our costs reasonable for our customers; 2) use of a Customer Satisfaction rating to track satisfaction levels of customers that have had recent contact with us; and 3) a reliability index measure, which combines three common industry indices in order to balance our focus on electric reliability. These reliability measures include: the Customer Average Interruption Duration Index (CAIDI), measuring the average restoration time for sustained outages; the System Average Interruption Frequency Index (SAIFI), which measures the average number of customers who had sustained outages (>5 minutes), divided by the customers served; and the Customer Experiencing Multiple Sustained Interruptions (more than 3) (CEMI[3]), measuring the percentage of customers that experienced more than three sustained outages in the year, 4) a response time metric that measures the percentage of time the Company responds within targeted time goals for dispatched natural gas emergency calls, and 5) a performance excellence metric demonstrating the Company’s commitment to continuously look for opportunities for efficiencies in order to keep costs reasonable for our customers.

Each of these targets are independent components to the incentive plan with individual targets or measures that must be achieved for a portion of the payout. The customer satisfaction, reliability index, response time and performance excellence measures are core objectives to our business therefore; these non-financial measures are designed as a “meets” or “not meets” metric, paying out only if the target of “meets” is achieved.

The O&M cost per customer target is based on the actual year end number of customers, targeted O&M expense and a formula for the payout to employees, based on the level of O&M savings below the target. This measure provides an incentive for employees to keep actual O&M costs as low as possible. Payments under this portion of the plan can range from 0% to 150% depending on the level of performance achieved. The formula for the payout, which was adopted in 2010, is structured such that as the level of savings below the O&M target increases, the payout to employees, as a percentage of the savings, is reduced.

Q. Please explain the use of a six-year average to restate incentive expense.

A. Since annual Company incentive plan payouts will vary year-to-year, the Company believes an average of annual payouts is most appropriate in order to "normalize" these costs. Often where there are revenues or expenses that can vary significantly from year-to-year, the Commission has approved averages to properly reflect a fair and reasonable level of revenue or expense to be included in customers' rates. Utilizing a six-year average of the Company's incentive plan payouts is consistent with other averaging methods utilized by this Commission in past proceedings. For example, as shown in Illustration No. 1 below using the years 2006 through 2011, one can see the large variability that can occur in each year in payout, and therefore the variability in customer rates if an average was not utilized, and the impact of the six-year average as proposed in this case:

Illustration No. 1

Historical Incentive Plan Payout

Line No.							
1	Test Period	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
2	Rate Case		**AVU-E-08-01**	**AVU-E-09-01**	**AVU-E-10-01**	**AVU-E-11-01**	**Current Filing**
3	**System** Expense	$ 4.406	$ 3.255	$ 2.856	$ 5.059	$ 9.371	$ 3.428
4	**ID - Electric** Share	$ 1.128	$ 0.833	$ 0.717	$ 1.270	$ 2.277	$ 0.819
5	Normalization Adjustment					(0.986)	0.311
6	Recovered in Rates/Proposed	$ 1.128	$ 0.833	$ 0.717	$ 1.270	$ 1.291	$ 1.130

Note:
CPI Index was removed from analysis.

Illustration No. 1 above[9], reflects the restating (reduction) / increase to test period expense of ($.986) million and $0.276 million (Idaho electric) for the years 2010 and 2011 respectively (Line No. 5). Therefore, customers benefited from the $.986 million reduction to the Company's revenue requirement in the previous GRC. To exclude this six-year average in the current case, would understate the expense that the Company has incurred over time, preventing the Company from recovering its costs over time, although customers have benefited from the O&M savings that have occurred, and triggered the incentive payout.

Q. What are some other examples where the use of an average has been used by the Company, and approved by the

[9] The incentive amounts shown on Line No. 6 (Recovered in Rates/Proposed) in Illustration No. 1 for columns 2009 and 2010 represent an approximate amount approved in the Company's prior general rate case proceedings (Case Nos. AVU-E-10-01 and AVU-E-11-01). Due to the black-box nature of the Company's prior settlements approved by the IPUC in Case Nos. AVU-E-10-01 and AVU-E-11-01, the Company made certain assumptions as to the incentive amounts approved in order to create the comparison used in Illustration No. 1, and the discussion that follows.

Commission, to determine the appropriate level of revenue or expense to include in its general rate case filings?

A. There are several examples of revenue or expense amounts which have been averaged or normalized and approved by this Commission. One example is the calculation of injuries and damages expense, which includes the restating adjustment described earlier in my testimony that replaces the amount accrued in the test period with a six-year rolling average of actual payments for injuries and damages not covered by insurance. Another example is the use of a five-year average for power plant availability.

Q. Briefly explain the reasoning behind the use of the CPI to adjust the average incentive level.

A. Incentive compensation is based on employees salary levels at the time of payout. These salary levels increase over time. If one does not adjust the historical years' expenses so that they are based on a comparable level of salaries, when the calculation is computed to determine the average, one is not using comparable levels of expenses in order to get to an "apples to apples" comparison.

Q. What is the impact of the Company's adjustment for a six-year average in this case?

A. The Company adjusted the six-year average by the CPI explained above, but also excluded all incentive target payouts that are not specifically related to reliability, customer service and operational efficiency targets, i.e., the earnings per share portion of the officer incentive plan are excluded from utility expenditures. The effect of this adjustment decreases electric NOI by $174,000 and natural gas NOI by $47,000.

Q. Please continue with explaining the adjustments on Page 7 of Exhibit 10, Schedules 1 and 2.

A. The next adjustment, is Electric Adjustment (2.12) - **Colstrip/CS2 Maintenance.** As approved in Order 32371 on September 30, 2011, (in Case Nos. AVU-E-11-01 and AVU-G-11-01), the Company deferred the non-fuel O&M costs (the amount of actual costs in excess of costs included in base rates) associated with the Company's thermal generating plant and is amortizing the prior year's deferred costs over a 3-year period. The amortization expense (one-third of the amount deferred for calendar years 2011 and 2012), increases expense by approximately $1.3 million, and decreases NOI by $857,000.

Electric Adjustment (2.13) and Natural Gas Adjustment (2.09) - **Restate Debt Interest**, restates debt interest using the Company’s pro forma weighted average cost of debt, as outlined in the testimony and exhibits of Mr. Thies, on the Results of Operations level of rate base shown in column (1.00) only, resulting in a revised level of tax deductible interest expense on actual test period rate base. The

Federal income tax effect of the restated level of interest for the test period decreases electric NOI by $191,000 and natural gas NOI by $33,000.

The Federal income tax effect of the restated level of interest on all other rate base adjustments included in the Company's filing are included and shown as an income impact of each individual rate base adjustment described elsewhere in this testimony.

Pro Forma Adjustments

Q. Please explain the significance of the adjustments beginning at page 8 on your Exhibit No. 10, Schedules 1 and 2.

A. The adjustments starting on page 8 are pro forma adjustments that recognize the jurisdictional impacts of items that will impact the pro forma operating period for known and measurable changes. They encompass revenue and expense items as well as additional capital projects. These adjustments bring the operating results and rate base to the final pro forma level for the test year. The pro forma adjustments shown in columns *(3.01)* through *(3.13)*, of pages 8 through 9 of Exhibit No. 15, Schedule 1 (electric), and columns *(3.01)* through *(3.11)*, of pages 8 through 9 of Exhibit No. 10, Schedule 2 (natural gas) are consistent with current regulatory principles and the treatment reflected in the last rate case, with a few proposed changes by the Company as described in my testimony below.

In addition to the explanation of adjustments provided herein, the Company has also provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the adjustments.

A summary of the adjustments follow:

Electric Adjustment (3.01) - **Pro Forma Power Supply**, was made under the direction of Mr. Johnson and is explained in detail in his testimony. This adjustment includes pro forma power supply related revenue and expenses to reflect the twelve-month period January 1, 2013 through December 31, 2013, using historical loads. Mr. Johnson's testimony outlines the system level of pro forma power supply revenues and expenses that are included in this adjustment. The adjustment in column 3.01 calculates the Idaho jurisdictional share of those figures. The net effect of this adjustment increases electric NOI by $1,529,000.

Electric Adjustment (3.02) - **Pro Forma Transmission Rev/Exp**, was made under the direction of Mr. Kinney and is explained in detail in his testimony. This adjustment includes pro forma transmission-related revenues and expenses to reflect the twelve-month period January 1, 2013 through December 31, 2013. The net effect of this adjustment increases electric NOI by $236,000.

Electric Adjustment (3.03) and Natural Gas Adjustment (3.01) - **Pro Forma Labor - Non-Exec**, reflects known and measurable changes to test period union and non-union wages and salaries, excluding executive salaries. For non-union employees, test period wages and salaries are restated to include the March 2012 overall actual increase of 2.6%, and 10 months of the planned March 2013 minimum increase of 2.6%. This 2012 minimum increase was presented to the Compensation Committee of the Board of Directors and was approved at the Board's May 2012 meeting.

Also included in this adjustment are the 2012 and 2013 union contract increases agreed to in 2010 of 3% for both years.

The net effect of this adjustment decreases electric NOI by $499,000 and natural gas NOI by $137,000.

Electric Adjustment (3.04) – **Pro Forma Generation Major O&M**, adjusts for incremental non-labor generation plant O&M costs planned for 2013 above the test period. These additional expenditures are mainly due to major O&M expenditures planned for the Company's thermal generation plant at Kettle Falls, and its hydro generation plants.[10]

[10] Major O&M expenditures of approximately $560,000 (system) planned at Avista's Kettle Falls thermal generation plant include upgrades to its boiler feed pump and main reclaimer bull gear, as well as replacement of its hog motor and expansion joint-turbine/condenser work. Major O&M expenditures of approximately $3.4 million (system) are planned at Avista's hydro facilities. This work includes approximately $2.1 million at Cabinet Unit for re-wedge stator winding maintenance, discharge ring repair, hub and oil head repair, replacement of wicket gate bushings,

The net effect of this adjustment decreases electric NOI by $590,000.

Electric Adjustment (3.05) and Natural Gas Adjustment (3.03)[11] - **Pro Forma Employee Benefits**, adjusts for changes in both the Company's pension and medical insurance expense and decreases electric NOI by $883,000 and natural gas NOI by $243,000.

Q. Please describe the pension expense portion of the Employee Benefits adjustment and Idaho's share of this expense.

A. The Company's pension expense portion of this adjustment is determined in accordance with Accounting Standard Codification 715 (ASC-715), and has increased on a system basis from approximately $23.5 million for the actual test year costs for the twelve months ended June 30, 2012, to $29.7 million for 2013. The increase in Idaho pension expense ($885,000 electric and $242,000 natural gas) is primarily due to a decrease in the discount rate used in calculating the pension expense and liability as well as a decrease in the expected return on assets and changes in other actuarial assumptions that are not predictable. At

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re-insulation of field windings, and rock scaling for access road safety. Additional major maintenance include projects at Long Lake dam of approximately $1 million for a FERC committed project to refurbish the interior coating of the four long lake penstocks and at the Post Falls north channel dam of approximately $300,000 for the rehabilitation of the piers and spillway aprons. For detail descriptions of activities, see Andrews workpapers filed with the Company's case.

[11] Natural Gas Adjustment (3.02) intentionally left blank.

this time the amounts included in this case are based on the most current available data. Preliminary pension expense is determined by an outside actuarial firm, in accordance with ASC-715, and provided to the Company late in the first quarter of each year. These calculations and assumptions are reviewed by the Company's outside accounting firm annually for reasonableness and comparability to other companies.

Q. Please now describe the medical insurance expense portion of the Employee Benefits adjustment and Idaho's share of this expense.

A. Medical insurance expense has increased on a system basis from $27.7 million for the actual test year costs for the twelve months ended June 30, 2012, to $31.3 million for 2013. The Company's Idaho medical insurance and post-retirement expense portion of this adjustment ($506,000 electric and $138,000 natural gas) adjusts for the medical-related costs planned for 2013 above the test period. In recent years, the Company has experienced increasing ASC 715 expense. ASC 715 requires employers to recognize the cost of providing post-retirement benefits on an accrual basis. The cost must be recognized during the working years of the employees to full eligibility date. Most of the increase in ASC 715 expense can be explained by declining interest rates, lower than expected investment returns, and greater amortization expense due to changes in the valuation of the actuarial liability.

The net impact of the increases in pension and medical costs is an increase in Idaho electric expense of approximately $1.4 million and natural gas expense of $380,000.

Electric Adjustment (3.06) and Natural Gas Adjustment (3.04) - **Pro Forma Insurance**, adjusts the test period insurance expense for general liability, directors and officers ("D&O") liability, and property to the actual cost of insurance policies that are in effect for 2012. Costs of system-wide insurance policies for 2012 varied only slightly from those policies in 2011. Insurance costs that are properly charged to non-utility operations have been excluded from this adjustment. The net effect of this adjustment increases electric NOI by $8,000 and natural gas NOI by $2,000.

Electric Adjustment (3.07) and Natural Gas Adjustment (3.05) - **Property Tax**, restates the test period accrued levels of property taxes to the 2013 rate period level using the most current information. As can be seen from my workpapers provided with the Company's filing, the property on which the tax is calculated is the property value as of December 31, 2012, reflecting the 2013 level of expense the Company will experience during the rate period. The net effect of this adjustment decreases electric NOI by $291,000 and natural gas NOI by $66,000.

Natural Gas Adjustment (3.06) - **Pro Forma Atmospheric Testing**, adjusts the test period expense for Atmospheric Corrosion expense to a three-year average. This expense is on a three-year rotation between the Company’s jurisdictions (Idaho, Washington and Oregon) and was therefore, coded directly to Idaho operations for the year in which the inspection occurs (2011 for Idaho was at a total cost of $390,000). The Company has included one-third of these costs in order to recover over a three-year period (2011-2013), and, therefore, has pro formed $130,000 for atmospheric O&M expense. The Company has received approval of this accounting treatment in its Oregon jurisdiction and has requested this treatment in the Company’s recent filed Washington general rate case as well, so the Company remains whole on an annual basis. This adjustment was made under the direction of Mr. Kopczynski and is described further in his testimony. The net effect of this adjustment increases natural gas NOI by $77,000.

Electric Adjustment (3.08) and Natural Gas Adjustment (3.07) – **Pro Forma IS/IT Costs**, adjusts for incremental IS/IT costs planned for 2013 above the test period. These additional expenditures are mainly due to the Company's replacement of the Customer Service Information System

(CIS), incremental labor to support various business processes, application support and additional security requirements, as well as increases in annual contractual agreements and maintenance and license fees.[12] The net effect of this adjustment decreases electric NOI by $224,000 and natural gas NOI by $47,000.

Electric Adjustment (3.09) and Natural Gas Adjustment (3.08) - **Pro Forma Capital Additions 2012**, pro forms in the capital cost and expenses associated with capital expenditures for 2012. This adjustment includes projects expected to be completed and transferred to plant-in-service by December 31, 2012, and thus were normalized to reflect annual amounts. The capital costs have been included for the appropriate pro forma period with the associated depreciation expense, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets. In addition, the total plant in service at December 31, 2011 (including accumulated depreciation and deferred FIT) was adjusted to an EOP December 31, 2012 adjusted balance. The

[12] Net increases in Information System / Information Technology O&M expenses total approximately $1.4 million system ($354,000 Idaho electric and $74,000 Idaho natural gas). These increases include increased expenses associated with the Company's Customer Service System (CIS) project (as described further in Company witness Mr. Kopczynski's testimony), due to incremental labor to support the new business processes and application support, and increased hosting, license and software maintenance fees. Additional increases are due to incremental labor to support other new and existing applications and security requirements, cost of living adjustments on existing contract obligations, and new software purchases, licenses and maintenance fees. For detail descriptions of incremental costs, see Andrews workpapers filed with the Company's case.

net effect of this adjustment decreases electric NOI by $1,859,000 and natural gas NOI by $442,000. The impact to total rate base is an increase in electric rate base of $20,705,000 and natural gas rate base of $4,449,000.

Electric Adjustment (3.10) and Natural Gas Adjustment (3.09) - **Pro Forma Capital Additions 2013**, pro forms in the capital cost and expenses associated with capital expenditures for 2013. This adjustment includes projects expected to be completed and transferred to plant-in-service during 2013, and thus were included on an AMA plant basis for the 2013 rate period. The capital costs have been included for the appropriate pro forma period with the associated depreciation expense, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets. In addition, the total plant in service at December 31, 2012 (including accumulated depreciation and deferred FIT) was adjusted to a 2013 AMA plant basis. The net effect of this adjustment decreases electric NOI by $589,000 and natural gas NOI by $124,000. The impact to total rate base is an increase in electric rate base of $1,582,000 and a reduction to natural gas rate base of $1,309,000.

Electric Adjustment (3.11) - **Pro Forma Energy Efficiency Load Adjustment (EELA)**, reflects the reduction in retail revenues due to energy efficiency programs, the resulting savings in power supply expense, and includes the change in all other revenue related expenses and taxes associated with this adjustment, as described in detail by Mr. Ehrbar. The net effect of this adjustment decreases electric NOI by $1,034,000.

Electric Adjustment (3.12) and Natural Gas Adjustment (3.10) - **Operation & Maintenance (O&M) Offsets**, includes a reduction to expense for anticipated operation and maintenance savings expected during the pro forma period, as compared to the test period. These O&M savings include reductions related to certain additional generation, transmission, distribution and general plant investment included in the 2011, 2012 and 2013 capital addition adjustments. The savings related to capital projects have been discussed further within Mr. Lafferty's (generation projects), Mr. Kinney's (distribution and transmission projects), and Mr. DeFelice's (general plant) direct testimony. Additional detail can be found within my workpapers included with the Company's filing. The net effect of this adjustment increases electric NOI by $72,000 and natural gas NOI by $4,000.

Electric Adjustment (3.13) and Natural Gas Adjustment (3.11) - **Depreciation Study**, as described in detail by Mr. DeFelice, reflects an increase in depreciation expense due to the utilization of new depreciation rates that were the result of a detailed depreciation study performed by a consultant from Gannett Fleming, Inc. The Company last changed its depreciation rates on January 1, 2008. The net effect of this adjustment decreases electric NOI by $300,000 and natural gas NOI by $306,000.

Summary

Q. How much additional net operating income would be required for the State of Idaho electric operations to allow the Company an opportunity to earn its proposed 8.46% rate of return on a pro forma basis?

A. The net operating income deficiency amounts to $7,259,000, as shown on line 5, page 2 of Exhibit No. 10, Schedule 1. The resulting revenue requirement is shown on line 7 and amounts to $11,393,000, or an increase of 4.58% over pro forma general business revenues.

Q. How much additional net operating income would be required for the State of Idaho natural gas operations to allow the Company an opportunity to earn its proposed 8.46% rate of return on a pro forma basis?

A. The net operating income deficiency amounts to $2,906,000, as shown on line 5, page 2 of Exhibit No. 10, Schedule 2. The resulting revenue requirement is shown on line 7 and amounts to $4,561,000, or an increase of 7.20% over pro forma general business and transportation revenues.

IV. ALLOCATION PROCEDURES

Q. Have there been any changes to the Company's system and jurisdictional procedures since the Company's last general electric and natural gas cases, Case Nos. AVU-E-11-01 and AVU-G-11-01?

A. No. For ratemaking purposes, the Company allocates revenues, expenses and rate base between electric and natural gas services and between Idaho, Washington and Oregon jurisdictions where electric and/or natural gas service is provided. The annually updated allocation factors used in this case have been provided with my workpapers.

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

A. Yes, it does.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-12-08
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-12-07
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 10
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	ELIZABETH M. ANDREWS
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
Line No.	DESCRIPTION	Actual Per Results Report	Total Adjustments	Pro Forma Total	Proposed Revenues & Related Exp	Pro Forma Proposed Total
	a	*b*	*c*	*d*	*e*	*f*
	REVENUES					
1	Total General Business	$256,134	($7,623)	$248,511	$11,393	$259,904
2	Interdepartmental Sales	209	-	209		209
3	Sales for Resale	46,558	(24,190)	22,368		22,368
4	Total Sales of Electricity	302,901	(31,813)	271,088	11,393	282,481
5	Other Revenue	56,621	(49,262)	7,359		7,359
6	Total Electric Revenue	359,522	(81,075)	278,447	11,393	289,840
	EXPENSES					
	Production and Transmission					
7	Operating Expenses	128,217	(51,506)	76,711		76,711
8	Purchased Power	88,611	(33,409)	55,202		55,202
9	Depreciation/Amortization	13,551	(882)	12,669		12,669
10	Regulatory Amortization	(10,077)	10,597	520		520
11	Taxes	6,246	380	6,626		6,626
12	Total Production & Transmission	226,548	(74,820)	151,728	-	151,728
	Distribution					
13	Operating Expenses	10,958	353	11,311		11,311
14	Depreciation/Amortization	11,013	2,757	13,770		13,770
15	Taxes	5,623	(3,085)	2,538		2,538
16	State Income Taxes	442	(188)	254	169	423
17	Total Distribution	28,036	(163)	27,873	169	28,042
18	Customer Accounting	4,362	(19)	4,343	30	4,373
19	Customer Service & Information	8,061	(7,460)	601		601
20	Sales Expenses	4	-	4		4
	Administrative & General					
21	Operating Expenses	22,070	1,793	23,863	27	23,890
22	Depreciation/Amortization	5,758	3,526	9,284		9,284
23	Taxes	-	7	7		7
24	Total Admin. & General	27,828	5,326	33,154	27	33,181
25	Total Electric Expenses	294,839	(77,136)	217,703	226	217,929
26	OPERATING INCOME BEFORE FIT	64,683	(3,939)	60,744	11,167	71,911
	FEDERAL INCOME TAX					
27	Current Accrual	6,740	(4,454)	2,286	3,908	6,194
28	Debt Interest	-	(327)	(327)		(327)
29	Deferred Income Taxes	8,783	3,275	12,058		12,058
30	Amortized Investment Tax Credit	(61)	(15)	(76)		(76)
31	NET OPERATING INCOME	$49,221	($2,418)	$46,803	$7,259	$54,062
	RATE BASE					
	PLANT IN SERVICE					
32	Intangible	$43,231	$10,992	$54,223		$54,223
33	Production	376,635	21,877	398,512		398,512
34	Transmission	174,765	18,459	193,224		193,224
35	Distribution	415,615	33,999	449,614		449,614
36	General	74,006	14,482	88,488		88,488
37	Total Plant in Service	1,084,252	99,809	1,184,061	-	1,184,061
	ACCUMULATED DEPRECIATION					
38	Intangible	1,966	4,747	6,713		6,713
39	Production	152,541	17,674	$170,215		170,215
40	Transmission	59,218	6,838	66,056		66,056
41	Distribution	129,763	21,919	151,682		151,682
42	General	31,320	7,630	38,950		38,950
43	Total Accumulated Depreciation	374,808	58,808	433,616	-	433,616
44	NET PLANT BEFORE DFIT	709,444	41,001	750,445	-	750,445
45	DEFERRED TAXES	(110,003)	(9,535)	(119,538)		(119,538)
46	NET PLANT AFTER DFIT	599,441	31,466	630,907	-	630,907
47	DEFERRED DEBITS AND CREDITS	1,150	(409)	741		741
48	WORKING CAPITAL	7,382	-	7,382		7,382
49	TOTAL RATE BASE	$607,973	$31,057	$639,030	$0	$639,030
50	RATE OF RETURN	8.10%		7.32%		8.46%

AVISTA UTILITIES
Calculation of General Revenue Requirement
Idaho - Electric System
TWELVE MONTHS ENDED JUNE 30, 2012

Line No.	Description	(000's of Dollars)
1	Pro Forma Rate Base	$639,030
2	Proposed Rate of Return	8.46%
3	Net Operating Income Requirement	$54,062
4	Pro Forma Net Operating Income	$46,803
5	Net Operating Income Deficiency	$7,259
6	Conversion Factor	0.63711
7	Revenue Requirement	$11,393
8	Total General Business Revenues	$248,720
9	Percentage Revenue Increase	4.58%

AVISTA UTILITIES
Pro Forma Cost of Capital
Idaho - Electric System

Proposed:

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
Total Debt	50.00%	6.02%	3.01%
Common	50.00%	10.90%	5.45%
Total	100.00%		8.46%

AVISTA UTILITIES
Revenue Conversion Factor
Idaho - Electric System
TWELVE MONTHS ENDED JUNE 30, 2012

Line No.	Description	Factor
1	**Revenues**	1.000000
	Expenses:	
2	Uncollectibles	0.002650
3	Commission Fees	0.002340
4	Idaho Income Tax	0.014845
5	Total Expenses	0.019835
6	Net Operating Income Before FIT	0.980165
7	Federal Income Tax @ 35%	0.343058
8	**REVENUE CONVERSION FACTOR**	0.63711

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Results of Operations	Deferred FIT Rate Base	Deferred Debits and Credits	Working Capital	Restate 2011 Capital	Eliminate B & O Taxes
	Adjustment Number	1.00	1.01	1.02	1.03	1.04	2.01
	Workpaper Reference	E-ROO	E-DFIT	E-DDC	E-WC	E-RCAP	E-EBO
	REVENUES						
1	Total General Business	$256,134	$0	$0	$0	$0	($3,161)
2	Interdepartmental Sales	209	-	-	-	-	-
3	Sales for Resale	46,558	-	-	-	-	-
4	Total Sales of Electricity	302,901	0	0	0	0	(3,161)
5	Other Revenue	56,621	-	-	-	-	-
6	Total Electric Revenue	359,522	0	0	0	0	(3,161)
	EXPENSES						
	Production and Transmission						
7	Operating Expenses	128,217	-	(64)	-	-	-
8	Purchased Power	88,611	-	-	-	-	-
9	Depreciation/Amortization	13,551	-	-	-	236	-
10	Regulatory Amortization	(10,077)	-	-	-	-	-
11	Taxes	6,246	-	-	-	-	-
12	Total Production & Transmission	226,548	0	(64)	0	236	0
	Distribution						
13	Operating Expenses	10,958	-	-	-	-	-
14	Depreciation/Amortization	11,013	-	-	-	187	-
15	Taxes	5,623	-	-	-	-	(3,153)
16	State Income Taxes 0.014845	442	-	-	-	(14)	(0)
17	Total Distribution	28,036	0	0	0	173	(3,153)
18	Customer Accounting	4,362	-	-	-	-	-
19	Customer Service & Information	8,061	-	-	-	-	-
20	Sales Expenses	4	-	-	-	-	-
	Administrative & General						
21	Operating Expenses	22,070	-	32	-	-	-
22	Depreciation/Amortization	5,758	-	-	-	247	-
23	Taxes	0	-	-	-	-	-
24	Total Admin. & General	27,828	0	32	0	247	0
25	Total Electric Expenses	294,839	0	(32)	0	656	(3,153)
26	OPERATING INCOME BEFORE FIT	64,683	0	32	0	(656)	(8)
	FEDERAL INCOME TAX						
27	Current Accrual	6,740	-	11	-	(230)	(3)
28	Debt Interest	0	3	4	-	(100)	-
29	Deferred Income Taxes	8,783	-	-	-	-	-
30	Amortized ITC - Noxon	(61)	-	-	-	-	-
31	NET OPERATING INCOME	$49,221	($3)	16	$0	($327)	($5)
	RATE BASE						
	PLANT IN SERVICE						
32	Intangible	$43,231	$0	$0	$0	($584)	$0
33	Production	376,635	-	-	-	3,377	-
34	Transmission	174,765	-	-	-	6,496	-
35	Distribution	415,615	-	-	-	8,422	-
36	General	74,006	-	-	-	3,992	-
37	Total Plant in Service	1,084,252	-	-	-	21,703	-
	ACCUMULATED DEPRECIATION/AMORT						
38	Intangible	1,966	-	-	-	(311)	-
39	Production	152,541	-	-	-	3,439	-
40	Transmission	59,218	-	-	-	1,294	-
41	Distribution	129,763	-	-	-	3,706	-
42	General	31,320	-	-	-	704	-
43	Total Accumulated Depreciation	374,808	-	-	-	8,832	-
44	NET PLANT	709,444	-	-	-	12,871	-
45	DEFERRED TAXES	(110,003)	(285)	-	-	(3,407)	-
46	Net Plant After DFIT	599,441	(285)	-	-	9,464	-
47	DEFERRED DEBITS AND CREDITS	1,150	-	(409)	-	-	-
48	WORKING CAPITAL	7,382	-	-	-	-	-
49	TOTAL RATE BASE	$607,973	($285)	($409)	$0	9,464	$0
50	RATE OF RETURN	8.10%	0				
50	REVENUE REQUIREMENT	3,474	(33)	(80)	-	1,770	8

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Uncollect. Expense	Regulatory Expense	Injuries and Damages	FIT/DFIT/ ITC/PTC Expense	ID PCA	Nez Perce Settlement Adjustment
	Adjustment Number	2.02	2.03	2.04	2.05	2.06	2.07
	Workpaper Reference	E-UE	E-RE	E-ID	E-FIT	E-EPCA	E-NPS
	REVENUES						
1	Total General Business	$0	$0	$0	$0	($6,732)	$0
2	Interdepartmental Sales	-	-	-	-	-	-
3	Sales for Resale	-	-	-	-	-	-
4	Total Sales of Electricity	0	0	0	0	(6,732)	0
5	Other Revenue	-	-	-	-	-	-
6	Total Electric Revenue	0	0	0	0	(6,732)	0
	EXPENSES						
	Production and Transmission						
7	Operating Expenses	-	-	-	-	(9,871)	(18)
8	Purchased Power	-	-	-	-	-	-
9	Depreciation/Amortization	-	-	-	-	-	-
10	Regulatory Amortization	-	-	-	-	-	-
11	Taxes	-	-	-	-	-	-
12	Total Production & Transmission	0	0	0	0	(9,871)	(18)
	Distribution						
13	Operating Expenses	-	-	-	-	-	-
14	Depreciation/Amortization	-	-	-	-	-	-
15	Taxes	-	-	-	-	-	-
16	State Income Taxes	2	1	(11)	-	-	0
17	Total Distribution	2	1	(11)	0	0	0
18	Customer Accounting	(165)	-	-	-	(15)	-
19	Customer Service & Information	-	-	-	-	-	-
20	Sales Expenses	-	-	-	-	-	-
	Administrative & General						
21	Operating Expenses	-	(37)	371	-	(16)	-
22	Depreciation/Amortization	-	-	-	-	-	-
23	Taxes	-	-	-	-	-	-
24	Total Admin. & General	0	(37)	371	0	(16)	0
25	Total Electric Expenses	(163)	(36)	360	0	(9,902)	(18)
26	OPERATING INCOME BEFORE FIT	163	36	(360)	0	3,170	18
	FEDERAL INCOME TAX						
27	Current Accrual	57	13	(126)	188	(2,345)	6
28	Debt Interest	-	-	-	-	-	-
29	Deferred Income Taxes	-	-	-	(180)	3,455	-
30	Amortized ITC - Noxon	-	-	-	-	-	-
31	NET OPERATING INCOME	$106	$23	($234)	($8)	$2,060	$12
	RATE BASE						
	PLANT IN SERVICE						
32	Intangible	$0	$0	$0	$0	$0	$0
33	Production	-	-	-	-	-	-
34	Transmission	-	-	-	-	-	-
35	Distribution	-	-	-	-	-	-
36	General	-	-	-	-	-	-
37	Total Plant in Service	-	-	-	-	-	-
	ACCUMULATED DEPRECIATION/AI						
38	Intangible	-	-	-	-	-	-
39	Production	-	-	-	-	-	-
40	Transmission	-	-	-	-	-	-
41	Distribution	-	-	-	-	-	-
42	General	-	-	-	-	-	-
43	Total Accumulated Depreciation	-	-	-	-	-	-
44	NET PLANT	-	-	-	-	-	-
45	DEFERRED TAXES	-	-	-	-	-	-
46	Net Plant After DFIT	-	-	-	-	-	-
47	DEFERRED DEBITS AND CREDITS	-	-	-	-	-	-
48	WORKING CAPITAL	-	-	-	-	-	-
49	TOTAL RATE BASE	$0	$0	$0	$0	$0	$0
50	RATE OF RETURN						
50	REVENUE REQUIREMENT	(166)	(37)	367	13	(3,233)	(18)

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

Line No.	DESCRIPTION	CS2 Levelized	Revenue Normalization	Misc Restating	Restate Incentives	Colstrip / CS2 Maintenance	Restate Debt Interest	Restated TOTAL
	Adjustment Number	2.08	2.09	2.10	2.11	2.12	2.13	R-Ttl
	Workpaper Reference	E-CS2	E-RN	E-MR	E-RI	E-CCOM	E-RDI	
	REVENUES							
1	Total General Business	$0	$4,874	$0	$0	$0	$0	$251,115
2	Interdepartmental Sales	-	-	-	-	-	-	209
3	Sales for Resale	-	-	-	-	-	-	46,558
4	Total Sales of Electricity	0	4,874	0	0	0	0	297,882
5	Other Revenue	-	-	-	-	-	-	56,621
6	Total Electric Revenue	0	4,874	0	0	0	0	354,503
	EXPENSES							
	Production and Transmission							
7	Operating Expenses	-	612	-	-	-	-	118,876
8	Purchased Power	-	-	-	-	-	-	88,611
9	Depreciation/Amortization	-	-	-	-	-	-	13,787
10	Regulatory Amortization	235	9,023	-	-	1,339	-	520
11	Taxes	-	-	-	-	-	-	6,246
12	Total Production & Transmission	235	9,635	0	0	1,339	0	228,040
	Distribution							
13	Operating Expenses	-	-	-	-	-	-	10,958
14	Depreciation/Amortization	-	-	-	-	-	-	11,200
15	Taxes	-	-	-	-	-	-	2,470
16	State Income Taxes	(3)	40	1	(8)	(20)	-	430
17	Total Distribution	(3)	40	1	(8)	(20)	0	25,058
18	Customer Accounting	-	14	-	-	-	-	4,196
19	Customer Service & Information	-	(7,478)	-	-	-	-	583
20	Sales Expenses	-	-	-	-	-	-	4
	Administrative & General							
21	Operating Expenses	-	11	(25)	276	-	-	22,682
22	Depreciation/Amortization	-	-	-	-	-	-	6,005
23	Taxes	-	-	-	-	-	-	-
24	Total Admin. & General	0	11	(25)	276	0	0	28,687
25	Total Electric Expenses	232	2,222	(24)	268	1,319	0	286,568
26	OPERATING INCOME BEFORE FIT	(232)	2,652	24	(268)	(1,319)	0	67,935
	FEDERAL INCOME TAX							
27	Current Accrual	(81)	928	8	(94)	(462)	191	4,803
28	Debt Interest	-	-	-	-	-	-	(92)
29	Deferred Income Taxes	-	-	-	-	-	-	12,058
30	Amortized ITC - Noxon	-	-	-	-	-	-	(61)
31	NET OPERATING INCOME	($150)	$1,724	$16	($174)	(857)	(191)	51,228
	RATE BASE							
	PLANT IN SERVICE							
32	Intangible	$0	$0	$0	$0	$0	$0	$42,647
33	Production	-	-	-	-	-	-	380,012
34	Transmission	-	-	-	-	-	-	181,261
35	Distribution	-	-	-	-	-	-	424,037
36	General	-	-	-	-	-	-	77,998
37	Total Plant in Service	-	-	-	-	-	-	1,105,955
	ACCUMULATED DEPRECIATION/AI							
38	Intangible	-	-	-	-	-	-	1,655
39	Production	-	-	-	-	-	-	155,980
40	Transmission	-	-	-	-	-	-	60,512
41	Distribution	-	-	-	-	-	-	133,469
42	General	-	-	-	-	-	-	32,024
43	Total Accumulated Depreciation	-	-	-	-	-	-	383,640
44	NET PLANT	-	-	-	-	-	-	722,315
45	DEFERRED TAXES	-	-	-	-	-	-	(113,695)
46	Net Plant After DFIT	-	-	-	-	-	-	608,620
47	DEFERRED DEBITS AND CREDITS	-	-	-	-	-	-	741
48	WORKING CAPITAL	-	-	-	-	-	-	7,382
49	TOTAL RATE BASE	$0	$0	$0	$0	$0	$0	$616,743
50	RATE OF RETURN							8.31%
50	REVENUE REQUIREMENT	236	(2,706)	(25)	273	1,346	300	1,489

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Power Supply	Pro Forma Transmission Rev/Exp	Pro Forma Labor Non-Exec	Pro Forma Generation Major O&M	Pro Forma Employee Benefits	Pro Forma Insurance	Pro Forma Property Tax
	Adjustment Number	3.01	3.02	3.03	3.04	3.05	3.06	3.07
	Workpaper Reference	E-PPS	E-PTR	E-PLN	E-HMM	E-PEB	E-PI	E-PT
	REVENUES							
1	Total General Business	$0	$0	$0	$0	$0	$0	$0
2	Interdepartmental Sales	-	-	-	-	-	-	-
3	Sales for Resale	(24,190)	-	-	-	-	-	-
4	Total Sales of Electricity	(24,190)	0	0	0	0	0	0
5	Other Revenue	(49,633)	371	-	-	-	-	-
6	Total Electric Revenue	(73,823)	371	0	0	0	0	0
	EXPENSES							
	Production and Transmission							
7	Operating Expenses	(43,777)	3	290	921	353	-	-
8	Purchased Power	(32,433)	-	-	-	-	-	-
9	Depreciation/Amortization	-	-	-	-	-	-	-
10	Regulatory Amortization				-			-
11	Taxes	-	-	-	-	-	-	380
12	Total Production & Transmission	(76,210)	3	290	921	353	0	380
	Distribution							
13	Operating Expenses	-	-	207	-	212	-	-
14	Depreciation/Amortization	-	-	-	-	-	-	-
15	Taxes	-	-	-	-	-	-	68
16	State Income Taxes	35	5	(15)	(14)	(32)	0	(7)
17	Total Distribution	35	5	192	(14)	180	0	61
18	Customer Accounting	-	-	72	-	82	-	-
19	Customer Service & Information	-	-	8	-	10	-	-
20	Sales Expenses	-	-	-	-	-	-	-
	Administrative & General							
21	Operating Expenses	-	-	205	-	733	(13)	-
22	Depreciation/Amortization	-	-	-	-	-	-	-
23	Taxes	-	-	-	-	-	-	7
24	Total Admin. & General	0	0	205	0	733	(13)	7
25	Total Electric Expenses	(76,175)	8	767	907	1,358	(13)	448
26	OPERATING INCOME BEFORE FIT	2,352	363	(767)	(907)	(1,358)	13	(448)
	FEDERAL INCOME TAX							
27	Current Accrual	823	127	(269)	(318)	(475)	4	(157)
28	Debt Interest	-	-	-	-	-	-	-
29	Deferred Income Taxes	-	-	-	-	-	-	-
30	Amortized ITC - Noxon	-	-	-	-	-	-	-
31	NET OPERATING INCOME	$1,529	$236	($499)	($590)	($883)	$8	($291)
	RATE BASE							
	PLANT IN SERVICE							
32	Intangible	$0	$0	$0	$0	$0	$0	$0
33	Production	-	-	-	-	-	-	-
34	Transmission	-	-	-	-	-	-	-
35	Distribution	-	-	-	-	-	-	-
36	General	-	-	-	-	-	-	-
37	Total Plant in Service	-	-	-	-	-	-	-
	ACCUMULATED DEPRECIATION/AI	-	-	-		-	-	
38	Intangible	-	-	-	-	-	-	-
39	Production	-	-	-	-	-	-	-
40	Transmission	-	-	-	-	-	-	-
41	Distribution	-	-	-	-	-	-	-
42	General	-	-	-	-	-	-	-
43	Total Accumulated Depreciation	-	-	-	-	-	-	-
44	NET PLANT	-	-	-	-	-	-	-
45	DEFERRED TAXES	-	-	-	-	-	-	-
46	Net Plant After DFIT	-	-	-	-	-	-	-
47	DEFERRED DEBITS AND CREDITS	-	-	-	-	-	-	-
48	WORKING CAPITAL	-	-	-	-	-	-	-
49	TOTAL RATE BASE	$0	$0	$0	$0	$0	$0	$0
50	RATE OF RETURN							
50	REVENUE REQUIREMENT	(2,399)	(370)	783	926	1,386	(13)	457

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma IS/IT Costs	Planned Capital Add 2012	Planned Capital Add 2013 AMA	PF Energy Efficiency Load Adj.	O&M Offsets	Depreciation Study	FINAL TOTAL
	Adjustment Number	3.08	3.09	3.10	3.11	3.12	3.13	F-Ttl
	Workpaper Reference	E-ISIT	E-CAP12	E-CAP13	E-EELA	E-Other	E-DS	
	REVENUES							
1	Total General Business	$0	$0	$0	($2,604)	$0	$0	$248,511
2	Interdepartmental Sales	-	-	-	-	-	-	209
3	Sales for Resale	-	-	-	-	-	-	22,368
4	Total Sales of Electricity	0	0	0	(2,604)	0	0	271,088
5	Other Revenue	-	-	-	-	-	-	7,359
6	Total Electric Revenue	0	0	0	(2,604)	0	0	278,447
	EXPENSES							
	Production and Transmission							
7	Operating Expenses	80	-	-	-	(35)	-	76,711
8	Purchased Power	-	-	-	(976)	-	-	55,202
9	Depreciation/Amortization	-	534	128	-	-	(1,780)	12,669
10	Regulatory Amortization	-				-	-	520
11	Taxes	-	-	-	-	-	-	6,626
12	Total Production & Transmission	80	534	128	(976)	(35)	(1,780)	151,728
	Distribution							
13	Operating Expenses	-	-	-	-	(66)	-	11,311
14	Depreciation/Amortization	-	457	263	-	-	1,850	13,770
15	Taxes	-	-	-	-	-	-	2,538
16	State Income Taxes	(9)	(83)	(23)	(24)	2	(13)	254
17	Total Distribution	(9)	374	240	(24)	(64)	1,837	27,873
18	Customer Accounting	-	-	-	(7)	-	-	4,343
19	Customer Service & Information	-	-	-	-	-	-	601
20	Sales Expenses	-	-	-	-	-	-	4
	Administrative & General							
21	Operating Expenses	274	-		(6)	(12)	-	23,863
22	Depreciation/Amortization	-	2,311	563	-	-	405	9,284
23	Taxes	-	-	-	-	-	-	7
24	Total Admin. & General	274	2,311	563	(6)	(12)	405	33,154
25	Total Electric Expenses	345	3,219	931	(1,013)	(111)	462	217,703
26	OPERATING INCOME BEFORE FIT	(345)	(3,219)	(931)	(1,591)	111	(462)	60,744
	FEDERAL INCOME TAX							
27	Current Accrual	(121)	(1,127)	(326)	(557)	39	(162)	2,286
28	Debt Interest	-	(218)	(17)	-	-	-	(327)
29	Deferred Income Taxes	-	-	-	-	-	-	12,058
30	Amortized ITC - Noxon	-	(15)	-	-	-	-	(76)
31	NET OPERATING INCOME	($224)	($1,859)	($589)	($1,034)	$72	($300)	$46,803
	RATE BASE							
	PLANT IN SERVICE							
32	Intangible	$0	$9,395	$2,181	$0	$0	$0	$54,223
33	Production	-	13,940	4,560	-	-	-	398,512
34	Transmission	-	9,788	2,175	-	-	-	193,224
35	Distribution	-	16,366	9,211	-	-	-	449,614
36	General	-	7,474	3,016	-	-	-	88,488
37	Total Plant in Service	-	56,963	21,143	-	-	-	1,184,061
	ACCUMULATED DEPRECIATION/A!							-
38	Intangible	-	2,816	2,242	-	-	-	6,713
39	Production	-	9,848	4,387	-	-	-	170,215
40	Transmission	-	3,769	1,775	-	-	-	66,056
41	Distribution	-	11,353	6,860	-	-	-	151,682
42	General	-	4,351	2,575	-	-	-	38,950
43	Total Accumulated Depreciation	-	32,137	17,839	-	-	-	433,616
44	NET PLANT	-	24,826	3,304	-	-	-	750,445
45	DEFERRED TAXES	-	(4,121)	(1,722)	-	-	-	(119,538)
46	Net Plant After DFIT	-	20,705	1,582	-	-	-	630,907
47	DEFERRED DEBITS AND CREDITS	-	-	-	-	-	-	741
48	WORKING CAPITAL	-	-	-	-	-	-	7,382
49	TOTAL RATE BASE	$0	20,705	1,582	-	-	$0	$639,030
50	RATE OF RETURN							7.32%
50	REVENUE REQUIREMENT	352	5,667	1,134	1,623	(113)	471	11,394

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
Line No.	DESCRIPTION	Actual Per Results Report	Total Adjustments	Pro Forma Total	Proposed Revenues & Related Exp	Pro Forma Proposed Total
	a	*b*	*c*	*d*	*e*	*f*
	REVENUES					
1	Total General Business	$68,808	$ (5,750)	$63,058	$4,561	$67,619
2	Total Transportation	400	(120)	280		280
3	Other Revenues	36,759	(36,603)	156		156
4	Total Gas Revenues	105,967	(42,473)	63,494	4,561	68,055
	EXPENSES					
	Production Expenses					
5	City Gate Purchases	75,399	(42,501)	32,898		32,898
6	Purchased Gas Expense	88	2	90		90
7	Net Nat Gas Storage Trans	(2,404)	2,767	363		363
8	Total Production	73,083	(39,732)	33,351	-	33,351
	Underground Storage					
9	Operating Expenses	275	-	275		275
10	Depreciation	188	(23)	165		165
11	Taxes	13	1	14		14
12	Total Underground Storage	476	(22)	454	-	454
	Distribution					
13	Operating Expenses	4,880	92	4,972		4,972
14	Depreciation	3,619	457	4,076		4,076
15	Taxes	2,137	(1,127)	1,010		1,010
16	State Income Taxes	75	(22)	53	68	121
17	Total Distribution	10,711	(600)	10,111	68	10,179
18	Customer Accounting	2,559	(253)	2,306	12	2,318
19	Customer Service & Information	2,308	(1,909)	399		399
20	Sales Expenses	3	-	3		3
	Administrative & General					
21	Operating Expenses	5,497	403	5,900	11	5,911
22	Depreciation/Amortization	1,434	1,089	2,523		2,523
23	Regulatory Amortizations	(34)	34	-		-
24	Taxes	-	-	-		-
25	Total Admin. & General	6,897	1,526	8,423	11	8,434
26	Total Gas Expense	96,037	(40,990)	55,047	91	55,138
27	OPERATING INCOME BEFORE FIT	9,930	(1,483)	8,447	4,470	12,917
	FEDERAL INCOME TAX					
28	Current Accrual	826	(477)	349	1,565	1,914
29	Debt Interest	-	(34)	(34)	-	(34)
30	Deferred FIT	1,679	(9)	1,670		1,670
31	Amort ITC	(17)	-	(17)		(17)
32	NET OPERATING INCOME	$7,442	($963)	$6,479	$2,905	$9,384
	RATE BASE: PLANT IN SERVICE					
33	Underground Storage	$9,622	$1,210	$10,832		$10,832
34	Distribution Plant	152,677	8,263	160,940		160,940
35	General Plant	17,567	6,550	24,117		24,117
36	Total Plant in Service	179,866	16,023	195,889	-	195,889
	ACCUMULATED DEPREC/AMORT					
37	Underground Storage	3,623	347	3,970		3,970
38	Distribution Plant	48,748	7,572	56,320		56,320
39	General Plant	5,542	2,992	8,534		8,534
40	Total Accum. Depreciation/Amort.	57,913	10,911	68,824	-	68,824
41	NET PLANT	121,953	5,112	127,065	-	127,065
42	DEFERRED FIT	(22,364)	(1,917)	(24,281)		(24,281)
43	Net Plant After DFIT	99,589	3,195	102,784	-	102,784
44	GAS INVENTORY	6,702	-	6,702		6,702
45	GAIN ON SALE OF BUILDING	(2)	2	-		-
46	OTHER	(66)	-	(66)		(66)
47	WORKING CAPITAL	1,510	-	1,510		1,510
48	TOTAL RATE BASE	$107,733	$3,197	$110,930	$0	$110,930
49	RATE OF RETURN	6.91%		5.84%		8.46%

AVISTA UTILITIES
Calculation of General Revenue Requirement
Idaho - Natural Gas
TWELVE MONTHS ENDED JUNE 30, 2012

Line No.	Description	(000's of Dollars)
1	Pro Forma Rate Base	$110,930
2	Proposed Rate of Return	8.46%
3	Net Operating Income Requirement	$9,385
4	Pro Forma Net Operating Income	$6,479
5	Net Operating Income Deficiency	$2,906
6	Conversion Factor	0.63711
7	Revenue Requirement	$4,561
8	Total General Business Revenues	$63,338
9	Percentage Revenue Increase	7.20%

AVISTA UTILITIES
PRO FORMA COST CAPITAL
Idaho - Natural Gas

Proposed:

Component	Capital Structure	Pro Forma Cost	Pro Forma Weighted Cost
Total Debt	50.00%	6.02%	3.01%
Common Equity	50.00%	10.90%	5.45%
Total	100.00%		8.46%

AVISTA UTILITIES
Revenue Conversion Factor
Idaho - Natural Gas System
TWELVE MONTHS ENDED JUNE 30, 2012

Line No.	Description	Factor
1	**Revenues**	1.000000
	Expenses:	
2	Uncollectibles	0.002651
3	Commission Fees	0.002340
4	Idaho State Income Tax	0.014845
5	Total Expenses	0.019836
6	Net Operating Income Before FIT	0.980164
7	Federal Income Tax @ 35%	0.343057
8	REVENUE CONVERSION FACTOR	0.63711

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Per Results Report	Deferred FIT Rate Base	Deferred Debits and Credits	Working Capital Restating	Restating 2011 Capital	Revenue Normalization & Gas Cost Adjust
	Adjsutment Number	1.00	1.01	1.02	1.03	1.04	2.01
	Workpaper Reference	G-ROO	G-DFIT	G-DDC	G-WC	G-PCAP	G-RNGC
	REVENUES						
1	Total General Business	$68,808	$ -	$ -	$ -	$ -	$ (4,528)
2	Total Transportation	400	-	-	-	-	(113)
3	Other Revenues	36,759	-	-	-	-	(36,603)
4	Total Gas Revenues	$105,967	-	-	-	-	(41,244)
	EXPENSES						
	Production Expenses						
5	City Gate Purchases	75,399	-	-	-	-	(42,501)
6	Purchased Gas Expense	88	-	-	-	-	(30)
7	Net Nat Gas Storage Trans	(2,404)	-	-	-	-	2,767
8	Total Production	73,083	-	-	-	-	(39,764)
	Underground Storage						
9	Operating Expenses	275	-	-	-	-	-
10	Depreciation/Amortization	188	-	-	-	2	-
11	Taxes	13	-	-	-	-	-
12	Total Underground Storage	476	-	-	-	2	-
	Distribution						
13	Operating Expenses	4,880	-	-	-	-	-
14	Depreciation/Amortization	3,619	-	-	-	42	-
15	Taxes	2,137	-	-	-	-	-
16	State Income Taxes 0.014845	75	-	(0)	-	(2)	6
17	Total Distribution	10,711	-	(0)	-	40	6
18	Customer Accounting	2,559	-	1	-	-	(12)
19	Customer Service & Information	2,308	-	-	-	-	(1,920)
20	Sales Expenses	3	-	-	-	-	-
	Administrative & General						
21	Operating Expenses	5,497	-	11	-	-	(11)
22	Depreciation/Amortization	1,434	-	-	-	66	
23	Regulatory Amortizations	(34)					34
24	Taxes	-	-	-	-	-	-
25	Total Admin. & General	6,897	-	11	-	66	23
26	Total Gas Expense	96,037	-	12	-	108	(41,667)
27	OPERATING INCOME BEFORE FIT	9,930	-	(12)	-	(108)	423
	FEDERAL INCOME TAX						
28	Current Accrual	826	-	(4)	-	(38)	148
29	Debt Interest	-	(3)	(0)	-	3	-
30	Deferred FIT	1,679	-	-	-	-	-
31	Amort ITC	(17)				-	-
32	NET OPERATING INCOME	$ 7,442	$ 3	$ (8)	$ -	$ (73)	$ 275
	RATE BASE						
	PLANT IN SERVICE						
33	Underground Storage	$9,622	$ -	$ -	$ -	$ 927	$ -
34	Distribution Plant	152,677	-	-	-	437	-
35	General Plant	17,567	-	-	-	778	-
36	Total Plant in Service	179,866	-	-	-	2,142	-
	ACCUMULATED DEPRECIATION/AMORT						
37	Underground Storage	3,623	-	-	-	72	-
38	Distribution Plant	48,748	-	-	-	1,875	-
39	General Plant	5,542	-	-	-	17	-
40	Total Accumulated Depreciation/Amortization	57,913	-	-	-	1,964	-
41	NET PLANT	121,953	-	-	-	178	-
42	DEFERRED TAXES	(22,364)	297	-	-	(420)	-
43	Net Plant After DFIT	99,589	297	-	-	(242)	-
44	GAS INVENTORY	6,702	-	-	-	-	-
45	GAIN ON SALE OF BUILDING	(2)	-	2	-	-	-
46	OTHER	(66)		-			
47	WORKING CAPITAL	1,510	-	-	-	-	-
48	**TOTAL RATE BASE**	**$ 107,733**	**$ 297**	**$ 2**	**$ -**	**$ (242)**	**$ -**
49	RATE OF RETURN	6.91%					
50	REVENUE REQUIREMENT	2,625	35	12	-	82	(431)

Exhibit No. 10
Case Nos. AVU-E-12-08 and AVU-G-12-07
E. Andrews, Avista
Schedule 2, Page 5 of 9

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Eliminate B & O Taxes	Uncollectible Expense	Regulatory Expense Adjustment	Injuries and Damages	FIT / DFIT Expense	Misc Restating Adjustments
	Adjsutment Number	2.02	2.03	2.04	2.05	2.06	2.07
	Workpaper Reference	G-EBO	G-UE	G-RE	G-ID	G-FIT	G-MR
	REVENUES						
1	Total General Business	$ (1,222)	$ -	$ -	$ -	$ -	$ -
2	Total Transportation	(7)	-	-	-	-	-
3	Other Revenues	-	-	-	-	-	-
4	Total Gas Revenues	(1,229)	-	-	-	-	-
	EXPENSES						
	Production Expenses						
5	City Gate Purchases	-	-	-	-	-	-
6	Purchased Gas Expense	-	-	-	-	-	-
7	Net Nat Gas Storage Trans	-	-	-	-	-	-
8	Total Production	-	-	-	-	-	-
	Underground Storage						
9	Operating Expenses	-	-	-	-	-	-
10	Depreciation/Amortization	-	-	-	-	-	-
11	Taxes	-	-	-	-	-	-
12	Total Underground Storage	-	-	-	-	-	-
	Distribution						
13	Operating Expenses	-	-	-	-	-	-
14	Depreciation/Amortization	-	-	-	-	-	-
15	Taxes	(1,229)	-	-	-	-	-
16	State Income Taxes	-	5	(0)	(0)	-	0
17	Total Distribution	(1,229)	5	(0)	(0)	-	0
18	Customer Accounting	-	(330)	-	-	-	-
19	Customer Service & Information	-	-	-	-	-	-
20	Sales Expenses	-	-	-	-	-	-
	Administrative & General						
21	Operating Expenses	-	-	2	20	-	(8)
22	Depreciation/Amortization	-	-	-	-	-	-
23	Regulatory Amortizations						
24	Taxes	-	-	-	-	-	-
25	Total Admin. & General	-	-	2	20	-	(8)
26	Total Gas Expense	(1,229)	(325)	2	20	-	(8)
27	OPERATING INCOME BEFORE FIT	-	325	(2)	(20)	-	8
	FEDERAL INCOME TAX						
28	Current Accrual	-	114	(1)	(7)	9	3
29	Debt Interest	-	-	-	-	-	-
30	Deferred FIT	-	-	-	-	(9)	-
31	Amort ITC	-	-	-	-	-	-
32	NET OPERATING INCOME	$ -	$ 211	$ (1)	$ (13)	$ -	$ 5
	RATE BASE						
	PLANT IN SERVICE						
33	Underground Storage	$ -	$ -	$ -	$ -	$ -	$ -
34	Distribution Plant	-	-	-	-	-	-
35	General Plant	-	-	-	-	-	-
36	Total Plant in Service	-	-	-	-	-	-
	ACCUMULATED DEPRECIATION/						
37	Underground Storage	-	-	-	-	-	-
38	Distribution Plant	-	-	-	-	-	-
39	General Plant	-	-	-	-	-	-
40	Total Accumulated Depreciation/Amor	-	-	-	-	-	-
41	NET PLANT	-	-	-	-	-	-
42	DEFERRED TAXES	-	-	-	-	-	-
43	Net Plant After DFIT	-	-	-	-	-	-
44	GAS INVENTORY	-	-	-	-	-	-
45	GAIN ON SALE OF BUILDING	-	-	-	-	-	-
46	OTHER						
47	WORKING CAPITAL	-	-	-	-	-	-
48	**TOTAL RATE BASE**	$ -	$ -	$ -	$ -	$ -	$ -
49	RATE OF RETURN						
50	REVENUE REQUIREMENT	-	(332)	2	20	-	(8)

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Restating Incentive Adjustment	Restate Debt Interest	Restated Total
	Adjsutment Number	2.08	2.09	
	Workpaper Reference	G-RI	G-DI	R-Ttl
	REVENUES			
1	Total General Business	$ -	$ -	$ 63,058
2	Total Transportation	-	-	280
3	Other Revenues	-	-	156
4	Total Gas Revenues	-	-	63,494
	EXPENSES			
	Production Expenses			
5	City Gate Purchases	-	-	32,898
6	Purchased Gas Expense	-	-	58
7	Net Nat Gas Storage Trans	-	-	363
8	Total Production	-	-	33,319
	Underground Storage			
9	Operating Expenses	-	-	275
10	Depreciation/Amortization	-	-	190
11	Taxes	-	-	13
12	Total Underground Storage	-	-	478
	Distribution			
13	Operating Expenses	-	-	4,880
14	Depreciation/Amortization	-	-	3,661
15	Taxes	-	-	908
16	State Income Taxes	(1)	-	83
17	Total Distribution	(1)	-	9,532
18	Customer Accounting	-	-	2,218
19	Customer Service & Information	-	-	388
20	Sales Expenses	-	-	3
	Administrative & General			-
21	Operating Expenses	73	-	5,584
22	Depreciation/Amortization	-	-	1,500
23	Regulatory Amortizations			-
24	Taxes	-	-	-
25	Total Admin. & General	73	-	7,084
26	Total Gas Expense	72	-	53,022
27	OPERATING INCOME BEFORE FIT	(72)	-	10,472
	FEDERAL INCOME TAX			
28	Current Accrual	(25)	33	1,058
29	Debt Interest	-	-	(1)
30	Deferred FIT	-	-	1,670
31	Amort ITC	-	-	(17)
32	NET OPERATING INCOME	$ (47)	$ (33)	$ 7,762
	RATE BASE			
	PLANT IN SERVICE			
33	Underground Storage	$ -	$ -	$ 10,549
34	Distribution Plant	-	-	153,114
35	General Plant	-	-	18,345
36	Total Plant in Service	-	-	182,008
	ACCUMULATED DEPRECIATION/			
37	Underground Storage	-	-	3,695
38	Distribution Plant	-	-	50,623
39	General Plant	-	-	5,559
40	Total Accumulated Depreciation/Amor	-	-	59,877
41	NET PLANT	-	-	122,131
42	DEFERRED TAXES	-	-	(22,487)
43	Net Plant After DFIT	-	-	99,644
44	GAS INVENTORY	-	-	6,702
45	GAIN ON SALE OF BUILDING	-	-	-
46	OTHER			(66)
47	WORKING CAPITAL	-	-	1,510
48	TOTAL RATE BASE	$ -	$ -	$ 107,790
49	RATE OF RETURN			7.20%
50	REVENUE REQUIREMENT	73	52	2,130

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Labor Non-Exec	Intentionally Left Blank	Pro Forma Employee Benefits	Pro Forma Insurance	Pro Forma Property Tax	Pro Forma Atmospheric Testing
	Adjsutment Number	3.01	3.02	3.03	3.04	3.05	3.06
	Workpaper Reference	G-PLN		G-PEB	G-PI	G-PT	G-PAT
	REVENUES						
1	Total General Business	$ -	$ -	$ -	$ -	$ -	$ -
2	Total Transportation	-	-	-	-	-	-
3	Other Revenues	-	-	-	-	-	-
4	Total Gas Revenues	-	-	-	-	-	-
	EXPENSES						
	Production Expenses						
5	City Gate Purchases	-	-	-	-	-	-
6	Purchased Gas Expense	9	-	23	-	-	-
7	Net Nat Gas Storage Trans	-	-	-	-	-	-
8	Total Production	9	-	23	-	-	-
	Underground Storage						
9	Operating Expenses	-	-	-	-	-	-
10	Depreciation/Amortization	-	-	-	-	-	-
11	Taxes	-	-	-	-	1	-
12	Total Underground Storage	-	-	-	-	1	-
	Distribution						
13	Operating Expenses	105	-	107	-	-	(120)
14	Depreciation/Amortization	-	-	-	-	-	-
15	Taxes	-	-	-	-	102	-
16	State Income Taxes	(3)	-	(6)	0	(2)	2
17	Total Distribution	102	-	101	0	100	(118)
18	Customer Accounting	41	-	47	-		-
19	Customer Service & Information	5	-	6	-	-	-
20	Sales Expenses	-	-	-	-	-	-
	Administrative & General						
21	Operating Expenses	54	-	197	(3)	-	-
22	Depreciation/Amortization	-	-	-	-	-	-
23	Regulatory Amortizations						
24	Taxes	-	-	-	-	-	-
25	Total Admin. & General	54	-	197	(3)	-	-
26	Total Gas Expense	211	-	374	(3)	101	(118)
27	OPERATING INCOME BEFORE FIT	(211)	-	(374)	3	(101)	118
	FEDERAL INCOME TAX						
28	Current Accrual	(74)	-	(131)	1	(36)	41
29	Debt Interest	-	-	-	-	-	-
30	Deferred FIT	-	-	-	-	-	-
31	Amort ITC	-	-	-	-	-	-
32	NET OPERATING INCOME	$ (137)	$ -	$ (243)	$ 2	$ (66)	$ 77
	RATE BASE						
	PLANT IN SERVICE						
33	Underground Storage	$ -	$ -	$ -	$ -	$ -	$ -
34	Distribution Plant	-	-	-	-	-	-
35	General Plant	-	-	-	-	-	-
36	Total Plant in Service	-	-	-	-	-	-
	ACCUMULATED DEPRECIATION/						
37	Underground Storage	-	-	-	-	-	-
38	Distribution Plant	-	-	-	-	-	-
39	General Plant	-	-	-	-	-	-
40	Total Accumulated Depreciation/Amor	-	-	-	-	-	-
41	NET PLANT	-	-	-	-	-	-
42	DEFERRED TAXES					-	
43	Net Plant After DFIT	-	-	-	-	-	-
44	GAS INVENTORY					-	
45	GAIN ON SALE OF BUILDING					-	
46	OTHER						
47	WORKING CAPITAL					-	
48	**TOTAL RATE BASE**	$ -	$ -	$ -	$ -	$ -	$ -
49	RATE OF RETURN						
50	REVENUE REQUIREMENT	215	-	382	(3)	104	(121)

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2012
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma IS/IT Costs	Pro Forma Capital Add 2012	Pro Forma Capital Add 2013 AMA	O&M Offsets	Depreciation Study	FINAL TOTAL
	Adjsutment Number	3.07	3.08	3.09	3.10	3.11	
	Workpaper Reference	G-DS	G-CAP12	G-CAP13	G-OFF	G-DS	F-Ttl
	REVENUES						
1	Total General Business	$ -	$ -	$ -	$ -	$ -	$ 63,058
2	Total Transportation	-	-	-	-	-	280
3	Other Revenues	-	-	-	-	-	156
4	Total Gas Revenues	-	-	-	-	-	63,494
	EXPENSES						
	Production Expenses						
5	City Gate Purchases	-	-	-	-	-	32,898
6	Purchased Gas Expense	-	-	-	-	-	90
7	Net Nat Gas Storage Trans	-	-	-	-	-	363
8	Total Production	-	-	-	-	-	33,351
	Underground Storage						
9	Operating Expenses	-	-	-	-	-	275
10	Depreciation/Amortization	-	5	2	-	(32)	165
11	Taxes	-	-	-	-	-	14
12	Total Underground Storage	-	5	2	-	(32)	454
	Distribution						
13	Operating Expenses	-	-	-	-	-	4,972
14	Depreciation/Amortization	-	146	29	-	240	4,076
15	Taxes	-	-	-	-	-	1,010
16	State Income Taxes	(1)	(11)	(3)	0	(7)	53
17	Total Distribution	(1)	135	26	0	233	10,111
18	Customer Accounting	-	-	-	-	-	2,306
19	Customer Service & Information	-	-	-	-	-	399
20	Sales Expenses	-	-	-	-	-	3
	Administrative & General						
21	Operating Expenses	74	-	-	(6)	-	5,900
22	Depreciation/Amortization	-	612	141	-	270	2,523
23	Regulatory Amortizations						-
24	Taxes	-	-	-	-	-	-
25	Total Admin. & General	74	612	141	(6)	270	8,423
26	Total Gas Expense	73	752	169	(6)	471	55,047
27	OPERATING INCOME BEFORE FIT	(73)	(752)	(169)	6	(471)	8,447
	FEDERAL INCOME TAX						
28	Current Accrual	(26)	(263)	(59)	2	(165)	349
29	Debt Interest	-	(47)	14	-	-	(34)
30	Deferred FIT	-	-	-	-	-	1,670
31	Amort ITC	-	-	-	-	-	(17)
32	NET OPERATING INCOME	$ (47)	$ (442)	$ (124)	$ 4	$ (306)	$ 6,479
	RATE BASE						
	PLANT IN SERVICE						
33	Underground Storage	$ -	$ 158	$ 125	$ -	$ -	$ 10,832
34	Distribution Plant	-	6,665	1,161	-	-	160,940
35	General Plant	-	4,462	1,310	-	-	24,117
36	Total Plant in Service	-	11,285	2,596	-	-	195,889
	ACCUMULATED DEPRECIATION/						
37	Underground Storage	-	192	83	-	-	3,970
38	Distribution Plant	-	3,671	2,026	-	-	56,320
39	General Plant	-	1,714	1,261	-	-	8,534
40	Total Accumulated Depreciation/Amor	-	5,577	3,370	-	-	68,824
41	NET PLANT	-	5,708	(774)	-	-	127,065
42	DEFERRED TAXES		(1,259)	(535)			(24,281)
43	Net Plant After DFIT	-	4,449	(1,309)	-	-	102,784
44	GAS INVENTORY		-	-			6,702
45	GAIN ON SALE OF BUILDING						
46	OTHER						(66)
47	WORKING CAPITAL						1,510
48	**TOTAL RATE BASE**	$ -	$ 4,449	$ (1,309)	$ -	$ -	$ 110,930
49	RATE OF RETURN						5.84%
50	REVENUE REQUIREMENT	74	1,284	21	(6)	480	4,561