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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO

CASE NO. AVU-E-11-01 CASE NO. AVU-G-11-01

DIRECT TESTIMONY OF ELIZABETH M. ANDREWS)

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

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I. INTRODUCTION

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

1

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
9 business experience?

10 Α. am a 1990 graduate of Eastern Washington Τ· 11 University with a Bachelor of Arts Degree in Business 12 Administration, majoring in Accounting. That same year, I 13 passed the November Certified Public Accountant exam, 14 earning my CPA License in August 1991¹. I worked for 15 Lemaster & Daniels, CPAs from 1990 to 1993, before joining the Company in August 1993. I served in various positions 16 17 within the sections of the Finance Department, including 18 General Ledger Accountant and Systems Support Analyst until 19 In 2000, I was hired into the State and Federal 2000. 20 Regulation Department as a Regulatory Analyst until my 21 promotion to Manager of Revenue Requirements in early 2007. 22 I have also attended several utility accounting, ratemaking 23 and leadership courses.

Q. As Manager of Revenue Requirements, what are your
responsibilities?

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

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1 As Manager of Revenue Requirements, aside from Α. 2 special projects, I am responsible for the preparation of 3 normalized revenue requirement and pro forma studies for 4 the various jurisdictions in which the Company provides 5 utility services. During the last ten and one-half years, 6 I have assisted or led the Company's electric and/or 7 natural gas general rate filings in Idaho, Washington and 8 Oregon.

9 Q. What is the scope of your testimony in this 10 proceeding?

11 My testimony and exhibits in this proceeding will Α. 12 generally cover accounting and financial data in support of 13 the Company's need for the proposed increase in rates. Ι 14 explain pro formed operating results, will including 15 expense and rate base adjustments made to actual operating 16 results and rate base. I incorporate the Idaho share of 17 the proposed adjustments of other witnesses in this case. 18 In addition, I will explain the Company's request for 19 deferred accounting treatment of changes in generating 20 plant operation and maintenance (O&M) costs related to its 21 Coyote Springs 2 natural gas-fired plant and its 15% 22 ownership share of the Colstrip 3 & 4 coal-fired generating 23 plants.

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

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1 prepared by me. These exhibits consist of worksheets, 2 which show actual 2010 operating results (twelve-month 3 period ending December 31, 2010), pro forma, and proposed 4 electric and natural gas operating results and rate base 5 for the State of Idaho. The exhibits also show the 6 calculation of the general revenue requirement, the 7 derivation of the Company's overall proposed rate of 8 return, the derivation of the net-operating-income-to-9 gross-revenue-conversion factor, and the specific pro forma 10 adjustments proposed in this filing.

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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?

16 Α. Yes. After taking into account all standard 17 Commission Basis adjustments, as well as additional pro 18 forma and normalizing adjustments, the pro forma electric 19 and natural gas rates of return ("ROR") for the Company's 20 Idaho jurisdictional operations are 7.57% and 7.31%, 21 respectivelv. Both return levels are below the Company's 22 requested rate of return of 8.49%. The incremental revenue 23 requirement necessary to give the Company an opportunity to 24 earn its requested ROR is \$9,009,000 for the electric 25 operations and \$1,921,000 for the natural gas operations. 26 The overall base electric increase associated with this request is 3.66%. The base natural gas increase is 2.72%. 27

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1 ο. What are the Company's rates of return that were 2 last authorized by this Commission for it's electric and 3 qas operations in Idaho? 4 The Company's currently authorized rate of return Α. 5 for its Idaho operations is 8.55%, effective October 1, 6 2010 for both our electric and natural gas systems. 7 8 III. ELECTRIC SECTION 9 Test Period for Ratemaking Purposes 10 Q. On what test period is the Company basing its 11 need for additional electric revenue? 12 Α. The test period being used by the Company is the 13 twelve-month period ending December 31, 2010, presented on 14 a pro forma basis. Currently authorized rates were based 15 upon the twelve-months ending December 31, 2009 test year 16 utilized in AVU-E-10-01, adjusted on a pro forma basis. 17 Q. Could you please explain the different rates of 18 return that you will be discussing in your testimony? 19 Α. Yes. There are three different rates of return 20 that will be discussed. The actual ROR earned by the 21 Company during the 2010 test period of 9.118², the pro

² As shown on Exhibit 10, Schedule 1, this return includes deferred federal income taxes (DFIT) on plant rate base, excluding minor additional DFIT amounts associated with Coeur d'Alene, Spokane River Relicensing and Montana Riverbed Lease deferrals included in separate restating adjustments described later in my testimony. ³ The Company will not have an opportunity to earn its current or requested allowed rate of return for the 2012 rate period without additional rate relief from this general rate case, due primarily to the 2011 and 2012 net increases in company expenditures included in the Company's filed case.

forma ROR of 7.24% (determined in my Exhibit No.10,
 Schedule 1) and the requested ROR of 8.49%.

Q. What are the primary factors driving the
Company's need for an electric increase?

5 Α. Approximately 90% of the Company's revenue 6 requirement requested in this case is due to an increase in 7 Net Plant Investment (including return on investment, 8 depreciation and taxes, and offset by the tax benefit of 9 interest). This increase is due to an increase of 10 approximately \$21.0 million in net plant rate base for the 11 Idaho jurisdiction.

12 The remaining 10% is due to increases in distribution, 13 operation and maintenance (O&M), and administrative and 14 general (A&G) expenses, offset by a reduction in net power 15 supply and transmission expenditures.

16 Also impacting the Company's request, the Company has 17 Energy Efficiency Load Adjustment included an (EELA) 18 Company's increasing the revenue requirement bv 19 approximately \$1.86 million. The reduced load from the 20 EELA causes an increase in revenue requirement in each of 21 the major cost categories because the foregone retail 22 revenue from the load reduction is designed to recover 23 costs in each of the categories.

Q. What were the major components of the increased
net plant investment included in the Company's filing?
A. Looking at the changes to "gross" plant in
service, Idaho "gross" plant increased by approximately

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1 \$66.2 million, as compared to what is currently included in 2 rates. In order to meet the energy and reliability needs 3 of our customers, \$23.0 million of this increase is due to 4 the Company's investment in thermal and hydro generating 5 facilities, as well as additional transmission investment. 6 Distribution "gross" plant increased \$30.1 million above 7 the current level included in rates, while general and 8 intangible "gross" plant increased \$13.1 million. After 9 adjusting for accumulated depreciation and amortization, 10 and accumulated deferred income taxes, the net increase to 11 rate base from these items is approximately \$21 million. 12 Lastly, the Company included a working capital adjustment in this case of \$7.7 million for fuel stock inventory, 13 14 materials and supplies.

15 The specific 2011 and 2012 pro forma capital 16 expenditures undertaken by the Company to expand and 17 replace its generation, transmission and distribution 18 facilities are discussed further by Company witnesses Mr. 19 Lafferty regarding production assets, and Mr. Kinnev 20 regarding transmission and distribution assets. In 21 addition to discussing the actual restating and pro forma 22 adjustments made regarding net plant investment, Company 23 witness Mr. DeFelice also describes all remaining 2011 and 24 2012 plant additions not described by Mr. Lafferty and Mr. 25 Kinney.

26 Q. Mr. DeFelice explains the restating pro forma 27 capital adjustments included in this case. Could you

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please briefly describe the conclusions drawn by Mr.
 DeFelice regarding the increased capital investment?

3 Α. As described in Mr. DeFelice's testimony, Yes. 4 the Company is making substantial levels of capital 5 investment in its electric and natural qas system 6 infrastructure to address the replacement and maintenance 7 of Avista's aging system, and to sustain reliability and 8 safetv. As soon as this new plant is placed in service, 9 the Company must start depreciating the new plant and incur 10 other costs related to the investment. Unless this new 11 investment is reflected in retail rates in a timely manner, 12 it has a negative impact on Avista's earnings, particularly 13 because the new plant is typically far more costly to 14 install than the cost of similar plant that was embedded in 15 rates decades earlier. As plant is completed and is 16 providing service to customers, it is appropriate for the 17 Company to receive timely recovery of the costs associated 18 with that plant.

19 Q. Could you please provide additional details 20 related to the changes in production and transmission 21 expense?

22 Α. Yes. As discussed in Company witness Mr. 23 Johnson's testimony, the level of Idaho's share of power 24 supply expense has <u>decreased</u> by approximately \$2.2 million 25 (\$6.4 million on a system basis) from the level currently 26 in base rates.

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1 This decrease in pro forma power supply expense over 2 the expense currently in base rates is caused primarily by 3 two factors, lower loads and lower market prices for 4 natural gas and power. Loads are lower by 50.8 aMW from 5 the authorized loads in current base rates, which used a 6 pro forma load projection. The reduction in load is a 7 result of using historical test-year loads and including 8 the Energy Efficiency Load Adjustment. The reduction in 9 load due to moving from a pro forma year load to a 10 historical test-year load is 30.7 aMW and the reduction in 11 load due to the Energy Efficiency Load Adjustment is 20.1 12 aMW. Mr. Johnson discusses in further detail the changes in 13 power supply expenses.

Pro forma transmission expenditures increased due in part to approximately \$747,000 of expenses in 2012 related to a North American Electric Reliability Corporation (NERC) Alert as discussed by Mr. Kinney.

18 Q. Could you please identify the main components of 19 the distribution, O&M and A&G expense changes included in 20 the Company's filing?

A. Yes. A number of expense items have increased
since the 2009 test year pro forma used in the last rate
case. For example, employee benefits such as wages and
medical insurance expenses have increased.

25 We are utilizing a 2010 test year, however, new 26 general electric rates resulting from this filing are not 27 expected to go into effect until late in 2011 or early

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1 2012. Accordingly, the Company has included a number of 2 pro forma adjustments to capture some of the cost changes 3 that the Company will experience from the test year. In particular, the Company has pro formed in the increased 4 5 costs associated with electric distribution vegetation 6 management costs of approximately \$1.3 million as discussed 7 by Mr. Kinnev, and increased medical expenses of 8 approximately \$658,000, discussed further below. These two 9 adjustments alone equate to over 75% of the additional 10 increases in distribution and other expense included in the 11 Company's filing.

12

13 <u>Revenue Requirement</u>

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

16 Exhibit No. 10, Schedule 1, shows actual Α. Yes. 17 and pro forma electric operating results and rate base for 18 the test period for the State of Idaho. Column (b) of page 19 1 of Exhibit No. 10, Schedule 1, shows 2010 actual 20 operating results and components of the average-of-monthly-21 average rate base as recorded (prior to deferred taxes); 22 column (c) is the total of all adjustments to net operating 23 income and rate base; and column (d) is pro forma results 24 of operations, all under existing rates. Column (e) shows 25 the revenue increase required which would allow the Company to earn an 8.49% rate of return. Column (f) reflects pro 26 27 forma electric operating results with the requested

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1 increase of \$9,009,000. The restating adjustments shown in 2 columns (c) through (aq), of pages 5 through 11 of Exhibit 3 No. 10, Schedule 1, are consistent with current regulatory 4 principles and the treatment reflected in the prior 5 Commission Order in Case No. AVU-E-10-01, with a few 6 proposed changes by the Company as described in my 7 testimony below.

Q. Would you please explain page 2 of Exhibit No.
9 10, Schedule 1?

10 A. Yes. Page 2 shows the calculation of the 11 \$9,009,000 revenue requirement at the requested 8.49% rate 12 of return.

13 Q. What does page 3 of Exhibit No. 10, Schedule 1 14 show?

15 Page 3 shows the proposed Cost of Capital and A. 16 Capital Structure utilized by the Company in this case, and 17 the weighted average cost of capital 8.49%. Company 18 witness Mr. Thies discusses the Company's proposed rate of 19 return and the pro forma capital structure utilized in this 20 case, while Company witness Dr. Avera provides additional 21 testimony related to the appropriate return on equity for 22 Avista.

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

A. Yes. Page 4 shows the derivation of the netoperating-income-to-gross-revenue-conversion factor. The
conversion factor takes into account uncollectible accounts

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receivable, Commission fees and Idaho State income taxes.
 Federal income taxes are reflected at 35%.

Q. Now turning to pages 5 through 11 of your Exhibit
No. 10, Schedule 1, would you please explain what those
5 pages show?

6 Α. Yes. Page 5 begins with actual operating results 7 and rate base (prior to inclusion of deferred taxes) for 8 the 2010 test period in column (b). Individual normalizing 9 and restating adjustments that are standard components of 10 our annual reporting to the Commission begin in column (c) 11 on page 5 and continue through column (ag) on page 9. 12 Individual pro forma adjustments begin in column (PF1) on 13 page 10 and continue through column (PF12) on page 11. The 14 final column on page 11 is the total pro forma operating 15 results and net rate base for the test period.

16

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

18 Q. Would you please explain each of these 19 adjustments, the reason for the adjustment and its effect 20 on test period State of Idaho net operating income and/or 21 rate base?

A. Yes, but before I begin, I will note that 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.

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1 The first adjustment, column (c) on page 5, entitled Deferred FIT Rate Base, reflects the rate base reduction 2 3 for Idaho's portion of deferred taxes. The adjustment 4 reflects the deferred tax balances arising from accelerated 5 tax depreciation (Accelerated Cost Recovery System, or 6 ACRS, and Modified Accelerated Cost Recovery, or MACRS) and 7 bond refinancing premiums. These amounts are reflected on 8 the average-of-monthly-average balance basis. The effect 9 on Idaho rate base is a reduction of \$104,677,000.

10 The adjustment in column (d), Deferred Gain on Office 11 Building, reflects the removal of the amortization gain 12 included in the Company's 2010 test period related to 13 Idaho's portion of the amortized gain on the sale of the 14 Company's general office facility. The facility was sold 15 in December 1986 and leased back by the Company. Although 16 the Company repurchased the building in November 2005, the 17 deferred gain was amortized over the period ending in 2011. 18 Therefore, during the 2012 rate period the average of 19 monthly averages (AMA) amount of the deferred gain is zero. 20 The effect on Idaho rate base is zero. The effect on Idaho 21 net operating income is an increase of \$43,000°.

22 The adjustment in column (e), Colstrip 3 AFUDC 23 Elimination, is reallocation of а rate base and

⁴ During the process of completing the Company's filing the Company discovered it had inadvertently reduced expense for removal of the deferred gain included in the test period. Rather, this adjustment should have removed the gain, increasing expense, decreasing net operating income \$43,000. The impact of correcting for this error increases the requested electric revenue requirement in this case by approximately \$135,000.

1 depreciation expense between jurisdictions. In Cause Nos. 2 U-81-15 and U-82-10, the Washington Utilities and 3 Transportation Commission (WUTC) allowed the Company a 4 return on a portion of Colstrip Unit 3 construction work in 5 progress (CWIP). A much smaller amount of Colstrip Unit 3 6 CWIP was allowed in rate base in Case U-1008-144 by the 7 IPUC. The Company eliminated the AFUDC associated with the 8 portion of CWIP allowed in rate base in each jurisdiction. 9 production Since facilities are allocated on the 10 Production/Transmission formula, the allocation of AFUDC is 11 reversed and a direct assignment is made. The rate base 12 adjustment reflects the average-of-monthly-averages amount 13 for the test period. The effect on Idaho net operating 14 income is a decrease of \$191,000. The effect of the 15 reallocation on Idaho rate base is an increase of 16 \$1,493,000.

17 The adjustment in column (f), Colstrip Common AFUDC, 18 is also associated with the Colstrip plants in Montana, and 19 increases rate base. Differing amounts of Colstrip common 20 facilities were excluded from rate base by this Commission 21 and the WUTC until Colstrip Unit 4 was placed in service. 22 The Company was allowed to accrue AFUDC on the Colstrip 23 common facilities during the time that they were excluded 24 from rate base. It is necessary to directly assign the 25 AFUDC because of the differing amounts of common facilities 26 excluded from rate base by this Commission and the WUTC. 27 In September 1988, an entry was made to comply with a

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1 Federal Energy Regulatory Commission (FERC) Audit 2 Exception, which transferred Colstrip common AFUDC from the 3 plant accounts to Account 186. These amounts reflect a 4 direct assignment of rate base for the appropriate average-5 of-monthly-averages amounts of Colstrip common AFUDC to the 6 Washington and Idaho jurisdictions. Amortization expense 7 associated with the Colstrip common AFUDC is charged 8 directly to the Washington and Idaho jurisdictions through 9 Account 406 and is a component of the actual results of 10 operations. The rate base adjustment reflects the average-11 of-monthly-averages amount for the test period. The effect 12 on Idaho rate base is an increase of \$774,000.

13 The adjustment in column (g), Kettle Falls & Boulder 14 Park Disallowances, decreases rate base. The amounts 15 reflect the Kettle Falls generating plant disallowance 16 ordered by this Commission in Case No. U-1008-185 and the 17 Boulder Park plant disallowance ordered by the IPUC in case 18 No. AVU-E-04-1. This Commission disallowed a rate of 19 return on \$3,009,445 of investment in Kettle Falls, and 20 \$2,600,000 million of investment in Boulder Park. The 21 disallowed investment, and related accumulated depreciation 22 and accumulated deferred taxes are removed. These amounts 23 are a component of actual results of operations. The 24 effect on Idaho rate base is a decrease of \$1,880,000.

25 The adjustment in column (h), Customer Advances, 26 decreases rate base for moneys advanced by customers for 27 line extensions, as they will be recorded as contributions

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in aid of construction at some future time. The effect on
 Idaho rate base is a decrease of \$858,000.

Q. Please turn to page 6 and explain the adjustments
4 shown there.

5 Α. Page 6 starts with the adjustment in column (i), 6 Weatherization and DSM Investment, which includes in rate 7 base the Sandpoint weatherization grant balance (FERC 8 account 124.350), and removes the 1994 DSM Program 9 amortization expense included in the 2010 test period.

10 Beginning in July 1994 accumulation of AFUCE⁵ ceased on Electric DSM and full amortization began on the balance 11 12 based on the measure lives of the investment. Beginning in 13 1995 the amortization rates were accelerated to achieve a 14 14 year weighted average amortization period, which was 15 completed in 2010. As no expense will be incurred during 16 the 2012 rate year the 2010 amortization is being 17 eliminated in this adjustment. The effect on Idaho rate 18 base is an increase of \$65,000. The effect on Idaho net 19 operating income is an increase of \$147,000.

20 The adjustment in column (i), Restating CDA 21 Settlement, adjusts the 2010 AMA test period annual 22 amortization expense, net asset (\$41.6 million (system) of 23 payments and deferred costs) and DFIT balances related to 24 the 2008 through 2010 CDA Tribe Settlement payments (Past 25 Storage/§10(e)) and deferred costs to a 2012 AMA basis.

⁵ Allowance for funds used to conserve energy.

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1 The regulatory treatment of the CDA Settlement was approved 2 by the Commission in Case No. AVU-E-09-01. The effect on 3 Idaho rate base is a decrease of \$317,000 below that in the 4 test period. The effect on Idaho net operating income is a 5 decrease of \$19,000.

6 The adjustment in column (k), Restating CDA Settlement 7 Deferral, adiusts the net assets and DFTT balances 8 associated with the 2008/2009 past storage and §10(e) 9 charges deferred for future recovery to a 2012 AMA basis, 10 and records the annual amortization expense based on a ten-11 year amortization, as approved in Docket No. AVU-E-10-01. 12 The effect on Idaho rate base is an increase of \$166,000. 13 The effect on Idaho net operating income is a decrease of 14 \$12,000.

15 The adjustment in column (1), Restating CDA/SRR 16 (Spokane River Relicensing) CDR, adjusts the net assets and 17 DFIT balances associated with the CDA Tribe settlement 4(e) 18 Spokane River relicensing conditions, deferred for future 19 recovery, to a 2012 AMA basis. The expense portion of this 20 adjustment includes the annual amortization of the net 21 total asset (\$12 million (system) of payments and deferred 22 costs); amortization of the deferred balance over a ten-23 year period, as approved in Case No. AVU-E-10-01; and the 24 annual \$2 million (system) of Coeur d'Alene Reservation 25 Trust Restoration Fund (CDR) payment expense over the 2010 26 AMA expense level. The effect on Idaho rate base is a

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decrease of \$68,000. The effect on Idaho net operating
 income is a decrease of \$223,000.

3 The adjustment in column (m), Restating Spokane River 4 Deferral, adjusts the net asset and DFIT balances related 5 to the Spokane River deferred relicensing costs to a 2012 6 AMA basis, and records the annual amortization expense 7 based on a ten-year amortization as approved in Case No. 8 AVU-E-10-01. The effect on Idaho rate base is an increase 9 of \$31,000. The effect on Idaho net operating income is a 10 decrease of \$2,000.

11 The adjustment in column (n), Restating Spokane River 12 PM&E Deferral, adjusts the net asset and DFIT balances 13 related to the Spokane River deferred PM&E costs to a 2012 14 AMA basis, and records the annual amortization expense 15 based on a ten-year amortization as approved in Case No. 16 The effect on Idaho rate base is an increase AVU-E-10-01. 17 of \$145,000. The effect on Idaho net operating income is a 18 decrease of \$13,000.

19 Q. Please turn to page 7 and explain the adjustments20 shown there.

21 Α. Page 7 starts with the adjustment in column (o), 22 Restating Montana Riverbed Lease, which reflects the costs 23 associated with the Montana Riverbed lease settlement. In 24 this settlement, the Company agreed to pay the State of 25 Montana \$4.0 million annually beginning in 2007, with 26 annual inflation adjustments, for a 10-year period for 27 leasing the riverbed under the Noxon Rapids Project and the

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1 Montana portion of the Cabinet Gorge Project. The first 2 two annual payments were deferred by Avista as approved in 3 Case No. AVU-E-07-10. In Case No. AVU-E-08-01 (see Order 4 No. 30647), the Commission approved the Company's 5 accounting treatment of the deferred payments, including 6 accrued interest, to be amortized over the remaining eight 7 years of the agreement starting October 1, 2008. This 8 adjustment includes amortization of one-eighth of the 9 deferred balance and the adjustment to lease payment 10 expense for the additional annual inflation. This 11 adjustment decreases Idaho net operating income by \$29,000 12 and increases rate base by \$996,000.

13 The adjustment in column (p), Working Capital, 14 increases total rate base for the Company's working capital 15 adjustment. Cash Working capital represents the funds 16 required to enable the Company to operate its business on a 17 daily basis. The need for these funds results from the fact 18 that there is a lag in time between the collection of 19 revenues for services rendered and the necessary outlay of 20 cash by the Company to pay the expenses of providing those 21 services. Cash working capital represents investor supplied 22 funds that are properly included in the Company's rate base 23 for ratemaking purposes. Application of the overall rate 24 of return to this element of rate base allows the Company 25 service the capital costs associated with the cash to 26 working capital.

1 Although there are various appropriate methods used to determine a Company's working capital, to reduce the 2 3 issues in this case⁶ the Company has calculated its working 4 capital in this proceeding by including Idaho's electric 5 portion of the 2010 average-monthly-average balances of 6 FERC accounts 151 (Fuel Stock Inventory) and 154 (Plant 7 Materials and Supplies). The Company believes this is a 8 reasonable to working capital, representing approach 9 specific items of expended funds to provide reliable 10 service to its customers. The effect on Idaho rate base is 11 an increase of \$7,710,000.

12 The next column marked by a dash, entitled **Subtotal** 13 Actual represents actual operating results and rate base 14 plus standard rate base adjustments that are included in 15 Commission Basis reporting, plus additional restating 16 adjustments required to annualize previous approved rate 17 base items.

Q. Please continue describing the adjustments on
 page 7 that continue after the Subtotal Actual column.

A. The adjustment in column (q), 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

⁶ The Company, of course, reserves the right to argue a different methodology in a future proceeding if appropriate.

1 adjustment eliminates any timing mismatch that exists
2 between the revenues and expenses by eliminating the
3 revenues and expenses in their entirety. B & O taxes are
4 passed through on a separate schedule, which is not part of
5 this proceeding. The effect of this adjustment is to
6 decrease Idaho net operating income by \$4,000.

7 The adjustment in column (r), **Property Tax**, restates 8 the test period accrued levels of property taxes to the 9 most current information available and eliminates any 10 adjustments related to the prior year. The effect of this 11 adjustment decreases Idaho net operating income by 12 \$309,000.

13 The adjustment in column (s), Uncollectible Expense, 14 restates the accrued expense to the actual level of net 15 write-offs for the test period. The effect of this 16 adjustment is to increase Idaho net operating income by 17 \$102,000.

18 The adjustment in column (t), **Regulatory Expense**, 19 which restates recorded 2010 regulatory expense to reflect 20 the IPUC assessment rates applied to expected revenues for 21 the test period period and the actual levels of FERC fees 22 paid during the test period. The effect of this adjustment 23 is to increase Idaho net operating income by \$2,000.

The adjustment in column (u), **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. A six-year rolling

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1 average and the reserve method of accounting for injuries 2 and damages, net of insurance proceeds, is a practical 3 methodology to deal with these normal utility operating 4 expenses that happen to occur on an irregular basis and 5 differ markedly in materiality. This methodology was accepted by the Idaho Commission in Case No. WWP-E-98-11, 6 7 and has been used since that time. The effect of this 8 adjustment is to increase Idaho net operating income by 9 \$396,000.

Q. Please turn to page 8 and explain the adjustmentsshown there.

12 Α. Page 8 starts with the adjustment in column (v), 13 FIT, adjusts the FIT calculated at 35% within Results of 14 Operations by removing the effect of certain Schedule M 15 items, matching the jurisdictional allocation of other 16 Schedule М items to related Results of Operations 17 allocations and adjusts the appropriate level of production 18 tax credits and income tax credits on qualified generation.

19 The net FIT and production tax credit adjustments 20 decrease Idaho net operating income by \$279,000. Adjusting 21 for the proper level of deferred tax expense for the test 22 period increases Idaho net operating income by \$210,000. 23 This adjustment also reflects the proper level of amortized 24 income tax credit for the test period decreasing Idaho net 25 Therefore, the operating income by an additional \$8,000. 26 net effect of this adjustment, all based upon a Federal tax

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1 rate of 35%, is to increase Idaho net operating income by
2 \$77,000.

3 The adjustment in column (w), Idaho PCA, removes the 4 effects of the financial accounting for the Power Cost 5 Adjustment (PCA). The PCA normalizes and defers certain 6 power supply costs on an ongoing basis between general rate 7 filings. Certain differences in actual power supply costs, 8 compared to those included in base retail rates are 9 deferred and then surcharged or rebated to customers in a 10 future period. Revenue adjustments due to the PCA and the 11 power cost deferrals affect actual results of operations 12 and need to be eliminated to produce a normal period. 13 Actual revenues and power supply costs are normalized in 14 adjustments in column (w) and column (PF1), respectively. 15 The effect of this adjustment is to decrease Idaho net 16 operating income by \$6,415,000.

17 The adjustment in column (x), Nez Perce Settlement 18 Adjustment, reflects a decrease in production operating 19 expenses. An agreement was entered into between the 20 Company and the Nez Perce Tribe to settle certain issues 21 regarding and earlier owned operated hydroelectric 22 generating facilities of the Company. This adjustment 23 directly assigns the Nez Perce Settlement expenses to the 24 Washington and Idaho jurisdictions. This is necessary due 25 to differing regulatory treatment in Idaho Case No. WWP-E-26 98-11 and Washington Docket No. UE-991606. The effect of

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1 this adjustment is to increase Idaho net operating income 2 by \$11,000.

The adjustment in column (y), Eliminate A/R Expenses, removes expenses incurred associated with the fees charged the Company for its customer accounts receivable program. The Company's accounts receivable program was terminated in December 2010. The effect of this adjustment is to increase Idaho net operating income by \$79,000.

9 The adjustment in column (z), Revenue Normalization, 10 is an adjustment taking into account known and measurable 11 changes that include revenue repricing (including the 12 current authorized rates approved in Case No. AVU-E-10-01), 13 weather normalization and a recalculation of unbilled 14 revenue. Schedule 91 Tariff Rider and Schedule 59 15 Residential Exchange are excluded from pro forma revenues, 16 and the related amortization expense is eliminated as well. 17 Company witness Ms. Knox is sponsoring this adjustment. 18 The effect of this particular adjustment is to increase 19 Idaho net operating income by \$11,504,000.

The adjustment in column (aa), is the Company's Miscellaneous Restating Adjustment. For this adjustment, the Company completed an extensive review of its 2010 expenditures included in its test period, removing 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

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1 between service and or jurisdiction, totaling approximately
2 \$143,000.

3 The Company also removed 10% of Avista Corp. director 4 fees (and 100% of director fees associated with Advantage 5 IO) totaling approximately \$35,000. Lastly, this 6 adjustment removes Idaho's electric portion of consulting 7 services, totaling approximately \$770,000 from the test 8 period to reduce the revenue requirement requested in this 9 The detail of these adjustments can be found within case. 10 my workpapers. The effect of this adjustment is to increase 11 Idaho net operating income by \$606,000.

Q. As noted above, the Company removed 10% of Avista
Corp. director fee expenses. What is the basis for
removing 10% of these costs?

In 2010 the Company requested from each of its 15 Α. 16 directors, based on their actual experience, the estimated on utility versus non-utility duties and 17 time spent 18 The responses from the Directors responsibilities. 19 indicated that approximately 90% of the Directors' time is 20 dedicated to utility matters, and approximately 10% to non-21 utility.

This 90/10 split is consistent with the average split that has been used in recent years by Avista's senior officers. Director fees paid to board members for their duties specific to other Avista boards, i.e. Advantage I.Q., were also removed. Using a 90/10 'sharing for the remaining director fees paid for participating in Avista

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Corp./Utility board meetings reduced the Company's expense
 included in this filing by approximately \$35,000.

3 Q. Please turn to page 9 and explain the adjustments
4 shown there.

A. Page 9 starts with the adjustment in column (ab), **Restating Incentives**, which restates the actual employee payroll incentives included in the Company's test period using a six-year average adjusted by the Consumer Price Index. The effect of this adjustment is to increase Idaho net operating income by \$631,000.

11 Q. Please briefly explain the Company's incentive12 plan.

13 incentive plan Α. Avista's current was first 14 designed in 2002, the goal of which was to focus on three 15 key elements: cost control, customer satisfaction and the 16 reliability of the energy we provide to our customers. The Employee Incentive Plan is a pay-at-risk plan whereby 17 18 employees are eligible to receive cash incentive pay if the 19 stated targets are achieved. The plan encourages employees 20 at all levels to focus on common objectives that are 21 designed to align the interests of employees with the 22 interests of our customers. Establishing specific targets 23 for each element, measuring progress toward meeting the 24 targets, and paying an incentive for achieving them 25 motivates employees to focus on the key elements each year. 26 How is the pay-at-risk component incorporated Q. 27 into Avista's total compensation package for employees?

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1 Α. Avista is committed to providing a total 2 compensation program that provides base salaries, 3 performance-based award programs and benefits that are 4 competitive in the marketplace. Market data shows that pay-5 at-risk or variable pay plans are prevalent in over 80% of 6 organizations, and most utilities, including Avista, have 7 some kind of pay-at-risk plan.

8 The Company views the Plan as a competitive necessity, 9 and a driver of desired behavior among employees, as well 10 as a means to achieve cost-control. For example, if the 11 existing incentive plan were to be eliminated, base 12 salaries would need to be adjusted in order for Avista's 13 total compensation to remain competitive with other 14 utilities.

15 A pay-at-risk component of compensation is not 16 designed to pay out the full incentive opportunity every 17 year, nor is it designed to have no payout for an extended 18 period of time. Pay-at-risk plans are designed to help 19 focus employees on making decisions that benefit the 20 Company and its customers, while at the same time 21 functioning as an integrated component of total 22 compensation.

Q. Please describe the specific targets included in
the Company's 2010 incentive plan?

A. The targets included in the Company's 2010 plan included: 1) an O&M cost per customer target metric to focus the business on controlling costs and driving

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1 efficiencies in order to keep our costs reasonable for our 2 customers; 2) use of a Customer Satisfaction rating to 3 track satisfaction levels of customers that have had recent 4 contact with us; and 3) a reliability index measure, which 5 combines three common industry indices in order to balance 6 focus on electric reliability. our These reliability 7 measures include: the Customer Average Interruption 8 Duration Index (CAIDI), measuring the average restoration 9 time for sustained outages; the System Average Interruption 10 Frequency Index (SAIFI), which measures the average number 11 of customers who had sustained outages (>5 minutes), 12 divided by the customers served; and the Customer 13 Experiencing Multiple Sustained Interruptions (more than 3) 14 (CEMI³). measuring the percentage of customers that 15 experienced more than three sustained outages in the year.

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 and reliability index 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 projected number of customers, targeted O&M expense and a savings mechanism between employees and the Company. This measure provides an incentive for employees to keep actual O&M costs as low as possible. Payments under this portion

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1 of the plan can range from 0% to 150% depending on the 2 level of performance achieved. In 2010 the company added a 3 sharing mechanism to the cost per customer target, sharing 4 costs savings at certain levels between employees and 5 customers.

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

8 Α. Since annual Company incentive plan payouts can 9 often vary year-to-year, the Company believes an average of 10 annual payouts is most appropriate in order to "normalize" 11 these costs. Often where there are revenues or expenses 12 that varv significantly from can vear-to-vear, the 13 Commission has approved averages to properly reflect a fair 14 and reasonable level of revenue or expense to be included 15 in customers' rates. Utilizing a six-year average of the 16 Company's incentive plan payouts is consistent with other 17 averaging methods utilized by this Commission in past 18 proceedings. For example, as shown in the table below 19 using the years 2005 through 2010, one can see the large 20 variability that can occur in each year in payout, and 21 therefore the variability in customer rates if an average 22 was not utilized, and the impact of the six-year average as 23 proposed in this case:

24

<u></u>]	<u>ustra</u>	tion	No.	1	(Sy:	stem)

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*6-Year Average - 2010 GRC (Millions)				
2005	\$6.2			
2006	\$4.7			
2007	\$3.4			
2008	\$2.9			
2009	\$5.1			
2010	\$9.4			
6-Yr Average	\$5.3			
Test Year Incentive Exp	\$9.4			
Restating Adjustment	(\$4.1)			

In this instance, the table above reflects a restating reduction to test period expense of \$4.1 million (system), showing a significant fluctuation in the level of expense between periods supporting the argument that use of an averaging methodology is appropriate.

16 Q. What are some other examples where the use of an 17 average has been used by the Company, and approved by the 18 Commission, to determine the appropriate level of revenue 19 or expense to include in its general rate case filings?

20 There are several examples of revenue or expense Α. 21 amounts which have been averaged or normalized and approved 22 by this Commission. One example is the calculation of 23 injuries and damages expense, which includes the restating 24 adjustment described earlier in my testimony that replaces 25 the amount accrued in the test period with a six-year 26 rolling average of actual payments for injuries and damages

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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.

5 Α. Incentive compensation is based on employees 6 salary levels at the time of payout. These salary levels 7 increase over time. If one does not adjust the historical 8 years' expenses so that they are based on a comparable 9 level of salaries, when the calculation is computed to 10 determine the average, one is not using comparable levels 11 of expenses in order to get to an "apples to apples" 12 comparison.

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

15 The Company adjusted the six-year average by the Α. 16 CPI explained above, but also excluded all incentive target 17 payouts that are not specifically related to reliability, 18 customer service and operational efficiency targets, *i.e.*, 19 the earnings per share portion of the officer incentive 20 plan are excluded from utility expenditures. The adjusted 21 six-year average reduces the Company's electric and natural 22 revenue requirement by approximately \$989,000 and qas 23 \$249,000 respectively.

Q. Please continue with explaining the adjustments
on Page 9 of Exhibit 10, Schedule 1.

A. The adjustment in column (ac), Restating CS2
Levelized Adjustment, adjusts the deferred return amounts

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1 related to Coyote Springs 2 (CS2) to the amounts that will 2 be recorded during the rate year. In the Company's 3 electric general rate case, Case No. AVU-E-04-1, Order No. 4 29602, dated October 8, 2004, the Commission approved the 5 deferral of return on CS2 investment in early years for 6 recovery in later years in order to levelize the revenue 7 requirement on CS2 plant investment for the first ten years 8 of operation of the plant. The ten-year period runs from 9 September 1, 2004 through August 31, 2014. This adjustment 10 restates the test period amount of amortization expense, 11 inclusive of the carrying charge on the deferred return, to 12 the amount that will be recorded in the rate year. The 13 change in deferred income tax expense from the test period 14 to the rate period is also reflected. This adjustment 15 reduces net operating income by \$182,000.

16 The adjustment in column (ad), Removal Colstrip 17 Lawsuit Settlement, reflects the removal of the 18 amortization of the Company's share of the lawsuit 19 settlement amount included in the 2010 test period. In 20 Case No. AVU-E-09-01 the Idaho Commission approved the two-21 year amortization treatment proposed by the Company 22 starting in August 1, 2009 through July 31, 2011. In July, 23 2010, Avista received insurance proceeds recovering the 24 majority of the amount yet to be amortized and recovered 25 from customers. This adjustment removes the test period 26 expense amount since the amortization period is complete

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prior to the 2012 rate period. This adjustment increases
 Idaho net operating income by \$148,000.

The adjustment in column (ae), Removal Chicago Climate 3 4 **Exchange**, removes the effect in the test period of 5 amortization revenue included related to the expiration of 6 the two-year amortization of the Chicago Climate Exchange 7 approved in AVU-08-01. In AVU-08-01 the IPUC approved a 8 two-year amortization (beginning in October 2008 through 9 September 2010) of the other revenue included in Idaho's 10 share of the revenues, net of expenses, from the sales of 11 Carbon Financial Instruments (CFIs) on the Chicago Climate 12 This adjustment decreases Idaho net operating Exchange. 13 income by \$219,000.

14 The adjustment in column (af), Operation & Maintenance 15 a reduction to (O&M) Savings, includes expense for 16 anticipated operation and maintenance savings expected 17 during the pro forma period, as compared to the 2010 test 18 These O&M savings include reductions related to period. 19 certain additional generation, transmission, distribution 20 and general plant investment included in the 2010, 2011 and 21 2012 capital addition adjustments. The savings related to 22 capital projects have been discussed further within Mr. 23 Lafferty's (generation projects), Mr. Kinney's 24 (distribution and transmission projects), and Mr. 25 DeFelice's (general plant) direct testimony. Additional 26 detail can be found within my workpapers included with the

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Company's filing. This adjustment increases Idaho net
 operating income by \$101,000.

3 The adjustment in column (ag), Restate Debt Interest, 4 restates debt interest using the Company's pro forma 5 weighted average cost of debt, as outlined in the testimony 6 and exhibits of Mr. Thies. As applied to Idaho's pro forma 7 level of rate base, this produces a pro forma level of tax 8 deductible interest expense. The Federal income tax effect 9 of the restated level of interest for the test period 10 decreases Idaho net operating income by \$276,000.

11 The last column on page 9, entitled Restated Total, 12 subtotals all the preceding columns (b) through column 13 excluding the subtotal column. These (ag), totals 14 represent actual operating results and rate base plus the 15 standard normalizing adjustments that the Company includes 16 in its annual Commission Basis reports, except power 17 supply.

18

19 Pro Forma Adjustments

Q. Please explain the significance of the 12 columns
beginning at page 10 on your Exhibit No. 10, Schedule 1.

A. The adjustments starting on page 10 are pro forma
adjustments that recognize the jurisdictional impacts of
items that will impact the pro forma operating period for

⁷ The restated total also includes an increase in expense necessary to annualize certain 2010 expenses included in the test period as restating adjustments, (i.e. Montana riverbed lease, Spokane River and CDA Tribe Settlement expense), and includes a reduction to expense for a 6-year average of incentives.

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.

5 Q. Please continue with your explanation of the 6 adjustments starting on page 10.

7 The adjustment in column (PF1), Pro Forma Power Α. 8 Supply, was made under the direction of Mr. Johnson and is 9 explained in detail in his testimony. This adjustment 10 includes pro forma power supply related revenue and 11 expenses to reflect the twelve-month period January 1, 2012 12 through December 31, 2012, using historical loads. Mr. 13 Johnson's testimony outlines the system level of pro forma 14 power supply revenues and expenses that are included in 15 this adjustment." The adjustment in column PF1 calculates 16 the Idaho jurisdictional share of those figures. The net 17 effect of the power supply adjustments decrease Idaho net 18 operating income by \$5,840,000.

19 The adjustment in column (PF2), **Pro Forma Energy** 20 Efficiency Load Adjustment, reflects the reduction in 21 retail revenues due to energy efficiency programs, the 22 resulting savings in power supply expense, and includes the 23 change in all other revenue related expenses and taxes

⁶ Mr. Johnson also explains the Company's use of historical loads in this case and the impact of the Energy Efficiency Load Adjustment described in adjustment PF2, rather than the use of pro forma loads used in the previous Company Case No. AVU-E-10-01. Due to the use of historical loads, the Company has also excluded the Production Property adjustment included in the Company's prior Case No. AVU-E-10-01.

associated with this adjustment, as described in detail by
 Mr. Ehrbar. The effect of this adjustment on Idaho net
 operating income is a decrease of \$1,184,000.

4 The adjustment in column (PF3), Pro Forma Labor-Non-5 Exec, reflects known and measurable changes to test period 6 union and non-union wages and salaries, excluding executive 7 salaries, which are handled separately in adjustment PF4. 8 For non-union employees, test period wages and salaries are 9 restated to include the March 2011 overall actual increase 10 of 2.8%, and 10 months of the planned March 2012 minimum 11 increase of 2.5%. This 2012 minimum increase was presented 12 to the Compensation Committee of the Board of Directors and 13 was approved at the Board's May 2011 meeting.

14 Also included in this adjustment are the 2011 and 2012 15 union contract increases agreed to in 2010 of 3% for both 16 methodology behind this The adjustment is years. 17 consistent with that used in Case No. AVU-E-10-01. The 18 effect of this adjustment on Idaho net operating income is 19 a decrease of \$625,000.

20 The adjustment in column (PF4), Pro Forma Labor-21 reflects known and measurable changes Executive, to 22 executive compensation, restating executive compensation 23 test period salary expense to actual salary levels at 2011. 24 This adjustment reflects the annual increase for the actual overall 2011 officer increase of 3.79%. Compensation costs 25 26 for non-utility operations are excluded, as executives 27 routinely charge a portion of their time to non-utility

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1 operations, commensurate with the amount of time spent on 2 such activities, based on a survey of each executive. The 3 methodology behind this adjustment is consistent with that 4 used in Case No. AVU-E-10-01. The effect of this 5 adjustment on Idaho net operating income is a decrease of 6 \$10,000.

7 The adjustment in column (PF5), Pro Forma Transmission 8 Rev/Exp, was made under the direction of Mr. Kinney and is 9 explained in detail in his testimony. This adjustment 10 includes pro forma transmission-related revenues and 11 expenses to reflect the twelve-month period January 1, 2012 12 through December 31, 2012. The net effect of the 13 transmission revenue and expense adjustments decreases 14 Idaho net operating income by \$760,000.

15 The adjustment in column (PF6), Pro Forma Capital 16 Additions 2010, pro forms in the capital cost and expenses 17 associated with adjusting the 2010 average-of-monthly-18 average (AMA) plant related balances to end-of-period (EOP) 19 balances for plant in service at December 31, 2010. The 20 capital costs have been included for the December 31, 2010 21 pro forma period with the associated depreciation expense 22 and property tax, as well as the appropriate accumulated 23 depreciation and deferred income tax rate base offsets. 24 This adjustment was made under the direction of Mr. 25 DeFelice and is described further in his testimony. This 26 adjustment is consistent with that included in the most 27 recent Idaho general rate case proceeding, Case No. AVU-E-

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10-01. This adjustment decreases Idaho net operating
 income by \$419,000 and increases rate base by \$11,643,000.
 Q. Please now turn to page 11 and continue with your
 explanation of the adjustments included on that page.

Column (PF7), Pro Forma Capital Additions 2011, 5 Α. 6 pro forms in the capital cost and expenses associated with 7 capital expenditures for 2011. This adjustment includes projects expected to be completed and transferred to plant-8 9 in-service by December 31, 2011, and thus were normalized 10 to reflect annual amounts. The capital costs have been 11 included for the appropriate pro forma period with the 12 associated depreciation expense and property tax, as well 13 as the appropriate accumulated depreciation and deferred 14 income tax rate base offsets. In addition, the total plant 15 in service at December 31, 2010 (including accumulated 16 depreciation and deferred FIT) was adjusted to an EOP 17 December 31, 2011 adjusted balance. This adjustment was 18 also made under the direction of Mr. DeFelice and is 19 described further in his testimony. This adjustment 20 decreases Idaho net operating income by \$1,941,000 and 21 increases rate base by \$11,578,000.

Column (PF8), **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 plantin-service during 2012, and thus were included on an AMA plant basis for the 2012 rate period. The capital costs

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1 have been included for the appropriate pro forma period 2 with the associated depreciation expense and property tax, 3 as well as the appropriate accumulated depreciation and 4 deferred income tax rate base offsets. In addition, the 5 total plant in service at December 31, 2011 (including 6 accumulated depreciation and deferred FIT) was adjusted to 7 a 2012 AMA plant basis. This adjustment was also made 8 under the direction of Mr. DeFelice and is described 9 further in his testimony. This adjustment decreases Idaho 10 net operating income by \$394,000 and decreases rate base by 11 \$2,043,000.

12 The adjustment in column (PF9), **Pro Forma Noxon** 13 **Generation 2011/2012**, pro forms in the 2011 Noxon Unit #2 14 generation plant upgrade (included in the 2010 rate case), 15 and the 2012 Noxon Unit #4 generation plant upgrade at a 16 2012 AMA basis, as explained further by Mr. Lafferty. These 17 Noxon upgrades are not included in the 2011 and 2012 18 capital additions explained above.

19 These unit upgrades are planned to increase unit 20 efficiency and boost unit ratings. The additional 21 generation from the Noxon Unit #2 and Unit #4, (Unit #2 22 completed in May 2011, and Unit #4 planned for May 2012) 23 has also been included in the Aurora Dispatch Model for the 24 rate year, as discussed by Company witness Mr. Kalich. 25 Including the additional generation from these Noxon 26 upgrades in the Dispatch Model, ultimately reducing power 27 supply expenses for customers in the 2012 rate year, and

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1 including these project in rate base for the rate period, 2 provides a proper match in revenues with expenses for these 3 projects. The Noxon Unit #4 project was included in rate 4 base and within the Aurora model at approximately 67% of 5 the cost and generation (equivalent to 8 months due to a 6 May 1, 2012 in-service date). This adjustment decreases 7 Idaho net operating income by \$113,000 and increases rate 8 base by \$4,650,000.

9 The adjustment in column (PF10), **Pro Forma Employee** 10 **Benefits**, adjusts for changes in both the Company's pension 11 and medical insurance expense and decreases Idaho net 12 operating income by \$433,000.

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

16 Α. The Company's pension expense portion of this 17 adjustment is determined in accordance with Financial 18 Accounting Standard 87 ("FAS-87"), and has remained fairly 19 flat on a system basis from approximately \$19.5 million for 20 the actual test year costs for the twelve months ended 21 December 31, 2010, to \$19.6 million for 2011. At this time 22 the amounts included in this case are based on the most 23 current available data. Preliminary Pension expense is 24 determined by an outside actuarial firm, in accordance with 25 FAS-87, and provided to the Company late in the first 26 quarter of each year. These calculations and assumptions 27 are reviewed by the Company's outside accounting firm

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1 annually for reasonableness and comparability to other 2 companies. Due to the timing of this report, additional 3 information may become known during the course of these 4 proceedings that may require a modification to this 5 adjustment.

6 Changes in pension expense typically are due primarily 7 to the investment performance of plan assets during the 8 past year. In addition, the Pension Protection Act (PPA) 9 of 2006 requires companies to annually increase the funding 10 level of their pension plans in order to eventually achieve 11 a fully-funded plan, which also impacts the plan asset 12 balance and level of expense.

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

16 Α. The Company's medical insurance expense is the 17 majority portion of this adjustment, adjusting for the 18 medical insurance costs planned for 2011 above the test 19 period. Medical insurance expense has increased on a 20 system basis from \$20.54 million for the actual test year 21 costs for the twelve months ended December 31, 2010, to 22 \$25.27 million for 2011. This increase in medical cost is 23 due to an aging workforce requiring more health care at an 24 ever increasing cost, which is consistent with what is 25 occurring on a national level. Large claims activity 26 driven by various diagnostic categories such as cancer and

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1 heart disease are also to blame for a portion of the 2 increase.

3 The net impact of the change in medical and pension
4 costs is an increase in Idaho expense of approximately
5 \$666,000.

6 Q. Please continue your explanation of the 7 adjustment columns on page 11.

8 Α. The adjustment in Column (PF11), **Pro** Forma 9 **Insurance**, adjusts the test period insurance expense for 10 general liability, directors and officers ("D&O") 11 liability, and property to the actual cost of insurance 12 policies that are in effect for 2011. Costs of system-wide 13 insurance policies for 2011 varied only slightly from those 14 policies in 2010. Insurance costs that are properly 15 charged to non-utility operations have been excluded from 16 This adjustment increases Idaho net this adjustment. 17 operating income by \$30,000.

18 The adjustment in column (PF12), **Pro Forma Vegetation** 19 **Management**, pro forms in the additional distribution 20 vegetation management (VM) O&M expense needed to reduce the 21 distribution VM cycle (expense level) to a four-year cycle 22 (expense level) to be used in 2012, as described further 23 by Mr. Kinney. This adjustment decreases Idaho net 24 operating income by \$822,000.

25 The last column, Pro Forma Total, reflects total pro26 forma results of operations and rate base consisting of

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test period actual results (twelve-months ending December
 31, 2010) and the total of all adjustments.

Q. Referring back to page 1, line 42, of Exhibit No.
10, Schedule 1, what was the pro forma electric rate of
return by the Company during the test period?

6 A. For the State of Idaho, the pro forma rate of 7 return is 7.57% under present rates. Thus, the Company 8 does not, on a pro forma basis for the test period, realize 9 the 8.49% rate of return requested by the Company in this 10 case.

11 Q. How much additional net operating income would be 12 required for the State of Idaho electric operations to 13 allow the Company an opportunity to earn its proposed 8.49% 14 rate of return on a pro forma basis?

A. The net operating income deficiency amounts to \$5,746,000, 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 \$9,009,000, or an increase of 3.66% over pro forma general business revenues.

20

21

IV. NATURAL GAS SECTION

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

A. The test period being used by the Company is the twelve-month period ending December 31, 2010, presented on a pro forma basis. Q. When was the last change to base rates in the
 Idaho jurisdiction?

A. The last change to base gas rates in Idaho
occurred on October 1, 2010 as a result of the Order
received in Case No. AVU-G-10-01.

6 Q. Could you please explain the different rates of 7 return shown in your natural gas results presented in your 8 testimony?

9 A. Yes. As discussed previously in the Electric
10 Section, there are three different rates of return
11 calculated. The actual ROR earned by the Company during
12 the 2010 test period of 7.21%, the pro forma ROR of 7.24%
13 (determined in my Exhibit No.10, Schedule 1) and the
14 requested ROR of 8.49%.

Q. What are the primary factors driving the
Company's need for additional natural gas revenues?

17 Α. The Company's natural gas request is driven by 18 changes in various operating cost components, approximately 19 two-thirds distribution O&M and A&G expenditures, such as 20 increased costs in employee benefits, i.e. wages and 21 medical insurance expenses, and one-third increased net 22 plant investment, due to additional Company investment in 23 underground storage facilities, distribution and general 24 plant.

25

The total of the increased operating cost components

[°] As shown on Exhibit 10, Schedule 1, this return includes deferred federal income taxes (DFIT) on plant rate base.

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requested in this case causes an increase in the fixed
 costs of providing gas service to customers. I describe
 the pro forma adjustments included in this case later in my
 testimony.

5

6 <u>Revenue Requirement</u>

Q. Would you please explain what is shown in Exhibit
8 No. 10, Schedule 2?

9 Α. Yes. Exhibit No. 10, Schedule 2 shows actual and pro forma gas operating results and rate base for the test 10 11 period for the State of Idaho. Column (b) of page 1 of 12 Exhibit No. 10, Schedule 2, shows 2010 actual operating 13 results and components of the average-of-monthly-average 14 rate base as recorded (prior to deferred taxes); column (c) is the total of all adjustments to net operating income and 15 is pro forma results of 16 rate base; and column (d) operations, all under existing rates. Column (e) shows the 17 18 revenue increase required which would allow the Company to 19 earn an 8.49% rate of return. Column (f) reflects pro 20 forma gas operating results with the requested increase of 21 \$1,921,000.

Q. Would you please explain page 2 of Exhibit No.
10, Schedule 2?

A. Yes. Page 2 shows the calculation of the \$1,921,000 revenue requirement at the requested 8.49% rate of return.

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1 Q. What does page 3 of Exhibit No. 10, Schedule 2 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 calculation of 8.49%. Mr. Thies discusses the Company's proposed rate of return and the pro forma capital structure utilized in this case, while Dr. Avera provides additional testimony related to the appropriate return on equity for Avista.

10 Q. Would you now please explain page 4 of Exhibit
11 No. 10, Schedule 2?

A. Yes. Page 4 shows the derivation of the netoperating-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, Schedule 2, would you please explain what those
pages show?

A. Yes. Page 5 begins with actual operating results and rate base (prior to inclusion of deferred taxes) for the 2010 test period in column (b). Individual normalizing adjustments that are standard components of our annual reporting to the Commission begin in column (c) on page 5 and continue through column (t) on page 8¹⁰. Individual pro

¹⁰ The restated total also includes an increase in rate base necessary to include the Company's requested working capital adjustment, and includes a reduction to expense for a 6-year average of incentives.

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1 forma adjustments begin in column (PF1) on page 8 and 2 continue through column (PF10) on page 9. The final column 3 on page 9 is the total pro forma operating results and rate 4 base for the test period.

5

6 Standard Commission Basis Adjustments

7 Q. Would you please explain each of these 8 adjustments, the reason for the adjustment and its effect 9 on test period State of Idaho net operating income and/or 10 rate base?

11 Yes, but before I begin, I will note that in Α. 12 addition to the explanation of adjustments provided herein, 13 Company has also provided workpapers outlining the 14 additional details related to each of the adjustments. The restating adjustments shown in columns (c) through (t) are 15 16 consistent with methodologies employed in our prior cases and current regulatory principles, with a few proposed 17 18 changes as described further in my testimony.

19 The first adjustment, column (c) on page 5, entitled 20 Deferred FIT Rate Base, reflects the rate base reduction 21 for Idaho's portion of deferred taxes. The adjustment 22 reflects the deferred tax balances arising from accelerated 23 tax depreciation (Accelerated Cost Recovery System, or 24 ACRS, and Modified Accelerated Cost Recovery, or MACRS), 25 bond refinancing premiums, and contributions in aid of 26 These amounts are reflected on the average construction.

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of monthly average balance basis. The effect on Idaho rate
 base is a reduction of \$19,934,000.

3 The adjustment in column (d), Deferred Gain on Office 4 Building, reflects the removal of the amortization expense included in the Company's 2010 test period related to 5 6 Idaho's portion of the amortized gain on the sale of the 7 Company's general office facility. The facility was sold 8 in December 1986 and leased back by the Company. Although 9 the Company repurchased the building in November 2005, the 10 deferred gain was amortized over the period ending in 2011. 11 Therefore, during the 2012 rate period the average of 12 monthly averages (AMA) amount of the deferred gain is zero. 13 The effect on Idaho rate base is zero. The effect on Idaho 14 net operating income is an increase of \$14,000¹¹.

15 The adjustment in column (e), **Gas Inventory**, reflects 16 the adjustment to rate base for the average-of-monthly-17 average value of gas stored at the Company's Jackson 18 Prairie underground storage facility through the test 19 period. The effect on Idaho rate base is an increase of 20 \$4,509,000.

21 The adjustment in column (f), Weatherization and DSM
22 Investment, removes the amortization expense included in
23 the test period due to the weatherization and DSM

¹¹ During the process of completing the Company's filing the Company discovered it had inadvertently reduced expense for removal of the deferred gain included in the test period. Rather, this adjustment should have removed the gain, increasing expense, decreasing net operating income \$14,000. The impact of correcting for this error increases the requested electric revenue requirement in this case by approximately \$44,000.

investment rate base being fully amortized in 2010. The
 effect of this adjustment is to increase Idaho net
 operating income by \$64,000.

4 The adjustment in column (q), entitled Customer 5 Advances, decreases rate base for funds advanced by 6 customers for line extensions, as they are generally 7 recorded as contributions in aid of construction at some 8 future time. The effect of this adjustment on Idaho rate 9 base is a decrease of \$74,000.

Q. Please turn to page 6 and explain the first
column shown there, and the adjustments that follow.

12 Α. The first column on page 6 is adjustment (h), 13 Working Capital, which increases total rate base for the 14 Company's working capital adjustment described further in 15 the Electric Section above. The Company has calculated its 16 gas working capital by including Idaho's gas portion of the 17 2010 average-monthly-average balances of FERC accounts 151 18 (Fuel Stock Inventory) and 154 (Plant Materials and 19 Supplies). The effect on Idaho rate base is an increase of 20 \$1,553,000.

21 The next column marked by a dash and labeled Subtotal 22 Actual, is a subtotal of columns (b) through (h) and 23 reflects the standard rate base adjustments, e.g., 24 adiustments that reflect rate base items previously addressed by the Commission.¹² 25

¹² This subtotal also includes an increase in rate base necessary to include the Company's requested working capital adjustment.

1 The next adjustment on page 6 in column (i), entitled 2 Revenue Normalization, is an adjustment taking into account 3 known and measurable changes that include revenue 4 normalization (including the current authorized rates 5 approved in Case No. AVU-G-10-01), which reprices customer 6 usage under presently effective rates, as well as weather 7 normalization and an unbilled revenue calculation. 8 Associated gas costs are replaced with gas costs computed 9 using normalized volumes at the currently effective 10 weighted-average-cost-of-gas, or WACOG rates in Schedule 11 150. Revenues associated with the temporary Gas Rate 12 Adjustment Schedule 155, Schedule 191 Tariff Rider, and 13 Schedule 199 Deferred SIT Adjustment are excluded from pro 14 forma revenues, and the related amortization expenses are 15 eliminated as well. Ms. Knox is sponsoring this 16 adjustment. The effect of this particular adjustment is to 17 increase Idaho net operating income by \$1,189,000.

18 The adjustment in column (j), Eliminate B & O Taxes, 19 eliminates the revenues and expenses associated with local 20 business and occupation taxes, which the Company passes 21 through to customers. The adjustment eliminates any timing 22 mismatch that exists between the revenues and expenses by 23 eliminating the revenues and expenses in their entirety. 24 B & O Taxes are passed through on a separate schedule, 25 which is not part of this proceeding. The effect of this 26 adjustment decreases Idaho net operating income by \$1,000.

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1 The adjustment in column (k), Property Tax, restates 2 the test period accrued levels of property taxes to the 3 most current information available and eliminates any 4 adjustments related to the prior year. The effect of this 5 adjustment decreases Idaho net operating income by \$23,000. 6 The adjustment in column (1), Uncollectible Expense, 7 restates the accrued expense to the actual level of net 8 write-offs for the test period. The effect of this 9 adjustment is to increase Idaho net operating income by 10 \$155,000.

11 Q. Please turn to page 7 and explain the adjustments12 shown there.

A. The first adjustment on page 7 in column (m), entitled **Regulatory Expense Adjustment**, restates recorded 2010 regulatory expense to reflect the IPUC assessment rates applied to revenues for the test period. The effect of this adjustment is to increase Idaho net operating income by \$26,000.

19 The adjustment in column (n), entitled Injuries and 20 Damages, is a restating adjustment that replaces the 21 accrual with the six-year rolling average of actual 22 injuries and damages payments not covered by insurance. 23 This methodology was accepted by the Idaho Commission in Case No. WWP-E-98-11, and has been used since that time. 24 The effect of this adjustment is to increase Idaho net 25 26 operating income by \$31,000.

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The adjustment in column (o), entitled **FIT**, adjusts 1 2 the FIT calculated at 35% within Results of Operations by 3 removing the effect of certain Schedule M items and matches 4 the jurisdictional allocation of other Schedule M items to 5 related Results of Operations allocations. This adjustment 6 also reflects the proper level of deferred tax expense for 7 the test period. The effect of this adjustment, all based 8 upon a Federal tax rate of 35%, is to increase Idaho net 9 operating income by \$2,000.

10 The adjustment in column (p), Eliminate A/R Expenses, 11 removes expenses incurred associated with the fees charged 12 the Company for its customer accounts receivable program. 13 The Company's accounts receivable program was terminated in 14 December 2010 as explained by Mr. Thies. The effect of 15 this adjustment is to increase Idaho net operating income 16 by \$13,000.

17 The adjustment in column (q) is titled **Miscellaneous** 18 **Restating Adjustments**. This adjustment removes a number of 19 non-operating or non-utility expenses, and removes or 20 restates other expenses incorrectly charged between service 21 and or jurisdiction, totaling approximately \$21,000.

The Company also removed 10% of Avista Corp. director fees (and 100% of director fees associated with Advantage IQ) totaling approximately \$9,000. Lastly, this adjustment removes Idaho's gas portion of consulting services, totaling approximately \$194,100 from the test period to reduce the revenue requirement requested in this case.

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This adjustment is described further in the Electric
 Section above and the detail of these adjustments can be
 found within my workpapers. The effect of this adjustment
 is to increase Idaho net operating income by \$144,000.

The adjustment in column (r), Restating Incentives, 5 6 restates the actual incentives included in the Company's 7 test period using a six-year average adjusted by the 8 Consumer Price Index. This adjustment is described further 9 in the Electric Section above. The effect of this 10 adjustment is to increase Idaho net operating income by 11 \$159,000.

12 The adjustment in column (s), Operation & Maintenance 13 (O&M) Savings, includes reduction а to expense for 14 anticipated operation and maintenance savings expected 15 during the pro forma period, as compared to the 2010 test 16 These O&M savings include reductions related to period. 17 certain additional general plant investment included in the 18 capital additions adjustments. Mr. DeFelice describes the 19 general plant savings within his direct testimony and 20 additional detail can be found within his workpapers 21 included with the Company's filing. This adjustment 22 increases Idaho net operating income by \$4,000.

Q. Please turn to page 8 and explain the adjustments
shown there.

25 A The first adjustment on page 8, column (t)
26 entitled, **Restate Debt Interest**, restates debt interest
27 using the Company's pro forma weighted average cost of

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1 debt, as outlined in the testimony and exhibits of Mr.
2 Thies. As applied to Idaho's pro forma level of rate base,
3 it produces a pro forma level of tax deductible interest
4 expense. The federal income tax effect of the restated
5 level of interest for the test period decreases Idaho's net
6 operating income by \$77,000.

7 The next column on page 8, entitled **Restated Total**, 8 subtotals all the preceding columns (b) through column (t), 9 excluding the subtotal column. These totals represent 10 actual operating results and rate base plus the standard 11 normalizing adjustments.¹³

12

13

Pro Forma Adjustments

Q. Please explain the significance of the 10 columns
subsequent to the Restated Total column on pages 8 through
9 of your Exhibit No. 10, Schedule 2.

17 Α. The adjustments starting on page 8 are pro forma 18 adjustments to reflect known and measurable changes between 19 the test period and the pro forma period. In this case, 20 they encompass revenue and expense items, and natural gas 21 inventory and capital projects. These adjustments bring 22 the operating results and rate base to the final pro forma 23 level for the test year.

Q. Please continue with your explanation of the
adjustments on page 8.

¹³ The restated total also includes an increase in rate base necessary to include the Company's requested working capital adjustment, and includes a reduction to expense for a 6-year average of incentives.

1 Α. The first adjustment on page 8 in column (PF1), 2 Pro Forma Labor-Non-Exec, reflects known and measurable 3 changes to test period union and non-union wages and 4 salaries, excluding executive salaries, which are handled 5 separately in adjustment PF2. This adjustment is described 6 further in the Electric Section above. The effect of this 7 adjustment is to decrease Idaho net operating income by 8 \$155,000.

9 The adjustment in column (PF2), Pro Forma Labor-10 **Executive**, reflects known and measurable changes to 11 executive compensation, restating executive compensation 12 test period salary expense to actual salary levels at 2011. 13 This adjustment is described further in the Electric 14 Section above. The methodology behind this adjustment is 15 consistent with that used in Case No. AVU-G-10-01. The 16 effect of this adjustment on Idaho net operating income is 17 a decrease of \$14,000.

18 The adjustment in column (PF3), **Pro Forma Employee** 19 **Benefits**, adjusts for changes in both the Company's pension 20 and medical insurance expense (as explained in the Electric 21 Section above) and decreases Idaho net operating income by 22 \$109,000.

The adjustment in Column (PF4), **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 2011 (as explained in the Electric Section

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above). This adjustment increases Idaho net operating
 income by \$8,000.

3 The adjustment in column (PF5), Pro Forma Survey & 4 Replacement Programs, pro forms additional incremental 5 operating and maintenance labor expense related to survey and replacement programs starting in 2011. The Company is 6 7 implementing a special cathodic protection program for the 8 purpose of finding and addressing isolated steel in its 9 natural gas piping systems. This adjustment was made under 10 the direction of Company witness Mr. Kopczynski and is This adjustment 11 described further in his testimony. 12 decreases Idaho net operating income by \$106,000.

Q. Please turn to page 9 and explain the adjustmentsshown there.

15 The first adjustment on Page 9 in column (PF6), Α. 16 entitled Pro Forma Atmospheric Testing, adjusts the test 17 period expense for Atmospheric Corrosion expense. This is 18 an inspection program to find conditions in the Company's 19 system that could lead to corrosion issues on customer 20 This program is a federally-mandated program meter sets. 21 that requires the Company to inspect all above ground steel 22 pipe at a frequency not to exceed three-years. This expense 23 is on a three-year rotation between the Company's 24 Oregon) jurisdictions (Idaho, Washington and and is 25 therefore, coded directly to Idaho operations for the year 26 in which the inspection occurs (2011 for Idaho estimated at 27 a total cost of \$450,000). The Company is proposing to

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1 collect one-third of these costs over a three-year basis 2 (2012-2014), and, therefore, has pro formed \$150,000 for 3 atmospheric O&M expense. The Company has received approval 4 of this accounting treatment in its Oregon jurisdiction and 5 has requested this treatment in the Company's recent filed 6 Washington general rate case as well, so the Company 7 remains whole on an annual basis. This adjustment was made under the direction of Mr. Kopczynski and is described 8 9 further in his testimony. This adjustment decreases Idaho 10 net operating income by \$86,000.

11 The adjustment in column (PF7), Pro Forma Capital 12 Additions 2010, pro forms in the capital cost and expenses 13 associated with adjusting the 2010 average-of-monthly-14 average (AMA) plant related balances to end-of-period (EOP) 15 balances for plant in service at December 31, 2010. The 16 capital costs have been included for the December 31, 2010 17 pro forma period with the associated depreciation expense 18 and property tax, as well as the appropriate accumulated 19 depreciation and deferred income tax rate base offsets. 20 This adjustment was made under the direction of Mr. 21 DeFelice and is described further in his testimony. This 22 adjustment is consistent with that included in the most 23 recent Idaho general rate case proceeding, Case No. AVU-G-24 10-01. This adjustment decreases Idaho net operating 25 income by \$104,000 and <u>decreases</u> rate base by \$497,000. 26 The adjustment in column (PF8), Pro Forma Capital 27 Additions 2011, pro forms in the capital cost and expenses

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1 associated with capital expenditures for 2011. This 2 adjustment includes projects expected to be completed and 3 transferred to plant-in-service by December 31, 2011, and 4 thus were normalized to reflect annual amounts. The 5 capital costs have been included for the appropriate pro 6 forma period with the associated depreciation expense and 7 the appropriate accumulated property tax, as well as 8 depreciation and deferred income tax rate base offsets. In 9 addition, the total plant in service at December 31, 2010 10 (including accumulated depreciation and deferred FIT) was 11 adjusted to an EOP December 31, 2011 adjusted balance. 12 This adjustment was also made under the direction of Mr. 13 DeFelice, is described further in his testimony, and is 14 consistent with that included in the most recent Idaho 15 general rate case proceeding, Case No. AVU-G-10-01. This 16 adjustment decreases Idaho net operating income by \$304,000 17 and decreases rate base by \$2,297,000.

18 The adjustment in column (PF9), Pro Forma Capital 19 Additions 2012, pro forms in the capital cost and expenses 20 associated with capital expenditures for 2012. This 21 adjustment includes projects expected to be completed and 22 transferred to plant-in-service during 2012, and thus were 23 included on an AMA plant basis for the 2012 rate period. 24 The capital costs have been included for the appropriate 25 pro forma period with the associated depreciation expense 26 and property tax, as well as the appropriate accumulated 27 depreciation and deferred income tax rate base offsets. In

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1 addition, the total plant in service at December 31, 2011 2 was adjusted to a 2012 AMA balance. This adjustment was 3 also made under the direction of Mr. DeFelice and is 4 described further in his testimony. This adjustment 5 decreases Idaho net operating income by \$64,000 and 6 decreases rate base by \$687,000.

7 The adjustment in column (PF10), Pro Forma JP Storage 8 2011, pro forms expenses, capital investment and inventory 9 for the increased storage capacity and deliverability 10 associated with the transfer of a portion of the Jackson 11 Prairie (JP) Storage facility to the utility on May 1, 12 2011. System assets with a net book value of approximately 13 \$11.6 million transferred to the utility on May 1, 2011, 14 comprised of approximately \$5.9 million of cushion gas and 15 approximately \$5.7 million of fixed assets. The accounting 16 treatment of the JP cushion gas recorded in both 17 recoverable and non-recoverable FERC accounts, and the 18 increases related to the additional plant, inventory and 19 O&M expenses were approved in Case No. AVU-G-10-01, Order 20 No. 32070, Settlement Stipulation, page 11, section 21 III.17(c).

22 Idaho's share of these assets on a 2012 average-of-23 basis monthly-average increases net rate base by 24 approximately \$1.6 million. The adjustment also includes a 25 rate base increase of \$3.2 million for the working gas and 26 recoverable cushion gas inventory associated with the 2011 27 additional storage. In addition, underground storage

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expense increased for the additional operating,
 depreciation and property taxes expense by approximately
 \$209,000.

4 Company witness Mr. Christie provides an overview of 5 the Jackson Prairie natural gas storage facility within his 6 testimony. The details of this adjustment can be found 7 within my workpapers included with the Company's filing. 8 The impact of this adjustment decreases Idaho net operating 9 income by \$134,000 and increases rate base by \$4,879,000.

10 The last column on page 9, **Pro Forma Total**, reflects 11 total pro forma results of operations and rate base 12 consisting of twelve-months ended December 31, 2010 actual 13 results and the total of all normalizing, restating and pro 14 forma adjustments.

Q. Referring back to page 1, line 44, of Exhibit No.
10, Schedule 2, what was the pro forma gas rate of return
realized by the Company during the test period?

A. For the State of Idaho, the pro forma rate of return is 7.31% under present rates. Thus, the Company does not, on a pro forma basis for the test period, realize the 8.49% rate of return requested by the Company in this case.

23 Q. How much additional net operating income would be 24 required for the State of Idaho gas operations to allow the 25 Company an opportunity to earn its proposed 8.49% rate of 26 return on a pro forma basis?

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1 The net operating income deficiency amounts to Α. 2 \$1,225,000, as shown on line 5, page 2 of Exhibit No. 10, 3 Schedule 2. The resulting revenue requirement is shown on 4 line 7 and amounts to \$1,921,000, or an increase of 2.72% 5 over pro forma general business and transportation 6 revenues.

V. ALLOCATION PROCEDURES

9 Q. Have there been any changes to the Company's 10 system and jurisdictional procedures since the Company's 11 last general electric and natural gas cases, Case Nos. AVU-12 E-10-01 and AVU-G-10-01?

13 Α. No. For ratemaking purposes, the Company 14 allocates revenues, expenses and rate base between electric 15 and gas services and between Idaho, Washington and Oregon 16 jurisdictions where electric and/or qas service is 17 provided. The annually updated allocation factors used in 18 this case have been provided with my workpapers.

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20 21

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VI. DEFERRED ACCOUNTING REQUEST FOR THE VARIABILITY IN GENERATING PLANT OPERATION AND MAINTENANCE COSTS

23 Q. Would you please explain the Company's request 24 for deferred accounting associated with the variability in 25 operation and maintenance costs related to its two major 26 thermal generating plants?

A. Yes. The Company is proposing to defer changesin operation and maintenance costs related to its Coyote

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Springs 2 (CS2) natural gas-fired generating plant located near Boardman, Oregon, and its 15 percent ownership share of the Colstrip 3 & 4 coal-fired generating plants located in southeastern Montana. Both the Coyote Springs 2 and Colstrip 3 & 4 plants have schedules where major maintenance is to be performed.

7 The Company is requesting deferred accounting 8 treatment for these two plants specifically (CS2 and 9 Colstrip) because major maintenance is scheduled every 10 third or fourth year, providing large cost swings for these 11 plants in any given year. This fluctuation in maintenance 12 costs is typically not experienced by the Company's other 13 hydro operating facilities or its Kettle Falls generating 14 plant. For example, each unit at Colstrip has a regularly 15 scheduled overhaul every third year. Since we have two 16 units, this means that two out of every three years will 17 scheduled major maintenance outage have а and its 18 associated costs. Whereas the maintenance interval at 19 Coyote Springs 2 is based on hours of operation. We 20 schedule these major outages in accordance with Original 21 Equipment Manufacturer (OEM) guidelines on wear patterns 22 and cycles for key plant equipment.

Therefore, depending on when the outages for each of these plants fall, we can have as much as two scheduled outages in one year or no scheduled outages, providing the potential for large cost fluctuations on a year-to-year basis. Unexpected outages also cause costs to fluctuate as

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1 more costs are incurred to repair the plant. However, in 2 an unexpected outage situation, we may on a case-by-case 3 basis have instances where operation and maintenance 4 expense may actually be lower than authorized, as a portion 5 of the repair costs are likely to be capitalized. The use 6 of deferred accounting would smooth out these costs.

7 How would the proposed deferred accounting work? Ο. 8 Α. The Company would compare actual, non-fuel, 9 operation and maintenance expenses for the Coyote Springs 2 10 and Colstrip 3 & 4 plants to the amount of expenses 11 authorized for recovery in its last general rate case, and 12 defer the difference from that currently authorized. The 13 deferral would occur annually, with a carrying charge, with 14 deferred costs being amortized over a three-year period, 15 beginning in January of the year following the period costs 16 The comparison of actual to authorized costs are deferred. 17 would use the combined costs from the Coyote Springs 2 and 18 Colstrip 3 & 4 plants. The reason for combining costs is 19 to allow for the possibility that there might be lower than 20 authorized costs from one plant that would offset higher 21 than authorized costs from another plant in a given year.

22 Q. Why are you including both operation and 23 maintenance expenses rather than just maintenance expense? 24 Α. Operation and maintenance expenses are combined 25 take into account that during times of to major 26 maintenance, operation will decline, expense while 27 maintenance expense will increase. By including both

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operation and maintenance expense, the decline in operation
 expense may partially offset the increase in maintenance
 expense.

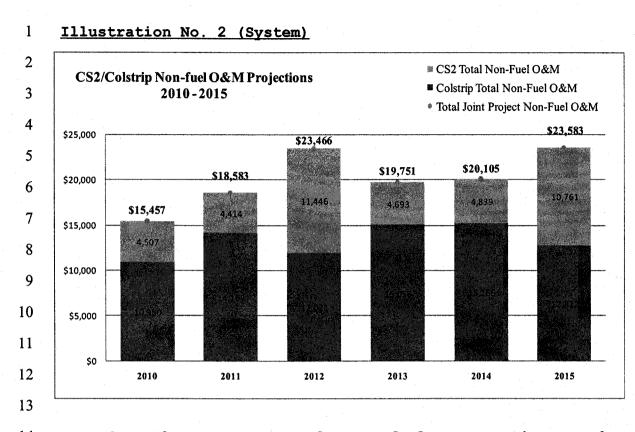
Q. Would you please explain how the Company proposes
to account for the deferred operations and maintenance
expenses?

7 Pursuant to *Idaho Code* § 61-524, the Company Α. 8 requests to defer the operations and maintenance expenses 9 referenced above in Account 182.3 - Other Regulatory 10 Assets. The deferrals would be allocated to the Idaho and 11 Washington jurisdictions based on the Production / 12 Transmission allocation percentages in place at the time 13 the deferrals are made, and placed in separate Idaho and 14 Washington sub-accounts. Account 182.3 - Other Regulatory 15 Assets would be debited, and Account 407.4 - Regulatory 16 Credits would be credited as the deferrals are recorded. 17 Amortization would be recorded by debiting Account 407.3 -18 Regulatory Debits, and crediting Account 182.3 - Other 19 Regulatory Assets. Interest would accrue on the Idaho 20 share of the deferrals, net of deferred federal income tax, 21 the Company's weighted cost of debt, updated and at 22 compounded semi-annually.

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

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1 Α. The system amount of actual, non-fuel, operations 2 and maintenance costs for the 2010 test period for the 3 indicated plants is shown below (millions): 4 5 Coyote Springs 2 \$ 4.5 6 Colstrip 3 & 4 \$11.0 7 Total (System) <u>\$15.5</u> 8 9 What is the forecast of operation and maintenance Q. 10 costs for the Coyote Springs 2 and Colstrip 3 &4 plants? 11 Α. The following Illustration No. 2 shows the system 12 forecast of non-fuel, operations and maintenance costs for 13 the plants separately, and in total, for the five-year 14 period of 2011 through 2015, as well as the actual costs 15 for the 2010 test period. The system forecast shows major 16 maintenance occurring for Coyote Springs 2 in 2012 and 17 2015, and for Colstrip 3 & 4 occurring in 2013 and 2014.



Q. What amount of non-fuel, operation and
maintenance expense for Coyote Springs 2 and Colstrip 3 & 4
should be included for recovery in a general rate case?

A. The amount of expense to be included for recovery in a general rate case should be the actual O&M expense recorded in the test period, excluding any amount deferred during the test period, plus the amortization of previously deferred costs in the test period.

22 Q. Why is it not appropriate to use a historic 23 average of operation and maintenance costs for the thermal 24 plants to determine the amount of expense to be included 25 for recovery in a general rate case?

A. The previous bar chart illustrates thevariability in operations and maintenance costs for the

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1 thermal plants, and the upward trend in costs. The Company 2 expects these costs to rise as the plants age, and as parts 3 and labor become more expensive. Use of a historic average 4 would likely understate the level of costs that the Company 5 will experience in the future. A historic average can also 6 be impacted by limiting, or expanding, the number of years 7 used in computing the average, depending on the annual 8 amounts of costs that have previously been incurred.

9 Q. Has the Company included or pro formed any 10 additional O&M expense in this case for 2012 above that 11 included in the 2010 test period?

12 A. No. Although the Company is anticipating 13 incurring this additional expense during the 2012 rate 14 period, this additional expense has not been included in 15 the Company's case.

16 Q. Why did the Company choose a three-year 17 amortization period?

18 Α. A three-year amortization period was chosen as a 19 reasonable recovery period since spikes in operations and 20 maintenance expenses can occur every three to five years. 21 For example, the Company's Colstrip units have outages two 22 out of three years, however, the CS2 unit, based on hours 23 typically dictates an outage every forth year. The three-24 year amortization period would generally fully amortize the 25 costs of major maintenance of a unit, prior to the major 26 maintenance occurring again for the same unit.

2 Q. Please address the filing requirements as 3 required in Order No. 29962.

OTHER

VII.

1

4 Α. In Order No. 29962 (Case Nos. AVU-E-05-9 and AVU-5 G-05-3), the Commission directed the Company to record 6 regulatory assets or liabilities associated with the 7 implementation of Statement of Financial Accounting 8 Standards (SFAS) 143. As a result of the Order, the 9 Company is required to file annually, and as part of any 10 rate case filing, all journal entries made under the requirements of SFAS 143. These ARO transactions have been 11 12 removed from the test year (twelve months ended December 13 31, 2010) Results of Operations and have no impact on the 14 Company's earnings or rate request in this case. The 15 journal entries for the calendar year 2010 have been filed 16 with the Commission in our annual compliance filing.

Q. Is the Company requesting a change in the annual
filing requirement that is required by Order No. 29962?

19 Α. Yes. The Company requests that the Commission 20 eliminate the annual filing requirement that is required by 21 Order No. 29962. Avista has filed the journal entries in 22 compliance filings for the past four years. The journal 23 entries have been routine in nature, including recording 24 accretion of the ARO liabilities and depreciation of the 25 ARO assets. Because of this, and the fact that all ARO 26 transactions are removed from Idaho results of operation, 27 the Company is requesting that filing obligations under the

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Commission's prior order be removed. The Company will
 maintain the same records regarding the ARO transactions
 and would have them available to Staff and any other party
 upon request.

5 Q. Does that conclude your pre-filed direct 6 testimony?

A. Yes, it does.

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

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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IN THE MATTER OF THE APPLICATION) OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE) STATE OF IDAHO

CASE NO. AVU-E-11-01 CASE NO. AVU-G-11-01

EXHIBIT NO. 10

ELIZABETH M. ANDREWS

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

AVISTA UTILITIES ELECTRIC RESULTS OF OPERATION IDAHO PRO FORMA RESULTS TWELVE MONTHS ENDED DECEMBER 31, 2010 (000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
Line No.	DROODEDTICAN	Actual Per Results	Total	Pro Forma	Proposed Revenues &	Pro Forma Proposed
MIK	d DESCRIPTION	Report b	Adjustments c	Total d	Related Exp e	Total f
			6		•	J.,
	REVENUES					
Ŧ	Total General Business	\$249,722	\$ (3,553)	\$246,169	\$9,009	\$255,17
2	Interdepartmental Sales	210		210		21
3	Sales for Resale	89,301	(74,555)	14,746		14,74
4	Total Sales of Electricity	339,233	(78,108)	261,125	9,009	270,13
5	Other Revenue	44,982	(39,125)	5,857		5,85
6	Total Electric Revenue	384,215	(117,233)	266,982	9,009	275,99
	EXPENSES					
	Production and Transmission					
7	Operating Expenses	124,933	(50,130)	74,803		74,80
8	Purchased Power	108,732	(58,813)	49,919		49,91
9	Depreciation and Amortization	7,293	8,052	15,345		15,34
10	Тахсв	5,264	668	5,932		5,93
11	Total Production & Transmission	246,222	(100,223)	145,999	0	145,99
	Distribution	· · · · ·		د فر الد بد بد		
12	Operating Expenses	8,746	1,495	10,241		10,24
13	Depreciation	10,295	1,640	11,935		11,93
14	Taxes	5,468	(2,422)	3,046	135	3,11
15	Total Distribution	24,509	713	25,222	135	25,35
16	Customer Accounting	3,920	(198)	3,722	15	3,73
17	Customer Service & Information	8.116	(7,585)	531		5
8	Sales Expenses	17	1	18		1
	Administrative & General		(1 //00)	01.018	18	21,9
1 9 20	Operating Expenses	23,695 5,206	(1,780) 1,219	21,915 6,425	10	6,43
20 21	Depreciation Taxes	3,200	241	0,425 241		24
21 22	Total Admin. & General	28,901	(320)	28,581	18	28.59
23	Total Electric Expenses	311,685	(107,612)	204,073	168	204,24
-						
24	OPERATING INCOME BEFORE FIT	72,530	(9,621)	62,909	8,841	71,7
	FEDERAL INCOME TAX					
25	Current Acerual	11,355	(4,336)	7,019	3,094	10,1
26	Deferred Income Taxes	7,176	1,307	8,483		8,41
27	Amortized Investment Tax Credit	(45)	(34)	(79)		C
	SETTLEMENT EXCHANGE POWER					
28	NET OPERATING INCOME	\$54,044	(\$6,558)	\$ 47,486	\$5,747	\$53,23
	RATE BASE					
	PLANT IN SERVICE					
29	Intangible	\$41,399	\$9,360	\$50,759		\$50,7
30	Production	371,892	21,117	393,009		393,0
31	Transmission	167,091	16,973	184,064		184,00
32	Distribution	406,221	33,403	439,624		439.6.
33	General	67,570	12,577	80,147		80,1
14	Total Plant in Service	1,054,173	93,430	1,147,603	0	1,147,6
35	ACCUMULATED DEPRECIATION	350,181	-57,393	407,574		407,5
16	ACCUM. PROVISION FOR AMORTIZATION	6,399		6,399		6,3
37	Total Accum. Depreciation & Amort.	356,580	57,393	413,973	0	413,9
38	GAIN ON SALE OF BUILDING					
19 10	WORKING CAPITAL DEFERRED TAXES		7,710 (114,339)	7,710 (114,339)		7,7 (114,3
ų.	PARTINGER PARTIE		(114,239)	1114,559		(117.5
11	TOTAL RATE BASE	\$697,593	(\$78,302)	\$627,001	\$ 0	\$627,0
42	RATE OF REFURN	7.75%		7.57%		8.4

8,49% Exhibit No. 10 U-E-11-01 and AVU-G-11-01

(9.1% including <-\$114,339> DFTT on Plant Rate base, see also page 5 of 11, Schedule 1)

E. Andrews, Avista Schedule 1, p. 1 of 11

AVISTA UTILITIES Calculation of General Revenue Requirement

IDAHO - Electric System

TWELVE MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	(000's of Dollars)
1	Pro Forma Rate Base	\$627,001
2	Proposed Rate of Return	8.49%
3	Net Operating Income Requirement	\$53,232
4.	Pro Forma Net Operating Income	\$47,486
5	Net Operating Income Deficiency	\$5,746
6	Conversion Factor	0.63778
7	Revenue Requirement	\$9,009
8	Total General Business Revenues	\$246,379
9	Percentage Revenue Increase	3.66%

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 1, p. 2 of 11

AVISTA UTILITIES

Calculation of General Revenue Requirement Idaho - Electric Pro Forma Cost of Capital (000's OF DOLLARS)

Black Box-Current Approved Cost of Capital								
Idaho	Capital		Weighted	Excludes STD				
Component	Structure	Cost	Cost					
Long-Term Debt	49.85%	6.050%	3.02%	ID Wtd Debt 3.02%				
Pref Trust	0.00%	0.000%	0.00%					
Common	50.15%	10.90%	5.47%					
Total	100.00%		8.49%					

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 1, p. 3 of 11

AVISTA UTILITIES CALCULATION OF CONVERSION FACTOR: IDAHO ELECTRIC TWELVE MONTHS ENDED DECEMBER 31, 2010

Revenue:	1.000000
Expense:	
Uncollectibles (1)	0.001665
Commission Fees (2)	0.002039
Idaho Income Tax (3)	0.015093
Total Expense	0.018797
Net Operating Income Before FIT	0.981203
Federal Incon 0.35	0.343421
REVENUE CONVERSION FACTOR	0.63778

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 1, p. 4 of 11

Line No.	DESCRIPTION	Results Report	Deferred FIT Rate Base	Deferred Gain on Office Building	Colstrip 3 AFUDC Elimination	Colstrip Common AFUDC	Kettle Falls & Boulder Park Disallow	Customer Advances
	4	b	¢	d	ę	ſ	Z	h
	REVENUES							
1	Total General Business	\$249,722						
2	Interdepartmental Sales	210						
3	Sales for Resale	89,301					ina in ainin an in thi an tarwin lay an an	
4	Total Sales of Electricity	339,233	0	Q	0	0	0	0
5	Other Revenue Total Electric Revenue	44,982	0	0	0	0	0	0
v	EXPENSES	504,010	v	0	ve.	,		
	Production and Transmission							
7	Operating Expenses	124,933						
8	Purchased Power	108,732						
9	Depreciation and Amortizatic	7,293			191			
10	Taxes	5,264						1. J.
11	Total Production & 1	246,222	0	Û	191	0	0	0
	Distribution							
12	Operating Expenses	8,746						
13	Depreciation	10,295						
14	Taxes	5,468		1				
15	Total Distribution	24,509	0	1	0	0	0	0
16	Customer Accounting	3,920						
17	Customer Service & Information	8,116						
18	Sales Expenses	17						
	Administrative & General							
19	Operating Expenses	23,695		(66)				
20	Depreciation	5,206						
21	Taxes							
22	Total Admin. & Gen	28,901	0	(66)	0	0	0	Ç
23	Total Electric Expenses	311,685	0	(65)	191	0	. 0	Ģ
24	OPERATING INCOME BEFORE FIT	72,530	0	65	(191)	0	0	C
	FEDERAL INCOME TAX							
25	Current Accrual	-11,355		22				
26	Deferred Income Taxes	7,176						
27	Amortized IIC - Noxon	(45)						
28	NET OPERATING INCOME	\$54,044	\$ 0	\$43	(\$191)	\$ 0	\$0	\$(
	RATE BASE		OKAY	OKAY	OKAY	OKAY	OKAY	OKAY
	PLANT IN SERVICE							
29	Intangible	\$41,399						
29 30	Production	341,399			7,325	774	(5,609)	
31	Transmission	167,091			الاستادية ا		(24003)	
32	Distribution	406,221						(858
33	General	67,570						(
34	Total Plant in Service	1,054,173	0	θ	7,325	774	(5,609)	(858
35	ACCUMULATED DEPRECIATION	350,181			5,832		(3,119)	
36	ACCUM. PROVISION FOR AMORTIZAT.	6,399						
37	Total Accum. Depreciation &	356,580	0	0	5,832	0	(3,119)	C
38	GAIN ON SALE OF BUILDING							
39	WORKING CAPITAL							
40	DEFERRED TAXES		(104,677)		,		610	
		\$697,593		50	\$1,493	\$774	(\$1,880)	(\$858

42 RATE OF REFURN

---- Actual (Excluding minor additional DFIT included in restating adjustments associated 9.1% with CDA, Spokane River & Montana deferral adjustments (j) thru (o))

> Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 1, p. 5 of 11

Line No.	DESCRIPTION	Weatherizn and DSM Investment	Restating CDA Settlement	Restating CDA Settlement Deferral	Restating CDA/SRR CDR	Restating Spokane River Deferral	Restating Spokane River PM&E Deferral
		1	j	k	J	m	n
	REVENUES						
1	Total General Business						,
2	Interdepartmental Sales						
3	Sales for Resale						
4	Total Sales of Electricity	0	0	0	0	0	0
5	Other Revenue						
б	Total Electric Revenue	0	0	0	0	0	0
	EXPENSES						
	Production and Transmission						
7	Operating Expenses				348		
8	Purchased Power						
9	Depreciation and Amortizatic		29	18		3	20
10	Taxes						
11	Total Production & 7	0	29	18	348	3	20
	Distribution						
12	Operating Expenses						
13	Depreciation						
14	Taxes	3			(5)		
15	Total Distribution	3	0	0	(5)		0
	and the second se					à	
16	Customer Accounting						
17 18	Customer Service & Information Sales Expenses	(229)					
	Administrative & General						
19	Operating Expenses						
20	Depreciation						
21	Taxes						
22	Total Admin. & Gen	0	0	0	0.	0	0
23	Total Electric Expenses	(226)	29	18	343	3	20
24	OPERATING INCOME BEFORE FIT	226	(29)	(18)	(343)	(3)	(20)
	FEDERAL INCOME TAX	ani)e				244	
25	Current Accrual	79	(10)	(6)	(120)	(1)	(7)
26 27	Deferred Income Taxes						
27	Amortized ITC - Noxon					-	
28	-	\$147	(\$19)	(\$12)	(\$223)	(\$2)	(\$13)
		OKAY	OKAY	ОКАЎ	OKAY	OKAY	OKAY
	RATE BASE						
	PLANT IN SERVICE						
29	Intangible			\$317		\$60	\$270
30	Production	65					
31	Transmission						
32	Distribution						
33	General						
34	Total Plant in Service	65	0	317	0	60	270
35	ACCUMULATED DEPRECIATION		487	62	105	12	47
36	ACCUM. PROVISION FOR AMORTIZAT		بدينة أأتدر والمستحد والمستح				ana ana amin'ny fantana amin'ny fantana amin'ny fantana amin'ny fantana amin'ny fantana amin'ny fantana amin'n
37	Total Accum. Depreciation &	0	487	62	105	12	47
38	그는 그들을 다니 한 국민은 것이 있다는 것이 같은 것이 같이 같이 같이 같이 같이 않는 것이 같이 없다.						
39 40	WORKING CAPITAL DEFERRED TAXES		170	(89)	37	(17)	(78)
-40	PREEKKEP IAAES		170	(89)			(7a) \$145
41	TOTAL RATE BASE	\$65	(\$317)	\$166	(\$68)	\$31	

42 RATE OF RETURN

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 1, p. 6 of 11

REVENUES P Q F Q F Q F Q F Q F Q F Q F Q F Q F Q F Q F Q F Q F Q F Q F Q F Q F Q F Q F Q<	Line No.	DESCRIPTION	Restating Montana Lease	Working Capital	Subtotal Actual	Eliminate B & O Taxes	Property Tax	Uncollect. Expense	Regulatory Expense	Injuries 2nd Damages
BitSYNNES S240.72: Total Centroperturbal Seles S240.72: Statis fits Reads S(J)117 0 <th0< th=""> <th0< th=""> <th0< th=""></th0<></th0<></th0<>	•••••			p			الأسبيب بمتقابلة فحمرتها			
1 Teta Gameral Busines \$20,022 \$(3,019) 3 Natio for Results \$210 \$(3,019) 4 Total Sate of Electricity 0 335,233 (3018) 0 0 0 5 Other Results 0 334,233 (3018) 0 0 0 0 5 Other Researce 0 334,233 (3018) 0 0 0 0 7 Operating Expense 46 125,327 0 0 0 0 9 Depresing Expense 46 125,327 0 297 0 0 0 10 Taxes 5,254 297 0 0 0 0 11 Taxes 10,255 1 12 9 0		DEMENTRO		•.			,			
2 Interconstructure 300 2 Stafe for Reade 93,01 0	1				\$740 777	\$/3 DTO				
3 Sols for Reade 9.31 0 9.321 0 9.321 30 (3018) 0						9(2,019)				
4 Total State of Ellectricity 0 0 349,233 (2) (3) (3) 0 <th0< th=""> 0 0 0</th0<>										
3 Other Revenue 44 582 1 1 1 6 Total Electric Revenue 0 0 384.215 (3.018) 0 <	4		0	0		(3.018)	0	0	0	0
6 Total Electric Revenue 0 0 384.215 (3.018) 0 0 0 0 0 ECPENSISS Production and Junamiasion Operating Expanses 46 125.327 Production and Junamiasion 7 Operating Expanses 46 125.327 Production and Junamiasion 7 5 Production and Junamiasion 7.534 277 0 0 0 11 Taxes 14 66 0 26.46.077 0 257 0 0 0 12 Operating Exponses 8.746 10.325 175 2 0 9 13 Depreciation 10.235 17.5 2 0 9 14 Taxes 13 2.20.5 (10.12) 175 2 0 9 15 Contoner Service & Altomation 7.887 (10.12) 175 2 0 9 16 Operating Exponses 2.5.626 (10.12) 175 (157) (2) (619) <tr< td=""><td>5</td><td></td><td></td><td>-</td><td></td><td>(-,-,-)</td><td></td><td></td><td></td><td></td></tr<>	5			-		(-,-,-)				
Production and Transmission 9 Openting Expenses 46 125.327 9 Depresenting and Amontizati. 7,354 10 Taxes 5,264 297 11 Total Production & 1 46 0 246,577 0 27 0 0 0 12 Opertuing Expenses 8,746 10,293 175 2 9 9 14 Taxes (1) 5,466 (,5012) 175 2 0 9 16 Customer Accounting 3,220 ((159) 1 2 0 9 17 Cotatomer Accounting 3,220 (159) 1	6	Total Electric Revenue	0	0		(3,918)	0	0	0	0
7 Operating Expanse 46 123.327 9 Depression and Amoritanic 7,554 108,732 9 Depression and Amoritanic 7,554 207 0 0 0 11 Total Productics & 1 46 0 246,877 0 297 0 0 0 12 Operating Expanse 8,746 10,235 1 1 1 1 1 1 2 0 9 13 Depression 11 0 24,697 (3,012) 175 2 0 9 14 Costomer Accounting 3,220 (159) 1 7 1		EXPENSES								
8 Perchased Forcer 108,732 9 Deprociation and Anontrazit. 7,534 10 Trees 3,264 207 11 Total Production & 1 46 0 246,877 0 297 0 0 0 12 Operating Expenses 8,746 10,395 11 75 2 9 0 9 14 Trees (1) 5,466 (3,012) 175 2 9 9 15 Total Distribution (1) 0 24,507 (3,012) 175 2 0 9 16 Customer Accounting 7,587 (1,59) 15 7 10<										
9 Depresiation and Amortizatic 7,554 11 Taxe 5,264 297 0 0 0 Distribution Operating Expenses 8,746 0 245,977 0 297 0 0 0 13 Operating Expenses (1) 5,466 (3,012) 175 2 0 9 14 Operating Expenses (1) 5,466 (3,012) 175 2 0 9 15 Outcome Accounting 3,920 (159) 17 17 17 17 17 17 18 19 Operating Expenses 17 17 17 19 Administrative & General 7,387 10 (619) 11 17 19 10 10 24,525 10 3 10 (10) 11 10 11 11 11 11 11 11 11 11 11 11 11 11 11 11 11 11 11			46							
10 Taxes $5,264$ 297 11 Taxes 66 $246,977$ 0 297 0 0 12 Operating Exposes $8,746$ $0,295$ 0 0 0 13 Deprotation $10,295$ 175 2 0 9 14 Taxes (1) $5,466$ $(3,012)$ 175 2 0 9 15 Total Distribution (1) 0 $24,607$ $(3,012)$ 175 2 0 9 16 Chatome Accounting $3,920$ (159) $7,887$ 3487 3487 3487 3487 3487 3487 3487 3487 3487 3487 $3417,473$ (159) (159) (159) (159) (159) (159) (1610) $(12,833)$ $(3,012)$ 475 (159) (1610) $(12,833)$ (159) (161) $(12,84)$ $(217,73)$ (161) $(12,84$										
11 Total Production & T 46 0 246,877 0 297 0 0 0 Discribution Operating Exponses 8.746 10.235 10.235 10.235 175 2 9 13 Depreciation 10.235 10.235 175 2 9 9 14 Description (1) 0 244,567 (3,012) 175 2 9 9 15 Total Distribution (1) 0 244,567 (3,012) 175 2 0 9 16 Customer Accounting 3,205 (157) (159) 17 17 17 Administrative & General 0 0 28,855 0 3 0 (3) (619) 18 Depreciation 2,205 3 0 (3) (619) 19 Operating Exponses 2,325 0 3 0 (3) (619) 19 Depreciation 2,325 0 3 0 (3) (619) (510) (517) (3)										
Distribution Distribution Distribution End of the state of th										
12 Operating Expenses 8,746 13 Depresition 10,235 14 Taxes (1) 5,666 15 Total Distribution (1) 0 16 Customer Accounting 3,920 (159) 17 Customer Accounting 7,887 (1) 18 Sales Expenses 17 Administrativa & General 0 0 28,835 0 3 (1) (619) 20 Poperentiang Repenses 23,629 (3) (619) (619) 21 Taxes 3 3 (3) (619) 22 Total Admin. & General 0 0 28,835 0 3 (3) (619) 23 Total Biotric Expenses 45 0 312,043 (3,012) 475 (157) (3) (610) 24 OPERATING INCOME IEATX Current Accrual (16) 11,296 (2) (166) 55 1 214 25 Current Accrual (16) 11,296 (2) (166) 52 350,67 <td>- 11</td> <td>Total Production & 1</td> <td>46</td> <td>0</td> <td>246,877</td> <td>0</td> <td>297</td> <td>0</td> <td>U</td> <td>0</td>	- 11	Total Production & 1	46	0	246,877	0	297	0	U	0
13 Depresidion 10.235 14 Taxes (1) 5.446 (3.012) 175 2 0 9 16 Customer Accounting 3.320 (1.59) (1.59) 7 2 0 9 16 Customer Accounting 3.320 (1.59) (1.59) (1.59) 7 17 Sales Represes 17 3 0 (3) (619) 19 Operating Represes 23.629 (3) 0 (3) (619) 21 Taxes 3 0 (3) (619) 22 Total Admin. & Gen 45 0 32.243 (3.012) 475 (157) (3) (610) 23 Total Bectric Expenses 45 0 32.243 (3.012) 475 (157) (3) (610) 24 OPERATING INCOME BEFOR (45) 0 72.172 (6) (473) 157 3 610 25 Current Accrual (16) 11.266 (2) (166) 55 1 214 <	4.44									
14 Texes (1) 5,445 (3,012) 175 2 9 15 Total Distribution (1) 0 24,567 (3,012) 175 2 0 9 16 Customer Accounting 3,220 (159) 175 2 0 9 17 Customer Service & Information 7,887 (159) 1<										
15 Total Distribution (1) 0 24,507 (3,012) 175 2 0 9 16 Customer Accounting 3,220 (159) 175 2 0 9 16 Customer Service & Information 7,387 1 17 15 Administrative & General 7,387 17 17 17 Administrative & General 0 0 23,629 (3) (619) 20 Depreciation 5,206 3 0 (3) (619) 21 Total Admin. & General 0 0 28,835 0 3 0 (3) (619) 23 Total Electric Expenses 45 0 312,043 (3,012) 475 (157) (3) (610) 24 OPERATING INCOME ELEPORE FIT (45) 0 72,172 (6) (475) 157 3 610 25 Current Account Exces 7,176 (45) 1214 22 23926 <t< td=""><td></td><td></td><td>ية ما الم</td><td></td><td></td><td></td><td>شديد . د</td><td></td><td></td><td></td></t<>			ية ما الم				شديد . د			
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17 Cuttome Service & Information 7,887 17 Administrative & General 17 9 Operating Expenses 17 Administrative & General 5,206 11 Totes 3 22 Total Admin. & Gen 0 0 28,835 0 3 0 (3) (619) 23 Total Admin. & Gen 0 0 28,835 0 3 0 (3) (610) 24 OPERATING INCOME BEFORE FIT (45) 0 72,172 (6) (475) 157 3 610 25 Current Accrual (16) 11,296 (2) (166) 55 1 214 26 Deferred Incean Faxes 7,76 <	13	Total Distribution	(i)	0	24,507	(3,012)	175	2	0	9
18 Sales Expenses 17 Administrative & General Depreciation 23,629 (3) (619) 20 Depreciation 5,206 21 Texes 3 22 Total Admin. & Gen 0 0 28,835 0 3 0 (3) (619) 23 Total Admin. & Gen 0 0 28,835 0 3 0 (3) (619) 24 Texes 3 0 312,043 (3,012) 475 (157) (3) (610) 25 OPERATING INCOME BEPORE FIT (45) 0 72,172 (6) (475) 157 3 610 PEDERAL INCOME TAX 11,296 (2) (166) 55 1 214 25 Current Acevual (16) 11,296 (2) (166) 55 1 214 26 Defered Income Taxes 7,176 OKAP	16	Customer Accounting			3,920			(159)		
Administrative & General 3 0 3 (3) (619) 19 Operating Expenses 5,206 3 0 (3) (619) 22 Total Admin. & Gen. 0 0 28,835 0 3 0 (3) (619) 23 Total Electric Expenses 45 0 312,043 (3,012) 475 (157) (3) (610) 24 OPERATING INCOME EBEFORE FIT (45) 0 72,172 (6) (475) 157 3 610. 25 Current Actrual (16) 11,296 (2) (166) 55 1 214 26 Defered Income Taxes 7,176 (45) 0 72,172 (6) 0510 25 1 214 27 Amortized IIC - Noxoa (16) 11,296 (2) (166) 55 1 214 28 NET OPERATING INCOME (329) \$0 \$33,745 (54) (8309) \$102 \$22 \$396 29 Intagible 542,046 1,533 375,90 31	17	Customer Service & Information			7,887					
19 Operating Expenses 23,629 (3) (619) 20 Deprociation 5,206 3 0 (3) (619) 21 Taxes 3 0 (3) (619) 23 Total Admin, & Gen. 0 0 28,835 0 3 0 (3) (619) 23 Total Electric Expenses 45 0 312,043 (3,012) 475 (157) (3) (610) 24 OPERATING INCOME ELEFORE FIT (45) 0 72,172 (6) (475) 157 3 610 PEDERAL INCOME TAX 25 Current Acervai (16) 11,296 (2) (166) 55 1 214 26 Deferred Incone Taxes 7,176 (45) 22 \$396 27 Amorized IIC - Noxon (329) \$0 \$53,745 (\$44) (\$309) \$102 \$2 \$396 28 NET OPERATING INCOME (\$29) \$0 \$57,745 (\$44) \$309) \$102 \$2 \$396 29 <td>18</td> <td>Sales Expenses</td> <td></td> <td></td> <td>17</td> <td></td> <td></td> <td></td> <td></td> <td></td>	18	Sales Expenses			17					
20 Depreciation 5,206 21 Taxes 3 0 (3) (619) 23 Total Admin. & Gen. 0 0 28,835 0 3 0 (3) (619) 24 OPERATING INCOME BEFORE FIT (45) 0 72,172 (6) (475) 157 3 610 PEDERAL INCOME BEFORE FIT (45) 0 72,172 (6) (475) 157 3 610 PEDERAL INCOME BEFORE FIT (45) 0 72,172 (6) (475) 157 3 610 20 Cortent Accrual (16) 11,296 (2) (166) 55 1 214 20 Cortent Accrual (16) 11,296 (2) (166) 55 1 214 21 Deferred Income Taxes 7,176 0KAY		Administrative & General								
21 Turses 3 22 Total Admin. & Gen. 0 0 28,835 0 3 0 (3) (619) 23 Total Electric Expenses 45 0 312,043 (3,012) 475 (157) (3) (610) 24 OPERATING INCOME BEFORE FIT (45) 0 72,172 (6) (475) 157 3 610 FEDERAL INCOME TAX Current Accrual (16) 11,296 (2) (166) 55 1 214 25 Current Accrual (16) 11,296 (2) (166) 55 1 214 26 Defered Income Taxes 7,176 (45) 1 214 214 27 Amortized IIC - Noxon (45) 0KAY 0KAY<		Operating Expenses			23,629				(3)	(619)
22 Total Admin. & Gen 0 0 28,835 0 3 0 (3) (619) 23 Total Electric Expenses 45 0 312,043 (3,012) 475 (157) (3) (610) 24 OPERATING INCOME BEFORE FIT (45) 0 72,172 (6) (475) 157 3 610 24 OPERATING INCOME TAX (16) 11,296 (2) (166) 55 1 214 26 Current Accrual (16) 11,296 (2) (166) 55 1 214 27 Amortized ITC - Noxon (16) 11,296 (2) (166) 55 1 214 28 NET OPERATING INCOME (329) \$0 \$53,745 (\$4) (\$309) \$102 \$2 \$336 28 NET OPERATING INCOME (329) \$0 \$53,745 (\$4) (\$309) \$102 \$2 \$336 29 Intangible					5,206					
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FEDERAL INCOME TAX Contrast Acernal (16) 11,296 (2) (166) 55 1 214 26 Deferred Income Taxes 7,176 7,176 7 7 7 7 7 7,176 7 7,176 7 7 7 7 7 7,176 7 7 7 7 7 7 7 7 7 7 7 7 7 7,176 7 7 7 7 7,176 7	23	Total Electric Expenses	45	0	312,043	(3,012)	475	(157)	(3)	(610)
25 Current Accrual (16) 11,296 (2) (166) 55 1 214 26 Deferred Income Taxes 7,176 7 7 7 7 7 1 214 27 Amortized ITC - Noxon (45) (45) 1 214 214 28 NET OPERATING INCOME (529) 50 \$53,745 (\$4) (\$309) \$102 \$2 \$396 OKAY OK OK OKAY OK OK <td>24</td> <td>OPERATING INCOME BEFORE FIT</td> <td>(45)</td> <td>0</td> <td>72,172</td> <td>(6)</td> <td>(475)</td> <td>157</td> <td>3</td> <td>610</td>	24	OPERATING INCOME BEFORE FIT	(45)	0	72,172	(6)	(475)	157	3	610
26 Deferred Income Taxes 7,176 27 Amerized ITC - Noxen (45) 28 NET OPERATING INCOME (529) \$0 \$53,745 (\$4) (\$309) \$102 \$2 \$396 RATE BASE PLANT IN SERVICE 29 Intangible \$42,046 31 Transmission 1,533 375,980 32 Distribution 405,363 33 General 67,570 34 Total Plant in Service 1,533 0 1,088,050 0 0 0 0 0 34 ACCUMULATED DEPRECIATION 353,607		FEDERAL INCOME TAX								
26 Deferred Income Taxes 7,176 27 Amortized ITC - Noxon (45) 28 NET OPERATING INCOME (529) \$0 \$53,745 (\$4) (\$309) \$102 \$2 \$396 28 NET OPERATING INCOME (\$29) \$0 \$53,745 (\$4) (\$309) \$102 \$2 \$396 RATE BASE PLANT IN SERVICE 0KAY	25	Current Accrual	(16)		11,296	(2)	(166)	-55	1	214
28 NET OPERATING INCOME (\$29) \$0 \$53,745 (\$4) (\$309) \$102 \$2 \$396 RATE BASE OKAY OK OKY OKY <td></td> <td></td> <td></td> <td></td> <td>7,176</td> <td></td> <td></td> <td></td> <td></td> <td></td>					7,176					
OKAY OKAY <th< td=""><td>27</td><td>Amortized ITC - Noxon</td><td></td><td></td><td>(45)</td><td></td><td></td><td></td><td></td><td></td></th<>	27	Amortized ITC - Noxon			(45)					
OKAY OKAY <th< td=""><td>70</td><td>NOT OPED ATIMIC INCOMO</td><td>1000</td><td></td><td>فروبو تدفرون</td><td>200</td><td>/aa.oo</td><td></td><td></td><td></td></th<>	70	NOT OPED ATIMIC INCOMO	1000		فروبو تدفرون	200	/aa.oo			
RATE BASE PLANT IN SERVICE 29 Intangible \$42,046 30 Production 1,533 375,980 31 Transmission 167,091 32 Distribution 405,363 33 General 67,570 34 Total Plant in Service 1,533 0 1,058,050 0 0 0 0 35 ACCUMULATED DEPRECIATION 353,607	20		ALL WAS ALL WAY TO THE WAY		323,143					Parameter and a state of the second
29 Intangible \$42,046 30 Production 1,533 375,980 31 Transmission 167,091 32 Distribution 405,363 33 General 67,570 34 Total Plant in Service 1,533 0 1,658,050 0 0 0 0 0 35 ACCUMULATED DEPRECIATION 353,607						UNU .	01011	ugani	uani	UQA1
30 Production 1,533 375,980 31 Transmission 167,091 32 Distribution 405,363 33 General 67,570 34 Total Plant in Service 1,533 0 1,058,050 0 0 0 0 35 ACCUMULATED DEPRECIATION 353,607 36 ACCUM. PROVISION FOR AMORTIZAT. 6,399 37 Total Accum. Depreciation & 0 0 360,006 0 0 0 0 38 GAIN ON SALE OF BUILDING 7,710 7,710 7,710 40 DEFERRED TAXES (537) (104,581)	20				\$45 BAF					
31 Transmission 167,091 32 Distribution 405,363 33 General 67,570 34 Total Plant in Service 1,533 0 1,058,050 0 0 0 0 0 35 ACCUMULATED DEPRECIATION 353,607 353,607 353,607 353,607 360,006 0			1 633							
32 Distribution 405,363 33 General 67,570 34 Total Plant in Service 1,533 0 1,058,050 0 0 0 0 35 ACCUMULATED DEPRECIATION 353,607 36 ACCUM. PROVISION FOR AMORTIZAT 6,399 37 Total Accum. Depreciation & 0 0 360,006 0 0 0 0 38 GAIN ON SALE OF BUILDING 7,710 7,710 7,710 0 <td></td> <td></td> <td>5554</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td>			5554							
33 General 67,570 34 Total Plant in Service 1,533 0 1,058,050 0										
34 Total Plant in Service 1,533 0 1,058,050 0										
36 ACCUM. PROVISION FOR AMORTIZAT: 6,399 37 Total Accum. Depreciation & 0 0 360,006 0 0 0 0 38 GAIN ON SALE OF BUILDING 7,710 7,710 7,710 39 WORKING CAPITAL 7,710 7,710 40 DEFERRED TAXES (537) (104,581)			1,533	0		0	Ô	Û	0	0
36 ACCUM. PROVISION FOR AMORTIZAT: 6,399 37 Total Accum. Depreciation & 0 0 360,006 0 0 0 0 38 GAIN ON SALE OF BUILDING 7,710 7,710 7,710 39 WORKING CAPITAL 7,710 7,710 40 DEFERRED TAXES (537) (104,581)	35				353,607					
38 GAIN ON SALE OF BUILDING 39 WORKING CAPITAL 7,710 40 DEFERRED TAXES (537)							- 			
39 WORKING CAPITAL 7,710 7,710 40 DEFERRED TAXES (537) (104,581)			0	Ó	360,006	0	Ø	0	0	0
40 DEFERRED TAXES (537) (104,581)										
			Sec. 1	7,710						
41 TOTAL RATE BASE \$996 \$7,710 \$601,173 \$0 \$0 \$0 \$0 \$0	40	DEFERRED TAXES	(537)		(104,581)					
	41	TOTAL RATE BASE	\$996	\$7,710	\$601,173	50	\$ 0	\$ 0	\$0	\$0

42 RATE OF RETURN

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 1, p. 7 of 11

Line No.	DESCRIPTION	FIT	ldaho PCA	Nez Perce Settlement Adjustment	Eliminate A/R Expenses	Revenue Normalization Adjustment	Mise A&G Restating Adjs
	A	v	w	X	y	Z	83
	REVENUES						
1	Total General Business		\$ (13,062)			\$16,751	
2	Interdepartmental Sales						
3	Sales for Resale	an an tao an					
4	Total Sales of Electricity	0	(13,062)	0	0	16,751	0
5	Other Revenue Total Electric Revenue	0	(13,062)	0	0	16,751	0
,	EXPENSES	v	(13,002)	0	V .	10,751	. 0
	Production and Transmission						
7	Operating Expenses		(3,227)	(17)		(371)	(1)
8	Purchased Power		(2,227)	(17)		(371)	ίυ
9	Depreciation and Amortizatic					6,429	
10	Taxes						
11	Total Production & 1	0	(3,227)	(17)	0	6,058	(1)
	Distribution						
12	Operating Expenses						(1)
13	Depreciation						
14	Taxes				\$2	271	14
15	Total Distribution	0	0	0	2	271	13
16	Customer Accounting		(33)		\$(124)	29	3
17	Customer Service & Information		(55)		4(104)	(7,339)	(28)
18	Sales Expenses					(,,,	(20)
	Administrative & General						
19	Operating Expenses		(33)			34	(919)
20	Depreciation		,				(,
21	Taxes						
22	Total Admin. & Gen	0	(33)	0	0	34	(919)
23	Total Electric Expenses	0	(3,293)	(17)	(122)	(947)	(932)
24	OPERATING INCOME BEFORE FIT	0	(9,769)	17	122	17,698	932
	FEDERAL INCOME TAX						
25	Current Accrual	(279)	(4,549)	6	\$43	6,194	326
26	Deferred Income Taxes	210	1,195	-	1.4	a gina a	
27	Amortized IIC - Noxon	(8)	5579-7L				
	1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 -						
28	NET OPERATING INCOME	\$77	(\$6,415)	\$11	\$79	\$11,504	\$6 06
	THE A COMMON AND A STORY	оклу	OKAY	OKAY	OKAY	ОКАҮ	OKAY
	RATEBASE						
20	PLANT IN SERVICE						
29 30	Intangible Production						
31							
31	Transmission Distribution						
32	General						
34	Total Plant in Service	0	0	Ő	0	0	0
35	ACCUMULATED DEPRECIATION		Ť		4	• • •	
36	ACCUMULATED DEPRECIATION ACCUM. PROVISION FOR AMORTIZAT						
30	Total Accum, Depreciation &	0	0		0	0	0
38	GAIN ON SALE OF BUILDING	v	U.	U	U	U	Ú.
39	WORKING CAPITAL						
40	DEFERRED TAXES						
41	TOTAL RATE BASE	\$0	\$ 0.	\$0	\$0	\$0	\$0
		49	ψų.	ريني	ۍې د د د د د د د د د د د د د د د د د د د		30

42 RATE OF RETURN

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 1, p. 8 of 11

Line		Restating Incentive	Restating CSZ	Removal Colstrip	Removal CCX	O&M Savings	Restate Debt	Restated
No.	DESCRIPTION 8	Adj	Levelized Adj ac	Stimmt Exp ad	Revenue at	l	Interest ag	TOTAL
	REVENUES			e 14			** <u>K</u>	
1	Total General Business							#070 000
2	Interdepartmental Sales							\$250,393
3	Sales for Resale							210
4	Total Sales of Electricity	0	0	0	0	0	0	89,301 339,904
5	Other Revenue	U	u u	U	0	U	U	
6	Total Electric Revenue	0	0	. 0 .	0	0	0	44,982 384,886
	EXPENSES							
	Production and Transmission							
7				199983		(00)		1
8	Operating Expenses			(230)		(99)		121,382
9	Purchased Power							108,732
	Depreciation and Amortizatic		280		342			14,605
10 11	Taxes Total Production & 1	0	280	(230)	342	(99)	Ó	5,561
11		<u>N</u>	289	(230)	342	(55)	0	230,280
	Distribution							
12	Operating Expenses					(35)		8,710
13	Depreciation							10,295
14	Taxes	15		3	(5)	2		2,942
15	Total Distribution	15	0	3	(5)	(33)	Û	21,947
16	Customer Accounting							3,636
17	Customer Service & Information					1. A.		520
18	Sales Expenses							. 17
	Administrative & General							
19	Operating Expenses	(986)				(23)		21,080
20	Depreciation	• •						5,206
21	Taxes							3
22	Total Admin. & Gen	(986)	0	0	0	(23)	0	26,289
23	Total Electric Expenses	(971)	280	(227)	337	(155)	Ű.	302,689
24	OPERATING INCOME BEFORE FTI	971	(280)	227	(337)	155	0	82,197
i. a	FEDERAL INCOME TAX	.				÷	د شدید	
25	Current Accrual	340		79	(118)	54	276	13,770
26	Deferred Income Taxes		(98)					8,483
27	Amortized ITC - Noxon							(53)
28	NET OPERATING INCOME	\$631	(\$182)	\$148	(\$219)	\$101	(\$276)	\$59,997
		OKAY	OKAY	OKAY	OKAY	OKAY	OKAY	
	RATE BASE							
	PLANT IN SERVICE							
29	Intangible							\$42,046
30	Production							375,980
31	Transmission							167,091
32	Distribution							405,363
33	General	and a state of the		·				67,570
34	Total Plant in Service	0	0	0	Õ	0	0	1,058,050
35	ACCUMULATED DEPRECIATION							353,607
36	ACCUM. PROVISION FOR AMORTIZAT.							6,399
37	Total Accum. Depreciation &	0	0	0	.0	0	0	360,006
38	GAIN ON SALE OF BUILDING							·
39	WORKING CAPITAL							7,710
40	DEFERRED TAXES					· · · · · · · · · · · · · · · · · · ·		(104,581)
		\$0	\$0	\$0	\$0	.\$0	\$0	\$601,173

42 RATE OF RETURN

Line No.	DESCRIPTION	Pro Forma Power Suppty	Pro Forma Energy Efficiency Load Adjustment	Pro Forma Labor Non-Exec	Pro Forma Labor Exec	Pro Forma Transmission Rev/Exp	Pro Forma Capital Add 2010	Pro Forma Capital Add 2011
	· · · · · · · · · · · · · · · · · · ·	PF1	PF2	PF3	PF4	PF5	PF6	PF7
	REVENUES							
1	Total General Business		\$ (4,224)					
2	Interdepartmental Sales		4 (4,004)					
3	Sales for Resale	(75,756)	\$1,201					
4	Total Sales of Electricity	(75,756)	and the second se	0	0	0	õ	0
5	Other Revenue	(38,770)		Ū	v	(355)	· .	Ŭ
6	Total Electric Resenue	(114,526)		0	0	(355)	0	0
	EXPENSES							
-	Production and Transmission							
7	Operating Expenses	(47,747)		371	2	743		
8	Purchased Power	(57,656)	\$ (1,157)					
9	Depreciation and Amortizatic					89	115	328
10 11	Taxes	1100 1000	7.4 - E-2789.		*****			224
11	Total Production & 1	(105,403)	(1,157)	371	2	832	115	552
10	Distribution							
12	Operating Expenses			243				
13 14	Depreciation					(. #2	972	\$34
15	Taxes Total Distribution	(138)		(15)		(18)	(10)	241
1.1	Total Distribution	(138)	(28)	228	0	(18)	962	775
16	Customer Accounting		\$ (7)	91				
17	Customer Service & Information		3.2.4	11				
18	Sales Expenses			1				
	Administrative & General							
19	Operating Expenses		\$ (9)	259	14			
20	Depreciation						(433)	1,480
21	Taxes							179
22	Total Admin. & Gen	0	(9)	259	14	Û	(433)	1,659
23	Total Electric Expenses	(105,541)	(1,201)	961	16	814	644	2,986
24	OPERATING INCOME BEFORE FIT	(8,985)	(1,822)	(961)	(16)	(1,169)	(644)	(2,986)
	FEDERAL INCOME TAX							
25	Current Accrual	(3,145)	\$ (638)	(336)	(6)	(409)	(225)	(1,045)
26	Deferred Income Taxes	(-,, +,,		(550)	(0)	(40))	(200)	(1,040)
27	Amortized ITC - Noxon							
							·····	
28	NET OPERATING INCOME	(\$5,840) <i>OKAY</i>	(\$1,184) OKAY	(\$625) OKAY	(\$10) OKAY	(\$760) OKAY	(\$419) ORAY	(\$1,941) OKAY
	RATEBASE	CRAI	Varia	ULAI	VAA	UKAI	QKAI	ULAI
	PLANT IN SERVICE							
29	Intangible						\$1,157	\$5,362
30	Production						2,949	5,552
31	Transmission						5,596	9,407
32	Distribution						7,648	19,155
33	General						4,306	6,332
34	Total Plant in Service	0	0	0	0	0	21,656	46,008
.35	ACCUMULATED DEPRECIATION						6,873	30,623
36	ACCUM. PROVISION FOR AMORTIZAT.						w ₂ Q7-7	
37	Total Accum. Depreciation &	.0	0	0	0	0	6,873	30,623
38	GAIN ON SALE OF BUILDING		*	*	.			**30##
39	WORKING CAPITAL							
40	DEFERRED TAXES						(3,140)	(3,807)
		\$0	\$0	\$0	\$ 0	S 0	\$11,643	\$11,578
41	TOTAL RATE BASE							

42 RATE OF RETURN

Line No.	DESCRIPTION	Pro Forma Capital Add 2012	Pro Forma Noxon Gen 2011 & 2012	Pro Forma Employee	Pro Forma Insurance	Pro Forma Vegetation	Pro Form
1101		PF8	PF9	Benefits PF10	PFII	Management PF12	TOTAL PFT
		4 4 9	177	FEIU	rrii	FF 14	£P I
4	REVENUES Total General Business						69.47 1.70
2	Interdepartmental Sales						\$246,169
3	Sales for Resale						210
4	Total Sales of Electricity	0	0	0	0	0	14,746
5	Other Revenue	•			v.,	Ų	5.857
6	Total Electric Revenue	0	0	Ő	0	0	266,982
	EXPENSES						
-	Production and Transmission						
7	Operating Expenses			52			74,803
8	Purchased Power	1	24				49,919
9	Depreciation and Amortizatio	57	151				15,345
10 11	Taxes Total Production & 1	81 138	66 217	52	<u>A</u>		5,932
14·	Total Production & 1	158	217	52	0	0	145,999
	Distribution						
12	Operating Expenses			. 4		1,284	10,241
13	Depreciation	134					11,935
14	Taxes	103	(3)	(10)	1	(19)	3,046
15	Total Distribution	237	(3)	(6)	· 1	1,265	25,222
16	Customer Accounting			2			3,722
17	Customer Service & Information			- - 2			531
18	Sales Expenses						186
4.46	Administrative & General						
19	Operating Expenses	1. march		618	(47)		21,915
20	Depreciation	172					6,425
21 22	Taxes Total Admin. & Gen	231	0	618	(47)	0	241 28,581
23	Total Electric Expenses	606	214	666	(46)	1,265	204,073
	· · · · · · · · ·		614	000	(40)	لالاغرا	2014,075
24	OPERATING INCOME BEFORE FIT	(606)	(214)	(666)	46	(1,265)	62,909
	FEDERAL INCOME TAX						
25	Current Accrual	(212)	(75)	(233)	16	(443)	7,019
26	Deferred Income Taxes			·			8,483
27	Amortized ITC - Noxon		(26)				(79
28	NET OPERATING INCOME	(\$394)	(\$113)	(\$433)	\$30	(\$822)	\$47,486
	andra harara san sa arar sa arar sa arar arar a	OKAY	OKAY	OKAY	OKAY	OKAY	00 P ₁ / _F u
	RATE BASE						
	PLANT IN SERVICE						
29	Intangible	\$1,994					\$\$0,759
30	Production	3,447	5,081				393,009
31	Transmission	1,970					184,064
32	Distribution	7,458					439,624
33	General	1,939					80,147
34	Total Plant in Service	16,808	5,081	0	0	0	1,147,603
35 26	ACCUMULATED DEPRECIATION	16,350	121				407,574
36	ACCUM. PROVISION FOR AMORTIZAT						6,399
37 38	Total Accum. Depreciation & GAIN ON SALE OF BUILDING	16,350	121	0	0	0	413,973
38 39	WORKING CAPITAL						7 710
39 40	DEFERRED TAXES	(2,501)	(310)				7,710 (114,339
***	an ana manima tana ana ana ana ana ana ana ana ana a	[4,4*V+]	(310)			· · ·	0
	TOTAL RATE BASE	(\$2,043)	\$4,650	\$0	\$0	\$0	\$627,001

42 RATE OF RETURN

7.57%

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 1, p. 11 of 11

AVISTA UTILITIES GAS RESULTS OF OPERATION IDAHO PRO FORMA RESULTS

TWELVE MONTHS ENDED DECEMBER 31, 2010 (000% OF DOLLARS)

	T T	Actual Per	PRESENT RAT	Ev.)		OSED RATES
e	DESCRIPTION	Actual Per Results Report	Total Adjustments	Pro Forma Total	Proposed Revenues & Related Exp	Pro Forma Proposed Total
	a a	b	c	d	e Kenated Exp	f
	REVENUES		Т.,	· •	•.	2
	Total General Business	\$62,878	\$7,304	\$70,182	\$1,921	\$72,103
2	Total Transportation	454	(122)	332		332
Ĺ.	Other Revenues	51,440	(51,310)	130		130
j e	Total Gas Revenues	114,772	(44,128)	70,644	1,921	72,565
	EXPENSES					
i	Exploration and Development Production					
6	City Gate Purchases	ne sas.	113 000			
r. r	Purchased Gas Expense	85,383 375	(43,898) 15	41,485		41,485
	Net Nat Gas Storage Trans	(1,561)		590		390
))	Total Production	84,197	1,570	· · · · · · · · · · · · · · · · · · ·	0	41.084
	Underground Storage	94,197	(42,313)	41,884	U	41,884
0	Operating Expenses	167	151	318		318
i.	Depreciation	154	28	182		182
2	Taxes	53	20	82		82
3	Total Underground Storage	374	208	582	0	582
	Distribution			÷	¥	
4	Operating Expenses	3,888	417	4,305		4,305
5	Depreciation	3,445	122	3,567		3,567
6	Taxes	1,672	(1,031)	641	29	670
7	Total Distribution	9,005	(492)	8,513	29	8,542
8	Customer Accounting	0.004	1000			A A
а 9	Customer Accounting Customer Service & Information	2,204 3,172	(196)	2,008	3	2,011 373
0	Sales Expenses	3,172	(2,799)			
4	Administrative & General	P.	U	7		7
1	Operating Expenses	5,400	(366)	5,034	4	5,038
2	Depreciation	5,400	(300) 683	5,034	4	3,038
3	Taxes	1.027	60	71		1,710
4	Total Admin. & General	6,438	377	6,815	4	6,819
5	Total Gas Expense	105,397	(45,215)	60,182	36	60,218
				~41105		vvie19
6	OPERATING INCOME BEFORE FIT	9,375	1,087	10,462	1,885	12,347
	FEDERAL INCOME TAX					
7	Current Accrual	(2,229)	446	(1,783)	660	(1,123
8	Deferred FIT	4,699	9.	4,708		4,708
9	Amort ITC	(17)		(17)		(17
_						1
0	NET OPERATING INCOME	6,922	\$632	7,554	\$1,225	\$8,779
	RATE BASE: PLANT IN SERVICE					
1	Underground Storage	8,839	1,896	10,735		10.735
2	Distribution Plant	148,345	4,376	152,721		152,721
3	General Plant	15,515	4,524	20,039		20,039
4	Total Plant in Service	172,699	10,796	183,495	0	183,495
	ACCUMULATED DEPRECIATION	2.1.mg/2.2	10,130	100,775	J	100,430
5	Underground Storage	3,488	331	3,819		3,819
6.	Distribution Plant	48,439	6,535	54,974		54,974
7	General Plant	4,822	2,096	6,918		6,918
g.	Total Accum. Depreciation	56,749	8,962	65,711	0.	65,711
9	DEFERRED FIT	0	(23,672)	(23,672)		(23,672
0	GAS INVENTORY	ŏ	7,737	7,737		7,737
1	WORKING CAPITAL	Ō	1,553	1,553		1,553
2	GAIN ON SALE OF BUILDING		0			0
1	TOTAL BATT2 BASP	110.000	1910 x 100	100 100	á.	
3 A	TOTAL RATE BASE RATE OF RETURN	115,950	(\$12,548)	103,402	\$0	103,402
4	MALL OF ACTUAN			7.31%	e base, see also j	-

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 2, p. 1 of 9

AVISTA UTILITIES Calculation of General Revenue Requirement Idaho - Gas TWELVE MONTHS ENDED DECEMBER 31, 2010 (000's OF DOLLARS)

Line No.	Description	IDAHO
1	Pro Forma Rate Base	\$103,402
2	Proposed Rate of Return	8.49%
3	Net Operating Income Requirement	\$8,779
4	Pro Forma Net Operating Income	\$7,554
5	Net Operating Income Deficiency	\$1,225
6	Conversion Factor	0.637780
7	Revenue Requirement	\$1,921
8	Total General Business Revenue	\$70,514
9	Percentage Revenue Increase	2,72%

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 2, p. 2 of 9

AVISTA UTILITIES Calculation of General Revenue Requirement Idaho - Gas Pro Forma Cost of Capital (000's OF DOLLARS)

	BlackBox-Currer	it approved C	Cost of Capital	
Idaho Component	Capital Structure	Cost	Weighted Cost	Excludes STD
ong-Term Debt	49.85%	6.050%	3.02%	ID Wtd Debt 3.02%
Pref Trust	0.00%	0.000%	0.00%	
Pref Stock			0.00%	
Common	50.15%	10.90%	5.47%	
Total	100.00%		8,49%	·

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 2, p. 3 of 9

AVISTA UTILITIES CALCULATION OF CONVERSION FACTOR: IDAHO GAS TWELVE MONTHS ENDED DECEMBER 31, 2010

Revenues	1.000000
Expense:	
Uncollectibles (1)	0.001665
Commission Fees (2)	0.002039
Idaho Income Tax (3)	0.015093
Total Expense	0.018797
Net Operating Income Before FIT	0.981203
Federal Inc 35.00%	0.343421
REVENUE CONVERSION FACTOR	0.63778

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 2, p. 4 of 9

Line Reenits FIT on Office Gas and DSM Customer No. DESCRIPTION Report Rate Bas Building Inventory Investment Advances b d ÷. e f 2 e REVENUES 1 **Total General Business** \$62,878 2 **Total Transportation** 454 3 Other Revenues 51,440 4 Total Gas Revenues 114.772 0 0 Ó 0 0 **EXPENSES** 5 **Exploration and Development** 0 Production City Gate Purchases 6 85,383 7 **Purchased Gas Expense** 325 Net Nat Gas Storage Trans 8 (1,561) 9 **Total Production** 84,197 0 0 0 0 Ô. **Underground Storage** 10 **Operating Expenses** 167 11 Depreciation 154 12 Taxes 53 Total Underground Storage 13 n 0 Ō 0 ñ 374 Distribution 14 **Operating Expenses** 3,888 15 Depreciation 3,445 16 Taxes 1,672 17 **Total Distribution** 0 9,005 0 0 ñ 2 18 **Customer** Accounting 2.204 0 0 0 0 Customer Service & Information (101) 19 3,172 Sales Expenses 20 7 Administrative & General 21 **Operating Expenses** 5,400 (21) 22 Depreciation 1,027 23 Taxes 11 0 24 Total Admin. & General 6.438 Ô (21) 0 0 Total Gas Expense 0 25 105.397 0 (21) 0 (99) 26 OPERATING INCOME BEFORE FIT 9,375 0 21 0 99 0 FEDERAL INCOME TAX 0 27 Current Accrual (2,229)35 7 28 Deferred FIT 4,699 Amort ITC 29 (17) NET OPERATING INCOME 30 \$6,922 \$14 \$64 \$0 \$0 \$0 ΟΚΑΥ OKAY OKAY OKAY OKAY RATE BASE: PLANT IN SERVICE 31 Underground Storage 8,839 32 **Distribution Plant** 148,345 (74) 33 **General Plant** 15,515 34 **Total Plant in Service** 172,699 0 (74) 0 0 0 ACCUMULATED DEPRECIATION 35 Underground Storage 3.488 36 **Distribution Plant** 48,439 37 General Plant 4,822 0 38 **Total Accum. Depreciation** 0 0 0 0 56,749 39 DEFERRED FIT (19,934) 0 GAS INVENTORY 40 0 4,509 WORKING CAPITAL 41 0 GAIN ON SALE OF BUILDING 42 0 TOTAL RATE BASE \$115,950 (\$74) 43 (\$19,934) \$0 \$4,509 \$0 RATE OF RETURN 44 7.2% <-- actual including DFIT on Plant Rate base

Per

Deferred

Deferred Gain

Weatherization

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 2, p. 5 of 9

1 2 3 4 5 5 6 7 8 9 9 10 11 12 13	a EVENUES Total General Business Total Transportation Other Revenues otal Gas Revenues otal Gas Revenues XPENSES Exploration and Development Production City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage	Capital h 0	Subtoral Actual \$62,878 454 51,440 114,772 0 85,383 375 (1,561) 84,197 167	Normalization i \$8,427 (114) (51,310) (42,997) (43,898) (9) 1,570 (42,337)	B & O Taxes j \$ (1,123) (8) (1,131)	Property Tax k 0	Uncollectible Expense 1 0
R 1 2 3 4 7 5 6 7 8 9 10 11 12 13	a EVENUES Total General Business Total Transportation Other Revenues otal Gas Revenues otal Gas Revenues XPENSES Exploration and Development Production City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage	h	Actual \$62,878 454 51,440 114,772 0 85,383 375 (1,561) 84,197 167	i \$8,427 (114) (51,310) (42,997) (43,898) (9) 1,570	Taxes j \$ (1,123) (8) (1,131)	Tax k	Expense I
R 1 2 3 4 7 5 6 7 8 9 9 10 11 12 13	a EVENUES Total General Business Total Transportation Other Revenues otal Gas Revenues otal Gas Revenues XPENSES Exploration and Development Production City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage	0	\$62,878 454 51,440 114,772 0 85,383 375 (1,561) 84,197 167	\$8,427 (114) (51,310) (42,997) (43,898) (9) 1,570	i \$ (1,123) (8) (1,131)	k 0	1
1 2 3 4 7 5 6 7 7 8 9 9 10 11 12 13	Total General Business Total Transportation Other Revenues otal Gas Revenues XPENSES Exploration and Development Production City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage		454 51,440 114,772 0 85,383 375 (1,561) 84,197 167	(114) (51,310) (42,997) (43,898) (9) 1,570	(8)		
1 2 3 4 7 5 6 7 7 8 9 10 11 12 13	Total General Business Total Transportation Other Revenues otal Gas Revenues XPENSES Exploration and Development Production City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage		454 51,440 114,772 0 85,383 375 (1,561) 84,197 167	(114) (51,310) (42,997) (43,898) (9) 1,570	(8)		
2 3 4 T 5 6 7 8 9 10 11 12 13	Total Transportation Other Revenues otal Gas Revenues XPENSES Exploration and Development Production City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage		454 51,440 114,772 0 85,383 375 (1,561) 84,197 167	(114) (51,310) (42,997) (43,898) (9) 1,570	(8)		
3 4 Th 5 6 7 8 9 10 11 12 13	Other Revenues otal Gas Revenues Exploration and Development Production City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage		51,440 114,772 0 85,383 375 (1,561) 84,197 167	(51,310) (42,997) (43,898) (9) 1,570	(1,131)		
4 T E 5 7 8 9 10 11 12 13	otal Gas Revenues XPENSES Exploration and Development Production City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage		114,772 0 85,383 375 (1,561) 84,197 167	(42,997) (43,898) (9) 1,570			
5 6 7 8 9 10 11 12 13	Exploration and Development Production City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage	0	85,383 375 (1,561) 84,197 167	(9) 1,570	0	0	
5 6 7 8 9 10 11 12 13	Exploration and Development Production City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage	0	85,383 375 (1,561) 84,197 167	(9) 1,570	0	0	0
6 7 8 9 10 11 12 13	Production City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage	0	85,383 375 (1,561) 84,197 167	(9) 1,570	0	0	0
7 8 9 10 11 12 13	City Gate Purchases Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage	0	375 (1,561) 84,197 167	(9) 1,570	0	0	ő
7 8 9 10 11 12 13	Purchased Gas Expense Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage	0	375 (1,561) 84,197 167	(9) 1,570	0	0	0
8 9 11 12 13	Net Nat Gas Storage Trans Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage	0	(1,561) 84,197 167	1,570	0	0	Ŭ
9 10 11 12 13	Total Production Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage	0	84,197 167	and the second	0	0	0
11 12 13	Underground Storage Operating Expenses Depreciation Taxes Total Underground Storage		167	(-	+.
11 12 13	Operating Expenses Depreciation Taxes Total Underground Storage						
12 13	Depreciation Taxes Total Underground Storage						
13	Total Underground Storage		154				
			53				
<i></i>	Distribution	0	374	0	0	0	0
4.4	ar and any second s						
14	Operating Expenses		3,888				
15	Depreciation		3,445				
16	Taxes		1,674	28	(1,130)	35	4
17	Total Distribution	0	9,007	28	(1,130)	35	4
18 C	ustomer Accounting		2,204	14	0		(242
	ustomer Service & Information		3,071	(2.721)	v.		(***
	ales Expenses		7	(
	dministrative & General		,				
21	Operating Expenses		5,379	17			
22	Depreciation		1,027	173			
23	Taxes		11				
24	Total Admin. & General	0	6,417	190	0	0	0
	otal Gas Expense	Ō	105,277	(44,826)	(1,130)	35	(238
	n na statistica da constructiva da constructiva da construcción da construcción da construcción da construcción			n an		Bu show	
	PERATING INCOME BEFORE FIT	0	9,495	1,829	(1)	(35)	238
	EDERAL INCOME TAX		0				
27	Current Accrual		(2,187)	640		(12)	83
28	Deferred FIT		4,699				
29	Amort ITC		(17)				
30 N	ET OPERATING INCOME	\$0	\$7,000	\$1,189	(\$1)	(\$23)	\$155
	-	OKAY		ОКЛҮ	ОКЛҮ	OKAY	OKAY
R	ATE BASE: PLANT IN SERVICE						
31	Underground Storage		8,839				
32	Distribution Plant		148,271				
33	General Plant		15,515				
34	Total Plant in Service	0	172,625	0	0	0	C
A	CCUMULATED DEPRECIATION						
35	Underground Storage		3,488				
36	Distribution Plant		48,439				
37	General Plant		4,822				
38	Total Accum. Depreciation	0	56,749	0	0	0	0
	EFERRED FTT		(19,934)		•	-	
	AS INVENTORY		4,509				
	VORKING CAPITAL	1,553	1,553				
	AIN ON SALE OF BUILDING		0				
							.
	OTAL RATE BASE ATE OF RETURN	\$1,553	\$102,004 6.86%	\$0	\$0	\$ 0	\$0

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 2, p. 6 of 9

Line No.	DESCRIPTION	Regulatory Expense Adjustment	Injuries and Damages	FIT	Eliminate A/R Expenses	Misc. Restating Adjs	Restating Incentive Adj	O&M Savings
	8	n j	n	0	р	9	٢	ş
	REVENUES							
1	Total General Business							
2	Total Transportation							
3	Other Revenues							
4	Total Gas Revenues	0	0	0	0	0	õ	Ô
	EXPENSES							
5	Exploration and Development Production							
6	City Gate Purchases							
7	Purchased Gas Expense					(1)		
8	Net Nat Gas Storage Trans							
9	Total Production	0	0	0	0	(1)	0	0
	Underground Storage							
-10 11	Operating Expenses Depreciation							
12	Taxes							
13	Total Underground Storage	0	0	Ó	0	0	0	0
	Distribution							
14	Operating Expenses					(5)		
15	Depreciation					-		
16 17	Taxes Total Distribution		1 	0	0	3 (2)	4	0
	i otar i Astributicar		· 4 ·	0	0	(2)		v
18	Customer Accounting	0			(20)	2		
19	Customer Service & Information					- 17		
20	Sales Expenses							
	Administrative & General							· · ·
21	Operating Expenses	(41)	(48)			(237)	(249)	(6)
22	Depreciation							
23 24	Taxes Total Admin. & General	2415	6(0)	0	0	(237)	(249)	(6)
25	Total Gas Expense	(41)	(48) (47)	0	(20)	(221)	(245)	(6)
and a second	L CHAT LONG LONGARIAN	(40)		V	(20)	(~~1)	<u> </u>	<u></u>
26	OPERATING INCOME BEFORE FIT FEDERAL INCOME TAX	40	. 47	0	20	221	245	6
27	Current Accrual	14	16	75	7	77		2
28	Deferred FIT			(77)			86	
29	Amort ITC	1 (jan - 10)						
30	NET OPERATING INCOME	\$26	\$31	\$2	\$13	\$144	\$159	\$4
		OKAY	OKAY	ОКАҮ	OKAY	OKAY	ΟΚΑΥ	OKAY
	RATE BASE: PLANT IN SERVICE							
31	Underground Storage							
32	Distribution Plant							
33	General Plant							
34	Total Plant in Service	0	0	0	-0	0	0	0
72	ACCUMULATED DEPRECIATION							
35 36	Underground Storage Distribution Plant							
37	General Plant							
38	Total Accum. Depreciation	0	0	0	-0	.0	0	0
39	DEFERRED FIT	v	v	U.	U	v	0	v
40	GAS INVENTORY							
41	WORKING CAPITAL							
42	GAIN ON SALE OF BUILDING							
		· • - ·	` ستعد	* #			يەرىغى:	s.m.
43 44	TOTAL RATE BASE BATE OF BETLIEN	\$0	\$0	<u>\$0</u>	\$0	\$0	\$0	\$0

44 RATE OF RETURN

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 2, p. 7 of 9

		Restate		Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma
Line		Debt	Restated	Labor	Labor	Employee	Insurance	Survey &
No,	DESCRIPTION	Interest	Total	Non-Exec PF1	Exec	Benefits PF3	PF4	Replacement PF5
		£	•	rri.	PF2	res	rra	113
	REVENUES							
1	Total General Business		\$70,182					
2	Total Transportation		332					
4	Other Revenues Total Gas Revenues	0	130	0	0	0	0	0
.4	Total Gas Revenues	U	70,644	U	. V	U	Ű	9
	EXPENSES							
5	Exploration and Development Production		0		·			
6	City Gate Purchases		41,485					
2	Purchased Gas Expense		365	11		14		
8	Net Nat Gas Storage Trans		9	••				
9	Total Production	0	41,859	11	0	14	0	0
-	Underground Storage	-						
10	Operating Expenses		167					
11	Depreciation		154					
12	Taxes		53					
13	Total Underground Storage	0	374	0	0	0	0.	0
14	Distribution Operating Expenses		3,883	120		2		165
15	Depreciation		3,445			-		
16	Тахсэ		620	(4)		(3)		(2)
17	Total Distribution	0	7,948	116	0	(1)	0.	163
10			1.000	49		14: -		
18 19	Customer Accounting Customer Service & Information		1,958 367	47				
20	Sales Expenses		30/ 7	0				
20	Administrative & General		,					
21	Operating Expenses		4,815	56	21	154	(12)	
22	Depreciation		1,200	24		1. S.	2.55.5	
23	Taxes							
24	Total Admin. & General	0	6,026	56	21	154	(12)	0
25	Total Gas Expense	0	58,539	238	21	168	(12)	163
~	0070 - TO 10 1000 - TO 10700 - TO		10 100	(778)	2955	(169)	12	(163)
26	OPERATING INCOME BEFORE FIT FEDERAL INCOME TAX	0	12,105	(238)	(21)	(168)	12	(105)
27	Current Accrual	77	(1,208)	(83)	(7)	(59)	4	(57)
28	Deferred FIT	**	4,708	(65)	(7)	(22)	4	(31)
29	Amort ITC		(17)					
30	NET OPERATING INCOME	(\$77)	\$8,622	(\$155)	(\$14)	(\$109)	\$8	(\$106)
90	THE OF LEAST THE BOOME	OKAY	00,022	OKAY	OKAY	OKAY	OKAY	OKAY
	RATE BASE: PLANT IN SERVICE							
31	Underground Storage		8,839					
32	Distribution Plant		148,271					
33	General Plant		15,515					· · · · · · · · · · · · · · · · · · ·
34	Total Plant in Service	0	172,625	0	0	0	0	0
	ACCUMULATED DEPRECIATION							
35	Underground Storage		3,488					
36	Distribution Plant		48,439					
37	General Plant		4,822					
38	Total Accum. Depreciation	0	56,749	0	0	0	0	0
39	DEFERRED FIT		(19,934)					
40	GAS INVENTORY		4,509					
41	WORKING CAPITAL		1,553					
42	GAIN ON SALE OF BUILDING		0		<u> </u>			
43	TOTAL RATE BASE	\$0	\$102,004	\$0	\$0	50	\$0	\$0

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 2, p. 8 of 9

Line		Pro Forma Atmospheric	Pro Forma Capital Add	Pro Forma Capital Add	Pro Forma Capital Add	Pro Forma JP	Pro Forma
No.	DESCRIPTION	Testing PF6	2010 PF7	2011 PF8	2012 PF9	Storage PF10	Total
	n sa	•••••	***				
	REVENUES						
1	Total General Business						\$70,182
3	Total Transportation Other Revenues						332
4	Total Gas Revenues	0	0		0	0	130
	Todal Gas Keyendes	v	U.	0	v	0	/0,044
	EXPENSES						
5	Exploration and Development Production						C
6	City Gate Purchases						41,485
7	Purchased Gas Expense						390
8	Net Nat Gas Storage Trans				· · · · · · · · · · · · · · · · · · ·		9
9	Total Production	0	0	0	0	0	41,884
	Underground Storage						
10	Operating Expenses					151	318
11	Depreciation		(9)	3	2	32	182
12	Taxes		· · ·	2	1	26	82
13	Total Underground Storage	0	(9)	5	3	209	582
	Distribution						
14	Operating Expenses	\$135					4,305
15	Depreciation		78	30	14		3.567
16	Taxes	\$ (2)	(2)	13	24	(3)	641
17	Total Distribution	133	76	43	38	(3)	8,513
18	Customer Accounting						2,008
19	Customer Service & Information						373
20	Sales Expenses						
20	Administrative & General						
21	Operating Expenses						5,034
22	Depreciation		93	374	43		1,710
23	Taxes			45	15		71
24	Total Admin. & General	0	93	419	58	0	6.815
25	Total Gas Expense	133	160	467	99	206	60,182
			- Article				
26	OPERATING INCOME BEFORE FIT	(133)	(160)	(467)	(99)	(206)	10,462
	FEDERAL INCOME TAX	an carrier	100	182.45	00	(77)	71.000
27	Current Accrual	\$ (47)	(56)	(163)	(35)	(72)	(1,783
28	Deferred FTT						4,708
29	Amont ITC				***		(11
30	NET OPERATING INCOME	(\$86)	(\$104)	(\$304)	(\$64)	(\$134)	\$7,554
		ОКАУ	OKAY	OKAY	OKAY	ОКЛҮ	
	RATE BASE: PLANT IN SERVICE				÷		1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 -
31	Underground Storage	•	\$ (34)	\$102	\$91	\$1,737	10,735
32	Distribution Plant		1,361	1,374	1,715		152,721
33	General Plant		532	3,000	992		20,039
34	Total Plant in Service	0	1,859	4,476	2,798	1,737	183,495
· _	ACCUMULATED DEPRECIATION					_	
35	Underground Storage		73	147	75	36	3,819
36	Distribution Plant		1,270	3,496	1,769		54,974
37	General Plant		(284)	1,482	898		6,918
38	Total Accum. Depreciation	0	1,059	5,125	2,742	36	65,71
39	DEFERRED FIT	ŭ	(1,297)	(1,648)			(23,672
40	GAS INVENTORY		(1,4,4,7,7)	(1,010)	(3,228	7,73
41	WORKING CAPITAL						1,55
42	GAIN ON SALE OF BUILDING						1,000
	n de general de la company de la company En la company de la company						
43	TOTAL RATE BASE	\$0	(\$497)	(\$2,297)	(\$687)	\$4,879	\$103,403
							7.31%

Exhibit No. 10 Case No. AVU-E-11-01 and AVU-G-11-01 E. Andrews, Avista Schedule 2, p. 9 of 9