



# Oregon

Kate Brown, Governor

## Public Utility Commission

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October 16, 2015

### ***Via Electronic Filing and Huddle***

OREGON PUBLIC UTILITY COMMISSION  
ATTENTION: FILING CENTER  
PO BOX 1088  
SALEM OR 97302-1088

**RE: Docket No. UG 288 – In the Matter of  
AVISTA CORPORATION, dba AVISTA UTILITIES,  
Request for a General Rate Revision.**

Enclosed for filing is Staff Opening Testimony in UG 288, together with a Certificate of Service and UG 288 Service List.

Exhibits 207, 303, 305, 500, 502, 503, 605, 800, 803, 1100, and 1103 are confidential.

Per Parties approval this voluminous filing both confidential and non-confidential will be uploaded to Huddle by close of business today. They will be available to the parties that were assigned confidential access to the Huddle information.

/s /Mark Brown  
Executive Assistant  
(503) 378-8287  
Email: mark.brown@state.or.us

CASE: UG 288  
WITNESS: MARIANNE GARDNER

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 100**

**Overall Rev Req, Uncollectibles,  
Working Cash Rev Sensitive state tax,  
State Tax, Escalation**

**Opening Testimony**

**October 16, 2015**

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Marianne Gardner. My business address is 201 High Street, SE  
3 Suite 100, Salem, Oregon 97301-3612.

4 **Q. Please describe your educational background and work experience.**

5 A. My Witness Qualification Statement is found in Exhibit Staff/101.

6 **Q. What is the purpose of your testimony?**

7 A. I am the revenue requirements summary witness for the Public Utility  
8 Commission of Oregon Staff (Staff) in this proceeding. I introduce Staff-  
9 sponsored adjustments and issues regarding Avista's (AVA's or Company's)  
10 filing in this docket, identified as UG 288. As such, I verify AVA's proposed  
11 revenue requirement utilizing Staff's revenue requirement model. This model  
12 is also used to calculate Staff's modified revenue requirement incorporating  
13 Staff's proposed adjustments to AVA's revenue requirement. Additionally, I  
14 provide background regarding specific issues I reviewed, my analysis, and my  
15 recommendations.

16 **Q. Did you prepare exhibits for this docket?**

17 A. Yes. I prepared the following exhibits.

18	Exhibit 102	DR Nos. 180 and 214 - SIT calculation
19	Exhibit 103	DR No. 135 – Bonus depreciation
20	Exhibit 104	Renewal of bonus depreciation
21	Exhibit 105	SIT calculation – Staff proposal

22 **Q. Will other Staff submit testimony regarding the issues they reviewed?**

23 A. Yes. Each Staff assigned to UG 288 is submitting separate testimony. In  
24 Part 1 of my testimony, I will introduce the Staff witnesses, their respective

1 assignments, and estimate the revenue requirement impact of Staff  
2 recommended adjustments to the Company's initial filing.

3 **Q. Are Staff's recommendations definitive of their final position regarding**  
4 **the Company's filed case?**

5 **A.** No. Staff reserves the right to revise its recommendations on these issues  
6 as the need arises due to additional discovery or based upon Staff's review  
7 of the intervening parties' testimony in this docket.

8 **Q. How is your testimony organized?**

9 **A.** My testimony is organized as follows:

10	Part 1, Revenue Requirement .....	3
11	Part 2, Specific Issues .....	5



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**PART 1, REVENUE REQUIREMENT**

**Q. Please provide a list of the rate case topics that Staff reviewed, introduce the responsible Staff, and identify those issues for which Staff recommends a revenue requirement adjustment.**

A. I have provided a listing in Table A.

Table A

Staff Issue Summary Avista Utilities UG 288 – General Rate Case 2016 Test Year (\$000)								
Company Filed General Rate Required Change to Revenue Requirement								\$8,557
Staff Proposed Adjustments								
Exhibit No.	Testimony Issue No.	Staff's Rev. Req. Model Adj. No.	Staff Witness	Description	Rev.	Exp.	Rate Base	Rev. Req. Effect
100	4	S-4.1	Marianne Gardner	Revenue Sensitive: State Effective Tax Rate				(41)
100	1	S-1	Marianne Gardner	Uncollectibles		(7)		(7)
100	2	S-2	Marianne Gardner	Working Cash			(1,090)	(116)
100	3	S-3	Marianne Gardner	Interest Synchronization				7
100	4	S-4.2	Marianne Gardner	State Tax		(1,213)		(1,353)
100	5	I-8	Marianne Gardner	Escalation				
200	1	S-0	Matt Muldoon	Cost of Capital				(1,552)
300	1	S-6	Judy Johnson	Information Technology			(1,243)	(132)
300	2	S-9	Judy Johnson	Distribution O&M		(550)		(568)
400	1 & 2	S-17	Ming Peng	Depreciation		(281)	(173)	(308)
500	1	S-7.1	Linnea Wittekind	D&O		(577)		(596)

500	2	S-7.2	Linnea Wittekind	Various A&G		(30)		(31)
600	1	S-8	Mitch Moore	Plant			(30,003)	(3,194)
700	3	S-10	Erik Colville	Other Gas Supply		(80)		(83)
700	1	I-1	Erik Colville	Gas Inventory				
700	5	I-2	Erik Colville	IRP				
700	2	I-3	Erik Colville	Storage Operating Expense				
700	4	I-8	Erik Colville	Purchased Gas Expense				
800	2	S-11	Brian Bahr	Medical Benefits		(175)		(181)
800	4	S-12	Brian Bahr	Wages & Salaries		(350)	(283)	(392)
800	3	S-13	Brian Bahr	Property Taxes		(67)		(69)
800	1	S-14	Brian Bahr	Pension Adjustment		(435)	(5,655)	(1,051)
900	1	S-15	Max St. Brown	Other Revenues - Misc. Revenue	34			(34)
900	2	I-9	Max St. Brown	Load Forecasting (Commercial & Industrial)				
1000	1	S-16	Suparna Bhattacharya	Load Forecasting (Residential,	867			925
1000	2	I-5	Suparna Bhattacharya	Decoupling and Public Purpose Charge				
1100	1	S-17	Jorge Ordonez	Cost Allocations		(9)		(9)
1200	1	I-6	Lisa Gorsuch	Advertising				
1300	1	I-7	George R. Compton	LRIC, Rate Spread and Rate Design				
Total Staff Proposed Adjustments (Base Rates)								(8,784)
Staff Calculated Revenue Requirements Change (Base Rates)								(227)

1 **Part 2, Specific Issues**

2 **Q. What areas of Avista's filing are you primarily responsible for**  
3 **reviewing?**

4 A. I reviewed the portions of the filing related to uncollectible expense, state  
5 income tax (SIT) and federal income tax (FIT), accumulated deferred income  
6 taxes (ADIT), and working capital allowance. In order to gain additional insight,  
7 I reviewed the Company's responses to related Standard Data Requests  
8 (SDRs), issued approximately 25 data requests, and reviewed the Company's  
9 responses to my data requests and multiple data requests in these areas  
10 submitted by other Staff and the intervening parties.

11 **Q. For each issue, please provide a summary of the Commission's**  
12 **historical treatment, the Company's filed proposal, Staff's analysis of**  
13 **the issue, and Staff's recommendation.**

14 A. Below is a summary of each issue. I have labeled each to correspond to  
15 Table A.

16 **Issue 1: Uncollectibles**

17 It is a long-standing policy of the Commission Staff to apply a three-year  
18 average methodology to determine the test year uncollectible expense for a  
19 utility's revenue requirement.<sup>1</sup> However, Commission Staff also examines  
20 other evidence to determine whether this approach results in a reasonable  
21 forecasted test year result.

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<sup>1</sup> See e.g., Order Nos. 14-015 and 09-422 (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on 3-year average); *but see* Order No. 05-871 (adopting stipulation for Idaho Power Company general rate increase with uncollectible expense based on 4-year average).

1           In this case, the Company includes \$347,000 as uncollectible expense in its  
2 proposed 2016 Average of Monthly Averages (AMA) test year.<sup>2</sup> According to  
3 the electronic workpapers accompanying the Company's initial filing, the  
4 Company calculated an uncollectible rate based on a three-year average  
5 (2012-2014) of net write offs to general revenues, (total business revenues and  
6 total transportation revenues) of 0.54956 percent.<sup>3</sup> The Company utilized this  
7 rate in its net income to gross revenue conversion factor<sup>4</sup>. However, the  
8 inferred rate for the Company's proposed 2016 test year is 0.56245 percent,  
9 (proposed 2016 test year uncollectible expense of \$347,000 divided by  
10 proposed 2016 test year combined business revenues and transportation  
11 revenues of \$61,781,000).

12           After analyzing and trending the various collections-related data for the years  
13 2010 through 2014 provided by the Company in responses to Staff data  
14 requests DR Nos. 170-174 and 210-211, I conclude that the uncollectible rate  
15 of 0.54956 percent reasonably forecasts the level of uncollectible expense for  
16 the 2016 test year. Therefore, I agree with the Company's inclusion of 0.54956  
17 percent in its proposed 2016 test year gross revenue conversion factors.

18           However, as demonstrated in the paragraph above, the Company's proposed  
19 2016 test year uncollectible expense of \$347,000 is not 0.54956 percent of the  
20 general business and transportation revenues. Therefore, I recommend that  
21 0.54956 percent uncollectible conversion rate be applied to the proposed 2016

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<sup>2</sup> Avista/501, Smith/1 at 12/Column c.

<sup>3</sup> Workpapers\UG-\_Smith WP (Avista) (May 2015)\Smith Native Format Workpapers\3.00 G-UE\2015 Uncollectible Accounts.xlsx.

<sup>4</sup> Avista/501, Smith/3 at 3.

1 test year general business revenues and transportation revenues. I will  
2 multiply Staff's recommended total revenue requirement by the 0.54956  
3 percent for the proper level of uncollectible expense.

4 **Issue 2: Working Cash**

5 Commission Staff's long-standing policy has been to exclude working capital  
6 from rate base for gas utilities. In Avista UG 201, UG 246 and UG 284, Staff's  
7 position has been that the natural gas and electric industries are sufficiently  
8 different, which compromises the accuracy of the Working Capital allocation to  
9 Oregon. In Avista's two most recent rate cases, UG 246 and UG 284, Staff  
10 stipulated to allowing Avista to include rate base materials and supplies in  
11 inventory costs. The Commission adopted those stipulations.

12 Avista proposes to increase rate base by \$1,090,000 for working capital in  
13 adjustment 2.08.<sup>5</sup> Referring to Ms. Smith's testimony, Avista/500, Smith/21 at  
14 lines 10-20, Ms. Smith states "Column (2.08), entitled Working Capital,  
15 increases total rate base for the Company's working capital adjustment." She  
16 also notes, in relevant part, "Working capital represents investor supplied funds  
17 that are properly included in the Company's rate base for ratemaking  
18 purposes." "... The Company has calculated its working capital in this  
19 proceeding using the Investor Supplied Working Capital (ISWC) method."

20 I recommend disallowing Avista's \$1,090,000 addition to rate base for  
21 working capital based on the ISWC method. This recommendation conforms  
22 to Staff's existing policy.

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<sup>5</sup> Avista/501, Smith/8 at line 251.

1

**Issue 3: Interest Synchronization**

2  
3 According to long-standing Commission policy, for ratemaking purposes, Staff  
4 routinely coordinates or “synchronizes” interest expense to reflect changes to  
5 the regulated utility’s cost of capital as initially filed in a general rate case. This  
6 is consistent with the treatment in Avista’s last general rate case, UG 284. This  
7 adjustment is dependent on Staff witness Matt Muldoon’s proposed  
8 modification to the Company’s weighted cost of debt in his adjustment, S-0,  
9 Cost of Capital. Once parties agree on the weighted cost of debt, or the  
10 Commission determines what this is, then interest must be coordinated or  
11 synchronized to determine the related adjustment for the income tax  
12 calculation.<sup>6</sup>

**Issue 4: State Income Taxes (SIT), SIT revenue sensitive rate, Federal  
Income Taxes (FIT), Accumulated Deferred Income Taxes (ADIT)**

15 Consistent with Internal Revenue Code Section (IRC Sec.) 168(f)(2) and  
16 168(i)(9), normalization rules for public utilities, the Commission requires that  
17 utilities normalize federal income taxes for revenue requirement purposes.  
18 Additionally, ORS 757.269 mandates the Commission balance the interests of  
19 utility customers and utility investors in setting rates that include income taxes.  
20 ORS 757.269 (1) states,

21 “[s]ubject to subsections (2) and (3) of this section,

22 amounts for income taxes included in rates are fair, just

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<sup>6</sup> For a more complete explanation, see Staff/700, Gardner/9 at lines 1-20 (Docket No. UE 294).

1                   and reasonable if the rates include current and deferred  
2                   income taxes and other related tax items that are based  
3                   on estimated revenues derived from the regulated  
4                   operation of the utility.” According to subsection (3),  
5                   *”During a ratemaking proceeding conducted under ORS*  
6                   *757.210 for an electricity or natural gas utility that pays*  
7                   *taxes a part of an affiliated group, the Public Utility*  
8                   *Commission may adjust the utility’s estimated income tax*  
9                   *expense based upon: (a) Whether the utility’s affiliated*  
10                  *group has a history of paying federal or state income taxes*  
11                  *that are less than the federal or state income taxes the*  
12                  *utility would pay to units of government if it were an*  
13                  *Oregon-only regulated utility operation; (b) Whether the*  
14                  *corporate structure under which the utility is held affects*  
15                  *the taxes paid by the affiliated group; or (c) Any other*  
16                  *considerations the commission deems relevant to protect*  
17                  *the public interest.”*

18                  Avista has included for FIT and SIT in their 2016 test year, \$6,594,000 and  
19                  \$1,877,000 respectively, for a total of \$8,472, 000.<sup>7</sup> According to Avista’s  
20                  response to Staff DR No. 212<sup>8</sup>, Avista does not normalize state income tax  
21                  expense. Avista estimated the 2016 AMA Test Year SIT using the

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<sup>7</sup> Avista/501, Smith/1 at lines 26-30/column e.

<sup>8</sup> Staff/102, Gardner/1.

1 apportionment method. Avista used this same methodology in UG 284.<sup>9</sup> For  
2 the incremental revenue requirement and for the net-to-gross factor, Avista  
3 used an 8 percent SIT rate.<sup>10</sup> Referring to Avista/500, Smith/30 Ms. Smith  
4 states, “The 8.0% tax rate was determined by “grossing up” the 0.614%  
5 apportionment rate for system taxable net income by Oregon’s share of system  
6 revenues. Oregon’s revenues from its natural gas operations represent  
7 approximately 7.68% of total revenues. Therefore, 0.614% divided by 7.68%  
8 equals 8.0%, which is the Oregon apportionment tax rate used in this filing.”

9 **Q. Does Avista’s proposed SIT, FIT and ADIT included in the 2016 test**  
10 **year conform to Commission policy?**

11 A. Avista’s normalization of FIT and the inclusion of ADFIT in rate base comply  
12 with both IRC regulation and Commission policy. However, while not violating  
13 IRC normalization rules, from my viewpoint, Avista’s application of the flow-  
14 through method for Oregon state income taxes appears to include an over-  
15 estimation of SIT in the Company’s Results of Operations report (ROO)  
16 compared to the Company’s Oregon excise tax return. Staff’s concern is that  
17 the tax benefits related to bonus depreciation and business energy tax credits  
18 (BETCs) are not flowing through to ratepayers, that the 2016 SIT expense may  
19 be excessive, and there is no offsetting effect of ADIT in rate base to counter  
20 balance the overstatement.

21 **Q. Would you please provide an illustration that supports Staff assertion**  
22 **that SIT may have been overstated.**

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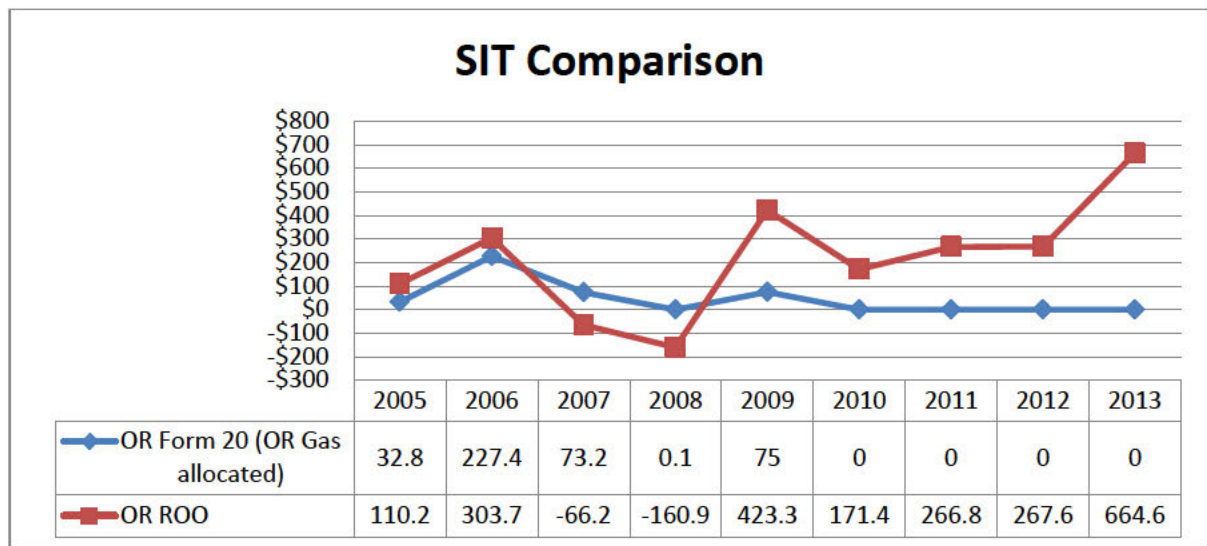
<sup>9</sup> Avista/500, Smith/28 at lines 10-14.

<sup>10</sup> Avista/500, Smith/29 at lines 9-23 and 30 at lines 1-19.



1 A. Yes. Table B below compares the Oregon gas jurisdiction’s share of Oregon  
 2 SIT from the Company’s filed Oregon Form 20 versus the Company’s filed  
 3 Oregon Results of Operations Report (ROO) for the years 2005 through 2013,  
 4 inclusive. Avista provided this information in Staff\_DR\_214\_Attachment A.xlsx  
 5 in response to Staff’s DR No. 214. The Company’s narrative response has  
 6 been included in Exhibit 102 and its excel attachment A is included in Staff’s  
 7 non-confidential workpapers, UG 288 Exhibit 102 Gardner DR 214.xls. As  
 8 Table B displays, the Company over-forecasted its ROO SIT expense from  
 9 2009 through 2013, inclusive. The 2013 ROO SIT jumps to \$664,600 versus  
 10 zero dollars for the 2013 tax return. The forecasted 2016 test year SIT doubles  
 11 to \$1,213,000.

12 Table B



13  
 14 **Q. What appear to be the main drivers for the Company’s over-estimation**  
 15 **of the ROO SIT for the years 2009 through 2013?**

1 A. Based on my review of the Company's response to DR No. 214, the main  
2 drivers have been the availability of Oregon Business Energy Tax Credits  
3 (BETCs) and bonus depreciation. As the Company notes in its response to  
4 Staff DR No. 135,<sup>11</sup> Congress reenacted bonus depreciation for 2008 and then  
5 has continually extended bonus depreciation for each tax year through 2014,  
6 inclusive. The Company was able to use bonus depreciation to lower taxable  
7 income and BETCs to offset Oregon Form 20 SIT.

8 **Q. What is the Company's position regarding the availability of bonus**  
9 **depreciation and BETCs for the 2015 forecast and 2016 test year?**

10 A. According to Avista witness Smith's testimony,<sup>12</sup> the Company predicted bonus  
11 depreciation would not be available for 2015 or 2016. As a result, the  
12 Company forecasted virtually all of its BETCs would be consumed against its  
13 projected 2015 SIT expense, leaving only \$11,558 of BETCs available for  
14 2016.<sup>13</sup> Without BETCs and bonus depreciation for offset, Avista forecast is  
15 \$1,213,787 of SIT expense for their Restated 2016 AMA Test Year.

16 **Q. Are there any indications that Congress may extend bonus**  
17 **depreciation for the 2015 and 2016 tax years?**

18 A. Yes. According to Baker Tilly, bonus depreciation has been available from  
19 2008 through 2014.<sup>14</sup> In July 2015, the Senate Finance Committee  
20 overwhelming voted to extend bonus depreciation for 2015 and 2016.<sup>15</sup> On

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<sup>11</sup> Staff/103, Gardner/1

<sup>12</sup> Avista/500, Smith/ 28 at lines 19-20 and 29 at lines 1-5.

<sup>13</sup> Staff/102, Gardner/3

<sup>14</sup> Staff/104, Gardner/1

<sup>15</sup> Staff/104, Gardner/2

1 September 17, 2012, the House Ways and Means Committee approved  
2 legislation to permanently extend bonus depreciation.<sup>16</sup> While any tax  
3 extender bill still has to pass the full Senate, the full House, and then be  
4 approved by the President before enacted into law, there appears to be strong  
5 legislative support to continue bonus depreciation through 2016 and perhaps  
6 permanently.

7 **Q. Based on this legislative news, does Staff propose an alternative**  
8 **estimate of state taxes for the 2016 test year?**

9 A. Yes. I have prepared an alternative calculation which I have included in my  
10 Exhibit 105. In my calculation, I assume the same level of bonus depreciation  
11 as Avista has included for 2014 for the 2015 forecast and the 2016 test year.  
12 As a result of including bonus depreciation for 2015 and 2016, there are  
13 sufficient BETCs available to credit against Oregon Form 20 SIT tax.  
14 Consequently, I conclude that Avista will owe no Oregon SIT for either year  
15 and recommend the full amount, \$1,213,787, of SIT expense be removed from  
16 the Company's Restated 2016 AMA Test Year.

17 **Q. Does Staff agree with the Company's proposed SIT rate of 8 percent**  
18 **used in Avista's 2016 test year conversion factor calculation?**

19 A. No. The Company's 8 percent rate is higher than the Oregon Form 20 SIT  
20 rate. According to the instructions to 2014 Oregon Form 20 line 16,  
21 "Calculated excise tax," Oregon taxable income greater than \$1 million is  
22 multiplied by 7.6% then \$66,000 is added for the tax on the first \$1 million.

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<sup>16</sup> Staff/104, Gardner/5

1 Using this formula, I propose a SIT revenue sensitive factor of 7.2812 percent  
2 based on my calculation of 2016 Oregon SIT before BETCs (OR SIT/OR  
3 taxable income =  $\$194.3\text{K}/2,688.6\text{K} = 7.2812$  percent)<sup>17</sup>. I recommend 7.2812  
4 percent be used as the SIT factor in the net-to-gross factor (conversion factor)  
5 for the incremental Revenue Requirement calculation.

6 **Issue 5: Escalation**

7 It is Staff policy to use the Consumer Price Index – All Urban Consumers as  
8 published by the State of Oregon Office of Economic Analysis for year over  
9 year escalation. The most recent release was August 26, 2015. According to  
10 Appendix A of this report, the percentage change for 2014 to 2015, and 2015  
11 to 2016, is 0.2 percent and 1.8 percent, respectively. Therefore, the escalator  
12 for 2014 actuals to the 2016 test year end would be approximately 1.2 percent.

13 According to the Company's supporting workpapers for Adjustment 2.00 G-  
14 FE that accompanied the Company's original filing, Avista utilized the  
15 December CPI – All Urban percentage change between 2013 and 2014 of 0.8  
16 percent to escalate 2014 non-labor costs for both 2015 and 2016. The 2016  
17 test year non-labor expenses were escalated approximately 1.16 percent over  
18 2014. (Ms. Smith states in her testimony that the CPI change was .08  
19 percent.<sup>18</sup> However, it appears that was a typographical error.)

20 Based on my review, I do not recommend any adjustment to the Company's  
21 escalation adjustment. This does not preclude other Staff recommending  
22 adjustments to specific expense accounts based on their individual analysis.

<sup>17</sup> Staff/105, Gardner/1 at cell S30

<sup>18</sup> Avista/500, Smith/12 at lines 15-20.

1 **Q. Does this conclude your testimony?**

2 A. Yes.

CASE: UG 288  
WITNESS: MARIANNE GARDNER

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 101**

**Witness Qualifications Statement**

**October 16, 2015**

**WITNESS QUALIFICATION STATEMENT**

NAME: Marianne Gardner

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Revenue Requirement Analyst  
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE., Suite 100  
Salem, OR. 97301

EDUCATION: Master of Business Administration  
Oregon State University, Corvallis, Oregon

Bachelor of Science in Accounting  
Montana State University, Bozeman, Montana

CPA, Oregon

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since March 2013, with my current position being a Senior Revenue Requirement Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of cost, revenue and policy issues for electric and natural gas utilities. As the revenue requirement summary witness, I have provided testimony in dockets UE 263, UG 246, UE 283, UG 284, UE 294, and UG 287.

I have approximately 23 years of professional accounting experience, including:

- Thirteen years as a cost accountant with responsibilities including cost accounting, budgeting, product costing, and the preparation of management reports;
- Four years experience in public accounting working in the areas of audit, tax and financial accounting for individual and small business clientele; and,
- Three years experience in non-profit accounting for an agency administrating funds under the Federal Job Training Partnership Act.

CASE: UG 288  
WITNESS: MARIANNE GARDNER

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 102**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**



**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/04/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Gardner	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 212	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

**REQUEST:**

Please explain whether the Company normalized Oregon state income tax expense and included the related Oregon deferred state income tax in rate base for the 2016 test year. If not, please explain why not. In the response, please cite any supporting testimony or data responses.

**RESPONSE:**

The Company does not normalized Oregon state income tax expense and therefore, the Company included no related Oregon deferred state income tax in rate base for the 2016 test year.

This information was provided in response to Staff\_DR\_138:

“First, the Company does not record deferred state income taxes. The Company uses the flow-through method for Oregon state income taxes.”

Avista did not address this issue in its testimony in the current case, since the accounting for state income taxes has not changed for several years. During 2010 and 2011, the Company brought to the attention of Oregon PUC Staff that even though for a short period of time, the Company had recorded deferred state income taxes on its books, the Company had not included deferred state income taxes in any of its rate cases. As part of the settlement in UG-171(4), which was the annual tax filing under ORS 757.268 (i.e. SB 408), the parties to the settlement agreed that Avista could write-off the deferred state income tax balance. This was described in Order 11-119 issued on April 11, 2011 as follows:

“The Stipulating Parties also agreed that Avista could eliminate a liability in the amount of \$911,709 for deferred state income taxes from its books. This balance accumulated as a result of Avista's use of the normalization method for recording state income taxes in Oregon. Because the flow-through method of accounting was used in setting customer rates, customers did not contribute to the accumulation of this balance. Thus, removing this balance improves Avista's earnings, but does not affect customer rates.”

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	07/09/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Gardner	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 180	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

**REQUEST:**

Referring to Avista/500, Smith/28 at 15-20 and 29 at 1-5, please explain:

- a. Whether the Company has any Oregon state income tax net operating losses available for carryback or carryforward.
- b. Whether Avista included accelerated depreciation deductions in its estimation of Oregon SIT for the 2016 test year.
  - i. If not, please explain why not; and,
  - ii. If so, please explain how Avista incorporated bonus and section 179 depreciation into its forecasted FIT and SIT for the 2016 test year.

**RESPONSE:**

- a. The Company did not have any Oregon state income tax net operating losses available for carryback or carryforward, as shown on the 2013 Oregon State Income Tax Return, which was provided in response to Staff\_DR\_176. The 2014 tax return has not been prepared, however, the Company does not anticipate a net operating loss.
- b. The Company provided the calculation of its estimated Oregon SIT for the 2016 test year in the original filed case (Smith workpapers). A copy is provided on page 2 of this response.
  - i. As described in Note (2) below, accelerated depreciation of \$41,652,584 (system level before applying Oregon's apportionment factor) was factored into the 2016 estimate. This was based on the 2014 accrual, which is the best information at this time.
  - ii. As described in response to Staff\_DR\_179, the Company does not use Section 179 deductions. As described in Note (3) below, the Company factored in \$0 bonus depreciation deduction, since that deduction is no longer available after 2014. Please see response to Staff\_DR\_179 that describes the Company's use of bonus depreciation.

Avista Utilities		Oregon SIT		Notes	
	2014	2015	2016	Estimate	Estimate
	Actual	Estimate	Estimate		
Corp Pre-Tax Income (2015/2016 per forecast)	179,408,135	183,159,000	204,518,000		
Less: Forecasted GRC Revenue			(52,934,000)		(1)
Adjusted Corp Pre-Tax Income	179,408,135	183,159,000	151,584,000		
Schedule M's					
Non-Plant	35,198,171	35,198,171	35,198,171		(2)
Plant - Tax Deprec over book	(41,652,584)	(41,652,584)	(41,652,584)		(2)
Plant - Bonus Depreciation	(90,000,000)				(3)
Plant - Repairs for prior years	(125,909,739)				(4)
Plant - Repairs for current year	(28,593,225)	(28,593,225)	(28,593,225)		(4)
Total Schedule M's	(250,957,377)	(35,047,638)	(35,047,638)		
Corp. Taxable Income	(71,549,242)	148,111,362	116,536,362		
Oregon Apportionment Factor	10.780%	10.780%	10.780%		
Oregon Taxable Income	(7,713,008)	15,966,405	12,562,620		
Oregon SIT Rate	7.600%	7.600%	7.600%		
Oregon SIT	(586,189)	1,213,447	954,759		
Less: Oregon BETCs (See attached spreadsheet)	0	(1,099,868)	(11,558)		
Net Oregon Taxes	(586,189)	113,579	943,201		
Oregon Natural Gas Allocation Factor	75%	75%	75%		
Natural Gas SIT	(439,641)	85,184	707,401		
Less: Test Period SIT			(416,386)		
Adjustment			1,123,787		
<b>Notes:</b>					
(1) The forecasted GRC revenue is removed from the accrual, since the SIT for revenue from this GRC will be calculated with the SIT rate in the conversion factor.					
(2) The Schedule M adjustments will be materially the same in 2015 and 2016					
(3) Bonus depreciation is not forecasted, since it has not been approved by IRS.					
(4) The repairs adjustment in 2014 was made up of: a) a one-time adjustment for 2010 - 2013, and b) the 2014 adjustment that will be available in 2015 and future years.					

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/06/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Gardner	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 214	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

**REQUEST:**

Referring to the Company's workpaper, 1) SIT Calculation 2014.xlsx , tab, 2016 Test Period, and Staff's attached spreadsheet file, Avista UG 288 DRs 214 Attachment A.xlsx, please modify Staff's spreadsheet file as follows:

- a. In the columns labeled, 2004 through 2013, inclusive, please populate with the actual data for those years in the same manner as the Company provided for 2014 through 2016; and,
- b. In rows 45 through 58, there is listed additional Oregon state income tax information that Staff would like the Company to provide grouped by report type; Result of Operations reports, General Ledger year end results, and tax credit schedule. Please provide the data for the calendar years 2004 through 2016, inclusive.

If the information is unavailable, please explain..

**RESPONSE:**

The Company has provided the historical information, as requested, except for 2004 in Staff\_DR\_214-Attachment A. The Company does not have a copy of the 2004 Federal Tax Return. In addition, the Company began using its Oracle accounting/financial system on January 1, 2005, therefore, information prior to 2005 is not readily available.

CASE: UG 288  
WITNESS: MARIANNE GARDNER

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 103**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	06/01/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Gardner	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Fed. Regulation
REQUEST NO.:	Staff – 135	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

**REQUEST:**

**Topic or Keyword: bonus depreciation, Accumulated Deferred Federal Income Tax (ADFIT)**

Referring to Exhibit No. 501, Avista/501, Smith, 1-11 at 242, please explain if the Total Accumulated DFIT amount includes a depreciation timing difference arising from bonus depreciation for any of the years 2014, 2015 or the 2016 test year. If not, please explain why not. If so, please explain how bonus depreciation was incorporated into the rate case.

**RESPONSE:**

An estimate of 2014 bonus tax depreciation was recorded in December 2014. The estimate was prepared based on information available at that time, but it will be subject to change as the final, more detailed calculation is prepared in preparation for the September 2015 filing of the company's 2014 federal tax return. Results of Operations (December 31, 2014 AMA) used as the base year in this rate case included the ADFIT associated with the 2014 estimated bonus depreciation on an AMA basis. The Company adjusted the AMA balance to an end-of period December 31, 2014 balance with Adjustment 2.05. The Company adjusted the December 31, 2014 EOP balance to an EOP December 31, 2015 balance with Adjustment 2.06.

Bonus depreciation was enacted as a temporary measure to help the ailing U.S. economy. It was originally scheduled to expire on December 31, 2008. However, due to the continuing bad economy, it had been continually extended by Congress, which enacted annual "tax extender" bills to continue it and certain other popular tax breaks each year. Congress failed to pass a tax extender bill in 2013 and 50% bonus depreciation expired at the end of 2013. Congress passed a tax extender package on December 16, 2014 which included an extension of 50% bonus depreciation through the end of 2014.

Because the credit expired, the Company has not incorporated any bonus depreciation for 2015 or 2016 in its filing.

CASE: UG 288  
WITNESS: MARIANNE GARDNER

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 104**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

Baker Tilly

# Insights

July 24, 2015

Articles

## *Bonus depreciation update for 2015*

In July 2015, the Senate Finance Committee voted 23 to 3 to extend bonus depreciation and the enhanced section 179 deduction through 2016. The full Senate has not indicated if or when it will act on this legislation and the House is not scheduled to take up extenders until the fall. In December 2014, Congress retroactively extended bonus depreciation and the \$500,000 limit for a section 179 deduction through 2014.

Bonus depreciation may result in substantial present value tax savings for businesses that already had plans to purchase or construct qualified property. Unlike section 179 expensing, you do not need net income to take bonus depreciation deductions. Further, bonus is not limited to smaller businesses or capped at a certain dollar level, but it is not available for used property, property used outside of the US, tax-exempt use property, or tax-exempt financed property. Also, many states are likely to opt out of this provision for state income tax purposes.

*Bonus depreciation has generally been available since Sept. 11, 2001, with a period of expiration in 2005, 2006, and 2007, and has ranged from 30 percent to 100 percent over the years, as shown in this chart:*

Start date	End date	Bonus amount
9/11/2001	5/5/2003	30%
5/6/2003	12/31/2004	50%
1/1/2008	9/8/2010	50%
9/9/2010	12/31/2011	100%
1/1/2012	12/31/2014	50%



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## *Senate Finance Committee approves renewal of expired tax provisions*

July 21, 2015

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### *In brief*

The Senate Finance Committee today voted 23 to 3 to approve legislation to extend more than 50 expired tax provisions, including key business provisions such as the Section 41 research credit, bonus depreciation, the exception for Subpart F financing, look-through treatment of payments between related controlled foreign corporations (CFCs), and increased Section 179 “small business” expensing limitations. The bill is similar to the one-year tax extender legislation enacted late last year, but would provide a two-year retroactive extension of certain expired tax provisions from January 1, 2015 through December 31, 2016. The Joint Committee on Taxation staff estimates the bill would cost approximately \$95.2 billion over 10 years, after taking into account \$1.8 billion in revenue offsets.

Finance Committee Chairman Orrin Hatch (R-UT) said it was important to move the tax extenders package forward as quickly as possible. He added that the Committee “should be working to make a number of these tax extender provisions permanent,” but that the debate about permanence should be deferred until a later time.

Earlier this year, the House passed legislation to extend permanently and modify the research credit. The House also has passed legislation this year to extend permanently increased Section 179 expensing limits, certain S corporation provisions, certain charitable giving provisions, and the federal deduction for state and local sales taxes. House Ways and Means Chairman Paul Ryan (R-WI) recently said that he hopes to address other tax extenders in September. For more on recent House action to address expired tax provisions, see our May 21 [Tax Insight](#).

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### *In detail*

The Finance Committee on July 21 approved legislation that retroactively extends for two years -- from January 1, 2015 through December 31, 2016 -- certain business and individual tax provisions that expired at the end of 2014.

Significant expired business provisions that would be extended through the end of

2016 include the research credit, look-through treatment of payments between related controlled foreign corporations (CFCs), and the Subpart F active financing exception. The bill also would renew 50-percent bonus depreciation for qualified property and would continue to allow an election to accelerate AMT credits in lieu of bonus depreciation.

Additional business tax provisions that would be extended through 2016 include the following:

- New markets tax credit, with modifications
- Work opportunity tax credit, with modifications
- 15-year straight-line cost recovery for qualified

leasehold improvements, qualified restaurant buildings and improvements, and qualified retail improvements

- 7-year recovery period for motorsports entertainment complexes
- Increased expensing limitations and treatment of certain real property as Section 179 property
- Special expensing rules for certain film, television, and theatrical productions
- Deduction allowable with respect to income attributable to domestic production activities in Puerto Rico
- Treatment of certain dividends of regulated investment companies (RICs)
- **Treatment of RICs as “qualified investment entities” under the Foreign Investment in Real Property Tax Act (FIRPTA)**
- Special rules applicable to qualified small business stock
- Reduction in S corporation recognition period for built-in gains tax
- Basis adjustment of S corporations making charitable contributions of property
- Increase in limit on cover over of rum excise tax revenues to Puerto Rico and the Virgin Islands
- Economic development credit for American Samoa
- Qualified zone academy bonds
- Enhanced charitable deduction for contributions of food inventory.

Additional energy tax provisions that would be extended through 2016 include the following:

- Beginning-of-construction date for renewable power facilities eligible to claim the electricity production credit or investment credit in lieu of the production credit
- Credit for construction of energy-efficient new homes
- Energy-efficient commercial building deduction, with modifications.

Individual tax provisions that would be extended through 2016 include the following:

- Deduction for state and local sales taxes
- Exclusion for discharge of indebtedness income on principal residences
- Parity in the exclusion for employer-provided mass transit and parking benefits and treatment of bicycle-sharing programs as transportation fringes
- Tax-free distributions from IRAs to certain public charities for individuals age 70-1/2
- Contributions of capital gain real property made for qualified conservation purposes
- Above-the-line deduction for certain teacher classroom expenses.

#### **Amendments considered by the Finance Committee**

Finance Committee members filed over 100 amendments to the original bill. Chairman Hatch incorporated some of these amendments into a

**modified Chairman’s Mark**, released the morning of the Finance Committee’s July 21 markup.

**The revised Chairman’s Mark includes** language modifying the research credit to allow qualifying small businesses to claim the credit against payroll taxes, for taxable years beginning after December 31, 2014. This benefit would be capped at \$250,000 per year and would be available only to companies less than five years old with less than \$5 million in gross receipts. In addition, this amendment would allow certain taxpayers to offset the research credit against liability for the alternative minimum tax (AMT).

**The modified Chairman’s Mark also** added \$1.8 billion in revenue offsets. These offsets would:

- Exclude from gross income certain clean coal power grants
- Modify the alternative fuels credit and excise tax for liquefied natural gas and liquefied petroleum gas
- Modify information reporting requirements for mortgage lenders.

**Note:** The House on July 15 approved a similar mortgage lender information reporting provision as part of Highway Trust Fund legislation.

The Committee adopted by voice vote an amendment offered by Senator Charles Grassley (R-IA) to convert the biodiesel fuels credit from a mixture credit to a production credit, and an amendment offered by Senator Debbie Stabenow (D-MI) to modify tax rules that exclude from gross income the discharge of certain qualified principal residence indebtedness.

Several amendments were offered and then withdrawn by Finance

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## Tax Insights

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Committee members who indicated their intent to pursue action on their proposals at a future date. These included amendments to make permanent bonus depreciation and certain other provisions, and amendments to eliminate or phase out the production tax credit and certain other renewable energy tax incentives.

Click [here](#) for information on the Finance Committee tax extenders legislation.

### **The takeaway**

Approval of tax extenders legislation by the Senate Finance Committee is a significant step toward renewing

expired business and individual tax provisions, although the timing of further action by the full Senate on tax extenders this year remains uncertain. The House and Senate also will need to reconcile their differing approaches to tax extender legislation.

### **Let's talk**

For a deeper discussion of how this might affect your business, please contact:

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#### SOLICITATION

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## *House of Representatives approves permanent extension of bonus depreciation*

July 11, 2014

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### *In brief*

The House today voted 258 to 160 to approve a bill (H.R. 4718) to permanently extend and modify on a retroactive basis Section 168(k) 50-percent bonus depreciation. The Joint Committee on Taxation (JCT) estimates that the proposed permanent bonus depreciation provision would reduce federal revenues by \$262.9 billion over 10 years. H.R. 4718 also would expand the election to accelerate alternative minimum tax (AMT) credits in lieu of bonus depreciation; JCT staff estimates this provision would reduce federal revenues by \$24.5 billion over the same period.

Today's action by the House is part of an ongoing effort by the House Ways and Means Committee to make permanent select expired tax provisions, including the research credit, 'look-through' treatment for controlled foreign corporations, Subpart F exceptions for active financing income, certain S corporation provisions, a group of charitable provisions, and individual tax provisions dealing with education and the child tax credit. For more on recent House actions on permanent tax extender bills, see our June 25 [WNTS Insight](#).

In contrast, the Senate Finance Committee in early April approved an \$85 billion 'tax extenders' bill (S. 2260) that would temporarily extend bonus depreciation and more than 50 other expired or expiring tax provisions on a retroactive basis through the end of 2015. Senate efforts to act on the Finance tax extenders bill have been delayed due to a lack of agreement on which floor amendments could be considered. For more on the Senate Finance Committee bill, see our April 3 [WNTS Insight](#).

The outlook for final legislative action on expired tax provisions remains unclear. At this time, final action on tax extenders is not expected to occur until after the November midterm Congressional elections.

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### *In detail*

#### ***Permanent bonus depreciation***

During House floor debate, Ways and Means Chairman Dave Camp (R-MI) noted the support of various business groups for permanent

extension of bonus depreciation.

"Bonus depreciation has received long-standing bipartisan support and has been renewed on a short-term basis for nine out of the last 12 years," Chairman

Camp noted. "After so many years of this policy being in place, it is time for us to agree that we should make it permanent so businesses can do what they do best – invest in the economy and hire new workers."

H.R. 4718 makes permanent the 50-percent additional first-year depreciation deduction for qualified property. The bill also expands the definition of qualified property to include qualified retail improvement property.

Under H.R. 4718, the \$8,000 increase in the limitation on the depreciation deductions allowed with respect to certain passenger automobiles is indexed for automobile price inflation. The increase does not apply to a taxpayer who elects to accelerate AMT credits for a taxable year.

H.R. 4718 also makes permanent the special rule for the allocation of bonus depreciation to a long-term contract.

H.R. 4718 makes permanent and modifies the election to increase the AMT credit limitation in lieu of bonus depreciation. Under the bill, the bonus depreciation amount for a taxable year is limited to a lesser of (1) 50 percent of the minimum tax credit for the first taxable year ending after December 31, 2013 (determined before the application of any tax liability limitation), or (2) the minimum tax credit for the taxable year allocable to the adjusted net minimum tax imposed for taxable years ending before January 1, 2014 (determined before the application of any tax liability limitation and determined on a first-in, first-out basis).

H.R. 4718 provides that in the case of a partnership having a single corporate partner owning (directly or indirectly) more than 50-percent capital and profits interests in the partnership, each partner takes into

account its distributive share of partnership depreciation in determining its bonus depreciation amount.

In addition, H.R. 4718 includes special rules for a taxpayer to claim bonus depreciation on trees or vines bearing fruits and nuts.

### ***Effect on the economy***

The Ways and Means Committee report for H.R. 4718 includes a Congressional Budget Office (CBO) **macroeconomic analysis of the bill's** effect on the US economy. CBO staff projects the bill will result in a small increase in business capital stock and in US gross domestic product (GDP), relative to present law.

**According to CBO's analysis**, the 50-percent expensing of certain investment expenditures provided for in this bill will increase the after-tax rate of return for investment in qualified expenditures, providing an incentive for increased investment in qualified capital. CBO staff also indicates that the bill provides an incentive for some substitution away from housing investment toward qualified investment – mostly business equipment.

Click [here](#) for a copy of H.R. 4718, and click [here](#) for copy of the Ways and Means Committee report, which also includes technical explanations and revenue estimates provided by JCT staff.

### ***White House veto threat***

A July 10 White House statement said **that the "Administration strongly opposes House passage of H.R. 4718,"** and indicated that President Obama

would veto the bill if it were presented to him by Congress. The statement notes that bonus depreciation was **enacted previously to "provide short-term stimulus to the economy."** The statement also indicates that the Administration opposes H.R. 4718 **because it** "includes no offsets and would add \$287 billion to the deficit over the next 10 years, wiping out more than one third of the deficit reduction achieved by the American **Taxpayer Relief Act of 2013."**

### ***The takeaway***

Congress must reconcile differences between the House and Senate before any final legislation can be sent to the White House for action by President Obama.

It remains unclear whether Congress will include any permanent tax law changes in legislation addressing expired tax provisions. At the same time, House passage of a permanent bonus depreciation bill and Senate Finance Committee approval of a two-year temporary bonus depreciation extension increases the likelihood that the provision will be extended at least temporarily as part of any final legislation addressing expired tax provisions.

Final action on tax extenders currently is not expected to occur until after the November midterm Congressional elections.

## ***Let's talk***

For a deeper discussion of how this might affect your business, please contact:

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#### SOLICITATION

This content is for general information purposes only, and should not be used as a substitute for consultation with professional advisors.

CASE: UG 288  
WITNESS: MARIANNE GARDNER

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 105**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

	A	B	N	O	P	Q	R	S
1								
2		Avista Utilities						
3		Oregon SIT	Provided by Company			OPUC Staff Projections		
4			2015	2016		2015	2016	
5			Estimate	Estimate	Notes	Staff Estimate	Staff Estimate	Staff notes
6		Corp Pre-Tax Income (2015/2016 per forecast)	183,159,000	204,518,000		183,159,000	204,518,000	
7		Less: Dividends				(50,999)	(50,999)	Included dividends since Avista regularly pays dividends
8		Less: Forecasted GRC Revenue	0	(52,934,000)	(1)		(52,934,000)	Avista 2016 forecast
9		Adjusted Corp Pre-Tax Income	183,159,000	151,584,000		183,108,001	151,533,001	
10								
11		Schedule M's						
12		Non-Plant	35,198,171	35,198,171	(2)	35,198,171	35,198,171	2014 actual
13		Plant - Tax Deprec over book	(41,652,584)	(41,652,584)	(2)	(41,652,584)	(41,652,584)	2014 actual
14		Plant- Bonus Depreciation			(3)	(90,000,000)	(90,000,000)	Staff assumes bonus depreciation will be extended for 2015 & 2016. Used Company 2014 actual to estimate.
15		Plant - Repairs for prior years			(4)			n/a
16		Plant - Repairs for current year	(28,593,225)	(28,593,225)	(4)	(28,593,225)	(28,593,225)	2014 actual
17		Total Schedule M's	(35,047,638)	(35,047,638)		(125,047,638)	(125,047,638)	
18								
19		Corp. Taxable Income	148,111,362	116,536,362		58,060,362	26,485,362	
20		Add: State Excise Tax			missing from			
21		Add: Other			accrual			
22		Revised Corp. Taxable Income	148,111,362	116,536,362		58,060,362	26,485,362	
23		Oregon Apportionment Factor	10.780%	10.780%		10.151%	10.151%	Average 2011-2013
24								
25		Oregon Taxable Income	15,966,405	12,562,620		5,893,959	2,688,644	
26		OR Apportionment of NOL C/F						
27			15,966,405	12,562,620		5,893,959	2,688,644	
28								
29								
30		Oregon SIT Rate	7.600%	7.600%		7.430%	7.228%	Staff calculated SIT rate for revenue sensitive
31								
32		Oregon SIT	1,213,447	954,759		437,941	194,337	OR tax calc = (Multiply taxable income greater than \$1M by X 7.6%) plus \$66,000
33		Less: Oregon BEITs (See attached spreadsheet)	(1,099,868)	(11,558)		(437,941)	(194,337)	
34		Net Oregon Taxes	113,579	943,201		0	0	
35								
36		Oregon Natural Gas Allocation Factor	75%	75%		75%	75%	
37								
38		Natural Gas SIT	85,184	707,401		0	0	
39								
40								
41		Less: Test Period SIT		(416,386)				
42								
43		Adjustment		1,123,787			(1,123,787)	Staff proposed adjustment to Avista's Restated AMA 2016 Test Year
44								
45			2015	2016		2015	2016	
46		Staff DR 214 a	Estimate	Estimate	Total	Staff Estimate	Staff Estimate	Total
47		Results of Operations Reports (use data from filed ROO for 2004-2014, and filed GRC for 2016)						
48		Oregon SIT from ROO-Column A						
49		Oregon Deferred SIT included in Accumulated Deferred Income Tax-Column A						
50								
51		General ledger (year end results)						
52		Oregon SIT apportion (Oregon jurisdiction - situs & allocated)						
53		Oregon accumulated deferred income tax (Oregon jurisdiction - situs and allocated)						
54								
55		Tax Credit Schedule						
56								
57		Oregon tax credit beginning balance	831,136	(1)		831,136	661,927	
58		Oregon tax credits generated	250,000	-	2,897,161	250,000	-	
59		Oregon tax credits generated-used to offset capital project			492,049			
60		Oregon tax credits purchased	18,731	11,558	1,195,057	18,731	11,558	
61		Oregon tax credits used	(1,099,868)	(11,558)	(4,584,267)	(437,941)	(194,337)	
62		Oregon tax credits expired						
63		Oregon tax credits ending balance	(1)	(1)	(0)	661,927	479,147	
64								
65								
66								
67								
68		Notes:						
69		(1) The forecasted GRC revenue is removed from the accrual, since the SIT for revenue from this GRC will be calculated with the SIT rate in the conversion						
70		(2) The Schedule M adjustments will be materially the same in 2015 and 2016						
71		(3) Bonus depreciation is not forecasted, since it has not been approved by IRS.						
72		(4) The repairs adjustment in 2014 was made up of: a) a one-time adjustment for 2010 - 2013, and						
73		b) the 2014 adjustment that will be available in 2015 and future years.						



CASE: UG 288  
WITNESS: Matt Muldoon

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 200**

**Opening Testimony**

**October 16, 2015**

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Matt Muldoon. I am a Senior Economist for the Public Utility  
3 Commission of Oregon (Commission or OPUC). My business address is:  
4 201 High Street, Suite 100, Salem, OR 97301-3612.

5 **Q. Please describe your educational background and work experience.**

6 A. My Witness Qualification Statement can be found in Exhibit Staff/201.

7 **Q. What is the purpose of your testimony?**

8 A. I am responsible for three Cost of Capital (CoC) issues in this docket:

- 9 1. Capital Structure,  
10 2. Cost of Common Equity, also known as Return on Equity (ROE), and  
11 3. Cost of Long-Term (LT) Debt.

12 **Q. What is your summary recommendation?**

13 A. I recommend a 49.86 percent equity capital structure, Avista Corporation's  
14 (AVA, Avista or Company) ROE of 9.11 percent, and a 5.515 percent Cost of  
15 LT Debt.

16 **Q. Did you prepare tables showing current, Avista-proposed and Staff  
17 proposed overall CoC?**

18 A. Yes, the following three tables provide that information.  
19

1

**Table 1**

<b>AVA Current OPUC Authorized (UG 284 Order No. 15-109)</b>			<b>AVA</b>
<b>Component</b>	<b>Percent of Total</b>	<b>Stipulated or Implied Cost</b>	<b>Weighted Average</b>
Long Term Debt	49.00%	5.452%	2.671%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	51.00%	9.50%	4.845%
	100.00%		<b>7.516%</b>

2

3

**Table 2**

<b>AVA Requested – UG 288</b>		<b>AVA Direct Testimony</b>		
<b>Component</b>	<b>Percent of Total</b>	<b>Cost</b>	<b>Weighted Average</b>	<b>ROR vs. Current</b>
Long Term Debt	<b>50.00%</b>	<b>5.53%</b>	2.765%	<b>0.199%</b>
Preferred Stock	0.00%		0.000%	
Common Stock	<b>50.00%</b>	<b>9.90%</b>	4.950%	
	100.00%		<b>7.715%</b>	

4

5

**Table 3**

<b>Staff Proposed – UG 288</b>		<b>Opening Testimony</b>		
<b>Component</b>	<b>Percent of Total</b>	<b>Cost</b>	<b>Weighted Average</b>	<b>ROR vs. Current</b>
Long Term Debt	<b>50.14%</b>	<b>5.515%</b>	2.765%	<b>-0.209%</b>
Preferred Stock	0.00%		0.000%	
Common Stock	<b>49.86%</b>	<b>9.110%</b>	4.542%	
	100.00%		<b>7.307%</b>	

6

7

8

**ISSUE 1 – CAPITAL STRUCTURE**

9

**Q. What is the basis for your recommendation for 49.86 percent equity and 50.14 percent LT Debt capital structure?**

10

11

**A. I have three reasons for supporting my recommended capital structure:**

- 1 1. This is my best estimate of capital structure at end of the 2016 test year  
2 inclusive of the results of two successive stock buyback programs.
- 3 2. This capital structure is within the range that optimizes the Company's  
4 financial performance balanced against the risk of leverage.
- 5 3. This capital structure excludes elements not historically considered LT  
6 Debt by the Commission. My recommended LT Debt portion of the  
7 capital structure excludes short term debt with maturities less than one  
8 year and imputed debt from the Company's contracts, consistent with  
9 ORS 757.415(3).<sup>1</sup>

## 10 **ISSUE 2 – COST OF COMMON EQUITY (ROE)**

11 **Q. Avista is requesting an ROE of 9.9 percent. This recommendation is**  
12 **based in part on the Company's ROE witness Mr. Adrien McKenzie's**  
13 **results of analysis estimating a 9.6 to 10.9 percent ROE range.<sup>2</sup> What**  
14 **are the primary reasons for the difference between the Company's**  
15 **requested 9.9 percent ROE and your recommended 9.11 percent ROE?**

16 A. The primary reasons for the differences between the Company's request and  
17 my recommended ROE are because the Company:

- 18 ☛ Relies heavily on models such as constant growth — single stage —  
19 Discounted Cash Flow (DCF) model of Professor Myron J. Gordon and  
20 Empirical Capital Asset Pricing Model (Empirical CAPM). These models

---

<sup>1</sup> Staff notes that Washington Utility and Transportation Commission (WUTC) proceedings, Avista investor presentations, and the Company's quarterly 10-Q and annual 10-K reporting to the U.S. Security and Exchange Commission (SEC) concerning capital structures and debt listings do include short-term and imputed debt. When such elements are backed out, data therein matches Staff findings herein.

<sup>2</sup> See Avista/300, McKenzie/5.

- 1 have merited no weight before the Commisison in recent general rate  
2 cases.
- 3 ☼ Fails to anticipate lower than historical long-term gross domestic product  
4 (GDP) growth rates.
  - 5 ☼ Relies in part on electric and non-utility stocks rather than gas peers.
  - 6 ☼ Fails to anticipate certain mergers and acquisitions in its gas peer group.
  - 7 ☼ Removes the low end of modeling estimates while retaining upper  
8 estimate outliers.<sup>3</sup>
  - 9 ☼ Relies on high estimates of risk premiums distorting Capital Asset Pricing  
10 Model (CAPM) modeling.
  - 11 ☼ Makes outboard size adjustments normally addressed within selection of  
12 peer groups to shift modeling results up by 80 basis points (bps).<sup>4</sup>
  - 13 ☼ Relies on Dr. Roger Morin's "Empirical CAPM" or (ECAPM). Were no  
14 unusual adjustments used in the basic CAPM model, CAPM returns a  
15 lower required ROE than Staff recommends. ECAPM (a method not  
16 commonly used by finance academics and professionals) presumes that  
17 the security market line could be pivoted at a designated point until a  
18 reasonable result is obtained. The argument is that a properly pivoted  
19 CAPM model will correct for CAPM's flaws. Essentially this is a method  
20 that augments CAPM ROE by a minimum of 50 bps.

21 **Q. How is your testimony organized?**

22 A. My testimony is organized as follows:

23	Issue 1 – Capital Structure	2
24	Issue 2 – Cost of Common Equity (ROE)	3
25	What is New in this Rate Case?	6
26	Overview of ROE Positions	15
27	Peer Screen	20
28	Sensitivity Analysis	23
29	Growth Rates	24
30	Alternative Models Examined	31
31	Single-Stage Gordon Growth DCF Modeling	32
32	Risk Premium Modeling	34
33	Rebuttal of Avista's CAPM Modeling	37
34	Avista's Comparative Riskiness	40

<sup>3</sup> As an example, please see Avista/300, McKenzie/39 at lines 6-7.

<sup>4</sup> See Avista/300, McKenzie/54-55.

1	Adjustment of Modeling Results	42
2	Hamada Equation	43
3	Informed Staff Analysis	44
4	Updates to Avista Models	48
5	Issue 3 – Cost of LT Debt	48
6	Conclusion	50

7 **Q. Did you prepare exhibits in support of your opening testimony?**

8 A. Yes. I prepared the following exhibits:

9	Staff/202 .....	Staff Peer Screening
10	Staff/203 .....	Staff Three Stage DCF Modeling
11	Staff/204 ....	Treasury Inflation Protected Securities (TIPS) Analysis
12	Staff/205	GDP Analysis with U.S. Bureau of Economic Analysis (BEA) Data
13	Staff/206 .....	Staff CAPM Modeling
14	Staff/207	<b>CONFIDENTIAL</b> Cost of LT Debt Table & Maturity Profile
15	Staff/208 ..	Southern Co.'s Proposed Acquisition of AGL Resources
16	Staff/209 .....	Value Line (VL) Gas and Water Utility Profiles
17	Staff/210 .....	Security Market Trends
18	Staff/211 .....	Frequency of Gas Utility Rate Case Filings
19	Staff/212 .....	SNL Overview of Energy Utility Rate Case ROEs
20	Staff/213 .....	Avista Investor Presentation for 2015 Q2.

21 **Q. Does your recommended ROE meet appropriate standards?**

22 A. Yes. The 9.11 percent ROE I recommend meets the *Hope* and *Bluefield*  
23 standards, as well as the requirements of Oregon Revised Statute  
24 (ORS) 756.040. My recommendations are consistent with establishing “fair  
25 and reasonable rates” that are both “commensurate with the return on  
26 investments in other enterprises having corresponding risks” and “sufficient to

1 ensure confidence in the financial integrity of the utility, allowing the utility to  
2 maintain its credit and attract capital.”<sup>5</sup>

3 **Q. Are these the same standards discussed in Avista’s testimony?**

4 A. Yes. Staff and Avista apply the same legal standards. However, Avista and  
5 Staff disagree on what ROE is commensurate with that of other utilities and  
6 other investment opportunities with risk exposure similar to Avista’s. When  
7 investors’ expected rate of return is measured using a reasonable expectation  
8 of long-term growth, and when risk is measured using an appropriate peer  
9 group of utilities, the resulting ROE is within the range recommended by Staff.

10 **WHAT IS NEW IN THIS RATE CASE**

11 **Q. What is new in this third general rate case that Avista has filed in as**  
12 **many years?**

13 A. I will discuss three considerations that newly-arise in this rate case:

14 First, this is the Company’s third consecutive annual rate case. Only one  
15 other publicly traded U.S. gas utility has filed rate cases so frequently in the  
16 last decade, and none of the gas utilities in Staff’s peer group have filed this  
17 often. Such frequent filing decreases Avista’s risk of and time to cost  
18 recovery as compared to peer gas utilities. Please see Staff/211, Muldoon/1  
19 for a full breakout of U.S. gas utility rate case filing frequency.

20 Second, projections of long-term growth rates by a broad consensus of  
21 U.S. Government, academic, business and analytic referent sources for U.S.

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<sup>5</sup> See ORS 756.040(1) (a) and (b).

1 gross domestic product (GDP) have been lowered since this past spring. The  
2 U.S. Federal Reserve's last estimate of September 18, 2015, projects the  
3 U.S. economy will grow yet slower between 1.8 percent and 2.2 percent in the  
4 long-run. Related to this is turbulence in the global markets. China's demand  
5 for raw materials plummeted this past summer, China's stock market in  
6 Shanghai dropped sharply, and China suddenly devalued its currency against  
7 the dollar. China's GDP growth was slowing by an uncertain but dramatic  
8 amount. Commodity prices dropped sharply. As many industrial  
9 commodities from copper to iron ore are priced in U.S. dollars, currencies of  
10 many global commodity exporting countries from Brazil to New Zealand  
11 dropped 20 to 40 percent against the U.S. dollar. Concerns about global  
12 markets and growth were sufficient to disrupt U.S. Federal Reserve (FED)  
13 monetary policy.

14 The third, and last, consideration is that merger and acquisition activity  
15 has reduced the pool of potential peer gas utilities available for this rate  
16 case's cost of capital modeling.

17 **Q. As to your first consideration, frequency of rate case filings, do**  
18 **Staff's peer utilities in its ROE modeling file rate cases less**  
19 **frequently than does Avista?**

20 A. In the last decade, only one of the gas utilities (in the pool from which Staff  
21 selected peers) filed three consecutive annual general rate cases. See  
22 Exhibit Staff/211. That gas utility did not pass Staff's peer screening.



1 **Q. Please discuss your second consideration: predicted slower long-**  
2 **term growth rates and turbulence in the global markets.**

3 A. John Lonski, Chief Economist of Moody's Capital Markets Research, Inc., on  
4 September 23, 2015, in "Credit Markets Review and Outlook" said that, "The  
5 world economy is in its worst shape since the Great Recession.

6 **Q. According to the Wall Street Journal print edition of September 8,**  
7 **2015, the U.S. has significantly less trade with China than much of the**  
8 **rest of the world, as shown in Figure 1 below. What indicates there is**  
9 **any sizable risk of contagion from stalled or contracting economies**  
10 **abroad?**

11 **Figure 1**

### Wild Ride

**Analysts say China's growth is slowing more than Beijing admits...**

Annual GDP change, inflation-adjusted



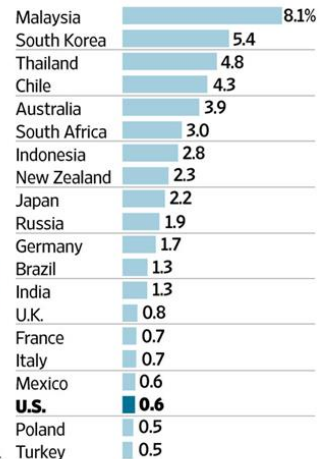
**...as uncertainty leads to wild swings in the market...**

Dow Jones Industrial Average, daily closes



**...but the U.S. economy is less affected.**

Exports to China as a share of GDP\*



\*In terms of value added in the exporting country to products that will be sold in China.  
Sources: Lombard Street Research, China's National Bureau of Statistics (GDP); WSJ Market Data Group (DJIA); OECD, Institute of International Finance, Haver (exports)

12  
13 A. Concerns rise beyond increased volatility in the U.S. Stock market in August  
14 to impacts on U.S. exports, U.S. Dollar exchange rates against other

1 currencies and low inflation rates. FED Reserve Chair Yellen explained that  
2 the long-signaled increase in interest rates did not happen in significant part  
3 because of concerns surrounding GDP growth in China and impacts on the  
4 U.S. as well as global economies. With this explanation, it was clear that the  
5 U.S. economy and internal monetary policy were not entirely insulated from  
6 declining global economic conditions.

7 **Q. How do the trends set forth above help or harm U.S. regulated**  
8 **utilities and Avista gas distribution operations in particular?**

9 A. Interest rates staying low longer increases demand for U.S. dividend paying  
10 utility stocks. Demand for utility bonds remains strong, even in private  
11 placement markets. U.S. corporations have shifted cash reserves into highly  
12 rated U.S. corporate bonds in lieu of commercial paper and U.S. Treasury  
13 Securities (UST), seeking improved yields.<sup>6</sup> And the U.S. Investor Owned  
14 Utility (IOU) combination of domestic U.S. sales and a strong dollar minimizes  
15 exposure to global risks while affording access to low cost capital and  
16 construction materials.

17 **Q. How do the trends discussed above affect Avista's CoC?**

18 A. Continued investor flight to safety, and reduction in risk and regulatory lag,  
19 merit a lower point ROE from within a range of reasonable ROEs. For  
20 example: the Maryland Commission recently found that a company that

---

<sup>6</sup> See the September 25, 2015, WSJ Article, "Big Buyers of Corporate Bonds: Other Corporations" by Vipal Monga.

1 engages in consecutive annual filings merited a lower than top end of range  
2 ROE due to the reduced risk.<sup>7</sup>

3 Global uncertainty prolongs a long period of investor flight to the quality  
4 and safety of U.S. regulated “investor owned utilities” (IOU) securities  
5 preserving continued utility access to capital at historically attractive costs.

6 **Q. Please continue with your discussion of lower long-term growth**  
7 **predictions.**

8 A. A broad, consensus of federal government agencies, economists and referent  
9 experts now project substantially lower long-term growth in U.S. GDP. Paired  
10 with another broad consensus that growth in U.S. gas sales will be less than  
11 the rate of GDP growth, this trend has serious implications not yet considered  
12 in Avista’s last rate case. This trend of reduced growth projections from the  
13 prior year is summarized in Figure 2.

14 **Figure 2**

<b>Growth Trends</b>	<b>Now</b>	<b>Prior</b>	<b>Difference</b>
<b>Tips Inflation Forecast</b>	2.12%	2.35%	<b>-0.23%</b>
<b>EIA</b>	4.57%	4.89%	<b>-0.32%</b>
<b>OMB</b>	4.30%	4.61%	<b>-0.31%</b>
<b>CBO</b>	4.20%	4.55%	<b>-0.35%</b>
<b>Composite</b>	4.71%	5.02%	<b>-0.31%</b>
<b>Historical 1980 – 2014</b>	5.05%	5.35%	<b>-0.30%</b>
<b>Indiana / Top 10 Blue Chip</b>	5.08%	5.78%	<b>-0.70%</b>

15 **Even Most Optimistic 1 in 10 Referent Experts  
No Longer Project Upbeat LT Growth**

<sup>7</sup> Public Service Commission of Maryland, Order No. 85374, Case No. 9299, at 78 (February 22, 2013).

1 **Q. What is the primary effect of projected lower long-term growth in your**  
2 **modeling?**

3 A. All else held constant in Staff's current modeling, the reduction in projected  
4 long-term GDP growth translates into a 31 basis point downward shift in the  
5 range of reasonable ROEs for Avista.

6 **Q. Have all these experts maintained their spring projections?**

7 A. Growth projects have variously stayed at the spring levels or declined further  
8 since then. Staff's modeling may not fully capture the downward trending.

9 **Q. Could you recap some of the underlying causes for this decline in**  
10 **long-term GDP growth projections?**

11 A. Ruchir Sharma, the head of emerging markets and global macro at Morgan  
12 Stanley Investment Management, suggests that three drivers may explain  
13 much of the decline in projected GDP growth:<sup>8</sup>

- 14 ☼ Lower than historical birth rates and disrupted immigration policies now
- 15 project to fewer working-age Americans 20 years from now;
- 16 ☼ A decline in the rate of growth of productivity or output per worker is also
- 17 a concerning factor; and
- 18 ☼ The United States' (U.S.) population is both aging and living longer.
- 19 Retiring persons represent a greater than historic burden on health care,
- 20 pensions and their working-age children.

21 **Q. What are some of the implications of current global economic**  
22 **conditions?**

23 A. The flight to safe securities like utility stocks and utility bonds is driven in part  
24 by the following factors:

---

<sup>8</sup> Please see "How the Birth Dearth Saps Economic Growth" by Ruchir Sharma in the print edition of the WSJ for September, 25, 2015.

- 1           ✿ Lower expected UST yields increase the attractiveness of U.S. utility  
2           security issues;<sup>9</sup>
- 3           ✿ Decreased global demand for commodities has stressed emerging  
4           market economies and currencies, thereby increasing demand for select  
5           safer U.S. issues.<sup>10</sup> The majority of securities were issued in the U.S. in  
6           the past year. In this time, according to the Wall Street Journal (WSJ),  
7           U.S. banks have captured half of all global banking revenue.<sup>11</sup>
- 8           ✿ Companies and investors lack a clear signal of where they are in the  
9           business cycle, impairing investment by Companies in durable goods,  
10          injecting external considerations into FED policy, and prompting investor  
11          caution.<sup>12</sup>
- 12          ✿ FED Chair Yellen’s clear and detailed explanations of FED actions and  
13          expectations depicted a downward adjustment to June’s long-term  
14          outlook. Chair Yellen also shared that despite the intention to raise rates  
15          several times in the next 18 months, U.S. monetary policy would be  
16          “highly accommodative for quite some time.”<sup>13</sup>
- 17          ✿ China’s economic challenges and government responses unsettled  
18          global markets and investors alike.<sup>14</sup>

19          The general conclusion is that recent events and the FED delay in raising  
20          interest rates are positive for U.S. regulated utilities.<sup>15</sup> See Staff/211.

21          **Q. How do you recommend the Commission address this economic**  
22          **decline?**

---

<sup>9</sup> See the September 25, 2015, WSJ article by Ming Zeng, “Treasury Yields Fall as Inflation Fears Diminish”.

<sup>10</sup> See the WSJ articles: “Brazil’s Real Hits Two-Decade Low” by Carolyn Cui and Paulo Trevisani published in the print edition on September 23, 2015; and “Emerging Markets Hit Hard as Global Rout Continues” by Andrey Ostroukh and Patrick McGroarty on August 25, 2015.

<sup>11</sup> See “U.S. Banks Rack Up Fees” in the WSJ MoneyBeat Column of September 28, 2015.

<sup>12</sup> See “How the World is Messing with the FED” by Justin Lahart in the September 26, 2015 WSJ; “Slow Global Growth Shows Policy Limits” by Ian Talley in the September 18, 2015, WSJ; “Utilities Regain Favor, Broad Markets Withdraw as FED Postpones Rate Move” by Brian Collins published jointly on September 21, 2015 by Regulatory Research Associates (RRA) and SNL Financial LC (SNL);

<sup>13</sup> See “Growth, Inflation Predictions Scaled Back” Associated Press, in the Oregonian on September 18, 2015.

<sup>14</sup> See “China Central Bank Cuts Interest Rates” by Lingling Wei in the August 215, 2015 WSJ;

<sup>15</sup> See “Wall Street Says FED’s Rate Decision is Good for Utilities” by Darren Sweeney of SNL Financial LC on September 18, 2015.

1 A. Staff's analysis shows multiple growth rate levels. Staff recommends a 9.11  
2 ROE that is in the midpoint of a reasonable range of ROEs, allowing for  
3 further corroboration of a substantial downshift in American growth  
4 expectations. This is a conservative ROE given that the available evidence at  
5 this time supports a slower long-term growth rate. Moreover, Staff's  
6 assessment does not rely on lower modeling results associated with many of  
7 the Company's suggested peers, and instead finds that Staff's screened peer  
8 group best fits investor expectations. See Exhibit Staff/203.

9 **Q. Are current economic conditions a pinnacle moment for energy**  
10 **utilities?**

11 A. Yes, there are three good reasons to believe financial conditions are near  
12 optimal now for U.S. utilities.

13 **Q. What is the first of these reasons?**

14 A. The first factor is insulation from global uncertainty. For example, Moody's  
15 points out that nearly all of regulated continental U.S. utility revenues and  
16 operating expenses are denominated in U.S. dollars. This provides a natural  
17 hedge against sustained U.S. dollar appreciation.

18 **Q. What is the second of these reasons?**

19 A. Continued low interest rates facilitate strategic investment to meet long-run  
20 utility needs, while making predictable dividend-paying equities more  
21 attractive to investors than global cyclical firms.

22 **Q. And what is the third element?**

1 A. Investor-stressing economic news continues to extend the investor “flight to  
2 quality/safety” freezing current conditions just right for regulated investor-  
3 owned utilities.<sup>16</sup>

4 **Q. Are you suggesting the Commission should consider whether current**  
5 **economic conditions make jurisdictional utilities less risky than other**  
6 **potential investments?**

7 A. Yes.

8 **Q. Are you also suggesting that utilities that file multiple consecutive**  
9 **annual general rate cases and receive expedited cost recovery face**  
10 **even less risk?**

11 A. Yes.

12 **Q. Please discuss your third new consideration: the effect of mergers**  
13 **and acquisitions on your peer group.**

14 A. There has been substantial utility merger and acquisition activity in the past  
15 year. Of particular note is Southern Company’s (Southern Co. or Southern)  
16 intent to purchase AGL Resources (AGL) for approximately eight billion  
17 dollars. Exhibit Staff/208 explains how the cash flows associated with AGL  
18 present an opportunity for Southern Co. to fund risky endeavors like new  
19 nuclear generating plants with internal funds. Staff’s sensitivity analysis ran

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<sup>16</sup> See “Economists’ Forecast: Here We Grow Again” by Kathleen Madigan, and “Why the Economy and the FED Keep Getting Knocked Off Track” by Jon Hilsenrath in the print edition of the WSJ for May 15, 2015. Articles like the above and “Workers’ “Productivity Declines Again” by Jeffrey Sparshott in the May 7, 2015, WSJ periodically deflate investor expectations for a return to pre-2008 economic conditions.

1 models with and without AGL. AGL is no longer a viable peer utility in the  
2 Company's modeling.

3 **Q. Please summarize your testimony on these issues.**

4 A. I discussed the following three new considerations since the last Avista  
5 general rate case: A) Frequent rate case filings have made Avista less risky  
6 than other U.S. gas utilities; B) U.S. long-term GDP growth projections have  
7 universally fallen due to fears regarding global financial stresses and lower  
8 U.S. productivity from an aging workforce; and C) Southern Co.'s purchase of  
9 AGL merits removal of AGL from Avista's modeling peers. Enough has  
10 changed since Avista's last general rate case, that the Commission may want  
11 to reduce Avista's point ROE substantially, depending in part on the  
12 Commission's confidence in current consensus economic forecasts of  
13 declining long-term GDP growth.

#### 14 **OVERVIEW OF ROE POSITIONS**

15 **Q. Describe the analysis underlying Staff's ROE recommendation.**

16 A. I continue to rely primarily on two different multistage "discounted cash flow"  
17 (DCF) models,<sup>17</sup> applied using a cohort group of peer utilities, to estimate the  
18 expected return on common equity required by Avista investors. I compare  
19 the results of my DCF analysis with national historical gas utilities' authorized  
20 ROE values as a check on the reasonableness of my ROE estimates. I also  
21 input parameters from some of the models used by Avista witness McKenzie

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<sup>17</sup> See, the Commission's discussion of multistage versus single-stage DCF models in Order No. 01-777 at page 27.



1 into Staff's models and contrast the analytic outputs with Avista witness  
2 McKenzie's results and with results from my two DCF models using Staff's  
3 inputs.

4 **Q. What is a DCF model?**

5 A. A DCF model estimates the cost of equity by determining the present value of  
6 the future cash flows that investors expect to receive from holding common  
7 stock. The current stock price is assumed to reflect investors' expectations  
8 for the stock, including future dividends and price appreciation.

9 The ROE under the DCF model is the rate that equates the current stock  
10 price and expected cash flows to investors.<sup>18</sup> A DCF model has three primary  
11 components: a current stock price, an expected dividend, and an expected  
12 growth rate in dividends.<sup>19</sup>

13 **Q. Describe the two DCF models that you used.**

14 A. My first model is a conventional three-stage Discounted Dividend Model,  
15 which Staff denotes as a "30-year Three-stage Discounted Dividend Model  
16 with Terminal Valuation based on Growing Perpetuity" (referred to as "Model  
17 X"). My second model is the "30-year Three-stage Discounted Dividend  
18 Model with Terminal Valuation Based on P/E Ratio" (referred to as "Model  
19 Y").

20 Both models require, for each proxy company analyzed by Staff, a  
21 "current" market price per share of common stock, estimates of dividends per

---

<sup>18</sup> Order No. 01-777 at 26.

<sup>19</sup> Order No. 07-015 at 32.

1 share to be received in the years 2015 through 2019, annual rates of dividend  
2 growth from 2020 through 2024, and a long-term growth rate applicable to  
3 dividends beyond 2024.

4 The three stages of the models are: 1) 2015-2019, where I use Value  
5 Line's (VL) forecasts of dividends per share for each company; 2) 2019-2024,  
6 where the rate of dividend growth converges from the average rate over the  
7 2015-2019 period to the growth rate in of the third stage; and 3) 2025-2044.  
8 This is the third "long-term" stage, for which growth rates are discussed.

9 Model X includes a terminal value calculation, in which I assume  
10 dividends per share grow indefinitely at the rate of growth in Stage 3  
11 ("growing perpetuity"). In contrast, Model Y terminates in a sale of stock  
12 where the price is determined by my escalated price/earnings (P/E) ratio.

13 **Q. Why did you use five years for Stages One and Two, and about 20 years**  
14 **for Stage Three?**

15 A. I presume a 30-year horizon is relevant for investors. This is consistent with  
16 long-standing Staff practices including those of former Staff member Steve  
17 Storm in the NW Natural general rate case of Docket No. UG 221, which the  
18 Commission adopted in Order No. 12-408. This time frame allows for  
19 investor consideration of 30-year U.S. Treasury Long Bond and other  
20 alternate investment opportunities. I use five years for Stage One as that is  
21 the timeframe for which Value Line estimates of future dividends are  
22 available. I use five years for Stage Two as that seems a reasonable length  
23 of time for individual companies' dividend growth rates that are materially

1 different from the growth rate used in Stage Three (and common to all  
2 companies) to converge to a LT dividend growth rate more representative of  
3 all gas utilities. I discuss the mechanics of this convergence below. I use 15  
4 to 20 years for Stage Three, corresponding to forward projections from  
5 federal sources, and calculate a terminal valuation for the sale of the  
6 Company's stock in 2043.

7 **Q. How do you address dividend timing?**

8 A. Each model uses two sets of calculations that differ in the assumed timing of  
9 dividend receipt. One set of calculations is based on the standard  
10 assumption that the investor receives dividends at the end of each period.

11 The second set of calculations assumes the investor receives dividends  
12 at the beginning of each period. Each model averages the unadjusted ROE  
13 values<sup>20</sup> produced with each set of calculations for each peer utility. This  
14 approach more closely replicates the "real world" quarterly receipt of  
15 dividends by investors; i.e., it takes into account the time value of money.

16 **Q. What accounts for differences in peer capital structures?**

17 A. Each model employs the Hamada equation<sup>21</sup> to calculate an adjustment for  
18 differences in capital structure between each peer utility and the Avista-  
19 proposed and Staff-assumed capital structure for Avista.<sup>22</sup> When few peer

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<sup>20</sup> The technical term for each of these estimates is the "internal rate of return," or IRR.

<sup>21</sup> Dr. Robert Hamada's Equation as used in Staff/202, Muldoon/4 separates the financial risk of a levered firm, represented by its mix of common stock, preferred stock, and debt, from its fundamental business risk. Staff corrects its ROE modeling for divergent amounts of debt, also referred to as leverage, between the Company and its peers.

<sup>22</sup> Staff describes this adjustment in recent cost of capital testimony. See, as an example, Staff's description in Docket No. UE 233 Exhibit Staff/800, Storm/54-57.

1 utilities are available, the Hamada equation ensures Staff's analysis  
2 addresses differences in peer utility capital structures.

3 **Q. What price do you use for each peer utility's stock?**

4 A. I use the average of closing prices for each utility from the first trading day in  
5 April, May, and June 2015 to represent a reasonable snapshot of 2015, Q2.

6 **Q. Did you review the impact of using prices from any other day of these  
7 months?**

8 A. No.

9 **Q. How do Staff's two DCF models differ?**

10 A. Model X uses the calculation of a growing perpetuity as part of the terminal  
11 valuation in 2043. This may be the most common approach used in  
12 multistage DCF models.

13 Model Y uses the current price-earnings (P/E) ratio<sup>23</sup> multiplied by the  
14 estimated "earnings per share" (EPS) in 2043, which establishes the stock's  
15 "selling price" in 2043 for terminal valuation. I estimate the 2043 EPS  
16 analogously with methods used to estimate the 2043 dividend in both models;  
17 i.e., based on VL estimates to which multiple growth rates are sequentially  
18 applied.

19 **Q. What is the purpose of Model Y?**

20 A. I followed Staff's practice in recent rate cases of including this model as a  
21 method by which to incorporate the fact that most companies have estimates

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<sup>23</sup> "Current" in this context means the price obtained, as previously described, divided by VL's estimated EPS; i.e., it is a forward P/E, not an historical P/E.

1 of future EPS and future dividends growing at different rates. Utilizing EPS  
2 that grows on a separate trajectory than dividends is the foundation for an  
3 alternative means of terminal valuation.<sup>24</sup>

4 **PEER SCREEN**

5 **Q. How did you select comparable companies (peers) to estimate Avista's**  
6 **ROE?**

7 A. I used companies that met the following criteria as peer utilities to the  
8 regulated gas utility activities of Avista Corporation:

- 9 1. Covered by VL as an Gas Utility;
- 10 2. Forecasted by VL to have Positive Dividend Growth;
- 11 3. LT Issuer Credit Rating equal or better than BBB- from S&P, or  
12 Baa3 from Moody's;
- 13 4. No Decline in Annual Dividend in Last Five Years Based on SNL;
- 14 5. Has 80 percent or greater Regulated Assets;
- 15 6. Has LT Debt under 56 percent in VL Capital Structure; and
- 16 7. Has No Recent Merger and Acquisition Activity.

17 **Q. Why do you eliminate companies that are not forecasted to have**  
18 **positive dividend growth?**

19 A. I use the same screening practice that Staff has used in the past. There is  
20 evidence that investors find common stock of dividend-cutting utilities less  
21 attractive. The stock prices for FPL Group's Florida Power and Light and for  
22

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<sup>24</sup> Please note that the approach used in this second model is not the same as using a singular estimate of the growth rate in EPS as the growth rate in dividends.

1 Niagara Mohawk Power Corporation declined sharply after dividend cuts.<sup>25</sup>  
2 These real-world findings are consistent with Staff's screening out gas utilities  
3 that have recently cut dividends.

4 **Q. Can gas utilities' common stock still enjoy active investment from**  
5 **global investors, who are looking for higher low-risk returns than the**  
6 **prevailing historically low-yielding global treasury bonds if they cease**  
7 **issuing predictable dividends?**

8 A. Please see Staff/210, Muldoon/34 for a discussion of this topic. In general,  
9 many institutional investors and fund managers can substitute only very  
10 predictable bond-like stocks or very safe, highly rated bonds for UST without  
11 exposure to more risk than pertinent governance allows.<sup>26</sup>

12 **Q. Is this currently a risky environment for interest rates?**

13 A. There is uncertainty over that. Yield on the UST 10-year note shown above  
14 has fallen to 1.994 percent and the UST 30-year bond has fallen to 2.826  
15 percent as posted by the WSJ on October 2, 2015, down from the rise shown  
16 in Figure 3 before the FED announced that it was not raising interest rates  
17 quite yet.

---

<sup>25</sup> An example of investor reaction to dividend cuts is found in The New York Times article, "Niagara Mohawk Stock Dives After Dividend Suspension", published January 25, 1996.

<sup>26</sup> Yahoo Finance on September 26, 2015, showed that over 70 percent of shares in Avista are held by institutional investors and mutual funds.

1

**Figure 3**

Source: WSJ Aug. 11, 2015

Source: WSJ Sep. 1, 2015

US Treasuries (UST)			Yield	US Treasuries (UST)			Yield
Maturity	Units		%	Maturity	Units		%
1	Months	Bill	0.0510	1	Months	Bill	0.0080
3			0.1040	3			0.0430
6			0.2320	6			0.2670
1	Years	Note	0.3600	1	Years	Note	0.3750
2			0.6730	2			0.7120
3			1.0050	3			1.0130
5			1.5270	5			1.4990
7			1.8890	7			1.8920
10			<b>2.1430</b>	10			<b>2.1740</b>
30	Bond	<b>2.8100</b>	30	Bond	<b>2.9350</b>		

2

3

**Q. Is there evidence that Avista addressed these concerns in its communication with investors?**

4

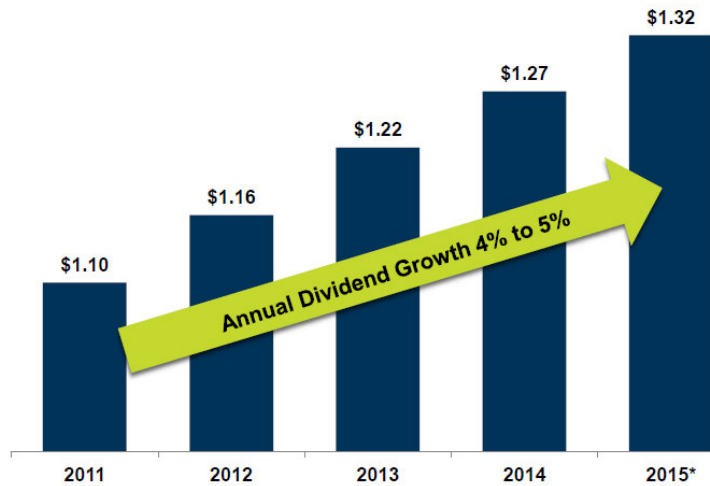
5

**A.** Yes. Avista's August 5, 2015 investor presentation provided in Staff/213, Muldoon/8 shows Avista can continue the dividend trend in Figure 4.

6

7

**Figure 4 — Avista's June 5, Q1 Dividend Overview**



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10

1 **Q. What cohort of companies resulted from your screens?**

2 A. Please see Staff/202, Muldoon/1-2 for detailed Staff screens and also for a  
3 table that shows the list of peer utilities obtained from Staff screens and those  
4 obtained from Avista screens in this rate case

5 **SENSITIVITY ANALYSIS**

6 **Q. After Avista filed this rate case did you perform sensitivities that**  
7 **removed gas utilities in the process of merging with other companies?**

8 A. Yes, I performed model runs both with and without AGL Resources (AGL).  
9 Southern Company is in the process of purchasing AGL. See Staff/208.

10 **Q. Did you also perform sensitivities that added water utilities able to pass**  
11 **Staff's screening methods to Staff's peer group?**

12 A. Yes, IOU water utilities closely track average gas utility performance.

13 **Q. How does Staff apply informed judgement to its modeling?**

14 A. Staff examined its full range of ROE results from 8.03 percent to 9.45 percent  
15 after all adjustments. Within that range Staff determined that 8.31 percent to  
16 9.45 percent was a reasonable narrowing of focus, excluding some of the  
17 Company's suggested peer companies. Further narrowing the focus to  
18 Staff's primary peers most like Avista was the best fit to capture investor  
19 expectations of Avista performance. Please note that this range also  
20 generates the highest modeling results, outperforming the Company's gas  
21 peer group.



1 **Q. Does Staff's removal of the lower end of modeling results from 8.03**  
2 **percent to 8.75 percent suggest Staff's results are fair, reasonable and**  
3 **conservative?**

4 A. Yes, this is a representative indicator that Staff recommendations are  
5 balanced, fact-based and reasonable.

6 **Q. Does running of these sensitivities replace or modify Staff's primary**  
7 **screening methods?**

8 A. No, Staff's results address the proposed acquisition of AGL resources by  
9 Southern Co. and look at expanding the peer group with water IOUs, but the  
10 results of my sensitivity analyses merely better inform the Commission.

11 **Q. Did the sensitivity of processing all of the Company peer utilities**  
12 **through Staff's three-stage DCF modeling provide useful information,**  
13 **including electric utilities and a variety of non-utility stocks?**

14 A. No. Staff rejects the Company's use of electric utilities as gas distribution  
15 peers, consistent with prior Commission practice. Staff's higher results using  
16 Staff's gas peers than Company proposed gas peers suggests that Staff's  
17 results are unbiased and reasonable.

18 **GROWTH RATES**

19 **Q. What is the single most important element of discounted dividend or**  
20 **DCF models when used to estimate investors' required ROE?**

21 A. The estimated rate of growth of future dividends is most important element. I  
22 refer specifically to the singular growth rate for constant growth DCF models  
23 and the long-term growth rate for multistage DCF models such as those I use.

1 **Q. What long-term growth rates did you use in the two DCF models?**<sup>27</sup>

2 A. I used three different long-term growth rates, with different methods employed  
3 in developing each.

4 The first method uses a 50 percent weight applied to the average annual  
5 growth rate resulting from estimates of long-term GDP by the EIA, the OMB,  
6 and the CBO, with each receiving one-third of the 50 percent weight.<sup>28</sup> The  
7 remaining 50 percent is the average annual historical real GDP growth rate,  
8 established using regression analysis, for the period 1980 through 2014,<sup>29</sup> to  
9 which I apply the TIPS inflation forecast.

10 The second long-term growth rate for Stage 3 dividends is a control  
11 reflecting Avista's Blue Chip & OMB growth rate.

12 The third Stage 3 annual growth rate, which I use primarily for illustrative  
13 purposes, is the Indiana / Top-10 Blue Chip most recent optimistic upper  
14 book-end projection as of April 2015.

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<sup>27</sup> Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. See, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, at Exhibit Staff/800, Storm/46 line through Storm/52 line 14.

<sup>28</sup> The EIA is the Energy Information Administration within the U.S. Department of Energy (DOE), OMB is the Office of Management and Budget, and CBO is the Congressional Budget Office. EIA and OMB's estimates are of nominal GDP. I applied to CBO's estimate of real GDP an inflation rate for the relevant timeframe developed using the Treasury Inflation-Protected Securities (TIPS) method described by Staff in testimony in multiple recent general rate case proceedings. See, as an example, in Docket No. UE 233 Exhibit Staff/800, Storm/50 line 4 through Storm/51 line 3. The TIPS forecast of annual inflation over the relevant Stage 3 timeframe is 2.12 percent, based on an average of interest rates for each of the months of April 2015, May 2015, and June 2015. It may be useful to think of the TIPS inflation rate forecast as a forward curve of dollars; i.e., market-based estimates of what a dollar will be worth in the future.

<sup>29</sup> Staff discussed this approach in recent Staff cost of equity testimony in several rate case proceedings. See, as an example, in Docket No. UE 233 Exhibits Staff/800, Storm/46, line 15 through Storm/50 line 3.

1 **Q. This past August the CBO cut projected U.S. GDP growth forecasts.<sup>30</sup>**

2 **Did you lower your inputs from the CBO from its long-term spring**

3 **forecast?**

4 A. No.

5 **Q. This September, John Lonski, Chief Economist for Moody's Capital**

6 **Research Inc. lowered GDP and earnings projections. Did you lower**

7 **your modeling inputs based on these forecasts?**

8 A. No, I did not.

9 **Q. According to the Bloomberg's "Spring-2015 Consensus Estimate" from**

10 **its survey of economists, the current upturn is expected to expire**

11 **during 2018-2019, creating declines from earlier projections. Did you**

12 **build these lower growth inputs into your modeling?**

13 A. No.

14 **Q. Duke University's Q3 2015 Survey of CFO's reflected further diminished**

15 **Blue Chip expectations of growth from this past spring. Did you shift**

16 **your long-term growth rates downward to reflect this new pessimism?**

17 A. No. Staff continues to rely on the spring 2015 carefully prepared long-term

18 projections shown in Table 4 below.

19

---

<sup>30</sup> Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. See, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, at Exhibit Staff/800, Storm/46 line through Storm/52 line 14.

1  
 2

**Table 4  
 GDP Growth Rates**

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates					
Component	Real Rate	TIPS Inflation Forecast	Nominal Rate	Weight	Weighted Rate
<i>EIA 2014 Placeholder</i>	2.40%	2.12%	4.57%	16.70%	0.76%
<b>OMB - White House 2016 Budget</b>			4.30%	16.70%	0.72%
<b>CBO</b>			4.20%	16.70%	0.70%
<b>Historical 1980 – 2014</b>	2.87%	2.12%	5.05%	50.0%	2.53%
<b>Composite</b>				100%	4.71%
<b>Historical 1980 – 2014 Q4</b>					
			5.05%	100.0%	5.05%
<b>Indiana U – Kelley 2018-35 Ctr Econometric Research</b>					
	2.90%	2.12%	5.08%	100.0%	5.08%
<b>Blue Chip* – Top 10% 2019 Values</b>					
	2.90%	2.12%	5.08%	100.0%	5.08%
<b>Blue Chip – Average</b>					
	2.40%	2.12%	4.57%	100.0%	4.57%
<b>Blue Chip – Bottom 10%</b>					
	1.90%	2.12%	4.06%	100.0%	4.06%

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- Q. You recommend relying on meticulously prepared long-term growth rates from referent sources published last spring over possibly fresher, lower consensus-growth rates from this quarter. Why is that?**
- A.** On leaving office, former FED Chairman Ben Bernanke advised analysts to be “cautious in their forecasts.” Taking that advice to heart, I recommend that the Commission treat Staff’s modeling results as a ceiling meriting reasonable confidence. This avoids the possibility that lower interim, consensus survey projections might suffer from downward bias due to recent successive global market shocks.

1     **Q. Table 4-B of Docket No. UE 294 Opening Testimony Staff/200,**  
2     **Muldoon/22 showed substantial declines in GDP growth projections this**  
3     **spring from a year ago. Are you suggesting that the Commission**  
4     **consider these spring growth projections as one of several sets of**  
5     **reasonably-sourced growth rates while declining to use lower**  
6     **snapshots of growth expectations from this more volatile quarter?**

7     A. Yes. Though long-term growth inputs appear to be eroding further, some of  
8     these projections are the result of surveys that may lack the same analytic  
9     rigor as the annual federal projections.

10    **Q. Does this approach capture a reasonable set of investor expectations**  
11    **similar to Staff's analysis in other recent general rate cases?**

12    A. Yes, Staff modeling captures the expectations of investors who think  
13    variously: A) that future conditions will mirror the past, B) that federal agency  
14    expert analysis informs the historical track record, and C) that the most  
15    optimistic 10 percent of Blue Chip referent persons surveyed have the pulse  
16    of the future.

17    **Q. Is it appropriate to use estimates of long-term GDP growth rates to**  
18    **estimate future dividends for gas utilities?**

19    A. Yes. In each of the Company's prior rate cases, Staff has shared plots of  
20    U.S. gas demand growth since 1950 on a 3-year moving average. This  
21    downward trending consumption curve allows GDP growth to be a  
22    conservative proxy for both gas sales and dividend growth rates.

23

1 **Q. Can relying on a long-term GDP growth overstate required ROE?**

2 A. Yes. It is possible that my modeling overstates required ROE for this reason.

3 **Q. What are the results of your multistage DCF models?**

4 A. Please see Exhibit Staff/203 for a summary followed by modeling detail.

5 **Q. How do these estimated ROE values compare with gas utilities' ROE**  
6 **values for 2015 General Rate Cases?**

7 A. These estimated ROEs are low compared with regulated U.S. utilities'  
8 authorized return on equity capital in 2015 as reported by SNL Financial, that  
9 range from a low ROE of 9.0 percent in New York for Central Hudson Gas  
10 and Electric to a high of 10.9 percent for Columbia Gas of Virginia, Inc. The  
11 Company's rate cases in each of the last two years provide greater detail.

12 **Q. Why do you address equity flotation costs when Avista is participating**  
13 **in stock buybacks of late, and not floating new public stock offerings?**<sup>31</sup>

14 A. My 12.5 bps upward adjustment is a durable modifier reflecting aggregate  
15 overall long-term cost to float new equity into perpetuity.

16 **Q. Avista witness McKenzie asks for 10 bps adjustment for equity flotation**  
17 **costs and provides citations to references that would justify less**  
18 **consideration.**<sup>32</sup> **Why is Staff making a higher adjustment?**

19 A. Staff's recommendation is based on Staff's own review restricted to actual  
20 costs of Commission jurisdictional energy utilities. Staff recommends this

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<sup>31</sup> Please see Avista/200, Thies/7-8 for a description of Avista's common stock buybacks.

<sup>32</sup> See Avista/300, McKenzie/53.

1 12.5 bps upward adjustment for flotation costs for all six Oregon energy IOUs  
2 on an ongoing basis.

3 **Q. What is your assessment of Mr. McKenzie's DCF analysis and results?**

4 A. Mr. McKenzie's single state DCF modeling has not been found to be reliable  
5 by the Commission in the past. Staff recommends the Commission use the  
6 more realistic expectations in Staff's modeling.

7 **Q. Did your analysis include the construction of a synthetic forward curve  
8 using UST TIPS break even points?**

9 A. Yes. My forward curve is provided in Exhibit Staff/204, reflecting implied  
10 market-based inflationary expectations. Staff's recommendations are  
11 consistent with market activity indicating investor expectations of future  
12 inflation.

13 **Q. Assume one ignored current downward adjustments by a broad  
14 spectrum of federal agencies and instead presumed that future U.S.  
15 GDP growth would look like the past 30 years. Would a ROE based on  
16 that assumption fall within Staff's recommended range?**

17 A. Yes, I extracted and ran regression on data from U.S. BEA to generate the  
18 annual real historical GDP growth rate shown in Table 4. My recommended  
19 range of ROEs includes values that presume GDP growth over the next thirty  
20 years would look like that of the past 30 years.

21 **Q. Do you show this analysis in your exhibits?**

22 A. Yes. Exhibit Staff/205 shows my analysis in support of this finding.

1 **Q. If utilities' dividends and EPS are growing at a faster rate than growth**  
2 **for the whole economy, then utilities would become a bigger part of the**  
3 **economy. Is that happening?**

4 A. No. Gas utilities are not becoming a larger and larger part of the US  
5 economy.<sup>33</sup>

6 **Q. What do you recommend to the Commission regarding Mr. McKenzie's**  
7 **results from his constant growth DCF model?**

8 A. Mr. McKenzie's constant growth DCF model offers little to inform the  
9 Commission in this case.<sup>34</sup> I recommend the Commission give little weight to  
10 the results of Mr. McKenzie's model.

11 **Q. How do your methods employed in this case differ from those utilized**  
12 **by Staff in Avista's prior two general rate cases, and in the recent**  
13 **Northwest Natural Gas Company rate case, UG 221?**

14 A. My methods and modeling are very similar to those employed by Staff in  
15 recent general rate cases, including UG 221.

16 **ALTERNATIVE MODELS EXAMINED**

17 **Q. What control modeling did you perform to corroborate your DCF**  
18 **results?**

19 A. I examined several alternative models that support my DCF modeling. While  
20 I do not recommend that any alternate approach should replace the

---

<sup>33</sup> See UE 283 Staff/200, Muldoon/17-22.

<sup>34</sup> For example, the Commission rejected consideration of parties' constant growth DCF models in Docket No. UE 115.



1 Commission's reliance on three-stage DCF modeling, such alternate models  
2 may offer a check on the reasonableness of my recommendation.

3 **SINGLE-STAGE GORDON GROWTH DCF MODELING**

4 **Q. Did you first examine the Company's constant Gordon growth DCF**  
5 **model?**

6 A. Yes. However, I note that Brealey, Myers and Allen, in the tenth edition of  
7 their textbook "Principles of Corporate Finance" caution that "the simple  
8 constant-growth DCF formula is an extremely useful rule of thumb, but no  
9 more than that."<sup>35</sup>

10 **Q. Do you view this model as simply an extremely imprecise vector**  
11 **pointing closer to 10 percent ROE than five percent ROE?**

12 A. Yes. As calculated by Avista, this vector would point toward the top end of  
13 my three-stage DCF results when considering a point ROE from among a  
14 reasonable range of ROEs.

15 **Q. Avista/300, McKenzie/37 explains how and why DCF results that are low**  
16 **should be eliminated, leaving high plausible results to dominate**  
17 **modeling recommendations. Is this reasonable?**

18 A. Not entirely. This is something like raising a "wet finger in the wind." It can  
19 give you a direction vector but has a great deal of trouble measuring accurate  
20 wind speed. However, if one adjusts growth to best federal annual estimates

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<sup>35</sup> "Principles of Corporate Finance", Brealey, Myers, and Allen, p 83 (10<sup>th</sup> Edition 2010).

1 and removes as many top outliers as low outliers, Mr. McKenzie's results are  
2 then consistent with my three-stage DCF modeling results.

3 **Q. Why are you uncomfortable relying too much on this simple Gordon**  
4 **growth model applied variously to gas utilities, electric utilities and non-**  
5 **utility companies such as those that make jams and jellies?<sup>36</sup>**

6 A. Gordon Growth single-stage DCF modeling makes the academic assumption  
7 that information about all future returns is contained in just a few values:  
8 namely the last dividend and an appropriate very long-term average growth  
9 rate.

10 **Q. Why is this not plausible in the real world?**

11 A. Were Gordon Growth even somewhat accurate, success in investing would  
12 be assured and there would be less need for the omnipresent investment  
13 disclaimer, "Past Performance is No Guarantee of Future Results." Staff  
14 recommends the Commission continue to assign little or no weight to Gordon  
15 Growth modeling and to be very skeptical of findings that average such weak  
16 extrapolations equally with results from much higher confidence modeling.

17 **Q. Does Mr. McKenzie's single-state Gordon Growth model become more**  
18 **predictive of Gas Utility required ROEs when used to analyze non-utility**  
19 **stocks?**

20 A. Theoretically, absent better information, one would consider all possible  
21 alternative investments that an investor, institution, company or fund might  
22 make compared to investing in a gas utility, such as investing in artwork or

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<sup>36</sup> See Avista/301, Schedule AMM-13, page 2 of 3.

1 jam production. Fortunately, we find ourselves in possession of both  
2 substantial vetted information and more predictive models.

3 **RISK PREMIUM MODELING**

4 **Q. Did you examine Mr. McKenzie's risk premium modeling?**

5 A. Yes, however risk premium modeling is not a terribly reliable methodology.

6 **Q. Do risk premium models track well through periods of time when FED**  
7 **policy is a key driver of ultra-low interest rates and when markets are**  
8 **dysfunctional as shown in the 2009 spikes in spreads over UST**  
9 **examined by Moody's in Staff/210, Muldoon/2?**

10 A. No. Historical spreads over UST and the historical spreads between stocks  
11 and bonds can be poor predictors of FED policy. A risk premium review can  
12 be a fairly good check on an investor's own comfort level before executing an  
13 investment decision, provided the investor can say, "The stocks in this sector  
14 for a given credit rating track the bonds in this sector like so, and I have good  
15 reason to believe they will continue to do so in the future." If the investor  
16 ceases to have confidence in that statement, then the risk premium ceases to  
17 be a good validity check for a more complex model.

18 **Q. When conflating stock and bond returns, is it obvious to investors**  
19 **whether the FED-driven low-interest-rate paradigm is different from pre-**  
20 **2008 patterns and durable into the future?**

21 A. No.

22

1     **Q. Is it clear whether exceedingly high spreads in 2008 and 2009 should be**  
2     **entirely eliminated or are in some way predictive of the future?**

3     A. No. If one includes spreads that dwarf current conditions, one is effectively  
4     projecting another financial crisis.

5     **Q. Are UST rate trends necessarily now a representative snapshot of where**  
6     **fixed income rates are heading?**

7     A. No. John Lonski, Chief Economist of Moody's Capital Markets Research, Inc.  
8     in Credit Markets Review and Outlook released March 21, 2015, called the  
9     current state of business activity "mediocre."<sup>37</sup> His assessment is that the  
10    recent jump by Treasury yields may have overstated any rise of inflation risk,  
11    and that there are no "observable facts" behind it. If he is right, UST prices  
12    will rise and yields fall once again, absent news recommending otherwise.  
13    So despite the FED's and other predictions of where interest rates will be in  
14    the future, one finds that each of the major predictions of five-year interest  
15    rate trends made near calendar year end of each the last four years were  
16    wrong.

17    **Q. Is there good reason to believe that Avista's examination of historical**  
18    **fixed income data is not predictive of the future – not even to describe**  
19    **conditions in 2016 at the end of the test year?**

20    A. Yes. The FED is considering whether the financial crisis and Great Recession  
21    permanently slowed the U.S. economy's growth potential, thereby lowering

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<sup>37</sup> Staff accessed Moody's reporting on May 22, 2015 at  
[https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC\\_181342](https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_181342)

1 the point at which the FED's benchmark interest rate should be considered  
2 neutral. April FED policy minutes released May 20, 2015, defined this  
3 "equilibrium rate" as the level of the FED funds rate, adjusted for inflation,  
4 consistent with the economy achieving, over a specified time horizon,  
5 maximum employment and price stability.<sup>38</sup>

6 **Q. Are you implying that FED management of rates might not match an**  
7 **extrapolation of prior fixed income activity?**

8 A. Yes, extrapolating historical data would have difficulty predicting trillion-dollar  
9 quantitative easing stimulus in the US, European Union and Japan. How the  
10 FED defines its target states can impact the timing and nature of FED actions  
11 which may overwhelm historic fixed income against common equities  
12 comparison trends.

13 **Q. Please discuss the Ibbotson approach you used.**

14 A. The Research Foundation of CFA Institute, an impartial non-profit  
15 organization, published "Rethinking the Equity Risk Premium" in 2011. Here,  
16 Professor Roger Ibbotson of the Yale School of Management, and other  
17 earlier examiners of how best to approach and calculate equity risk  
18 premiums, share their current thinking and findings.

19 "In the 85 years covered by the Ibbotson data, stocks delivered a real  
20 return of 6.6% against 2.1% for bonds, supporting a 4.5% equity risk

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<sup>38</sup> Staff accessed the WSJ article, "A New, Lower Normal for FED Rates? FED Officials' Lively Debate" by Pedro Nicolaci da Costa on May 22, 2015, at [www.WSJ.com](http://www.WSJ.com).

1 premium.”<sup>39</sup> Adding that 4.5 percent to about a potential 4.00 percent UST  
2 risk free rate for end of 2016, would suggest that an investor looking just for a  
3 quick rough estimate should demand about an 8.5 percent ROE to be  
4 satisfied to own a stock of average risk at year end 2016.

### 5 **REBUTTAL OF AVISTA’S CAPM MODELING**

6 **Q. Did you examine and make adjustments to Avista’s CAPM modeling?**

7 A. Yes. The Company generates both a variant of traditional CAPM and  
8 ECAPM. As I see no investor or fund management firm using ECAPM, I  
9 suggest the Commission afford ECAPM no weight whatsoever. For CAPM, I  
10 note that the Company relies on an overly-high market risk premium.

11 I calculate expected returns using both Value Line and Yahoo Finance  
12 Betas which employ different indices, sampling methods and assumptions  
13 about mean reversion. Relying on an Ibbotson market risk premium of 4.50  
14 percent, I see a range of expected return of 6.37 percent to 9.33 percent.  
15 These values are markedly lower than the expected returns of Mr. McKenzie.

16 **Q. What do you conclude regarding the direction CAPM offers?**

17 A. The Company appears to ignore the low end of industry practice using  
18 CAPM. Avista also relies on a high market risk premium. When Staff’s typical  
19 finance approach is added to Avista’s CAPM work, the result is a lower return  
20 on capital midpoint.

21

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<sup>39</sup> “Rethinking the Equity Risk Premium,” Research Foundation of CFA Institute p 81 (2011).

1 **Q. What are Staff's intermediate CAPM findings?**

2 A. Staff's modeling generates a midpoint 7.85 percent and a top 9.33 percent  
3 return on peer equity in my pre-tax CAPM results considering both 10- and  
4 30-year UST as risk free rates, and considering both VL and Yahoo Finance  
5 Betas.

6 **Q. Understanding that both Staff and the Commission have placed minimal**  
7 **weight on CAPM modeling results and that Staff only discusses**  
8 **Company results as a check in due diligence on Staff findings, what is**  
9 **the implication of CAPM expected returns on risky assets?**

10 A. William Forsyth Sharpe, Professor of Economics at Stanford and one of  
11 winners of the 1990 Nobel Memorial Prize in Economic Sciences for the  
12 CAPM suggests that the expected return on a portfolio of stocks, as  
13 estimated by CAPM, should approximate the peer securities' cost of capital.

14 In the context of this rate case, CAPM can be interpreted as a downward  
15 pointing vector suggesting that one can reasonably look at less than the  
16 upper end of Staff's three-stage DCF modeling results. Exhibit Staff/206  
17 shows a typical CAPM model for Avista stock inclusive of common variations.

18 **Q. What is the formula used in this CAPM modeling?**

19 A. The formula follows in Figure 5.

1

## Figure 5 – CAPM Formula

$$\bar{r}_a = r_f + \beta_a (\bar{r}_m - r_f)$$

Where :

$r_f$  = Risk free rate

$\beta_a$  = Beta of the security

$\bar{r}_m$  = Expected market return

$(\bar{r}_m - r_f)$  = Equity market premium

2

3

**Q. Avista's current Rate of Return (ROR) is 7.516. Do lower CAPM results, while holding Avista's Cost of LT Debt at Company requested levels in this rate case, suggest that Avista's required ROE could be lower?**

4

5

6

A. Yes, CAPM modeling contains more information than Gordon Growth estimations and does suggest that Avista's required ROE should be lower than currently authorized. However, I recommend that the Commission put little weight on this methodology.

7

8

9

10

**Q. What is the contribution of your CAPM review?**

11

A. Though the Commission does not favor CAPM, I conducted this review considering that the Commission could alter its policy going forward.

12

13

**Q. Are you saying that persons who manage money at risk gain little new information from a typically calculated CAPM, other than a downward vector recommending use of the midpoint or lower in your other modeling?**

14

15

16

17

A. Yes. I merely show how CAPM is usually calculated in comparison with the calculations Avista has prepared for the Commission's consideration. And

18



1 given the low-pointing vector, the Commission may want to consider a lower  
2 point ROE than the highest modeling result in my range of reasonable ROEs.

3 **AVISTA'S COMPARATIVE RISKINESS**

4 **Q. Is Avista as a regulated utility less risky than the average publicly**  
5 **traded U.S. stock?**

6 A. Yes. Avista is unique among Staff's peers, as the peer group has been  
7 compiled by Staff for purposes of determining an appropriate ROE. Only one  
8 other regulated gas utility has filed three consecutive general rate cases in  
9 the last decade. Avista has in comparison reduced regulatory lag in cost  
10 recovery, further reducing its risk compared to its peer gas utilities.

11 **Q. Do Avista's frequent rate filings impact ratepayer perception regarding**  
12 **its risks and attractiveness of investment opportunity?**

13 A. Prompt cost recovery and regulatory certainty has allowed Avista to depict the  
14 Company as a solid opportunity for investors seeking five percent to six  
15 percent rate base growth. As discussed earlier, the Company states in its  
16 June 2015 communication to investors that the Company is well positioned  
17 for the future. Staff finds that these characteristics also afford the Company  
18 access to historically low-cost capital.

19 **Q. What do these rough alternative modeling methods, which are regularly**  
20 **used by investors for ballpark calculations, indicate?**

21 A. Investors applying the simple constant-growth DCF formula see a  
22 recommendation of the top end of Staff's range of reasonable ROEs.  
23 Investors applying Ibbotson equity premium thinking or traditional CAPM

1 modeling see a recommendation at the lower end of Staff's range of  
2 reasonable ROEs.

3 **Q. How could investors check the reasonableness of modeling results?**

4 A. Without consideration of below average risk due to multiple-year consecutive  
5 rate cases, investors applying the full spectrum of supported growth rates  
6 ranging from a composite (relying on historical experience and federal  
7 projections) to most optimistic Top 10 Blue Chip from Avista's last general  
8 rate case in my three-stage DCF models would generate ROEs ranging from  
9 8.03 percent to 9.45 percent. Finding my peers to be a better fit for Avista's  
10 profile than the Company's peers, investors could narrow expectations to  
11 Staff's 8.76 percent to 9.45 percent reasonable range of ROEs with a  
12 recommended midpoint of 9.11 percent ROE. Table 5 below summarizes my  
13 modeling results.

14 **Table 5**  
15 **Results of Staff's Modeling**  
16 **(See Exhibit Staff/203 for more detail)**

<b>Best Fit Range of Reasonable ROEs</b>	<b>8.76%</b>	<b>to</b>	<b>9.45%</b>	<b>ROE</b>
<small>(Best fit is Staff's Hamada adjusted screened gas utilities that have simial characteristics to AVA Regulated Gas Operations)</small>				
<b>Midpoint of Best Fit Modeling Results</b>	<b>9.11%</b>		<b>ROE</b>	
<small>(Staff's informed judegment excludes some of the lower range of modeling results depicted above)</small>				

17  
18 **Q. Referring to Table 6 below, please explain why a 9.11 percent midpoint**  
19 **is a reasonable point ROE?**

20 A. The Commission's authorized ROE in Avista's last general rate case is a  
21 sound starting point for a check of reasonableness of my recommendations.  
22 The first adjustment to last general rate case results is to reduce the cost of

1 equity for changes in growth expectations. The lowering of growth  
 2 expectations reduces the cost of equity by 31 basis points yielding an ROE of  
 3 9.19 percent. The next adjustment is to reflect the reduction in risk  
 4 associated with frequent general rate case filings. Avista's very frequent rate  
 5 cases and tracking mechanisms for prompt cost recovery of new facilities in  
 6 my reasoned judgement merit a further drop of up to about 20 basis points.  
 7 This provides a range of 9.00 to 9.19 percent. My recommended point ROE  
 8 value of 9.11 percent falls solidly within that range of reasonable ROEs, as  
 9 shown below in Table 6.

10 **Table 6**  
 11 **Check for Reasonableness of Staff's Point ROE**

<a href="#">Check of Reasonableness:</a>			
<b>Last Commission Authorized ROE:</b>		<b>9.50%</b>	
Change in Long-Term GDP Growth		<b>9.19%</b>	(less 31 bps)
Reduction in risk from frequent rate cases, and prompt cost recovery for new facilities.	<b>9.00%</b>	to	<b>9.19%</b>
<b>Staff Point ROE Recommendation:</b>		<b>9.11%</b>	<b>ROE</b>
* Staff Blue Chip Data is sourced from Table 1 Blue Chip Economic Forecast, Feb. 2015			
<b>Note:</b> This analysis does not reflect further downward correction by the CBO on Aug. 25, 2015 For example Staff's modeling of 2015 GDP growth is not reduced from 2.9% to 2.0%			
See "CBO Cuts US 2015 GPD Forecast to 2% from 2.9%" by Nick Timiraos – WSJ – Aug. 25, 2015			

12  
 13 **ADJUSTMENT OF MODELING RESULTS**

14 **Q. What sets Avista apart from the risks of its own proxy group as you**  
 15 **have assembled?**

16 A. Avista has filed three rate cases in the past three years. Given the  
 17 Company's relatively low growth rate, capacity to file a rate case each year,  
 18 and less need to plan for long term, Avista has become less risky than its  
 19 peer utilities. The Maryland commission finds that similar factors reduce risk

1 and regulatory lag in the current environment, meriting a lower point ROE  
2 from within a reasonable range of ROEs.<sup>40</sup> Avista is therefore not subject to  
3 much regulatory lag and is demonstrating better ability to manage risk than  
4 the Company's peers.

5 **Q. In Order No. 09-020, the Commission concluded that the adoption of**  
6 **decoupling justified a ROE reduction of 10 bps. Do you recommend a**  
7 **similar outboard reduction in ROE for Avista now?**

8 A. No. I recommend the Commission consider a lower than top ROE from within  
9 the range of reasonable ROEs in my modeling reflective of the lower risk  
10 profile Avista has achieved by effectively managing regulatory lag.

11 **Q. Are you opposed to regulatory certainty for Avista?**

12 A. No. I merely note that Avista has successfully managed regulatory risk  
13 suggesting that Avista Corporation is operating within a supportive regulatory  
14 environment. I do not see this as a negative, because this finding is  
15 supportive of the Company's credit ratings.

#### 16 HAMADA EQUATION

17 **Q. Your application of the Hamada Equation to un-lever peer utility capital**  
18 **structures and to re-lever at Avista's target capital structure increases**  
19 **required ROE by 18 bps. Why is this adjustment reasonable?**

20 A. I usually employ the Hamada Equation as a check on the reasonableness of  
21 my modeling results. As earlier discussed, my screening criteria already

---

<sup>40</sup> See Public Service Commission of Maryland, Order No. 85374, Case No. 9299, at 78 –  
February 22, 2013, accessible at:  
[http://webapp.psc.state.md.us/Intranet/Casenum/CaseForm\\_new.cfm](http://webapp.psc.state.md.us/Intranet/Casenum/CaseForm_new.cfm)

1 identify peers that have a very close capital structure to Avista's. Use of the  
2 Hamada adjusted results helps ensure that I have captured all material risk in  
3 my analysis.

4 **Q. In addition to your 65 standard data requests and 25 multiple-part follow  
5 up data requests, did you also rely on other Company information?**

6 A. Yes. I relied on some inputs that the Company provided by phone and email,  
7 which were followed up with additional data requests, that are not yet  
8 returned as of the compiling of this testimony.

9 **INFORMED STAFF ANALYSIS**

10 **Q. Did you take into account information from other models?**

11 A. Yes. I performed a constant-growth DCF model analysis using the Company's  
12 inputs and methods and performed a rough equity risk premium analysis  
13 relying on an approach discussed by Professor Roger Ibbotson of the Yale  
14 School of Management in *Rethinking the Equity Risk Premium*.<sup>41</sup> I also  
15 showed how CAPM as typically calculated suggests my three-stage DCF  
16 modeling is reasonable and well considered.

17 **Q. Do you monitor and analyze current and projected market conditions?**

18 A. Yes. My analysis includes analysis of the current economic climate and its  
19 impact on my estimates of long-term growth. I also rely heavily on feeds from  
20 SNL Financial LC (SNL), Bloomberg, Moody's, S&P, WSJ and other sources to

---

<sup>41</sup> Staff/200, Muldoon/24-25.

1 make sure that my financial understandings are reflective of investor  
2 expectations. Please see a cross section of recent news in Exhibit Staff /210.

3 **Q. Did you develop your recommendations while informed by authorized**  
4 **ROEs in other parts of the country?**

5 A. Yes. I examined recently authorized ROEs across the nation. Please see  
6 Exhibit Staff/212 for SNL's midyear utility rate case ROE trends.

7 **Q. Did you use robust and proven analytical methodologies?**

8 A. Yes. My methods are similar to Staff's work over the last decade.

9 **Q. Briefly recap changes in estimates of long-term growth in GDP since**  
10 **the last Avista general rate case.**

11 A. From 2008 through Avista's last general rate case, referent economists,  
12 government agencies, university business schools, and business leaders  
13 expressed at least some expectation on average that American worker  
14 populations, productivity and aggregate output would return to pre-recession  
15 trends. Over the last year the broad consensus was that America has  
16 challenging fundamental problems in sustaining historic GDP growth.

17 **Q. As the growth rate is pivotal in this case, please describe what long-**  
18 **term growth rates you relied on.**

19 A. The lowest estimate of long-term GDP growth, 4.71 percent, is a weighted  
20 average of historic GDP and forecasts from three federal sources. 50 percent  
21 weight is applied to the aggregate estimates of long-term GDP by the EIA, the  
22 OMB, and the CBO, with each federal source receiving one-third of the 50  
23 percent weight. The remaining 50 percent is the average annual historical real

1 GDP growth rate, established with a regression analysis, for the period 1980  
2 through 2014, to which I applied the TIPs inflation forecast.

3 **Q. What is your second growth rate?**

4 A. My second long-term growth rate 5.05 percent captures historical growth.

5 **Q. What is your third growth rate?**

6 A. My third growth rate, 5.08 percent, is the current Indiana/Blue Chip Top 10  
7 growth projection through 2019. This reflects the growth that 9 of 10 referent  
8 and informed current Blue Chip survey responders would find higher than they  
9 could support. It also matches the modeling input cited by Indiana University's  
10 Kelley School of Business. This value may be seen as the highest current  
11 expectation of forward GDP rates for financial modeling purposes.

12 **Q. How are the three growth rates used in your analysis?**

13 A. Using the cohort of proxy companies that met my screens, I ran each of its two  
14 DCF models three times, each time using a different long-term growth rate.

15 **Q. How did you evaluate the Company's peer cohort and other tests?**

16 A. After performing these initial runs, I performed sensitivity analysis.

17 **Q. How did you test the impact of Avista's peer company selection?**

18 A. I ran each of its models using Avista's cohort of gas proxy group, again using  
19 the three different long-term growth rates for the third stage of growth as  
20 discussed above.

21 **Q. How did you adjust for capital structures divergent to Avista's?**

1 A. I used the Hamada equation to de-lever or remove debt from the proxy  
2 companies and then to re-lever or add debt to match Avista's 50 percent equity  
3 target capital structure in this rate case.

4 **Q. What other adjustment did you make in this case?**

5 A. I made an upward adjustment of 12.5 basis points to account for the cost of  
6 Avista's equity flotation inclusive of a portion of interest carrying cost for an  
7 equity forward provision.

8 **Q. Does your range of reasonable ROEs encompass the entirety of these**  
9 **modeling results including the results for each peer group and**  
10 **sensitivity examined?**

11 A. Yes. The lower end of my range of reasonable ROEs is most impacted by my  
12 composite growth rate, which is informed by federal forecasts of GDP growth  
13 as compared to like projections from the same agencies a year ago.

14 **Q. Is the upper end of your range of reasonable ROEs driven by results**  
15 **from the Company's peer group utilizing the top growth rate?**

16 A. Interestingly no. My upper range of reasonable ROEs is from my peer group  
17 utilizing the highest growth rate adjusted for capital structure divergent from  
18 Avista's.

19 **Q. Does your recommendation include results from the Company's peer**  
20 **group?**

21 A. Yes, it does, but because the Company's peer group did not produce the  
22 highest modeling results, my range of reasonable ROEs brackets the results



1 for the Company's peer group. If I were to rely on the Company's gas peer  
2 group, my upper limit in my range of recommended ROEs would be lower.

3 **UPDATES TO AVISTA MODELS**

4 **Q. As you discussed earlier, currently Staff has the freshest data in its**  
5 **modeling along with more current long-term projections. Should the**  
6 **Commission see dated inputs as technical deficiencies?**

7 A. No, the Staff data is fairly recent and can be relied upon to produce reasonable  
8 results.

9 **Q. Does Staff's screening eliminate companies that are not like Avista?**

10 A. Yes. The point of screening is to identify a small group of companies with very  
11 similar characteristics to Avista that can act as a close proxy for Avista. By  
12 modeling and examining the proxy group, investors may project information not  
13 directly observable from Avista. As the peer group grows, information is diluted  
14 by information from companies that no longer resemble Avista closely.

15 **ISSUE 3 – COST OF LT DEBT**

16 **Q. Have you compiled a summary table illustrating your calculation of**  
17 **Avista's Cost of LT Debt?**

18 A. Yes, please see confidential Exhibit Staff/207.

19 **Q. Is this table updated to reflect Avista's 2015 planned debt issuance(s)?**

20 A. Yes. This table remains confidential until the Company informs the public of  
21 issuance detail.

1 **Q. How do you recommend the Commission address planned 2015 bond**  
2 **issuances and 2016 debt in general?**

3 A. I recommend the Commission utilize actual debt issuance information for 2015  
4 and my pro forma projections for 2016.

5 **Q. Did you prepare a debt maturity profile for Avista?**

6 A. Yes. It is provided in Staff/207, Muldoon/3.

7 **Q. Need the Commission wait for any updates to resolve Cost of LT Debt?**

8 A. No, the Commission can review my confidential LT Debt table, and debt  
9 maturity profile in Exhibit Staff/207 and the maturities of the Company's  
10 issuances over the last five years. This material provides the information for  
11 the Commission to make an informed decision regarding Cost of LT Debt,  
12 without having to wait for more detail about 2015 planned issuances.

13 **Q. To review, do you recommend 5.515 percent cost of LT Debt for Avista,**  
14 **reflective of all updates by the Company and market movements since**  
15 **its filing in this rate case?**

16 A. Yes. My recommendation recognizes that investment banks have priced in  
17 uncertainties in the form of higher spreads over UST than were present in the  
18 bond markets a year ago. However, my analysis is based on Bloomberg  
19 monthly average forward curves for times of planned issuances and may  
20 overstate future issuance costs if falling UST yields reported October 2, 2015  
21 continue.

22

1 **CONCLUSION**

2 **Q. What is your recommendation regarding ROE?**

3 A. I recommend that the Commission consider a range of reasonable ROEs from  
4 8.76 percent to 9.45 percent, and a point ROE of 9.11 percent. This is the  
5 midpoint in my range of reasonable ROEs.

6 **Q. How do you conclude your testimony?**

7 A. Avista common stock and bond offerings remain attractive to institutional and  
8 to conservative investors who rely on stable growing dividends to meet their  
9 obligations in turn. Due to predictable dividend growth into the future, Avista  
10 stock has recently also been an excellent alternative to investing in currently  
11 low yielding UST. And given recent global volatility and uncertainty, the  
12 Company's stocks and bonds continue to be an appealing safe haven for  
13 investors.

14 **Q. Are Avista's stock and bond offerings largely insulated from many**  
15 **global uncertainties and also from recent offering reductions and**  
16 **withdrawals in debt markets?**

17 A: Yes. Investment banks and debt markets have become skittish on debt for  
18 uncertain purposes such as to build shopping centers and to expand mining  
19 operations. This only increases the appeal of Avista's securities as a safe  
20 harbor for investors to ride out global uncertainties.<sup>42</sup>

21 **Q. Why do you recommend the Commission consider a lower point ROE**  
22 **than the uppermost ROE resultant from your modeling?**

---

<sup>42</sup> See "Debt Market Tumult Hits Corporate Bond Sales" by Mike Cherney in the WSJ of September 28, 2015.

1 A: There are two key reasons: First, this is Avista's third consecutive annual  
2 general rate case, complete with methods for rapid cost recovery and income  
3 certainty. Avista's management has controlled risk and regulatory lag well.  
4 Avista is now less risky than its peers. Only one other U.S. gas utility filed  
5 general rate cases with Avista's frequency in the last decade.

6 **Q. What is the second reason?**

7 A: Since Avista's last general rate case, there has developed a broad consensus  
8 that U.S. GDP will not return to pre-recession trends. My modeling inputs are  
9 anchored in part in projections from referent sources this past spring. Even  
10 lower consensus growth projections since then may be accurate. But I feel  
11 that the annual numbers from this past spring are carefully compiled by  
12 federal government experts and other sources. Current lower spot growth  
13 estimates may be overshooting downward and may be subject to correction  
14 by the time annual projections are again prepared for 2016.

15 **Q. Do you expect a lower authorized ROE to hurt Avista's credit profile?**

16 A: No, Moody's Investors Service on March 1, 2015 examined this subject in its  
17 publication, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit  
18 Profiles."

19 **Q. What are the key drivers underlying Moody's findings?**

20 A: Moody's review, provided as Exhibit Staff/210, noted three key factors:

- 21 1. More Timely Cost Recovery Helps Offset Falling ROEs;
- 22 2. Utilities' Cash Flow is Somewhat Insulated from Lower ROEs; and
- 23 3. Utilities' Actual Financial Performance Remains Stable.

1     **Q. Investor behavior such as that described in Staff/210, Muldoon/5**  
2           **appears to anticipate lower inflation than the FED projects. Is there a**  
3           **risk that your use of quarterly FED data overstates required ROE?**

4     A: That is a reasonable concern. However, reliance on vetted quarterly inputs  
5           avoids overreliance on spot information that may be driven downward in part  
6           by successive recent market surprises and shocks.

7     **Q. Does that conclude your testimony?**

8     A. Yes.

CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 201**

**Witness Qualification Statement**

**October 16, 2015**

## WITNESS QUALIFICATION STATEMENT

NAME: Matthew J. Muldoon

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: Senior Economist  
Utility Program  
Energy – Rates Finance and Audit Division

ADDRESS: 201 High Street, Suite 100  
Salem, OR 97301-3612.

EDUCATION: In 1981, I received a Bachelors of Arts Degree in Political Science from the University of Chicago. In 2007, I received a Masters of Business Administration from Portland State University with a certificate in Finance.

EXPERIENCE: From April of 2008 to the present, I have been employed by the OPUC. My current responsibilities include financial and rate analysis with an emphasis on Cost of Capital. I have worked on Cost of Capital in the following general rate case dockets: AVA UG 186; UG 201, UG 246, and UG 284 current; NWN UG 221; PAC UE 246, and UE 263; PGE UE 262, UE 283, and UE 294 current.

From 2002 to 2008 I was Executive Director of the Acceleration Transportation Rate Bureau, Inc. where I developed new rate structures for surface transportation and created metrics to insure program success within regulated processes.

I was the Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002. There I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for rate modeling.

OTHER: I have prepared, and defended formal testimony in contested hearings before the OPUC, ICC, STB, WUTC and ODOT. I have also prepared OPUC Staff testimony in BPA rate cases.

CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 202**

**Staff Peer Screening**

**Exhibits in Support  
of Opening Testimony**

**October 16, 2015**



### Acronyms and Abbreviations Used

<b>CIK</b>	SEC Central Index Key
<b>EDGAR</b>	SEC Electronic Data Gathering, Analysis and Retrieval System
<b>EI</b>	Edison Electric Institute
<b>EIN</b>	IRS Employer Identification Number
<b>IRS</b>	U.S. Internal Revenue Service
<b>SEC</b>	U.S. Securities and Exchange Commission
<b>SIC</b>	Standard Industrial Code
<b>SNL</b>	SNL Financial, LC – A financial information gathering firm
<b>U.S.</b>	United States of America
<b>VL</b>	Value Line Investment Survey, The

Moody's		S&P		Fitch		DBRS		
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	
Aaa	P-1	AAA	A-1+	AAA	F1+	AAA	R-1H	High Grade
Aa1		AA+		AA+		AA(high)		
Aa2		AA		AA		AA		R-1M
Aa3		AA-		AA-		AA(low)		
A1		A+	A-1	A+	F1	A(high)		
A2		A		A		A	R-1L	Upper medium grade
A3	P-2	A-	A-2	A-	F2	A(low)		
Baa1		BBB+		BBB+		BBB(high)	R-2H	
Baa2	P-3	BBB	A-3	BBB	F3	BBB	R-2M	Lower medium grade
Baa3		BBB-		BBB-		BBB(low)	R-2L, R-3	
Ba1		BB+	B	BB+	B	BB(high)	R-4	Non-investment grade speculative
Ba2		BB		BB		BB		
Ba3		BB-		BB-		BB(low)		
B1		B+		B+		B(high)		
B2		B		B		B		Highly speculative
B3		B-		B-		B(low)		
Caa1	Not prime	CCC+	C	CCC	C	CCC(high)	R-5	Substantial risks
Caa2		CCC				CCC		
Caa3		CCC-				CCC(low)		
		CC		CC		CC		

Source: [http://en.wikipedia.org/wiki/Credit\\_rating](http://en.wikipedia.org/wiki/Credit_rating)



Utility Continuity Screen																						
Natural Gas		1 Sensitivity with AWK, CWT, MSEX, & YORW																				
AVA UG 288		2 Sensitivity with AGL																				
Note: All VL Diversified Gas Co.'s Eliminated due to M&A Activity																						
#	Abbreviated Utility	UG 288 AVA	UG 288 Staff	VL Corporate Name Gas Utility	NYS, NSDQ Ticker	SNL Key	IRS EIN	SEC File	VL Region	VL 8/7/2015 Beta	VL 8/7/2015 Timliness	VL 8/7/2015 Safety	VL 8/7/2015 Technical	Yahoo Fin. 8/6/2015 Beta	Yahoo Fin. 8/6/2015 Mkt Cap \$ Billions	VL 8/7/2015 Mkt Cap \$ Billions	Gas or Water U. w VL Beta < 1 8/7/2015	VL ID No.	SNL or VL No Div Declines 5 years	Either / Or S&P Local LT 8/10/2015 Rating ≥ BBB-	Moody's Local LT 8/10/2015 Rating ≥ Baa3	2014 10-K Regulated Revenues ≥ 80% U.S.
-	Avista	No	No	Avista Corporation (For reference Purposes Only)	AVA	4057075	91-0462470	1-3701	West	0.80	2	2	2	0.62	2.02	1.45919	-	9677	Pass	BBB	Baa2	92%
-	Cascade	No	No	Cascade Natural Gas Corp.	MDU	4057112	91-0599090	1-7196	West	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	Pass	BBB+	none	100%
1	AGL	Yes	Sensitivity	AGL Resources, Inc.	GAS	4057108	58-2210952	1-14174	East	0.80	3	1	5	0.28	5.76	5.90	Yes	785	Pass	BBB+	W Jan 2015	*
2	Atmos	Yes	No	Atmos Energy Corp.	ATO	4057157	75-1743247	1-10042	Central	0.85	2	1	4	0.66	5.54	5.40	Yes	802	Pass	A-	A2	59%
3	Laclede	Yes	No	The Laclede Group, Inc.	LG	4002506	74-2976504	1-16681	Central	0.70	3	2	4	0.54	2.32	2.30	Yes	5203	Pass	A-	Baa2	84%
4	New Jersey	Yes	No	New Jersey Resources Corp.	NJR	4057128	22-2376465	1-8359	East	0.80	3	1	4	0.92	2.43	2.60	Yes	6359	Pass	A	Aa2	25%
5	NiSource	Yes	No	NiSource Inc.	NI	4057051	35-2108964	1-16189	East	0.85	N/A	3	N/A	0.54	5.35	14.90	Yes	6188	Pass	BBB+	Ba1	50%
6	Northwest Natural	Yes	Yes	Northwest Natural Gas Company	NWN	4057132	93-0256722	1-15973	West	0.70	3	1	4	0.73	1.18	1.20	Yes	6490	Pass	A+	A3	96%
7	Piedmont	Yes	Yes	Piedmont Natural Gas Company, Inc.	PNY	4057136	56-0566998	1-6196	East	0.80	4	2	4	0.68	2.99	2.90	Yes	7094	Pass	A	A2	93%
8	South Jersey	Yes	No	South Jersey Industries, Inc.	SJI	4057146	22-1901645	1-6364	East	0.85	3	2	3	1.21	1.64	1.80	Yes	8281	Pass	BBB+	A2	61%
9	Southwest Gas	Yes	No	Southwest Gas Corporation	SWX	4041957	88-0085720	1-7850	West	0.85	2	3	5	0.86	2.54	2.50	Yes	8314	Pass	BBB+	A3	67%
10	UGI	No	No	UGI Corporation (Propane Focus / VL)	UGI	4057537	23-2668356	1-11071	East	0.95	2	2	4	0.79	6.03	6.30	Yes	9166	Pass	None	A2	13%
11	WGL	Yes	No	WGL Holdings, Inc.	WGL	4007261	52-2210912	1-16163	East	0.80	3	1	4	0.89	2.75	2.80	Yes	9668	Pass	A+	A3	49%
12	American States	No	No	American States Water Company	AWR	N/A	95-4676679	1-14431	Water	0.70	3	2	2	1.39	1.46	1.50	Yes	8288	Pass	A+	Withdrawn	73%
13	American Water	No	Sensitivity	American Water Works Company, Inc.	AWK	N/A	51-0063696	1-34028	Water	0.70	2	3	2	0.55	9.32	9.80	Yes	8442	Pass	A	A3	89%
14	Aqua America	No	No	Aqua America, Inc.	WTR	N/A	23-1702594	1-6659	Water	0.70	3	2	2	0.93	4.53	4.70	Yes	7056	Pass	None	A3	98%
15	CA Water	No	Sensitivity	California Water Service Group	CWT	N/A	77-0448994	1-13883	Water	0.75	3	3	2	1.27	1.02	1.20	Yes	1574	Pass	A+	Withdrawn	97%
16	CT Water	No	No	Connecticut Water Service, Inc.	CTWS	N/A	06-0739839	0-8084	Water	0.65	3	3	2	0.59	0.38	0.40	Yes	2274	Pass	A	Withdrawn	94%
17	Consol Water	No	No	Consolidated Water Co. Ltd.	CWCO	N/A	98-0619652	0-25248	Water	0.90	4	3	3	1.29	0.18	0.18	Yes	9991	Pass	None	Withdrawn	36%
18	Middlesex Water	No	Sensitivity	Middlesex Water Co.	MSEX	N/A	22-1114430	0-422	Water	0.75	3	2	2	0.60	0.37	0.38	Yes	5950	Pass	A-	Withdrawn	88%
19	SJW	No	No	SJW Corp.	SJW	N/A	77-0066628	1-8966	Water	0.80	4	3	2	0.73	0.68	0.63	Yes	7824	Pass	None	Withdrawn	96%
20	York Water	No	Sensitivity	York Water Company (The)	YORW	N/A	23-1242500	1-34245	Water	0.70	3	2	2	0.77	0.30	0.27	Yes	6182	Pass	A-	Withdrawn	100%
TOTAL PEERS		11	2																			
			7																			
			w Sensitivities																			
				Gas Utility	AVG:	0.81																
					STDV:	0.07																
				H <sub>2</sub> O Utility	AVG:	0.74																
					STDV:	0.07																
					VL																	



#	Abbreviated Utility	UG 288 AVA	UG 288 Staff	VL 2015 LT Debt < 56% of Capital	VL 2018-2020 LT Debt % of Capital	VL 2015 Common Equity % of Capital	VL Preferred Stock of Capital	VL Div. Growth Rate > 0%	No M&A Activity in Last 4 Years	Bloomberg M&A Under 11% of Mkt Cap	M&A Activity in Last 5 Years	#	
-	Avista	No	No	50.83%	53.97%	49.2%	0.0%	Pass	Pass	9%	2014 Purchase of AERC, parent of AK Electric Light and Power for \$170 M & Sale of Ecova	-	
-	Cascade	No	No	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	
1	AGL	Yes	Sensitivity	48.0%	50.0%	52.0%	0.0%	Pass	Fail	Fail / Aug 2015	*Acquired Nicor Dec. 2011, Divested Compass Energy, Tropical Shipping. Southern Co to Buy / WSJ Aug. 2015	1	
2	Almos	Yes	No	44.5%	45.0%	55.5%	0.0%	Pass	Pass	7%		2	
3	Laclede	Yes	No	54.0%	51.0%	46.0%	0.0%	Pass	Fail	125%	Acquired Missouri Gas 975M Sep 2013. Proposal to buy AL Gas -- Pending	3	
4	New Jersey	Yes	No	32.5%	27.5%	67.5%	0.0%	Pass	Pass	0%		4	
5	NiSource	Yes	No	56.0%	56.0%	44.0%	0.0%	Pass	Fail	*	* Spinoff of Columbia Pipeline Group -- Balance Sheet In Flux / VL. 2015,6 Ops will vary widely / VL & SNL	5	
6	Northwest Natural	Yes	Yes	44.5%	44.0%	55.5%	0.0%	Pass	Pass	0%		6	
7	Piedmont	Yes	Yes	48.0%	43.0%	52.0%	0.0%	Pass	Pass	N/A	Acquired Privatized Service to Fort Bragg, NC per Oct. 2013 agreement w US DOD per SNL	7	
8	South Jersey	Yes	No	47.0%	47.0%	53.0%	0.0%	Pass	Pass	0%		8	
9	Southwest Gas	Yes	No	49.0%	47.5%	51.0%	0.0%	Pass	Pass	0%		9	
10	UGI	No	No	54.0%	46.0%	48.0%	0.0%	Pass	Fail	50%	Purchase of Heritage Propane Jan 2013 -- Very Heavy Propane Position	10	
11	WGL	Yes	No	32.5%	29.0%	66.0%	1.5%	Pass	Pass	0%		11	
12	American States	No	No	41.0%	42.0%	59.0%	0.0%	Pass	Pass	0%		12	
13	American Water	No	Sensitivity	53.5%	55.0%	46.4%	0.1%	Pass	Pass	N/A	Acquired Mt. Ebo Sewage	13	
14	Aqua America	No	No	49.5%	50.0%	50.5%	0.0%	Pass	Fail	ACQ	16 Acquisitions in 2014 -- 300 Purchases in last 2 decades / VL.	14	
15	CA Water	No	Sensitivity	43.0%	41.5%	57.0%	0.0%	Pass	Pass	0%		15	
16	CT Water	No	No	45.5%	47.5%	54.4%	0.1%	Pass	Fail	ACQ	Purchased Maine Water in Jan 2012, and Purchase of Biddeford & Saco in Maine in Dec. 2012.	16	
17	Consol Water	No	No	0.0%	0.0%	99.9%	0.1%	Pass	Pass	0%	Unclear Earnings Results for Foreign Operations beyond those serving San Diego and Tijuana / VL.	17	
18	Middlesex Water	No	Sensitivity	40.5%	43.5%	58.4%	1.1%	Pass	Pass	0%		18	
19	S.JW	No	No	52.5%	53.5%	47.5%	0.0%	Pass	Fail	ACQ	Acquired Bexar Metropolitan Water Dist. -- Large 1-time 2014 profits.	19	
20	York Water	No	Sensitivity	47.5%	48.0%	52.5%	0.0%	Pass	Pass	0%		20	
TOTAL PEERS		11	2										
			7										
			w Sensitivities										



Avista - Gas Peer Dividends

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
		UG 288		Value Line Estimated Dividend																											
#	Abbreviated Utility	UG 288 AVA	UG 288 Staff	Ticker	2010 Q1	2010 Q2	2010 Q3	2010 Q4	2010 Yr	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2011 Yr	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2012 Yr	2010-12 Average	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2013 Yr	2011-13 Average	2014 Q1	2014 Q2	2014 Q3		
1	AGL	Yes	Sensitivity	GAS	0.44	0.44	0.44	0.44	1.76	0.45	0.45	0.45	0.55	1.90	0.36	0.46	0.46	0.46	1.74	1.80	0.47	0.47	0.47	0.47	1.88	1.84	0.49	0.49	0.49		
2	Atmos	Yes	No	ATO	0.335	0.335	0.335	0.34	1.35	0.34	0.34	0.34	0.345	1.37	0.345	0.345	0.345	0.35	1.39	1.37	0.35	0.35	0.35	0.37	1.42	1.39	0.37	0.37	0.37		
3	Laclede	Yes	No	LG	0.395	0.395	0.395	0.395	1.58	0.405	0.405	0.405	0.405	1.62	0.415	0.415	0.415	0.415	1.66	1.62	0.425	0.425	0.425	0.425	1.70	1.66	0.44	0.44	0.44		
4	New Jersey	Yes	No	NJR	0.34	0.34	0.34	0.34	1.36	0.18	0.18	0.18	0.18	0.72	0.19	0.19	0.19	0.40	0.97	1.02	0.00	0.20	0.20	0.20	0.6	0.76	0.21	0.21	0.21		
5	NiSource	Yes	No	NI	0.23	0.23	0.23	0.23	0.92	0.23	0.23	0.23	0.23	0.92	0.23	0.23	0.24	0.24	0.94	0.93	0.24	0.24	0.25	0.25	0.98	0.95	0.25	0.25	0.28		
6	Northwest Natural	Yes	Yes	NWN	0.415	0.415	0.415	0.435	1.68	0.435	0.435	0.435	0.445	1.75	0.445	0.445	0.445	0.455	1.79	1.74	0.455	0.455	0.455	0.46	1.83	1.79	0.46	0.46	0.46		
7	Piedmont	Yes	Yes	PNY	0.27	0.28	0.28	0.28	1.11	0.28	0.29	0.29	0.29	1.15	0.29	0.30	0.30	0.60	1.49	1.25	0.00	0.31	0.31	0.31	0.93	1.19	0.31	0.32	0.32		
8	South Jersey	Yes	No	SJI	0.00	0.165	0.165	0.348	0.68	0.00	0.183	0.183	0.3840	0.75	0.00	0.202	0.202	0.423	0.83	0.75	0.00	0.222	0.222	0.458	0.90	0.83	0.00	0.237	0.237		
9	Southwest Gas	Yes	No	SWX	0.238	0.25	0.25	0.25	0.99	0.25	0.265	0.265	0.265	1.05	0.265	0.295	0.295	0.295	1.15	1.06	0.295	0.33	0.33	0.33	1.29	1.16	0.33	0.365	0.365		
10	WGL	Yes	No	WGL	0.370	0.378	0.378	0.378	1.50	0.378	0.39	0.39	0.39	1.55	0.39	0.40	0.40	0.40	1.59	1.55	0.40	0.42	0.42	0.42	1.66	1.60	0.42	0.44	0.44		
11	13 American Water	No	Sensitivity	AWK					0.86	0.22	0.23	0.23	0.23	0.91	0.23	0.23	0.25	0.50	1.21	0.99	0.00	0.28	0.28	0.28	0.84	0.99	0.28	0.31	0.31		
12	15 CA Water	No	Sensitivity	CWT					0.60	0.154	0.154	0.154	0.15	0.62	0.1575	0.1575	0.1575	0.1575	0.63	0.62	0.16	0.16	0.16	0.16	0.64	0.63	0.1625	0.1625	0.1625		
13	18 Middlesex Water	No	Sensitivity	MSEX					0.72	0.183	0.183	0.183	0.185	0.73	0.185	0.185	0.185	0.1875	0.74	0.73	0.1875	0.1875	0.1875	0.19	0.75	0.74	0.19	0.19	0.19		
14	20 York Water	No	Sensitivity	YORW					0.52	0.131	0.131	0.131	0.131	0.52	0.134	0.134	0.134	0.134	0.54	0.53	0.14	0.1431	0.1431	0.1431	0.57	0.54	0.1431	0.1431	0.1431		
TOTAL		10	2	Note: Staff Halves Historic Values for NJR to Reflect 2/1 Split																											
			7	w Sensitivities																											

Avista - Gas Peer EPS

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
		UG 288		Value Line Estimated EPS																											
#	Abbreviated Utility	UG 288 AVA	UG 288 Staff	Ticker	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2012 Yr	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2013 Yr	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2014 Yr	2012-14 Average	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2015 Yr	2013-15 Average	2016 Q1	2016 Q2	2016 Q3		
1	AGL	Yes	Sensitivity	GAS	1.12	0.28	0.08	0.84	2.32	1.31	0.41	0.24	0.68	2.64	2.81	0.48	0.19	1.24	4.72	3.23	1.62	0.30	0.20	0.98	3.10	3.49	1.75	0.35	0.25		
2	Atmos	Yes	No	ATO	0.68	1.12	0.31	0.00	2.11	0.85	1.23	0.36	0.08	2.52	0.95	1.38	0.45	0.23	3.01	2.55	0.96	1.35	0.47	0.22	3.00	2.84	1.00	1.45	0.51		
3	Laclede	Yes	No	LG	1.12	1.32	0.38	(0.03)	2.79	1.14	1.34	0.25	(0.30)	2.43	1.09	1.59	0.33	(0.35)	2.66	2.63	1.09	2.18	0.20	(0.32)	3.15	2.75	1.15	1.90	0.30		
4	New Jersey	Yes	No	NJR	0.55	0.90	0.05	(0.14)	1.36	0.43	0.82	0.12	(0.01)	1.36	0.47	1.81	0.05	(0.23)	2.10	1.61	0.65	1.16	0.10	(0.16)	1.75	1.74	0.66	1.17	0.11		
5	NiSource	Yes	No	NI	0.66	0.23	0.06	0.42	1.37	0.69	0.23	0.16	0.49	1.57	0.85	0.25	0.10	0.49	1.69	1.54	0.85	0.25	0.15	0.60	1.85	1.70	0.95	0.30	0.20		
6	Northwest Natural	Yes	Yes	NWN	1.51	0.05	(0.39)	1.05	2.22	1.40	0.08	(0.31)	1.07	2.24	1.40	0.04	(0.32)	1.04	2.16	2.21	1.04	0.10	(0.30)	1.06	1.90	3.30	1.40	0.10	(0.30)		
7	Piedmont	Yes	Yes	PNY	1.05	0.70	(0.06)	(0.03)	1.66	1.18	0.74	(0.03)	(0.11)	1.78	1.26	0.80	(0.09)	(0.13)	1.84	1.76	1.18	0.82	(0.05)	(0.10)	1.85	1.82	1.22	0.86	(0.02)		
8	South Jersey	Yes	No	SJI	0.83	0.14	0.07	0.49	1.53	0.76	0.16	(0.02)	0.62	1.52	1.01	0.15	(0.05)	0.47	1.58	1.54	0.86	0.16	0.03	0.60	1.65	1.58	0.93	0.18	0.04		
9	Southwest Gas	Yes	No	SWX	1.70	(0.08)	(0.09)	1.33	2.86	1.73	0.22	(0.06)	1.22	3.11	1.51	0.21	0.04	1.25	3.01	4.00	1.53	0.23	0.05	1.34	3.15	3.09	1.62	0.28	0.07		
10	WGL	Yes	No	WGL	1.13	1.58	0.08	(0.11)	2.68	1.14	1.75	(0.03)	(0.55)	2.31	0.99	1.84	0.02	(0.17)	2.68	2.56	1.16	2.02	0.00	(0.28)	2.90	2.63	1.18	2.04	0.03		
11	13 American Water	No	Sensitivity	AWK	0.28	0.66	0.87	0.30	2.11	0.32	0.57	0.84	0.33	2.06	0.39	0.62	0.86	0.52	2.39	2.19	0.45	0.70	1.00	0.45	2.60	2.35	0.50	0.75	1.05		
12	15 CA Water	No	Sensitivity	CWT	0.03	0.31	0.56	0.12	1.02	0.01	0.28	0.61	0.12	1.02	(0.11)	0.36	0.7	0.24	1.19	1.08	0.00	0.32	0.73	0.15	1.20	1.14	0.00	0.31	0.74		
13	18 Middlesex Water	No	Sensitivity	MSEX	0.11	0.23	0.38	0.17	0.89	0.20	0.28	0.36	0.19	1.03	0.2	0.29	0.42	0.22	1.13	1.02	0.21	0.31	0.43	0.20	1.15	1.10	0.22	0.32	0.45		
14	20 York Water	No	Sensitivity	YORW	0.15	0.17	0.22	0.18	0.72	0.17	0.18	0.19	0.21	0.75	0.16	0.22	0.23	0.28	0.89	0.79	0.19	0.25	0.26	0.25	0.95	0.86	0.2	0.26	0.28		
TOTAL		10	2	Note: Staff Halves Historic Values for NJR to Reflect 2/1 Split																											
			7	w Sensitivities																											



Historical and Near Term  
VL Dividends, and  
VL Earnings per Share

Avista - Gas Peer Dividends

#	Abbreviated Utility	UG 288 AVA	UG 288 Staff	Ticker	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	#			
					2014 Q4	2014 Yr	2012-14 Average	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2015 Yr	2013-15 Average	2016 Yr	2017 Yr	2018 Yr	2019 Yr	2020 Yr	VL Avg. 2018 - 20 / Yr	Div Growth 2018-20 vs. 2012-14				
1	AGL	Yes	Sensitivity	GAS	0.49	1.96	1.86	0.51	0.51	0.51	0.51	2.04	1.96	2.10	2.20	2.30	2.40	2.50	2.40	4.3%	1			
2	Atmos	Yes	No	ATO	0.39	1.50	1.44	0.39	0.39	0.39	0.39	1.56	1.49	1.64	1.72	1.81	1.90	1.99	1.90	4.8%	2			
3	Laclede	Yes	No	LG	0.44	1.76	1.71	0.46	0.46	0.46	0.46	1.84	1.77	1.92	2.01	2.10	2.20	2.30	2.20	4.3%	3			
4	New Jersey	Yes	No	NJR	0.23	0.86	0.81	0.23	0.23	0.23	0.23	0.92	0.79	0.94	0.95	0.97	0.98	0.99	0.98	3.2%	4			
5	NiSource	Yes	No	NI	0.26	1.02	0.98	0.26	0.26	0.26	0.28	1.06	1.02	1.10	1.13	1.17	1.20	1.23	1.20	3.4%	5			
6	Northwest Natural	Yes	Yes	NWN	0.465	1.85	1.82	0.465	0.465	0.465	0.47	1.87	1.85	1.91	1.97	2.03	2.10	2.17	2.10	2.4%	6			
7	Piedmont	Yes	Yes	PNY	0.32	1.27	1.23	0.32	0.33	0.33	0.33	1.31	1.17	1.35	1.39	1.43	1.47	1.51	1.47	3.0%	7			
8	South Jersey	Yes	No	SJI	0.488	0.96	0.90	0.00	0.251	0.251	0.52	1.02	0.96	1.10	1.18	1.26	1.35	1.44	1.35	7.1%	8			
9	Southwest Gas	Yes	No	SWX	0.365	1.43	1.29	0.365	0.405	0.425	0.425	1.62	1.44	1.74	1.85	1.97	2.10	2.23	2.10	8.5%	9			
10	WGL	Yes	No	WGL	0.44	1.74	1.66	0.463	0.463	0.463	0.463	1.85	1.75	1.87	1.91	1.95	1.99	2.03	1.99	3.0%	11			
11	13 American Water	No	Sensitivity	AWK	0.31	1.21	1.09	0.31	0.34	0.34	0.34	1.33	1.13	1.42	1.51	1.60	1.70	1.80	1.70	7.7%	13			
12	15 CA Water	No	Sensitivity	CWT	0.1625	0.65	0.64	0.1675	0.1675	0.1675	0.1675	0.67	0.65	0.69	0.77	0.87	0.97	1.07	0.97	7.2%	15			
13	18 Middlesex Water	No	Sensitivity	MSEX	0.1925	0.76	0.75	0.1925	0.1925	0.1925	0.1925	0.77	0.76	0.78	0.80	0.83	0.85	0.87	0.85	2.1%	18			
14	20 York Water	No	Sensitivity	YORW	0.1431	0.57	0.56	0.1495	0.1495	0.1495	0.1495	0.60	0.58	0.63	0.68	0.73	0.79	0.85	0.79	5.9%	20			
TOTAL		10	2																			AVA Peers	4.4%	Mean
			7																			Staff Gas	2.7%	
			w Sensitivities																			Staff Gas w AGL	3.3%	
																						Staff Gas w H <sub>2</sub> O	4.7%	
																						Staff Gas w AGL & H <sub>2</sub> O	4.7%	

Avista - Gas Peer EPS

#	Abbreviated Utility	UG 288 AVA	UG 288 AVA	Ticker	31	32	33	34	35	36	37	38	39	#			
					2016 Q4	2016 Yr	2014-16 Average	2017 Yr	2018 Yr	2019 Yr	2020 Yr	VL Avg 2018 - 20 / Yr	EPS Growth 2018-20 vs. 2012-14				
1	AGL	Yes	Sensitivity	GAS	1.00	3.35	3.72	3.74	4.17	4.65	5.13	4.65	6.3%	1			
2	Atmos	Yes	No	ATO	0.24	3.20	3.07	3.87	4.67	5.65	6.63	5.65	14.2%	2			
3	Laclede	Yes	No	LG	(0.25)	3.10	2.97	3.43	3.80	4.20	4.60	4.20	8.1%	3			
4	New Jersey	Yes	No	NJR	(0.14)	1.80	1.88	1.82	1.83	1.85	1.87	1.85	2.4%	4			
5	NiSource	Yes	No	NI	0.60	2.05	1.86	2.22	2.40	2.60	2.80	2.60	9.1%	5			
6	Northwest Natural	Yes	Yes	NWN	1.10	2.30	2.12	2.59	2.93	3.30	3.67	3.30	6.9%	6			
7	Piedmont	Yes	Yes	PNY	(0.06)	2.00	1.90	2.03	2.07	2.10	2.13	2.10	3.0%	7			
8	South Jersey	Yes	No	SJI	0.65	1.80	1.68	2.01	2.24	2.50	2.76	2.50	8.4%	8			
9	Southwest Gas	Yes	No	SWX	1.43	3.40	3.19	3.66	3.95	4.25	4.55	4.25	1.0%	9			
10	WGL	Yes	No	WGL	(0.25)	3.00	2.86	3.11	3.23	3.35	3.47	3.35	4.6%	11			
11	13 American Water	No	Sensitivity	AWK	0.50	2.80	2.60	2.94	3.09	3.25	3.41	3.25	6.8%	13			
12	15 CA Water	No	Sensitivity	CWT	0.15	1.20	1.20	1.31	1.42	1.55	1.68	1.55	6.3%	15			
13	18 Middlesex Water	No	Sensitivity	MSEX	0.21	1.20	1.16	1.25	1.30	1.35	1.40	1.35	4.8%	18			
14	20 York Water	No	Sensitivity	YORW	0.26	1.00	0.95	1.05	1.10	1.15	1.20	1.15	6.5%	20			
TOTAL		10	2												AVA Peers	6.4%	Mean
			7												Staff Gas	5.0%	
			w Sensitivities												Staff Gas w AGL	5.4%	
															Staff Gas w H <sub>2</sub> O	5.7%	
															Staff Gas w AGL & H <sub>2</sub> O	5.8%	



UG 288 Staff Hamada Adjustments																																	
Yahoo Finance																																	
\$ Stock Closing Price 1st Trading Day of Month																																	
#	Abbreviated Utility	UG 246 AVA	UG 246 Staff	Ticker	April 4/1/2015			May 5/1/2015			June 6/1/2015			3-Day Avg \$ Stock Price	Div Yield at Recent Price	VL 2015 Return on Common Equity	VL 2015 Cap Structure		VL Beta	2015 VL Tax Rate	Hamada Unlevered Beta	Relevered Beta Equity at 50.0%	Equity Risk Premium	Hamada Adjustment Equity At 51.00%	#								
					April 4/1/2015	May 5/1/2015	June 6/1/2015	April 4/1/2015	May 5/1/2015	June 6/1/2015	% Long Term Debt	% Common Equity																					
1	1	AGL	Yes	Sensitivity	GAS	50.27	50.37	50.36	50.33	3.9%	9.0%	48.0	52.0	0.80	37.5%	0.51	0.82	4.20%	0.10%	1	1												
2	2	Atmos	Yes	No	ATO	54.00	54.02	54.09	54.04	2.8%	9.5%	44.5	55.5	0.85	39.5%	0.57	0.92	4.20%	0.29%	2	2												
3	3	Laclede	Yes	No	LG	51.93	53.51	53.83	53.09	3.3%	8.5%	54.0	46.0	0.70	29.0%	0.38	0.65	4.20%	-0.20%	3	3												
4	4	New Jersey	Yes	No	NJR	30.51	30.07	29.97	30.18	2.8%	12.5%	32.5	67.5	0.80	35.0%	0.61	1.01	4.20%	0.86%	4	4												
5	5	NiSource	Yes	No	NI	43.42	47.18	47.06	45.89	2.2%	8.5%	56.0	44.0	0.85	37.0%	0.47	0.77	4.20%	-0.34%	5	5												
6	6	Northwest Natural	Yes	Yes	NWN	46.70	44.70	44.52	45.31	4.1%	6.5%	44.5	55.5	0.70	40.0%	0.47	0.76	4.20%	0.24%	6	6												
7	7	Piedmont	Yes	Yes	PNY	37.44	37.29	37.37	31.89	4.0%	11.0%	48.0	52.0	0.80	25.0%	0.47	0.83	4.20%	0.11%	7	7												
8	8	South Jersey	Yes	No	SJI	52.75	52.78	60.41	55.31	1.7%	11.5%	47.0	53.0	0.85	25.0%	0.51	0.89	4.20%	0.18%	8	8												
9	9	Southwest Gas	Yes	No	SWX	55.00	54.56	55.21	54.92	2.6%	9.5%	49.0	51.0	0.85	35.0%	0.52	0.86	4.20%	0.06%	9	9												
10	11	WGL	Yes	No	WGL	55.01	57.54	57.70	56.75	3.1%	12.0%	32.5	66.0	0.90	39.0%	0.69	1.11	4.20%	0.90%	10	10												
11	13	American Water	No	Sensitivity	AWK	54.52	52.87	52.85	53.41	2.3%	8.5%	53.5	46.5	0.70	39.5%	0.41	0.66	4.20%	-0.16%	11	11												
12	15	CA Water	No	Sensitivity	CWT	23.87	23.89	24.14	23.97	2.7%	9.0%	43.0	57.0	0.75	28.5%	0.49	0.84	4.20%	0.36%	15	12												
13	18	Middlesex Water	No	Sensitivity	MSEX	22.77	21.83	21.91	22.17	3.4%	9.0%	40.5	58.5	0.75	34.5%	0.52	0.85	4.20%	0.44%	13	13												
14	20	York Water	No	Sensitivity	YORW	25.16	22.36	22.64	23.39	2.4%	11.5%	47.5	52.5	0.7	29.5%	0.43	0.73	4.20%	0.12%	14	14												
TOTAL		10	2	SII 2/1 Stock Split in May 2015 is addressed by doubling the May and June share prices.		26.39		26.33		Dividend Yield = (Annual Dividends per Share) / Price per Share		AVA Peer Group		Staff Peer Group		AGL Sensitivity		Water Sensitivity		AGL & Water Sensitivity		Mean		0.22%		0.18%		0.15%		0.18%		0.17%	

CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 203**

**Staff Three Stage DCF Modeling**

**Exhibits in Support  
of Opening Testimony**

**October 16, 2015**

## Required ROE Results from Three Stage DCF Modeling

Model <b>X</b> : 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity ( <b>Hamada Adjusted</b> )						
<b>X</b>	Composite Growth	4.71%	Historical Growth	5.05%	Top-10 LT Blue Chip Growth	5.08%
<b>Avista Gas Peers</b>	7.90%	Implied Average ROE	8.16%	Implied Average ROE	8.18%	Implied Average ROE
<b>Staff Gas Peers</b>	8.38%		8.62%		8.64%	
Sensitivity w AGL	8.45%		8.70%		8.72%	
Sensitivity w Water	8.07%		8.32%		8.34%	
Sensitivity w AGL & Water	8.15%		8.40%		8.42%	
Model <b>Y</b> : 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale ( <b>Hamada Adjusted</b> )						
<b>Y</b>	Composite Growth	4.71%	Historical Growth	5.05%	Top-10 LT Blue Chip Growth	5.08%
<b>Avista Gas Peers</b>	8.23%	Implied Average ROE	8.44%	Implied Average ROE	8.45%	Implied Average ROE
<b>Staff Gas Peers</b>	9.11%		9.31%		9.33%	
Sensitivity w AGL	8.91%		9.11%		9.13%	
Sensitivity w Water	8.02%		8.22%		8.24%	
Sensitivity w AGL & Water	8.10%		8.29%		8.31%	

**Values Shown Above Are NOT Adjusted Upward Yet for Equity Flotation Costs**



## Staff Interpretation of ROE Modeling Results

<b>Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :</b>					<b>12.5</b>	bps
<b>Range of Modeled Results</b>	Full	<b>8.03%</b>	<b>to</b>	<b>9.45%</b>	<b>ROE</b>	
	Narrowed	<b>8.31%</b>	<b>to</b>	<b>9.45%</b>	<b>ROE</b>	
<b>Best Fit Range of Reasonable ROEs</b>		<b>8.76%</b>	<b>to</b>	<b>9.45%</b>	<b>ROE</b>	
(Best fit is Staff's Hamada adjusted screened gas utilities that have simial characteristics to AVA Regulated Gas Operations)						
<b>Midpoint of Best Fit Modeling Results</b>			<b>9.11%</b>		<b>ROE</b>	
(Staff's informed judgemenet excludes some of the lower range of modeling results depicted above)						
<u><b>Check of Reasonableness:</b></u>						
<b>Last Commission Authorized ROE:</b>			<b>9.50%</b>			
Change in Long-Term GDP Growth			<b>9.19%</b>		(less 31 bps)	
Reduction in risk from frequent rate cases, and prompt cost recovery for new facilities.		<b>9.00%</b>	<b>to</b>	<b>9.19%</b>		
<b>Staff Point ROE Recommendation:</b>			<b>9.11%</b>		<b>ROE</b>	
* Staff Blue Chip Data is sourced from Table 1 Blue Chip Economic Forecast, Feb. 2015						
<b>Note:</b> This analysis does not reflect further downward correction by the CBO on Aug. 25, 2015						
For example Staff's modeling of 2015 GDP growth is not reduced from 2.9% to 2.0%						
See "CBO Cuts US 2015 GPD Forecast to 2% from 2.9%" by Nick Timiraos – WSJ – Aug. 25, 2015						

**Illustration of each model is provided on the following pages.**

**E.O.Y. Cash Flows** **Staff** **UG 288** **Model X**

Annual Growth Rate - Stage 3: **5.05%**

Dividend Growth with Terminal Value as Perpetuity

#	Abbreviated Utility	AVA	Staff	IRR	% of NPV <sub>Div</sub>	NPV @ IRR	Recent Price*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2043 Terminal Value	2044 Div	2044 Perpetuity	#
1	AGL	Yes	Sensitivity	8.7%	55.5%	0.00	(50.33)	1.96	2.10	2.20	2.30	2.40	2.40	2.50	2.62	2.73	2.86	2.98	3.13	3.29	3.45	3.63	3.81	4.00	4.21	4.42	4.64	4.88	5.12	5.38	5.65	5.94	6.24	6.55	6.89	7.23	7.60	228.82	7.99	220.84	1
2	Almos	Yes	No	7.7%	69.6%	0.00	(54.04)	1.50	1.64	1.72	1.81	1.90	1.90	1.99	2.09	2.19	2.30	2.41	2.53	2.68	2.79	2.83	3.08	3.24	3.40	3.57	3.75	3.94	4.14	4.35	4.57	4.80	5.05	5.30	5.57	5.85	6.14	247.05	6.45	240.59	2
3	Laclede	Yes	No	8.2%	62.3%	0.00	(53.09)	1.76	1.92	2.01	2.10	2.20	2.20	2.30	2.40	2.51	2.62	2.73	2.87	3.01	3.17	3.33	3.49	3.67	3.86	4.05	4.26	4.47	4.70	4.93	5.18	5.45	5.72	6.01	6.31	6.63	6.97	241.48	7.32	234.17	3
4	New Jersey	Yes	No	7.4%	74.5%	0.00	(30.18)	0.86	0.94	0.95	0.97	0.98	0.98	0.98	1.03	1.06	1.10	1.13	1.19	1.25	1.31	1.38	1.45	1.52	1.60	1.68	1.76	1.85	1.95	2.05	2.15	2.26	2.37	2.49	2.62	2.75	2.89	134.79	3.03	131.76	4
5	NISource	Yes	No	6.9%	83.5%	0.00	(48.89)	1.02	1.10	1.13	1.17	1.20	1.20	1.23	1.26	1.32	1.37	1.42	1.49	1.56	1.64	1.73	1.81	1.91	2.00	2.10	2.21	2.32	2.44	2.58	2.69	2.83	2.97	3.12	3.28	3.44	3.62	208.88	3.80	203.08	5
6	Northwest Natural	Yes	Yes	8.3%	58.2%	0.00	(45.31)	1.85	1.91	1.97	2.03	2.10	2.10	2.17	2.22	2.28	2.33	2.39	2.51	2.64	2.77	2.91	3.08	3.21	3.37	3.54	3.72	3.91	4.11	4.32	4.53	4.76	5.00	5.26	5.52	5.80	6.09	200.53	6.40	194.13	6
7	Piedmont	Yes	Yes	8.4%	58.1%	0.00	(31.89)	1.27	1.35	1.39	1.43	1.47	1.47	1.51	1.56	1.61	1.66	1.71	1.79	1.88	1.98	2.08	2.19	2.30	2.41	2.53	2.66	2.80	2.94	3.08	3.24	3.40	3.58	3.76	3.95	4.15	4.38	141.91	4.58	137.34	7
8	South Jersey	Yes	No	7.1%	83.4%	0.00	(55.31)	0.96	1.10	1.18	1.28	1.35	1.35	1.44	1.54	1.65	1.77	1.88	1.99	2.09	2.19	2.31	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42	3.59	3.77	3.96	4.16	4.37	4.60	4.83	267.51	5.07	252.44	8
9	Southwest Gas	Yes	No	8.3%	63.0%	0.00	(54.92)	1.43	1.74	1.85	1.97	2.10	2.10	2.23	2.42	2.63	2.85	3.09	3.24	3.41	3.56	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.57	5.85	6.15	6.46	6.79	7.13	7.49	7.87	201.27	8.27	253.01	9
11	WGL	Yes	No	7.5%	71.1%	0.00	(56.75)	1.74	1.87	1.91	1.95	1.99	1.99	2.03	2.10	2.16	2.23	2.30	2.41	2.53	2.66	2.80	2.94	3.09	3.24	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.58	5.86	253.18	6.15	247.01	11
13	American Water	No	Sensitivity	7.7%	71.8%	0.00	(53.41)	1.21	1.42	1.51	1.60	1.70	1.70	1.80	1.94	2.09	2.26	2.43	2.55	2.69	2.91	2.95	3.10	3.26	3.43	3.60	3.78	3.97	4.17	4.38	4.60	4.84	5.08	5.34	5.61	5.89	6.19	250.62	6.50	244.12	13
15	CA Water	No	Sensitivity	8.5%	61.1%	0.00	(23.97)	0.65	0.69	0.77	0.87	0.97	0.97	1.07	1.15	1.24	1.33	1.42	1.49	1.57	1.65	1.73	1.82	1.91	2.00	2.11	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.45	3.62	114.79	3.80	110.99	15
18	Middlesex Water	No	Sensitivity	7.7%	67.7%	0.00	(22.17)	0.76	0.78	0.80	0.83	0.85	0.85	0.87	0.89	0.91	0.93	0.95	1.00	1.05	1.10	1.16	1.22	1.28	1.34	1.41	1.48	1.56	1.63	1.72	1.80	1.90	1.99	2.09	2.20	2.31	2.42	96.09	2.55	95.55	18
20	York Water	No	Sensitivity	7.8%	70.5%	0.00	(23.33)	0.57	0.63	0.68	0.73	0.79	0.79	0.85	0.90	0.95	1.01	1.07	1.12	1.18	1.24	1.30	1.37	1.44	1.51	1.59	1.67	1.75	1.84	1.93	2.03	2.13	2.24	2.35	2.47	2.59	2.73	108.80	2.86	105.94	20
TOTALS		10	2		Mean																																				

**B.O.Y. Cash Flows** **Staff** **UG 288** **Model X**

#	Abbreviated Utility	AVA	Staff	IRR	% of NPV <sub>Div</sub>	NPV @ IRR	Recent Price*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2043 Terminal Value	2044 Div	2044 Perpetuity	#
1	AGL	Yes	Sensitivity	8.8%	63.3%	0.00	(50.33)	2.10	2.20	2.30	2.40	2.40	2.50	2.62	2.73	2.86	2.98	3.13	3.29	3.45	3.63	3.81	4.00	4.21	4.42	4.64	4.88	5.12	5.38	5.65	5.94	6.24	6.55	6.89	7.23	7.60	7.98	229.38	8.38	220.98	1
2	Almos	Yes	No	7.9%	67.4%	0.00	(54.04)	1.64	1.72	1.81	1.90	1.90	1.99	2.09	2.19	2.30	2.41	2.53	2.66	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.94	4.14	4.35	4.57	4.80	5.05	5.30	5.57	5.85	6.14	6.45	247.17	6.78	240.39	2
3	Laclede	Yes	No	8.3%	60.1%	0.00	(53.09)	1.92	2.01	2.10	2.20	2.20	2.30	2.40	2.51	2.62	2.73	2.87	3.01	3.17	3.33	3.49	3.67	3.86	4.05	4.26	4.47	4.70	4.93	5.18	5.45	5.72	6.01	6.31	6.63	6.97	7.32	241.81	7.89	234.12	3
4	New Jersey	Yes	No	7.5%	72.9%	0.00	(30.18)	0.94	0.95	0.97	0.98	0.98	0.99	1.03	1.06	1.10	1.13	1.19	1.25	1.31	1.38	1.45	1.52	1.60	1.68	1.76	1.85	1.95	2.05	2.15	2.26	2.37	2.49	2.62	2.75	2.89	3.03	135.30	3.19	132.11	4
5	NISource	Yes	No	7.0%	81.8%	0.00	(48.89)	1.10	1.13	1.17	1.20	1.20	1.23	1.26	1.32	1.37	1.42	1.49	1.56	1.64	1.73	1.81	1.91	2.00	2.10	2.21	2.32	2.44	2.58	2.69	2.83	2.97	3.12	3.28	3.44	3.62	3.80	207.36	3.99	203.37	5
6	Northwest Natural	Yes	Yes	8.5%	58.5%	0.00	(45.31)	1.91	1.97	2.03	2.10	2.10	2.17	2.22	2.28	2.33	2.39	2.51	2.64	2.77	2.91	3.08	3.21	3.37	3.54	3.72	3.91	4.11	4.32	4.53	4.76	5.00	5.26	5.52	5.80	6.09	6.40	201.76	6.73	195.04	6
7	Piedmont	Yes	Yes	8.5%	58.2%	0.00	(31.89)	1.35	1.39	1.43	1.47	1.47	1.51	1.56	1.61	1.66	1.71	1.79	1.88	1.98	2.08	2.19	2.30	2.41	2.53	2.66	2.80	2.94	3.08	3.24	3.40	3.58	3.76	3.95	4.15	4.38	4.58	142.64	4.81	137.83	7
8	South Jersey	Yes	No	7.2%	81.0%	0.00	(55.31)	1.10	1.18	1.26	1.35	1.35	1.44	1.54	1.65	1.77	1.88	1.99	2.09	2.19	2.31	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42	3.59	3.77	3.96	4.16	4.37	4.60	4.83	5.07	250.90	5.33	251.57	8
9	Southwest Gas	Yes	No	8.5%	60.0%	0.00	(54.92)	1.74	1.85	1.97	2.10	2.10	2.23	2.42	2.63	2.85	3.09	3.24	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.57	5.85	6.15	6.46	6.79	7.13	7.49	7.87	8.27	259.97	8.89	251.29	9
11	WGL	Yes	No	7.7%	69.5%	0.00	(56.75)	1.87	1.91	1.95	1.99	1.99	2.03	2.10	2.16	2.23	2.30	2.41	2.53	2.66	2.80	2.94	3.09	3.24	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.58	5.86	6.15	254.23	6.46	247.76	11
13	American Water	No	Sensitivity	7.9%	69.1%	0.00	(53.41)	1.42	1.51	1.60	1.70	1.70	1.80	1.94	2.09	2.26	2.43	2.55	2.68	2.81	2.95	3.10	3.26	3.43	3.60	3.78	3.97	4.17	4.38	4.60	4.84	5.08	5.34	5.61	5.89	6.19	6.50	249.83	6.83	243.00	13
15	CA Water	No	Sensitivity	8.7%	58.0%	0.00	(23.97)	0.69	0.77	0.87	0.97	0.97	1.07	1.15	1.24	1.33	1.42	1.49	1.57	1.65	1.73	1.82	1.91	2.00	2.11	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.45	3.62	3.80	114.23	3.99	110.23	15
18	Middlesex Water	No	Sensitivity	7.8%	66.1%	0.00	(22.17)	0.78	0.80	0.83	0.85	0.85	0.87	0.89	0.91	0.93	0.95	1.00	1.05	1.10	1.16	1.22	1.28	1.34	1.41	1.48	1.56	1.63	1.72	1.80	1.90	1.99	2.09	2.20	2.31	2.42	2.55	98.68	2.68	96.00	18
20	York Water	No	Sensitivity	7.9%	68.0%	0.00	(23.33)	0.63	0.68	0.73	0.79	0.79	0.85	0.90	0.95	1.01	1.07	1.12	1.18	1.24	1.30	1.37	1.44	1.51	1.59	1.67	1.75	1.84	1.93	2.03	2.13	2.24	2.35	2.47	2.59	2.73	2.86	108.57	3.01	105.56	20
TOTALS		10	2		Mean																																				

**Average B.O.Y. & E.O.Y. Cash Flows** **Model X**

#	Abbreviated Utility	AVA	Staff	Average IRR	% of NPV <sub>Div</sub>	Average 2014 - 2019	Dividend Growth Rates
1	AGL	Yes	Sensitivity	8.8%	64.4%	3.4%	3.3%
2	Almos	Yes	No	7.8%	68.5%	3.7%	3.7%
3	Laclede	Yes	No	8.3%	61.2%	3.5%	3.4%
4	New Jersey	Yes	No	7.4%	73.7%	1.0%	1.0%
5	NISource	Yes	No	7.0%			



5.05% Annual Growth Rate - Stage 3

E.O.Y. Cash Flows

Staff Model Y

EPS Growth to Determine a Sale Terminal Value

EPS Growth

#	Abbreviated Utility	AVA	Staff	IRR	Terminal Value as % of NPV <sub>TV</sub>	NPV @ IRR	Recont Price*	2014 - 2043																																						Terminal Value	2044 Div	2044 Sale	2043 #		
								Initial Stage					Transition Stage					Final Stage																																	
1	AGL	Yes	Sensitivity	8.5%	52.0%	0.00	(50.33)	1.96	2.10	2.20	2.30	2.40	2.40	2.50	2.62	2.73	2.86	2.98	3.13	3.29	3.46	3.63	3.81	4.00	4.21	4.42	4.64	4.88	5.12	5.38	5.65	5.94	6.24	6.55	6.89	7.23	7.60	204.97	7.98	196.99	1										
2	Almos	Yes	No	9.0%	99.8%	0.00	(54.04)	1.50	1.64	1.72	1.81	1.90	1.90	1.99	2.09	2.19	2.30	2.41	2.53	2.66	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.94	4.14	4.35	4.57	4.80	5.05	5.30	5.57	5.85	6.14	566.61	6.45	560.16	2										
3	Laclede	Yes	No	9.1%	76.2%	0.00	(53.09)	1.76	1.92	2.01	2.10	2.20	2.20	2.30	2.40	2.51	2.62	2.73	2.87	3.01	3.17	3.33	3.49	3.67	3.86	4.05	4.26	4.47	4.70	4.93	5.18	5.45	5.72	6.01	6.31	6.63	6.97	360.90	7.32	353.60	3										
4	New Jersey	Yes	No	6.3%	59.9%	0.00	(30.18)	0.86	0.94	0.95	0.97	0.98	0.98	0.99	1.03	1.08	1.10	1.13	1.19	1.25	1.31	1.38	1.45	1.52	1.60	1.68	1.76	1.85	1.95	2.05	2.15	2.26	2.37	2.49	2.62	2.75	2.89	66.25	3.03	83.22	4										
5	NISource	Yes	No	8.0%	97.2%	0.00	(45.69)	1.02	1.10	1.13	1.17	1.20	1.20	1.23	1.28	1.32	1.37	1.42	1.49	1.55	1.64	1.73	1.81	1.91	2.00	2.10	2.21	2.32	2.44	2.58	2.69	2.83	2.97	3.12	3.28	3.44	3.62	305.99	3.80	302.20	5										
6	Northwest Natural	Yes	Yes	9.2%	70.6%	0.00	(45.31)	1.85	1.91	1.97	2.03	2.10	2.10	2.17	2.22	2.28	2.33	2.39	2.51	2.64	2.77	2.91	3.06	3.21	3.37	3.54	3.72	3.91	4.11	4.32	4.53	4.76	5.00	5.26	5.52	5.80	6.09	260.55	6.40	264.15	6										
7	Piedmont	Yes	Yes	8.1%	53.3%	0.00	(31.60)	1.27	1.35	1.39	1.43	1.47	1.47	1.51	1.56	1.61	1.66	1.71	1.79	1.88	1.98	2.08	2.19	2.30	2.41	2.53	2.66	2.80	2.94	3.08	3.24	3.40	3.58	3.76	3.95	4.15	4.36	122.08	4.58	117.50	7										
8	South Jersey	Yes	No	8.1%	97.4%	0.00	(55.31)	0.90	1.10	1.18	1.26	1.35	1.35	1.44	1.54	1.65	1.77	1.89	1.99	2.09	2.19	2.31	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42	3.59	3.77	3.96	4.16	4.37	4.60	4.83	379.91	5.07	374.84	8										
9	Southwest Gas	Yes	No	8.2%	61.8%	0.00	(54.92)	1.58	1.65	1.80	2.01	2.24	2.50	2.76	3.00	3.25	3.62	3.80	4.00	4.20	4.41	4.63	4.87	5.11	5.37	5.64	5.93	6.23	6.54	6.87	7.22	7.58	7.97	8.37	8.79	9.24	9.70	252.21	8.27	243.94	9										
10	11 WGL	Yes	No	7.6%	71.4%	0.00	(58.75)	1.74	1.87	1.91	1.95	1.99	1.99	2.03	2.10	2.16	2.23	2.30	2.41	2.53	2.66	2.80	2.94	3.09	3.24	3.41	3.58	3.76	3.95	4.15	4.36	4.59	4.81	5.05	5.31	5.58	5.86	254.74	6.15	248.59	11										
11	13 American Water	No	Sensitivity	8.0%	76.5%	0.00	(53.41)	1.21	1.42	1.51	1.60	1.70	1.70	1.80	1.94	2.09	2.26	2.43	2.55	2.68	2.81	2.95	3.10	3.26	3.43	3.60	3.78	3.97	4.17	4.38	4.60	4.84	5.08	5.34	5.61	5.89	6.19	286.17	6.50	279.67	13										
12	15 CA Water	No	Sensitivity	8.7%	64.1%	0.00	(23.97)	0.65	0.69	0.77	0.87	0.97	0.97	1.07	1.15	1.24	1.33	1.42	1.49	1.57	1.65	1.73	1.82	1.91	2.00	2.11	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.45	3.62	125.29	3.80	121.49	15										
13	16 Middlesex Water	No	Sensitivity	7.7%	67.1%	0.00	(22.17)	0.76	0.78	0.80	0.83	0.85	0.85	0.87	0.89	0.91	0.93	0.95	1.00	1.05	1.10	1.16	1.22	1.28	1.34	1.41	1.48	1.56	1.63	1.72	1.80	1.90	1.99	2.08	2.20	2.31	2.42	96.40	2.55	93.85	18										
14	20 York Water	No	Sensitivity	7.9%	73.3%	0.00	(23.39)	0.57	0.63	0.68	0.73	0.79	0.79	0.85	0.90	0.95	1.01	1.07	1.12	1.18	1.24	1.30	1.37	1.44	1.51	1.59	1.67	1.75	1.84	1.93	2.03	2.13	2.24	2.35	2.47	2.59	2.73	117.66	2.86	114.79	20										
TOTALS								10	2	Mean																																									
									7	8.3%	73.1%	0.0%	Avista Gas																																						
										8.6%	76.6%	0.0%	Staff Gas																																						
										8.6%	86.9%	0.0%	Staff Sensitivity w AGL																																						
										8.3%	72.3%	0.0%	Staff Sensitivity w Water																																						
										8.3%	78.6%	0.0%	Staff Sensitivity w AGL and Water																																						



B.O.Y. Cash Flows

Staff Model Y EPS Growth

					6																					2043	2044	2044																				
					Terminal Value as % of NPV <sub>Div</sub>	NPV @ IRR	Recent Price*	Initial Stage					Transition Stage					Final Stage										Terminal Value	2044 Div	2044 Safe	2043	#																
#	Abbreviated Utility	AVA	Staff	IRR				2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2043	#									
1	1	AGL	Yes	Sensitivity	8.8%	52.5%	0.00	(50.33)	2.10	2.20	2.30	2.40	2.40	2.50	2.62	2.73	2.86	2.98	3.13	3.29	3.45	3.63	3.81	4.00	4.21	4.42	4.64	4.88	5.12	5.39	5.65	5.94	6.24	6.55	6.89	7.23	7.60	7.98	223.44	8.38	215.05	14.74	1					
2	2	Almos	Yes	No	8.3%	74.3%	0.00	(54.04)	1.64	1.72	1.81	1.90	1.90	1.99	2.09	2.19	2.30	2.41	2.53	2.66	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.94	4.14	4.35	4.57	4.80	5.05	5.30	5.57	5.85	6.14	6.45	301.32	8.78	294.54	15.53	2					
3	3	Laclede	Yes	No	8.3%	60.1%	0.00	(53.09)	1.92	2.01	2.10	2.20	2.20	2.30	2.40	2.51	2.62	2.73	2.87	3.01	3.17	3.33	3.49	3.67	3.86	4.05	4.26	4.47	4.70	4.93	5.18	5.45	5.72	6.01	6.31	6.63	6.97	7.32	241.36	7.69	233.67	15.19	3					
4	4	New Jersey	Yes	No	7.8%	77.2%	0.00	(30.18)	0.94	0.95	0.97	0.98	0.98	0.99	1.03	1.06	1.10	1.13	1.19	1.25	1.31	1.38	1.45	1.52	1.60	1.68	1.76	1.85	1.95	2.05	2.15	2.26	2.37	2.49	2.62	2.75	2.89	3.03	153.61	3.49	150.42	11.71	4					
5	5	NISource	Yes	No	6.1%	69.3%	0.00	(45.89)	1.10	1.13	1.17	1.20	1.20	1.23	1.28	1.32	1.37	1.42	1.49	1.56	1.64	1.73	1.81	1.91	2.00	2.10	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.26	3.44	3.62	3.80	142.86	3.99	138.67	7.10	5					
6	6	Northwest Natural	Yes	Yes	8.2%	52.6%	0.00	(45.31)	1.91	1.97	2.03	2.10	2.10	2.17	2.22	2.28	2.33	2.39	2.51	2.64	2.77	2.91	3.06	3.21	3.37	3.54	3.72	3.91	4.11	4.32	4.53	4.76	5.00	5.26	5.52	5.80	6.09	6.40	177.75	6.73	171.02	8.87	6					
7	7	Piedmont	Yes	Yes	11.0%	93.6%	0.00	(31.88)	1.35	1.39	1.43	1.47	1.47	1.51	1.56	1.61	1.66	1.71	1.79	1.88	1.98	2.08	2.19	2.30	2.41	2.53	2.66	2.80	2.94	3.08	3.24	3.40	3.58	3.76	3.95	4.15	4.36	4.58	412.91	4.81	408.10	18.64	7					
8	8	South Jersey	Yes	No	9.8%	116.9%	0.00	(55.31)	1.10	1.18	1.26	1.35	1.35	1.44	1.54	1.65	1.77	1.89	1.99	2.09	2.19	2.31	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42	3.59	3.77	3.96	4.16	4.37	4.60	4.83	5.07	675.42	5.33	670.09	15.75	8					
9	9	Southwest Gas	Yes	No	11.5%	105.4%	0.00	(54.92)	1.74	1.85	1.97	2.10	2.10	2.23	2.42	2.63	2.85	3.09	3.24	3.41	3.59	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.57	5.86	6.15	6.46	6.79	7.13	7.49	7.87	8.27	895.99	8.68	867.30	21.00	9					
10	11	WGL	Yes	No	7.3%	64.6%	0.00	(56.75)	1.87	1.91	1.95	1.99	1.99	2.03	2.10	2.16	2.23	2.30	2.41	2.53	2.65	2.80	2.94	3.09	3.24	3.41	3.58	3.78	3.95	4.15	4.36	4.59	4.81	5.05	5.31	5.58	5.86	6.15	220.01	6.46	213.54	11.10	10					
11	13	American Water	No	Sensitivity	6.5%	46.7%	0.00	(53.41)	1.42	1.51	1.60	1.70	1.70	1.80	1.94	2.09	2.26	2.43	2.55	2.68	2.81	2.95	3.10	3.26	3.43	3.60	3.78	3.97	4.17	4.38	4.60	4.84	5.08	5.34	5.61	5.89	6.16	6.50	124.41	6.83	117.58	9.80	13					
12	15	CA Water	No	Sensitivity	9.1%	64.3%	0.00	(23.97)	0.69	0.77	0.87	0.97	0.97	1.07	1.15	1.24	1.33	1.42	1.49	1.57	1.65	1.73	1.82	1.91	2.00	2.11	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.45	3.62	3.80	137.42	3.99	133.43	22.27	15					
13	18	Middlesex Water	No	Sensitivity	5.7%	31.9%	0.00	(22.17)	0.78	0.80	0.83	0.85	0.85	0.87	0.89	0.91	0.93	0.95	1.00	1.05	1.10	1.16	1.22	1.28	1.34	1.41	1.46	1.58	1.63	1.72	1.80	1.90	1.99	2.08	2.20	2.31	2.42	2.55	30.00	2.68	27.32	7.27	18					
14	20	York Water	No	Sensitivity	6.5%	45.6%	0.00	(23.39)	0.63	0.66	0.73	0.79	0.79	0.85	0.90	0.95	1.01	1.07	1.12	1.18	1.24	1.30	1.37	1.44	1.51	1.56	1.67	1.75	1.84	1.93	2.03	2.13	2.24	2.35	2.47	2.59	2.73	2.85	54.12	3.01	51.11	12.89	20					
TOTALS					10	2			Mean		68.3%		0.0%		Avista Gas		Staff Gas		Staff Sensitivity w AGI)		Staff Sensitivity w Water		Staff Sensitivity w AGI and Water)		6.7%		73.2%		0.0%		9.4%		68.3%		0.0%		7.8%		55.8%		0.0%		6.9%		60.3%		0.0%	

Average B.O.Y. & E.O.Y. Cash Flows

Model Y EPS Growth

					6				
					Terminal Value as % of NPV <sub>Div</sub>	Average 2014 - 2019			
#	Abbreviated Utility	AVA	Staff	Average IRR		Dividend Growth Rates			
						EOY			
1	1	AGL	Yes	Sensitivity	8.8%	52.2%	3.4%	3.3%	3.4%
2	2	Almos	Yes	No	8.3%	67.0%	3.7%	3.7%	3.7%
3	3	Laclede	Yes	No	8.7%	68.1%	3.5%	3.4%	3.4%
4	4	New Jersey	Yes	No	7.1%	68.5%	1.0%	1.0%	1.0%
5	5	NISource	Yes	No	7.0%	63.2%	2.2%	2.2%	2.2%
6	6	Northwest Natural	Yes	Yes	8.7%	61.8%	2.4%	2.4%	2.4%
7	7	Piedmont	Yes	Yes	9.6%	73.6%	2.2%	2.1%	2.1%
8	8	South Jersey	Yes	No	9.0%	107.1%	5.3%	5.1%	5.2%
9	9	Southwest Gas	Yes	No	9.8%	84.1%	4.8%	4.7%	4.8%
10	11	WGL	Yes	No	7.4%	68.0%	1.6%	1.6%	1.6%
11	13	American Water	No	Sensitivity	7.2%	61.8%	4.6%	4.5%	4.6%
12	15	CA Water	No	Sensitivity	8.9%	64.2%	8.9%	8.6%	8.7%
13	18	Middlesex Water	No	Sensitivity	6.7%	49.5%	2.2%	2.2%	2.2%
14	20	York Water	No	Sensitivity	7.2%	69.5%	5.8%	5.7%	5.8%
TOTALS					10	2	Mean		
							w Sensitivities		
							Avista Gas		
							Staff Gas		
							Staff Sensitivity w AGI)		
							Staff Sensitivity w Water		
							Staff Sensitivity w AGI and Water)		
							8.22%		
							70.6%		
							3.7%		
							9.13%		
							67.5%		
							2.3%		
							8.96%		
							62.5%		
							2.6%		
							8.04%		
							61.7%		
							4.3%		
							8.12%		
							60.3%		
							4.2%		

CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 204**

**Staff Synthetic Forward Curve TIPS Analysis**

**Exhibits in Support  
of Opening Testimony**

**October 16, 2015**



2024 through 2044 TIPS-Implied Average Annual Inflation Rate: **2.12%**

Yr. End Mo.-Yr.	Years	Individually Implied Price Levels					Implied Forward Curve/Price Level					Implied Price Level	Check
		5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr		
Dec-14	0	100.00	100.00	100.00	100.00	100.00	100.00					100.00	
Dec-15	1	101.41	101.61	101.83	101.95	102.02	101.41					101.41	
Dec-16	2	102.85	103.25	103.70	103.93	104.09	102.85					102.85	
Dec-17	3	104.30	104.91	105.60	105.95	106.19	104.30					104.30	
Dec-18	4	105.77	106.60	107.54	108.02	108.34	105.77					105.77	
Dec-19	5	107.27	108.31	109.51	110.12	110.53	107.27					107.27	
Dec-20	6		110.06	111.52	112.26	112.77		109.53				109.53	
Dec-21	7		111.83	113.56	114.45	115.05		111.83				111.83	
Dec-22	8			115.64	116.68	117.38			114.46			114.46	
Dec-23	9			117.76	118.95	119.76			117.16			117.16	
Dec-24	10			119.92	121.26	122.18			119.92			119.92	
Dec-25	11				123.62	124.65				122.39		122.39	122.46
Dec-26	12				126.03	127.17				124.91		124.91	125.06
Dec-27	13				128.48	129.75				127.49		127.49	127.71
Dec-28	14				130.99	132.37				130.11		130.11	130.41
Dec-29	15				133.54	135.05				132.79		132.79	133.17
Dec-30	16				136.13	137.78				135.53		135.53	136.00
Dec-31	17				138.78	140.57				138.32		138.32	138.88
Dec-32	18				141.49	143.41				141.17		141.17	141.82
Dec-33	19				144.24	146.32				144.08		144.08	144.82
Dec-34	20				147.05	149.28				147.05		147.05	147.89
Dec-35	21					152.30					150.25	150.25	151.02
Dec-36	22					155.38					153.52	153.52	154.22
Dec-37	23					158.52					156.86	156.86	157.49
Dec-38	24					161.73					160.28	160.28	160.83
Dec-39	25					165.00					163.77	163.77	164.23
Dec-40	26					168.34					167.33	167.33	167.71
Dec-41	27					171.75					170.97	170.97	171.27
Dec-42	28					175.22					174.69	174.69	174.89
Dec-43	29					178.77					178.50	178.50	178.60
Dec-44	30					182.38					182.38	182.38	182.38



Average Quarterly Values for FRB H15 Data

See FRB H.15 Tab for Data Feed Sources.

Staff TIPS Analysis

Quarterly Aggregation

Average Monthly Inflation Indexed Rates by Quarter					
Qtr	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-Q1	1.33	1.81	2.07		
2003-Q2	1.15	1.61	1.94		
2003-Q3	1.36	1.84	2.21		
2003-Q4	1.24	1.65	2.01		
2004-Q1	0.82	1.26	1.71		
2004-Q2	1.26	1.69	2.05		
2004-Q3	1.17	1.55	1.89	2.28	
2004-Q4	0.93	1.30	1.69	2.08	
2005-Q1	1.17	1.41	1.71	1.93	
2005-Q2	1.30	1.44	1.68	1.83	
2005-Q3	1.59	1.70	1.82	1.98	
2005-Q4	1.92	1.98	2.04	2.13	
2006-Q1	2.00	2.05	2.09	2.08	
2006-Q2	2.34	2.39	2.46	2.48	
2006-Q3	2.37	2.37	2.37	2.38	
2006-Q4	2.40	2.36	2.32	2.29	
2007-Q1	2.28	2.33	2.33	2.36	
2007-Q2	2.35	2.40	2.44	2.49	
2007-Q3	2.38	2.44	2.45	2.46	
2007-Q4	1.54	1.81	1.92	2.11	
2008-Q1	0.58	1.02	1.32	1.81	
2008-Q2	0.79	1.17	1.48	2.03	
2008-Q3	1.18	1.47	1.70	2.16	
2008-Q4	2.73	2.92	2.60	2.73	
2009-Q1	1.37	1.54	1.79	2.34	
2009-Q2	1.12	1.37	1.72	2.31	
2009-Q3	1.17	1.41	1.74	2.22	
2009-Q4	0.58	0.94	1.37	1.98	
2010-Q1	0.47	0.94	1.43	2.00	2.16
2010-Q2	0.46	0.91	1.36	1.77	1.88
2010-Q3	0.20	0.57	1.06	1.68	1.76
2010-Q4	-0.11	0.28	0.75	1.48	1.65
2011-Q1	0.07	0.67	1.09	1.71	2.00
2011-Q2	-0.29	0.33	0.80	1.49	1.78
2011-Q3	-0.65	-0.22	0.28	0.95	1.25
2011-Q4	-0.75	-0.39	0.05	0.61	0.85
2012-Q1	-1.02	-0.60	-0.17	0.51	0.78
2012-Q2	-1.08	-0.75	-0.35	0.35	0.66
2012-Q3	-1.27	-1.01	-0.63	0.02	0.43
2012-Q4	-1.42	-1.15	-0.76	-0.02	0.36
2013-Q1	-1.40	-0.98	-0.59	0.19	0.56
2013-Q2	-1.04	-0.62	-0.25	0.47	0.80
2013-Q3	-0.32	0.17	0.56	1.16	1.43
2013-Q4	-0.29	0.25	0.57	1.19	1.50
2014-Q1	-0.16	0.37	0.58	1.11	1.39
2014-Q2	-0.25	0.27	0.43	0.88	1.44
2014-Q3	-0.13	0.24	0.32	0.72	0.98
2014-Q4	0.19	0.39	0.45	0.75	0.95

Average Monthly Nominal UST Rates by Quarter					
Qtr	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-Q1	2.91	3.46	3.92	4.90	
2003-Q2	2.57	3.13	3.62	4.59	
2003-Q3	3.14	3.72	4.23	5.17	
2003-Q4	3.25	3.78	4.29	5.16	
2004-Q1	2.99	3.52	4.02	4.89	
2004-Q2	3.72	4.18	4.60	5.36	
2004-Q3	3.51	3.92	4.30	5.07	
2004-Q4	3.49	3.85	4.17	4.87	
2005-Q1	3.88	4.09	4.30	4.76	
2005-Q2	3.87	3.99	4.16	4.55	
2005-Q3	4.04	4.11	4.21	4.51	
2005-Q4	4.39	4.42	4.49	4.77	
2006-Q1	4.55	4.55	4.57	4.76	4.64
2006-Q2	4.99	5.02	5.07	5.29	5.14
2006-Q3	4.84	4.85	4.90	5.09	4.99
2006-Q4	4.60	4.60	4.63	4.83	4.74
2007-Q1	4.65	4.65	4.68	4.90	4.80
2007-Q2	4.76	4.79	4.85	5.07	4.99
2007-Q3	4.50	4.60	4.73	5.01	4.94
2007-Q4	3.79	3.98	4.26	4.65	4.61
2008-Q1	2.75	3.15	3.66	4.40	4.41
2008-Q2	3.16	3.46	3.89	4.59	4.58
2008-Q3	3.11	3.44	3.86	4.49	4.45
2008-Q4	2.18	2.63	3.25	3.97	3.68
2009-Q1	1.76	2.23	2.74	3.69	3.45
2009-Q2	2.23	2.88	3.31	4.19	4.17
2009-Q3	2.47	3.12	3.52	4.28	4.32
2009-Q4	2.30	2.98	3.46	4.27	4.33
2010-Q1	2.42	3.16	3.72	4.49	4.62
2010-Q2	2.25	2.93	3.49	4.20	4.37
2010-Q3	1.55	2.19	2.79	3.60	3.85
2010-Q4	1.49	2.18	2.86	3.84	4.16
2011-Q1	2.12	2.83	3.46	4.32	4.56
2011-Q2	1.86	2.55	3.21	4.07	4.34
2011-Q3	1.15	1.78	2.43	3.34	3.70
2011-Q4	0.95	1.50	2.05	2.75	3.04
2012-Q1	0.90	1.44	2.04	2.80	3.14
2012-Q2	0.79	1.24	1.82	2.55	2.94
2012-Q3	0.67	1.08	1.64	2.37	2.75
2012-Q4	0.69	1.12	1.71	2.46	2.86
2013-Q1	0.83	1.32	1.95	2.75	3.14
2013-Q2	0.92	1.39	2.00	2.78	3.15
2013-Q3	1.51	2.12	2.71	3.44	3.72
2013-Q4	1.44	2.12	2.75	3.50	3.79
2014-Q1	1.60	2.22	2.76	3.42	3.68
2014-Q2	1.66	2.19	2.62	3.18	3.23
2014-Q3	1.70	2.16	2.50	3.01	3.26
2014-Q4	1.60	2.00	2.28	2.69	2.97

Implied Market-based Inflationary Expectations					
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr
2003-Q1	1.58	1.65	1.85		
2003-Q2	1.42	1.52	1.68		
2003-Q3	1.78	1.87	2.03		
2003-Q4	2.01	2.13	2.28		
2004-Q1	2.17	2.26	2.31		
2004-Q2	2.47	2.50	2.55		
2004-Q3	2.34	2.37	2.41	2.79	
2004-Q4	2.56	2.55	2.48	2.79	
2005-Q1	2.72	2.68	2.58	2.83	
2005-Q2	2.57	2.55	2.48	2.72	
2005-Q3	2.44	2.41	2.39	2.52	
2005-Q4	2.47	2.44	2.45	2.64	
2006-Q1	2.55	2.50	2.48	2.69	
2006-Q2	2.65	2.62	2.61	2.80	
2006-Q3	2.47	2.48	2.52	2.71	
2006-Q4	2.20	2.24	2.31	2.54	
2007-Q1	2.36	2.32	2.35	2.54	
2007-Q2	2.41	2.39	2.41	2.58	
2007-Q3	2.13	2.16	2.28	2.55	
2007-Q4	2.24	2.17	2.34	2.54	
2008-Q1	2.17	2.13	2.34	2.59	
2008-Q2	2.37	2.29	2.40	2.56	
2008-Q3	1.93	1.96	2.16	2.33	
2008-Q4	-0.55	-0.29	0.65	1.24	
2009-Q1	0.39	0.69	0.95	1.35	
2009-Q2	1.11	1.51	1.60	1.88	
2009-Q3	1.30	1.72	1.77	2.06	
2009-Q4	1.72	2.04	2.09	2.29	
2010-Q1	1.96	2.22	2.28	2.49	2.47
2010-Q2	1.80	2.03	2.13	2.43	2.49
2010-Q3	1.35	1.63	1.73	1.92	2.09
2010-Q4	1.59	1.90	2.12	2.36	2.51
2011-Q1	2.05	2.16	2.37	2.61	2.56
2011-Q2	2.15	2.22	2.41	2.57	2.56
2011-Q3	1.81	2.00	2.15	2.39	2.45
2011-Q4	1.71	1.89	1.99	2.14	2.19
2012-Q1	1.92	2.04	2.20	2.29	2.36
2012-Q2	1.86	1.99	2.17	2.21	2.28
2012-Q3	1.94	2.09	2.28	2.35	2.31
2012-Q4	2.11	2.27	2.47	2.48	2.50
2013-Q1	2.23	2.31	2.54	2.55	2.58
2013-Q2	1.95	2.01	2.25	2.32	2.34
2013-Q3	1.82	1.95	2.15	2.29	2.29
2013-Q4	1.73	1.86	2.17	2.31	2.29
2014-Q1	1.77	1.85	2.18	2.30	2.29
2014-Q2	1.90	1.92	2.20	2.30	1.79
2014-Q3	1.83	1.92	2.18	2.28	2.29
2014-Q4	1.41	1.61	1.83	1.95	2.02



FRB H.15 Market Yield on U.S. Treasury (UST) Securities at Constant Maturity, Quoted on an Investment Basis in Percent Per Year  
Staff Accessed , Feb. 5, 2015 at: <http://federalreserve.gov/releases/h15/data.htm>

Last Updated: 1-Apr-14 @ <http://www.federalreserve.gov/releases/h15/data.htm>

Monthly						Monthly						Annual						Annual						
TIPS-05m	5	Year	Inflation Indexed	H.15 ID	RIFLFGCY05 XII_N.M	UST-05m	5	Year	H.15 ID	RIFLFGCY05 N.M	TIPS-05a	5	Year	Inflation Indexed	H.15 ID	RIFLFGCY05 XII_N.A	UST-05a	5	Year	H.15 ID	RIFLFGCY05 N.A			
TIPS-07m	7				RIFLFGCY07 XII_N.M	UST-07m	7			RIFLFGCY07 N.M	TIPS-07a	7				RIFLFGCY07 XII_N.A	UST-07a	7			RIFLFGCY07 N.A			
TIPS-10m	10				RIFLFGCY10 XII_N.M	UST-10m	10			RIFLFGCY10 N.M	TIPS-10a	10				RIFLFGCY10 XII_N.A	UST-10a	10			RIFLFGCY10 N.A			
TIPS-20m	20				RIFLFGCY20 XII_N.M	UST-20m	20			RIFLFGCY20 N.M	TIPS-20a	20				RIFLFGCY20 XII_N.A	UST-20a	20			RIFLFGCY20 N.A			
TIPS-30m	30	RIFLFGCY30 XII_N.M	UST-30m	30	RIFLFGCY30 N.M	TIPS-30a	30	RIFLFGCY30 XII_N.A	UST-30a	30	RIFLFGCY30 N.A													
Month	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m	Month	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m	Year	TIPS-05a	TIPS-07a	TIPS-10a	TIPS-20a	TIPS-30a	Year	UST-05a	UST-07a	UST-10a	UST-20a	UST-30a	
2003-01	1.55	2.10	2.29			2003-01	3.05	3.60	4.05	5.02		2003	1.27	1.73	2.06			2003	2.97	3.52	4.01	4.96		
2003-02	1.24	1.74	1.99			2003-02	2.90	3.45	3.90	4.87		2004	1.04	1.45	1.83	2.14		2004	3.43	3.87	4.27	5.04		
2003-03	1.09	1.60	1.84			2003-03	2.78	3.34	3.81	4.82		2005	1.50	1.93	1.81	1.97		2005	4.05	4.15	4.29	4.54		
2003-04	1.36	1.85	2.18			2003-04	2.93	3.47	3.96	4.91		2006	2.28	2.29	2.31	2.31		2006	4.75	4.76	4.80	5.00	4.91	
2003-05	1.18	1.61	1.91			2003-05	2.52	3.07	3.57	4.52		2007	2.15	2.25	2.29	2.38		2007	4.43	4.51	4.63	4.91	4.84	
2003-06	0.91	1.37	1.72			2003-06	2.27	2.84	3.33	4.34		2008	1.30	1.83	1.77	2.18		2008	2.80	3.17	3.68	4.36	4.28	
2003-07	1.30	1.78	2.11			2003-07	2.87	3.45	3.98	4.92		2009	1.08	1.32	1.86	2.21		2009	2.20	2.82	3.28	4.11	4.08	
2003-08	1.48	1.97	2.32			2003-08	3.37	3.96	4.45	5.39		2010	0.28	0.68	1.15	1.73	1.82	2010	1.93	2.62	3.22	4.03	4.25	
2003-09	1.29	1.80	2.19			2003-09	3.18	3.74	4.27	5.21		2011	-0.41	0.00	0.55	1.19	1.47	2011	1.52	2.16	2.78	3.62	3.91	
2003-10	1.21	1.68	2.08			2003-10	3.19	3.75	4.29	5.21		2012	-1.19	-0.67	-0.48	0.22	0.56	2012	0.76	1.22	1.80	2.54	2.92	
2003-11	1.27	1.64	1.96			2003-11	3.29	3.81	4.30	5.17		2013	0.78	-0.29	0.07	0.75	1.07	2013	1.17	1.74	2.35	3.12	3.45	
2003-12	1.23	1.64	1.98			2003-12	3.27	3.79	4.27	5.11		2014	-0.09	0.32	0.44	0.88	1.11	2014	1.64	2.14	2.64	3.07	3.34	
2004-01	1.09	1.48	1.88			2004-01	3.12	3.65	4.19	5.01														
2004-02	0.86	1.31	1.76			2004-02	3.07	3.59	4.08	4.94														
2004-03	0.52	0.88	1.47			2004-03	2.79	3.31	3.83	4.72														
2004-04	1.02	1.49	1.90			2004-04	3.39	3.89	4.35	5.16														
2004-05	1.34	1.77	2.09			2004-05	3.85	4.31	4.72	5.46														
2004-06	1.41	1.80	2.15			2004-06	3.93	4.35	4.73	5.45														
2004-07	1.29	1.68	2.02			2004-07	3.99	4.11	4.50	5.24														
2004-08	1.12	1.51	1.86			2004-08	3.47	3.90	4.28	5.07														
2004-09	1.10	1.48	1.80			2004-09	3.36	3.75	4.13	4.89														
2004-10	0.97	1.35	1.73			2004-10	3.35	3.75	4.10	4.85														
2004-11	0.90	1.27	1.68			2004-11	3.53	3.88	4.19	4.89														
2004-12	0.92	1.28	1.67			2004-12	3.60	3.93	4.23	4.88														
2005-01	1.13	1.40	1.72			2005-01	3.71	3.97	4.22	4.77														
2005-02	1.08	1.33	1.63			2005-02	3.77	3.97	4.17	4.81														
2005-03	1.29	1.49	1.79			2005-03	4.17	4.33	4.50	4.89														
2005-04	1.23	1.42	1.71			2005-04	4.00	4.16	4.34	4.75														
2005-05	1.28	1.41	1.65			2005-05	3.85	3.94	4.14	4.56														
2005-06	1.39	1.49	1.67			2005-06	3.77	3.86	4.00	4.35														
2005-07	1.67	1.75	1.88			2005-07	3.98	4.06	4.18	4.48														
2005-08	1.71	1.79	1.89			2005-08	4.12	4.18	4.26	4.53														
2005-09	1.40	1.56	1.70			2005-09	4.01	4.08	4.20	4.51														
2005-10	1.70	1.82	1.94			2005-10	4.33	4.38	4.46	4.74														
2005-11	1.97	2.03	2.06			2005-11	4.45	4.48	4.54	4.83														
2005-12	2.09	2.10	2.12			2005-12	4.39	4.41	4.47	4.73														
2006-01	1.93	1.98	2.01			2006-01	4.35	4.37	4.42	4.65														
2006-02	1.98	2.02	2.05			2006-02	4.57	4.58	4.57	4.73														
2006-03	2.09	2.15	2.20			2006-03	4.72	4.71	4.72	4.91														
2006-04	2.26	2.34	2.41			2006-04	4.90	4.94	4.99	5.22														
2006-05	2.30	2.36	2.45			2006-05	5.00	5.03	5.11	5.35														
2006-06	2.45	2.48	2.53			2006-06	5.07	5.08	5.11	5.29														
2006-07	2.46	2.48	2.51			2006-07	5.04	5.05	5.09	5.25														
2006-08	2.27	2.29	2.29			2006-08	4.82	4.83	4.88	5.08														
2006-09	2.38	2.35	2.32			2006-09	4.87	4.88	4.72	4.93														
2006-10	2.51	2.45	2.41			2006-10	4.69	4.69	4.73	4.94														
2006-11	2.41	2.35	2.29			2006-11	4.58	4.58	4.60	4.78														
2006-12	2.28	2.28	2.25			2006-12	4.53	4.54	4.56	4.78														
2007-01	2.47	2.47	2.44			2007-01	4.75	4.75	4.76	4.95														
2007-02	2.34	2.38	2.36			2007-02	4.71	4.71	4.72	4.93														
2007-03	2.04	2.14	2.18			2007-03	4.48	4.50	4.58	4.81														
2007-04	2.12	2.20	2.28			2007-04	4.59	4.62	4.69	4.95														
2007-05	2.29	2.32	2.37			2007-05	4.87	4.89	4.75	4.98														
2007-06	2.85	2.87	2.89			2007-06	5.03	5.05	5.10	5.29														
2007-07	2.60	2.63	2.64			2007-07	4.88	4.93	5.00	5.19														
2007-08	2.39	2.45	2.44			2007-08	4.43	4.53	4.67	5.00														
2007-09	2.14	2.24	2.26																					



CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 205**

**Staff Historical GDP Analysis with BEA Data**

**Exhibits in Support  
of Opening Testimony**

**October 16, 2015**

**Bureau of Economic Analysis (BEA)**  
Current-Dollar and "Real" Gross Domestic Product (GDP)

Annual			Quarterly				1980 through 2014 Q4		
<a href="http://www.bea.gov/national/index.htm">http://www.bea.gov/national/index.htm</a>			(Seasonally adjusted annual rates)				Average	5.37%	Nominal
Yr	GDP in billions of current dollars	GDP in billions of chained 2009 dollars	Quarter	GDP in billions of current dollars	GDP in billions of chained 2009 dollars	Qtr#	Average	2.74%	Real
1929	104.6	1,058.6	1947q1	243.1	1,934.5	1	1	8.783381	1980
1930	92.2	960.7	1947q2	246.3	1,932.3	2	2	8.762895	
1931	77.4	904.8	1947q3	250.1	1,930.3	3	3	8.761378	
1932	59.5	788.2	1947q4	260.3	1,960.7	4	4	8.779742	
1933	57.2	778.3	1948q1	266.2	1,989.5	5	5	8.800219	1981
1934	66.8	862.2	1948q2	272.9	2,021.9	6	6	8.792899	
1935	74.3	939.0	1948q3	279.5	2,033.2	7	7	8.804310	
1936	84.9	1,060.5	1948q4	280.7	2,035.3	8	8	8.792585	
1937	93.0	1,114.6	1949q1	275.4	2,007.5	9	9	8.775704	1982
1938	87.4	1,077.7	1949q2	271.7	2,000.8	10	10	8.791125	
1939	93.5	1,183.6	1949q3	273.3	2,022.8	11	11	8.777525	
1940	102.9	1,286.1	1949q4	271.0	2,004.7	12	12	8.778495	
1941	129.4	1,490.3	1950q1	281.2	2,084.6	13	13	8.791516	1983
1942	166.0	1,771.8	1950q2	290.7	2,147.6	14	14	8.814078	
1943	203.1	2,073.7	1950q3	306.5	2,230.4	15	15	8.833463	
1944	224.6	2,239.4	1950q4	320.3	2,273.4	16	16	8.853880	
1945	228.2	2,217.8	1951q1	336.4	2,304.5	17	17	8.873552	1984
1946	227.8	1,960.9	1951q2	344.5	2,344.5	18	18	8.890961	
1947	249.9	1,939.4	1951q3	351.8	2,392.8	19	19	8.900753	
1948	274.8	2,020.0	1951q4	356.6	2,398.1	20	20	8.908895	
1949	272.8	2,008.9	1952q1	360.2	2,423.5	21	21	8.918583	1985
1950	300.2	2,184.0	1952q2	361.4	2,428.5	22	22	8.927899	
1951	347.3	2,360.0	1952q3	368.1	2,446.1	23	23	8.943140	
1952	367.7	2,456.1	1952q4	381.2	2,526.4	24	24	8.950611	
1953	389.7	2,571.4	1953q1	388.5	2,573.4	25	25	8.959836	1986
1954	391.1	2,556.9	1953q2	392.3	2,593.5	26	26	8.964414	
1955	426.2	2,739.0	1953q3	391.7	2,578.9	27	27	8.974441	
1956	450.1	2,797.4	1953q4	386.5	2,539.8	28	28	8.979606	
1957	474.9	2,858.3	1954q1	385.9	2,528.0	29	29	8.985572	1987
1958	482.0	2,835.3	1954q2	386.7	2,530.7	30	30	8.997729	
1959	522.5	3,031.0	1954q3	391.6	2,559.4	31	31	9.006754	
1960	543.3	3,108.7	1954q4	400.3	2,609.3	32	32	9.023131	
1961	563.3	3,188.1	1955q1	413.8	2,683.8	33	33	9.028735	1988
1962	605.1	3,383.1	1955q2	422.2	2,727.5	34	34	9.041863	
1963	638.6	3,530.4	1955q3	430.9	2,784.1	35	35	9.047621	
1964	685.8	3,734.0	1955q4	437.8	2,780.8	36	36	9.060784	
1965	743.7	3,976.7	1956q1	440.5	2,770.0	37	37	9.070814	1989
1966	815.0	4,238.9	1956q2	446.8	2,792.9	38	38	9.078847	
1967	861.7	4,355.2	1956q3	452.0	2,790.6	39	39	9.086080	
1968	942.5	4,569.0	1956q4	461.3	2,836.2	40	40	9.088195	
1969	1,019.9	4,712.5	1957q1	470.6	2,854.5	41	41	9.099085	1990
1970	1,075.9	4,722.0	1957q2	472.8	2,848.2	42	42	9.102944	
1971	1,167.8	4,877.8	1957q3	480.3	2,875.9	43	43	9.103189	
1972	1,282.4	5,134.3	1957q4	475.7	2,846.4	44	44	9.094638	
1973	1,428.5	5,424.1	1958q1	468.4	2,772.7	45	45	9.089934	1991
1974	1,548.8	5,396.0	1958q2	472.8	2,790.9	46	46	9.097664	
1975	1,689.9	5,385.4	1958q3	480.7	2,855.5	47	47	9.102454	
1976	1,877.6	5,675.4	1958q4	500.4	2,922.3	48	48	9.106800	
1977	2,086.0	5,937.0	1959q1	511.1	2,976.6	49	49	9.118554	1992
1978	2,356.6	6,267.2	1959q2	524.2	3,049.0	50	50	9.129510	
1979	2,832.1	6,466.2	1959q3	525.2	3,043.1	51	51	9.139188	
1980	2,862.5	6,450.4	1959q4	529.3	3,055.1	52	52	9.148156	
1981	3,211.0	6,617.7	1960q1	543.3	3,123.2	53	53	9.151026	1993
1982	3,345.0	6,491.3	1960q2	542.7	3,111.3	54	54	9.156950	
1983	3,638.1	6,792.0	1960q3	546.0	3,119.1	55	55	9.161812	
1984	4,040.7	7,285.0	1960q4	541.1	3,081.3	56	56	9.175076	
1985	4,346.7	7,593.8	1961q1	545.9	3,102.3	57	57	9.184838	1994
1986	4,590.2	7,860.5	1961q2	557.4	3,159.9	58	58	9.198409	
1987	4,870.2	8,132.6	1961q3	568.2	3,212.6	59	59	9.204292	
1988	5,252.6	8,474.5	1961q4	581.6	3,277.7	60	60	9.215577	
1989	5,657.7	8,786.4	1962q1	585.2	3,336.8	61	61	9.218993	1995
1990	5,979.6	8,955.0	1962q2	602.6	3,372.7	62	62	9.222476	
1991	6,174.0	8,948.4	1962q3	609.6	3,404.8	63	63	9.231005	
1992	6,538.3	9,266.6	1962q4	613.1	3,418.0	64	64	9.238072	
1993	6,876.7	9,521.0	1963q1	622.7	3,458.1	65	65	9.244616	1996
1994	7,308.8	9,905.4	1963q2	631.8	3,501.1	66	66	9.261927	
1995	7,684.1	10,174.8	1963q3	645.0	3,569.5	67	67	9.271134	
1996	8,100.2	10,561.0	1963q4	654.8	3,595.0	68	68	9.281047	
1997	8,606.5	11,034.9	1964q1	671.1	3,672.7	69	69	9.289235	1997
1998	9,089.2	11,525.9	1964q2	680.8	3,716.4	70	70	9.304213	
1999	9,660.6	12,085.9	1964q3	692.8	3,766.9	71	71	9.316860	
2000	10,284.8	12,559.7	1964q4	698.4	3,780.2	72	72	9.324588	
2001	10,621.8	12,682.2	1965q1	719.2	3,873.5	73	73	9.334432	1998
2002	10,977.5	12,908.8	1965q2	732.4	3,926.4	74	74	9.344084	
2003	11,510.7	13,271.1	1965q3	750.2	4,006.2	75	75	9.357087	
2004	12,274.9	13,773.5	1965q4	773.1	4,100.6	76	76	9.373369	
2005	13,093.7	14,234.2	1966q1	797.3	4,201.9	77	77	9.381323	1999
2006	13,855.9	14,613.8	1966q2	807.2	4,219.1	78	78	9.389532	
2007	14,477.8	14,873.7	1966q3	820.8	4,249.2	79	79	9.402043	
2008	14,718.6	14,830.4	1966q4	834.9	4,285.6	80	80	9.419247	
2009	14,418.7	14,418.7	1967q1	846.0	4,324.9	81	81	9.422148	2000
2010	14,964.4	14,783.8	1967q2	851.1	4,328.7	82	82	9.440857	
2011	15,517.9	15,020.6	1967q3	866.6	4,366.1	83	83	9.442083	
2012	16,163.2	15,389.2	1967q4	883.2	4,401.2	84	84	9.447726	
2013	16,788.1	15,710.3	1968q1	911.1	4,480.6	85	85	9.444883	2001
2014	17,420.7	16,089.8	1968q2	936.3	4,588.4	86	86	9.450168	
			1968q3	952.3	4,599.3	87	87	9.447000	
			1968q4	970.1	4,619.8	88	88	9.449775	
			1969q1	995.4	4,691.6	89	89	9.458941	2002
			1969q2	1,011.4	4,706.7	90	90	9.464440	
			1969q3	1,032.0	4,736.1	91	91	9.469299	
			1969q4	1,040.7	4,715.5	92	92	9.469932	
			1970q1	1,053.5	4,707.1	93	93	9.475102	2003
			1970q2	1,070.1	4,715.4	94	94	9.484337	
			1970q3	1,088.5	4,757.2	95	95	9.500948	
			1970q4	1,091.5	4,708.3	96	96	9.512569	
			1971q1	1,137.8	4,834.3	97	97	9.518303	2004
			1971q2	1,159.4	4,861.9	98	98	9.525604	
			1971q3	1,180.3	4,900.0	99	99	9.534653	
			1971q4	1,193.6	4,914.3	100	100	9.543263	
			1972q1	1,233.8	5,002.4	101	101	9.553866	2005
			1972q2	1,270.1	5,118.3	102	102	9.559073	
			1972q3	1,293.8	5,165.4	103	103	9.567441	
			1972q4	1,332.0	5,251.2	104	104	9.573135	
			1973q1	1,380.7	5,380.5	105	105	9.585078	2006
			1973q2	1,417.6	5,441.5	106	106	9.588064	
			1973q3	1,438.8	5,411.9	107	107	9.588955	
			1973q4	1,478.1	5,462.4	108	108	9.596752	
			1974q1	1,494.7	5,417.0	109	109	9.607370	2007
			1974q2	1,534.2	5,431.3	110	110	9.604994	
			1974q3	1,563.4	5,378.7	111	111	9.611697	
			1974q4	1,603.0	5,357.2	112	112	9.615259	
			1975q1	1,619.6	5,292.4	113	113	9.608412	2008
			1975q2	1,656.4	5,333.2	114	114	9.613362	
			1975q3	1,713.8	5,421.4	115	115	9.608553	
			1975q4	1,765.9	5,494.4	116	116	9.607200	
			1976q1	1,824.5	5,618.5	117	117	9.613246	2009
			1976q2	1,856.9	5,661.0	118	118	9.618895	
			1976q3	1,890.5	5,689.8	119	119	9.625157	
			1976q4	1,938.4	5,732.5	120	120	9.631899	
			1977q1	1,992.5	5,799.2	121	121	9.639108	2010
			1977q2	2,060.2	5,913.0	122	122	9.646820	
			1977q3	2,122.4	6,				



1983q4	3,798.1	7,001.5	148
1984q1	3,912.8	7,140.6	149
1984q2	4,015.0	7,266.0	150
1984q3	4,087.4	7,337.5	151
1984q4	4,147.6	7,396.0	152
1985q1	4,237.0	7,469.5	153
1985q2	4,302.3	7,537.9	154
1985q3	4,394.6	7,655.2	155
1985q4	4,453.1	7,712.6	156
1986q1	4,516.3	7,784.1	157
1986q2	4,555.2	7,819.8	158
1986q3	4,619.6	7,898.6	159
1986q4	4,669.4	7,939.5	160
1987q1	4,736.2	7,995.0	161
1987q2	4,821.5	8,084.7	162
1987q3	4,900.5	8,158.0	163
1987q4	5,022.7	8,292.7	164
1988q1	5,090.6	8,339.3	165
1988q2	5,207.7	8,449.5	166
1988q3	5,299.5	8,498.3	167
1988q4	5,412.7	8,610.9	168
1989q1	5,527.4	8,687.7	169
1989q2	5,628.4	8,766.1	170
1989q3	5,711.6	8,831.5	171
1989q4	5,763.4	8,850.2	172
1990q1	5,890.8	8,947.1	173
1990q2	5,974.7	8,981.7	174
1990q3	6,029.5	8,983.9	175
1990q4	6,023.3	8,907.4	176
1991q1	6,054.9	8,865.6	177
1991q2	6,143.6	8,934.4	178
1991q3	6,218.4	8,977.3	179
1991q4	6,279.3	9,016.4	180
1992q1	6,380.8	9,123.0	181
1992q2	6,492.3	9,223.5	182
1992q3	6,586.5	9,313.2	183
1992q4	6,697.6	9,406.5	184
1993q1	6,748.2	9,424.1	185
1993q2	6,829.6	9,480.1	186
1993q3	6,904.2	9,526.3	187
1993q4	7,032.8	9,653.5	188
1994q1	7,136.3	9,748.2	189
1994q2	7,269.8	9,881.4	190
1994q3	7,352.3	9,939.7	191
1994q4	7,476.7	10,052.5	192
1995q1	7,545.3	10,086.9	193
1995q2	7,604.9	10,122.1	194
1995q3	7,706.5	10,208.8	195
1995q4	7,799.5	10,281.2	196
1996q1	7,893.1	10,348.7	197
1996q2	8,061.5	10,529.4	198
1996q3	8,159.0	10,626.8	199
1996q4	8,287.1	10,739.1	200
1997q1	8,402.1	10,820.9	201
1997q2	8,551.9	10,984.2	202
1997q3	8,691.8	11,124.0	203
1997q4	8,788.3	11,210.3	204
1998q1	8,889.7	11,321.2	205
1998q2	8,994.7	11,431.0	206
1998q3	9,146.5	11,580.6	207
1998q4	9,325.7	11,770.7	208
1999q1	9,447.1	11,864.7	209
1999q2	9,557.0	11,962.5	210
1999q3	9,712.3	12,113.1	211
1999q4	9,926.1	12,323.3	212
2000q1	10,031.0	12,359.1	213
2000q2	10,278.3	12,582.5	214
2000q3	10,357.4	12,607.7	215
2000q4	10,472.3	12,679.3	216
2001q1	10,508.1	12,643.3	217
2001q2	10,638.4	12,710.3	218
2001q3	10,639.5	12,670.1	219
2001q4	10,701.3	12,705.3	220
2002q1	10,834.4	12,822.3	221
2002q2	10,934.8	12,893.0	222
2002q3	11,037.1	12,955.8	223
2002q4	11,103.8	12,984.0	224
2003q1	11,230.1	13,031.2	225
2003q2	11,370.7	13,152.1	226
2003q3	11,625.1	13,372.4	227
2003q4	11,816.8	13,526.7	228
2004q1	11,988.4	13,606.5	229
2004q2	12,181.4	13,706.2	230
2004q3	12,367.7	13,830.8	231
2004q4	12,562.2	13,950.4	232
2005q1	12,813.7	14,099.1	233
2005q2	12,974.1	14,172.7	234
2005q3	13,205.4	14,291.8	235
2005q4	13,381.6	14,373.4	236
2006q1	13,648.9	14,546.1	237
2006q2	13,799.8	14,589.6	238
2006q3	13,908.5	14,602.6	239
2006q4	14,068.4	14,716.9	240
2007q1	14,233.2	14,726.0	241
2007q2	14,422.3	14,838.7	242
2007q3	14,569.7	14,938.5	243
2007q4	14,685.3	14,991.8	244
2008q1	14,668.4	14,889.5	245
2008q2	14,813.0	14,963.4	246
2008q3	14,843.0	14,891.6	247
2008q4	14,549.9	14,577.0	248
2009q1	14,383.9	14,375.0	249
2009q2	14,340.4	14,355.6	250
2009q3	14,384.1	14,402.5	251
2009q4	14,566.5	14,541.9	252
2010q1	14,681.1	14,604.8	253
2010q2	14,888.6	14,745.9	254
2010q3	15,057.7	14,845.5	255
2010q4	15,230.2	14,939.0	256
2011q1	15,238.4	14,881.3	257
2011q2	15,460.9	14,989.6	258
2011q3	15,587.1	15,021.1	259
2011q4	15,785.3	15,190.3	260
2012q1	15,956.5	15,275.0	261
2012q2	16,094.7	15,336.7	262
2012q3	16,268.9	15,431.3	263
2012q4	16,332.5	15,433.7	264
2013q1	16,502.4	15,538.4	265
2013q2	16,619.2	15,606.6	266
2013q3	16,872.3	15,779.9	267
2013q4	17,078.3	15,916.2	268
2014q1	17,044.0	15,831.7	269
2014q2	17,328.2	16,010.4	270
2014q3	17,599.8	16,205.6	271
2014q4	17,710.7	16,311.6	272

CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 206**

**Staff CAPM Results  
(Capital Asset Pricing Model)**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

1	2	3	4	5	6	7	8	9	10	11	12	13
Natural Gas AVA UG 288	VL Gas IOUs 1	Sensitivity with AGL (Purchase by Southern Co. Pending)										
#	Abbreviated Utility	UG 288 AVA	UG 288 Staff	VL Corporate Name Gas Utility	NYS, NSDQ Ticker	SNL Key	IRS EIN	SEC File	VL Region	VL 8/7/2015 Beta	Yahoo Fin. 8/6/2015 Beta	2015 VL Tax Rate
-	Avista	No	No	Avista Corporation <i>(For reference Purposes Only)</i>	AVA	4057075	91-0462470	1-3701	West	0.80	0.62	
-	Cascade	No	No	Cascade Natural Gas Corp.	MDU	4057112	91-0599090	1-7196	West	N/A	N/A	
1	AGL	Yes	Sensitivity	AGL Resources, Inc.	GAS	4057108	58-2210952	1-14174	East	0.80	0.28	37.5%
2	Atmos	Yes	No	Atmos Energy Corp.	ATO	4057157	75-1743247	1-10042	Central	0.85	0.66	39.5%
3	Laclede	Yes	No	The Laclede Group, Inc.	LG	4002506	74-2976504	1-16681	Central	0.70	0.54	29.0%
4	New Jersey	Yes	No	New Jersey Resources Corp.	NJR	4057128	22-2376465	1-8359	East	0.80	0.92	35.0%
5	NiSource	Yes	No	NiSource Inc.	NI	4057051	35-2108964	1-16189	East	0.85	0.54	37.0%
6	Northwest Natural	Yes	Yes	Northwest Natural Gas Company	NWN	4057132	93-0256722	1-15973	West	0.70	0.73	40.0%
7	Piedmont	Yes	Yes	Piedmont Natural Gas Company, Inc.	PNY	4057136	56-0556998	1-6196	East	0.80	0.68	25.0%
8	South Jersey	Yes	No	South Jersey Industries, Inc.	SJI	4057145	22-1901645	1-6364	East	0.85	1.21	25.0%
9	Southwest Gas	Yes	No	Southwest Gas Corporation	SWX	4041957	88-0085720	1-7850	West	0.85	0.88	35.0%
10	UGI	No	No	UGI Corporation <b>(Propane Focus / VL)</b>	UGI	4057537	23-2668356	1-11071	East	0.95	0.79	
11	WGL	Yes	No	WGL Holdings, Inc.	WGL	4007261	52-2210912	1-16163	East	0.80	0.89	39.0%

**Staff's Representative CAPM Modeling Results**

3.09%	Risk Free Rate as 10 Yr UST as of Jan. 15, 2016
3.83%	Risk Free Rate as 30 Yr UST as of Jan. 15, 2016
4.50%	Ibbotson Market Risk Premium

$R_{AVA} = R_f + \text{Beta} * \text{MRP}$

#	Abbreviated Utility	Ticker	VL		UG 288 AVA	UG 288 Staff	w 10 Yr Forward UST		w 30 Yr Forward UST	
			8/7/2015	8/6/2015			CAPM w VL Beta	CAPM w Yahoo Beta	CAPM w VL Beta	CAPM w Yahoo Beta
1	AGL	GAS	0.80	0.28	Yes	Sensitivity	6.69%	4.35%	7.43%	5.09%
2	Atmos	ATO	0.85	0.66	Yes	No	6.92%	6.06%	7.66%	6.80%
3	Laclede	LG	0.70	0.54	Yes	No	6.24%	5.52%	6.98%	6.26%
4	New Jersey	NJR	0.80	0.92	Yes	No	6.69%	7.23%	7.43%	7.97%
5	NiSource	NI	0.85	0.54	Yes	No	6.92%	5.52%	7.66%	6.26%
6	Northwest Natural	NWN	0.70	0.73	Yes	Yes	6.24%	6.38%	6.98%	7.12%
7	Piedmont	PNY	0.80	0.68	Yes	Yes	6.69%	6.15%	7.43%	6.89%
8	South Jersey	SJI	0.85	1.21	Yes	No	6.92%	8.54%	7.66%	9.28%
9	Southwest Gas	SWG	0.85	0.88	Yes	No	6.92%	7.05%	7.66%	7.79%
10	UGI	UGI	0.95	0.79	No	No	7.37%	6.65%	8.11%	7.39%
11	WGL	WGL	0.80	0.89	Yes	No	6.69%	7.10%	7.43%	7.84%

AVA:	6.69%	6.39%	7.43%	7.13%
Staff w/o AGL:	6.47%	5.95%	7.32%	6.69%
Staff w AGL:	6.54%	6.26%	7.21%	7.00%

Range	From:	5.95%	To:	7.43%
Overall	Midpoint	6.69%		

**CAPM Results Interpreted as Required Rate of Return**

Avg Tax Rate	2015	
Co Peers	34%	Using Company's Filing as High End of Potential Inputs
Staff Peers w/o AGL	33%	
Staff Peers w AGL	34%	

AVA Proposed (UG 288)			Co. Filing Detail
Component	Percent of Total	Cost	Weighted Average
Long Term Debt	50%	5.530%	2.77%
Preferred Stock	0%		0.00%
Common Stock	50%	9.900%	4.95%
	100%		7.72%

**High End**

ROE ex PreTax CAPM			(LT Debt as Filed)
Component	Percent of Total	Cost	Weighted Average
Long Term Debt	50%	5.53%	2.77%
Common Stock	50%	9.33%	4.67%
	100%		7.43%

**Low End**

ROE ex PreTax CAPM			(LT Debt as Filed)
Component	Percent of Total	Cost	Weighted Average
Long Term Debt	50%	5.53%	2.77%
Common Stock	50%	6.37%	3.18%
	100%		5.95%

**PreTax Range of CAPM ROE's**

Range of ROEs From	6.37%	to	9.33%
	Midpoint: 7.85%		

CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 207**

**CONFIDENTIAL  
Cost of Long-Term Debt**

**Exhibits in Support  
of Opening Testimony**

**October 16, 2015**

**STAFF EXHIBIT 207**

**IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE**

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CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
OF  
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**STAFF EXHIBIT 208**

**Southern Co.'s Proposes Acquisition  
Of AGL Resources**

**Exhibits in Support  
of Opening Testimony**

**October 16, 2015**

## Southern Co. to Buy AGL Resources for \$8 Billion

by Cassandra Sweet – WSJ – Aug 25, 2015  
Chelsey Dulaney contributed to this article.

**Deal will create the second-biggest utility company in U.S. by customers**



A Southern Co. facility in Mississippi last year.

**Southern Co.** agreed to buy natural-gas utility **AGL Resources Inc.** for about **\$8 billion**, a move that would give the electricity provider a big chunk of the fast-growing gas market from New Jersey to Florida.

The acquisition would double the number of Southern's customers to nine million, making it the second-largest utility in the U.S., the company said on Monday, and providing it with new revenue to help offset its rising costs.

Terms of the deal call for **AGL Resources shareholders to receive \$66 in cash** for each share, a **38% premium to AGL's closing price on Friday of \$47.86 a share.**

Shares of AGL traded up 28% to \$61.41 apiece on Monday, still well below the offer price, while Southern shares dropped 5% to \$43.58 amid a broad decline in U.S. stocks.

**Both companies' boards of directors have approved the merger**, they said.

The deal, valued at \$12 billion including debt, is the latest move by a large electric utility to buy exposure to the booming natural gas market. **U.S. demand for electricity is stagnating** – and the **fortunes of coal and nuclear power are faltering** – but **demand for inexpensive natural gas is on the rise** around America.

“Natural gas will play a greater and greater role in primary energy needs,” Tom Fanning, Southern’s chief executive, said on a conference call. **“Driving this deal are growth opportunities.”**

Southern has struggled in recent years with other investments in coal- and nuclear-powered electricity generation projects.

**Delays and cost overruns** have hit the company as it tries to build **new reactors in Georgia**, as well as a **first-of-its-kind clean-coal power plant in Mississippi**. Southern has tried to get regulators to agree to rate increases in certain areas to help cover soaring costs, but so far its success has been limited.

The merger “should provide a crucial **diversification** away from Southern’s headline-grabbing construction projects,” said Angie Storozynski, a utility-industry analyst at [Macquarie Group](http://quotes.wsj.com/MQBKY).<http://quotes.wsj.com/MQBKY>



Costs have risen at a Southern project in Waynesboro, Ga., shown in 2014.

Southern’s bid for AGL expands its roster of customers and bolsters its **ability to buy low-cost natural gas to supply its own power plants**. Burning gas creates far less air pollution than coal, which also could help meet increasingly strict federal utility-pollution limits.

**Southern, based in Atlanta, operates 73 power plants and has 4.4 million retail customers in Georgia, Alabama, Mississippi and Florida. Last year** the company’s power-plant portfolio was **40% coal-powered, 40% gas, 16% nuclear and 4% hydroelectric** and other sources, according to Southern’s annual report. By 2020,

company management hopes as much as 55% of its electricity will be generated from gas if prices stay low, while coal would be reduced to 21%.

The number of coal-fired power plants is widely expected to decline around the U.S. because of tougher air pollution regulations which aim to limit carbon emissions from power plants. Since no new coal plants are likely to be built, and nuclear power has largely fallen out of favor owing to the huge cost of constructing new plants, utilities like Southern are increasingly turning to natural-gas-fired power plants to supply energy needs.

**AGL, which also is based in Atlanta, has 4.5 million natural-gas customers in Georgia, Tennessee, New Jersey, Maryland, Florida, Illinois and Virginia.** It serves additional customers through a joint venture called **SouthStar Energy Services**.

**AGL also operates several gas storage plants and is developing gas pipeline projects**, said John Somerhalder II, AGL's chief executive.

One of those projects is a joint venture with Southern rivals **Duke Energy Inc.** and **Dominion Resources**.<http://quotes.wsj.com/D> AGL and **Piedmont Natural Gas** have joined with Duke and Dominion to build a **\$5 billion, 550-mile natural gas pipeline** that will stretch **from West Virginia to Virginia and North Carolina**.

**Adding a growing natural gas utility business with increasing revenue** to its business could help Southern **offset** some of the **problems** it has faced from two budget-busting projects.

**Costs have ballooned** at Southern's Georgia Power utility, which is **building new nuclear power reactors in Waynesboro, Ga.** In Mississippi, Southern's Kemper clean coal project **is turning into one of the most expensive fossil fuel plants ever built** in the U.S.

In the case of Kemper, the company has had to write down billions of dollars' worth of charges. Regulators are now weighing whether Southern's shareholders or its customers will have to foot future bills.

Southern expects the AGL deal to add to its per-share earnings in the first full year after closing, which is expected in the second half of 2016.





## Mergers: Southern Co. Bids for AGL Resources

by Ken Silverstein, Editor-in-Chief – Public Utilities Fortnightly

Aug. 25, 2015 – <http://spark.fortnightly.com/fortnightly/mergers-southern-co-bids-agl-resources>

The stock market may be in turmoil but the utility sector seems to know where it is headed – away from coal and into natural gas, and renewables. That trend was underscored by today's announcement that **Southern Company** would be **buying AGL Resources**, the **Atlanta-based natural gas distribution company**.

That deal comes atop a **series of mergers and acquisitions** in the utility sector that have **focused on stable cash flows** and dividends. They are commonly called "YieldCos" and they are mostly centered on the renewable energy industry that receives tax credits and that sells to customers under long term contracts, typically around 15 years. That's according to Price WaterHouse Coopers, which spoke to this reporter by phone before the Southern/AGL deal was announced.

Such YieldCos accounted for about 85 percent of the deal activity last quarter, says Jeremy Fago, PwC's U.S. power and utilities deal leader. "Costs have fallen too but when I think of stable cash flows, it is a focus on the **ability to generate a return**. Renewables is the area where those contracts have been."

Regulated utilities are also hot commodities: **Both Southern and AGL are in Atlanta, with one focused on power generation and transmission and the other on natural gas delivery – complementary businesses.**

As the utility sector transitions from coal to natural gas as a way to reduce air emissions, the deal makes sense – and as Chief Executive Tom Fanning put it, "skating to where the puck may be." That's what he said at the Edison Electric Institute meeting, referring to how Southern would conduct business in the coming years. He repeated that to reporters covering today's merger news, noting that negotiations started on the deal last February.

"**Earnings profile and cash flow** are still a focus," adds PwC's Fago, referring to strategic asset acquisitions, as well as complementary deals and mergers between equals. "We do see investor interest in the regulated utility space. It is both financial and strategic. We expect to see continued activity there."

As for the major proposal just made public, **Southern will pay \$66 for each share of AGL** (link is external), which is a **premium of 38 percent over AGL's current stock price**. The **deal is valued at \$12 billion**.

**Georgia Public Utility Commission** Chair Chuck Eaton, profiled by the Fortnightly last fall, told the Atlanta Journal Constitution that natural gas is the catalyst – that it is today's preferred fuel because of its cost, abundance and carbon emissions, which are about half that of coal. The commission **must approve the deal**. The **Federal Energy Regulatory Commission** and the **Federal Trade Commission must also weigh in**.

## **Southern's Acquisition of AGL Resources Will Significantly Increase Debt**

Michael G. Haggarty, Assoc. Managing Director – Moody's –Aug. 27, 2015

Last Monday, The **Southern Company** (Baa1 negative) said that it had agreed to **acquire AGL Resources**, Inc. (unrated), an **Atlanta-based natural gas distribution company**, for approximately **\$8 billion in cash**. The transaction will result in a **significant increase in debt** at the Southern holding company at a time when debt has already been increasing, partly to support funding needs at utility subsidiary Mississippi Power Company (Baa2 negative) and portfolio growth at wholesale power subsidiary Southern Power Company (Baa1 stable).

Although **Southern intends to issue \$3 billion of equity to finance the transaction** between now and 2019, **initial debt financing will raise leverage for several years**. The **addition of up to \$8 billion of debt at the Southern holding company at the transaction's close will increase parent company debt to \$10-\$11 billion** (around 25% of consolidated debt) **from less than \$3 billion currently** (10% of total consolidated debt), **pressuring cash flow coverage metrics**. Southern's ratio of consolidated cash flow from operations (**CFO pre-working capital to debt**) will likely fall to around 15% immediately following the acquisition from 20% currently, a level that would be **weak for its current rating** and compared with most other Baa1-rated utility holding company peers. For these reasons, we changed Southern's rating **outlook to negative from stable** when the transaction was announced.

Although AGL provides Southern with regulatory and operational diversity, cash flow coverage metrics will be lower for an extended period as equity is issued over four years. AGL also generates lower financial coverage metrics than Southern currently does, with AGL's ratio of CFO pre-working capital to debt expected to decline to the low- to mid-teens from the mid- to high-teens as it issues debt to fund planned capital investments. The combination of **higher debt and lower cash flow coverage ratios will likely lead to a one-notch downgrade of Southern before the transaction's close**, which Southern estimates will be in the **second half of 2016**.

The AGL acquisition comes while **Southern's risk profile has been increasing** and its **relative position in its current rating has weakened** as a result of **cost increases and schedule delays at the Vogtle new nuclear** plant being built by its largest utility subsidiary, **Georgia Power Company** (A3 stable). Southern's credit quality has also been pressured by approximately **\$2 billion of pre-tax (\$1.2 billion after-tax) charges taken for unrecoverable costs at the Kemper Integrated Gasification Combined Cycle (IGCC) plant** Mississippi Power is building. Southern is also providing significant liquidity to Mississippi Power through intercompany loans. Finally, Southern has been supporting the expansion of wholesale power subsidiary Southern Power into renewable energy through some parent company debt financing.

**Nevertheless**, the **acquisition of AGL will significantly increase the scale, scope, and diversity of Southern's predominantly electric generating business by adding one of the largest natural gas local distribution companies in the country**, with seven local distribution companies serving more than 4.5 million customers in seven states. Notably, this includes the Atlanta Gas Light Company in Georgia, AGL's

second-largest local distribution company, providing opportunities for some synergies and cost savings with Georgia Power. The acquisition would also help **reduce Southern's concentration risk** associated with the large Vogtle and Kemper construction projects because the **combined organization would be larger and more diverse.**

CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 209**

**Value Line (VL)  
Gas and Water Utility Profiles**

**Exhibits in Support  
of Opening Testimony**

**October 16, 2015**



September 4, 2015

## NATURAL GAS UTILITY

540

INDUSTRY TIMELINESS: 65 (of 96)

Stocks within *Value Line's* Natural Gas Utility Industry have had to contend with very volatile financial markets of late. One driving force is China, given that its economy (the second largest in the world behind the United States) is showing indications of losing steam. To make matters worse, there are lingering concerns about oil prices that, at the time of this writing, dropped to their lowest level in several years. But investor anxiety has lessened, to a certain extent, by the Chinese central bank's sudden decision to, once again, lower interest rates to promote economic activity. Moreover, looking at the United States, there were some favorable recent statistics for new home sales, and consumer confidence has improved, both of which suggest that the economic recovery is on track. During all this market turbulence, which seems to occur more often these days, shares in the Natural Gas Utility group are holding up better than many of those in other sectors. One key reason for this is their generous levels of dividend income, which tend to provide a measure of much-needed stability.

## Natural Gas Prices

Natural gas quotations have been relatively low for some time, and it appears that these trends will continue. Even so, that scenario is generally good for regulated utility operations, in part, because it ought to lead to diminished prices for customers, thus bringing down bad-debt expense. Furthermore, there is an increased possibility that homeowners will switch from alternative fuel sources, such as propane, to natural gas. (At the present time, it's estimated that more than 50% of all households in the United States use natural gas.) It is important to mention, nevertheless, that companies in our category also possess nonregulated businesses, which tend to underperform when gas prices are in a slump. Companies with some exposure to this arena include *New Jersey Resources*, *WGL Holdings*, *Atmos Energy*, *AGL Resources*, and *South Jersey Industries*.

## Rate Filings

A number of these utilities must settle cases with their respective state commissions when attempting to change their current rates. The local governments evaluate those rates and determine the return on equity these companies can achieve for a certain period of time. Rate cases generally occur when operational expenses pressure profitability. Thus, at any given time, there are usually several rate cases pending here. As a result, the status of rate cases remains carefully watched in this sector. A favorable ruling can increase what a company might charge customers and, in turn, bolster earnings. It's worth mentioning that, during the first nine months of fiscal 2015 (ends September 30th), *Atmos Energy* managed to complete 15 rate-case proceedings, resulting in a \$75.9 million rise in annual operating income. The state commissions generally try to strike a balance between consumer and shareholder interests in making decisions. When the regulatory environment is relatively quiet, utilities might place greater emphasis on expense-reduction initiatives and nonregulated businesses (which include pipelines and energy marketing & trading).

## Attractive Dividends

The main feature of utility equities is their dividend income. At the time of this writing, the average yield for the 12 companies in our universe was about 3.4%, significantly higher than the *Value Line* median of 2.4%. Standouts include *NiSource Inc.*, *Northwest Natural Gas*, *Laclede Group*, *Piedmont Natural Gas*, and *South Jersey Industries*. When the financial markets exhibit greater volatility, healthy dividend yields tend to act like an anchor, so to speak.

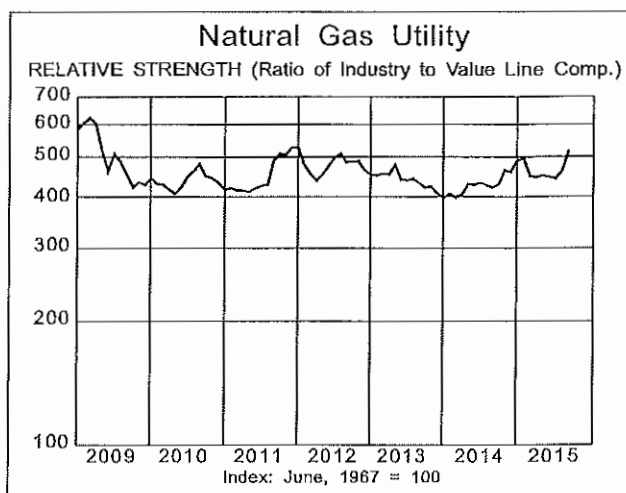
## Business Prospects Out To 2018-2020

We are generally optimistic about the sector's operating performance over the long haul. Indeed, natural gas should remain abundant in this country, thanks to new technologies, so a shortage does not appear likely anytime soon. Moreover, there are limited alternatives for the services the companies in our group offer. Also, it's a challenge for new entrants in the market, given such factors as the size of existing competitors and the considerable initial capital outlays that are required. Finally, the nation's population (over 320 million right now) ought to continue on a steady, upward course, which augurs well for future demand for utility services.

## Conclusion

Stocks within the Natural Gas Utility Industry ought to draw the attention of income-hungry investors with a conservative orientation (given that a number of these issues are ranked favorably for Safety and boast high grades for Price Stability). It is important to note that companies possessing larger nonregulated operations might well offer a higher potential for returns, but profits could be more volatile than for companies with a greater emphasis on the more stable utility segment. As always, our readers are advised to carefully examine the following reports before making a commitment.

Frederick L. Harris, III



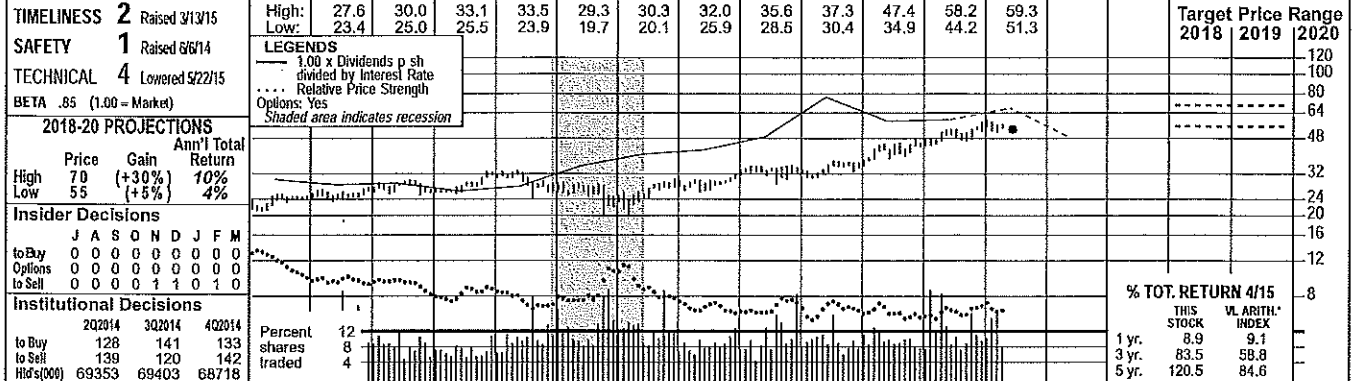
AGL RESOURCES NYSE-GAS		RECENT PRICE	49.56	P/E RATIO	16.0 (Trailing: 14.0 Median: 14.0)	RELATIVE P/E RATIO	0.84	DIV'D YLD	4.1%	VALUE LINE									
<b>TIMELINESS</b> 3 Lowered 12/26/14	High: 33.7 Low: 26.5	39.3 32.0	40.1 34.4	44.7 35.2	39.1 24.0	37.5 24.0	40.1 34.2	43.7 34.1	42.9 36.6	49.3 38.9	56.7 45.2	57.8 46.5	Target Price 2018   2019   2020						
<b>SAFETY</b> 1 Raised 9/9/11	<b>LEGENDS</b> 1.10 x Dividends p sh divided by Interest Rate Relative Price Strength Options: Yes Shaded area indicates recession																		
<b>TECHNICAL</b> 5 Lowered 6/5/15																			
<b>BETA</b> .80 (1.00 = Market)	<b>2018-20 PROJECTIONS</b> Price Gain Ann'l Total High 75 (+50%) 14% Low 65 (+30%) 10%																		
<b>Insider Decisions</b> J A S O N D J F M to Buy 0 0 0 0 0 0 0 0 0 0 0 0 Options 0 0 0 0 0 0 0 0 0 0 0 0 to Sell 1 1 1 1 1 1 1 1 1 1 1 1																			
<b>Institutional Decisions</b> 202014 3Q2014 4Q2014 to Buy 216 201 205 to Sell 162 196 201 Hld's(000) 78232 79006 77255																			
<b>18-20</b> Percent shares traded 18 12 6																			
<b>% TOT. RETURN 4/15</b> THIS STOCK W. ARITH. INDEX 1 yr. -3.3 9.1 3 yr. 44.7 58.8 5 yr. 58.1 84.6																			
<b>1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016</b>																			
18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	29.88	30.42	19.97	33.28	38.83	45.01	37.90	41.95	Revenues per sh <sup>A</sup>	48.80
2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	4.90	5.05	3.06	5.82	6.15	7.87	6.75	7.55	"Cash Flow" per sh	9.30
.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	2.88	3.00	2.12	2.31	2.64	4.71	3.70	3.35	Earnings per sh <sup>A,B</sup>	4.65
1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	1.72	1.76	1.90	1.74	1.88	1.96	2.04	2.10	Div'ds Decl'd per sh <sup>C,F</sup>	2.40
2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	6.14	6.54	3.65	6.64	6.30	6.43	6.75	7.25	Cap'l Spending per sh	7.20
11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	22.95	23.24	28.33	28.96	30.54	31.63	33.15	34.20	Book Value per sh <sup>D</sup>	36.65
57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	77.54	78.00	117.10	117.86	118.89	119.65	122.00	124.00	Common Shs Outst'g <sup>E</sup>	125.00
21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	11.2	12.5	18.8	17.2	16.7	11.0	16.7	11.0	Avg Ann'l P/E Ratio	15.0
1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	.75	.80	1.18	1.09	.94	.58	.58	.58	Relative P/E Ratio	.95
5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%	5.4%	4.7%	4.8%	4.4%	4.3%	3.8%	3.8%	3.8%	Avg Ann'l Div'd Yield	3.4%
<b>CAPITAL STRUCTURE as of 3/31/15</b> Total Debt \$4711 mill. Due in 5 Yrs \$2764 mill. LT Debt \$3524 mill. LT Interest \$181 mill. (Total interest coverage: 4.9x)																			
Leases, Uncapitalized Annual rentals \$33 mill. Pension Assets-12/14 \$906 mill. Oblig. \$1098 mill.																			
<b>Pfd Stock None</b>																			
Common Stock 119,934,611 shs. as of 4/23/15 <b>MARKET CAP: \$5.9 billion (Large Cap)</b>																			
<b>CURRENT POSITION (SMILL)</b>																			
Cash Assets	105	32	41																
Other	2628	2858	2038																
Current Assets	2733	2890	2079																
Accts Payable	432	312	285																
Debt Due	1842	2152	1187																
Other	848	755	899																
Current Liab.	3122	3219	2371																
Fix. Chg. Cov.	373%	612%	488%																
<b>ANNUAL RATES</b> Past 10 Yrs. Past 5 Yrs. Est'd '12-'14 of change (per sh)																			
Revenues	8.0%	3.5%	4.0%																
"Cash Flow"	7.0%	7.0%	6.0%																
Earnings	4.5%	3.0%	6.5%																
Dividends	5.5%	2.0%	4.5%																
Book Value	7.5%	6.5%	3.0%																
<b>AGL Resources reported lackluster first-quarter results.</b> Despite decent operations across the utility segment, earnings per share of \$1.62 underperformed our expectations, as the wholesale services segment had a significant downturn in profitability. Though last year's record profit looked poised to fall in 2015, the quarterly outcome was worse than we had projected. Thus, we have lowered our 2015 estimate by \$0.65 a share, to \$3.10.																			
<b>The rest of the year should have respectable results.</b> Increased customer growth and accelerating rider programs should allow for decent results in the utility segment, and the company is filing rates cases for additional revenues. Indeed, AGL is asking for an additional \$10 million annually in Florida City, and it submitted a request to recover \$178 million in Georgia. Rate relief should boost profitability, if approved.																			
<b>The company's pipeline investments should pay off over the long haul.</b> Indeed, the pipelines lower the cost of transporting natural gas to the Georgia, New Jersey, and Virginia coverage areas, and have higher allowable return rates. This																			
<b>ought to increase earnings by around \$0.20 annually, once the projects are put into service in the 2017-2018 time frame.</b> Too, we expect they will allow for less earnings volatility.																			
<b>The balance sheet is in solid condition.</b> Debt-to-equity has trended lower in recent years. However, the debt-equity ratio may be near a low point, as management plans to relever AGL to fuel capital expenditures, including an anticipated \$300 million bond issuance this fall. Cash flows remain solid and should fuel the payout over the coming years. AGL Resources could be in the market for an acquisition.																			
<b>Shares of AGL Resources are attractive for several reasons.</b> Despite being only neutrally ranked for Timeliness, this issue holds above-average total return potential for a utility. Too, it delivers a strong current payout, and has decent dividend growth potential. This issue should appeal to risk-averse investors, as it carries our Highest Safety mark (1). All told, most long-term investors should find this issue to be appealing.																			
<i>John E. Seibert III</i> June 5, 2015																			
<b>Company's Financial Strength</b> A <b>Stock's Price Stability</b> 95 <b>Price Growth Persistence</b> 60 <b>Earnings Predictability</b> 50																			

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002. (B) Diluted earnings per share. May not add up due to rounding. Excl. nonrecurring gains (losses): '99, \$0.39; '00, \$0.13; '01, \$0.13; '03, (\$0.07); '08, \$0.13; '14, (\$0.67). Next earnings report due late July. (C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2014: \$1,952 million, \$16.38/share. (E) In millions. (F) Excluding special dividends from the Nicor merger.

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<b>ATMOS ENERGY CORP. NYSE-ATO</b>										RECENT PRICE	<b>53.20</b>	P/E RATIO	<b>17.5</b> (Trailing: 17.8; Median: 15.0)	RELATIVE P/E RATIO	<b>0.92</b>	DIV'D YLD	<b>3.0%</b>	<b>VALUE LINE</b>
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	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC '18-'20
Revenues per sh <sup>A</sup>	61.75	75.27	68.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	43.15	46.35	54.15
"Cash Flow" per sh	3.90	4.26	4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.55	5.75	6.60
Earnings per sh <sup>A B</sup>	1.72	2.00	1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.00	3.20	3.80
Div'ds Decl'd per sh <sup>C</sup>	1.24	1.26	1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.64	1.90
Cap'l Spending per sh	4.14	5.20	4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.05	8.90	9.40
Book Value per sh	19.90	20.16	22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.85	32.70	36.65
Common Shs Outst'g <sup>D</sup>	80.54	81.74	89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	105.00	110.00	120.00
Avg Ann'l P/E Ratio	16.1	13.5	15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	16.1	16.1	16.5
Relative P/E Ratio	.86	.73	.84	.82	.83	.84	.90	1.01	.89	.84	.84	.84	1.05
Avg Ann'l Div'd Yield	4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	3.1%	3.1%	3.0%
Revenues (\$mill) <sup>A</sup>	4973.3	6152.4	5098.4	7221.3	4969.1	4789.7	4347.6	3438.5	3886.3	4940.9	4530	5100	6500
Net Profit (\$mill)	136.8	162.3	170.5	180.3	179.7	201.2	199.3	192.2	230.7	289.8	315	350	460
Income Tax Rate	37.7%	37.6%	35.8%	38.4%	34.4%	38.5%	36.4%	33.8%	38.2%	39.2%	39.6%	39.5%	40.0%
Net Profit Margin	2.7%	2.6%	2.9%	2.5%	3.6%	4.2%	4.6%	5.6%	5.9%	5.9%	7.0%	6.9%	7.1%
Long-Term Debt Ratio	57.7%	57.0%	52.0%	50.8%	49.9%	45.4%	49.4%	45.3%	48.8%	44.3%	44.5%	45.0%	45.0%
Common Equity Ratio	42.3%	43.0%	48.0%	49.2%	50.1%	54.6%	50.6%	54.7%	51.2%	55.7%	55.5%	55.0%	55.0%
Total Capital (\$mill)	3785.5	3828.5	4092.1	4172.3	4346.2	3987.9	4461.5	4315.5	5036.1	5542.2	6030	6540	8000
Net Plant (\$mill)	3374.4	3629.2	3836.8	4136.9	4439.1	4793.1	5147.9	5475.6	6030.7	6725.9	7500	8100	10200
Return on Total Cap'l	5.3%	6.1%	5.9%	5.9%	5.9%	6.9%	6.1%	6.1%	5.9%	6.4%	6.5%	6.5%	7.0%
Return on Shr. Equity	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	9.5%	9.5%	10.5%
Return on Com Equity	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	9.5%	9.5%	10.5%
Retained to Com Eq	2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	3.3%	2.8%	4.0%	4.7%	4.5%	4.5%	5.5%
All Div'ds to Net Prof	73%	63%	65%	65%	68%	62%	62%	65%	56%	51%	52%	52%	50%

**CAPITAL STRUCTURE** as of 3/31/15  
 Total Debt \$2680.2 mill. Due in 5 Yrs \$950.0 mill.  
 LT Debt \$2455.2 mill. LT Interest \$145.0 mill.  
 (LT Interest earned: 4.7%; Annual Interest coverage: 4.7x)  
 Leases, Uncapitalized Annual rentals \$16.7 mill.  
 Pfd Stock None  
 Pension Assets-9/14 \$434.8 mill.  
 Oblig. \$493.6 mill.  
 Common Stock 101,018,788 shs.  
 as of 5/1/15  
**MARKET CAP: \$5.4 billion (Large Cap)**

**CURRENT POSITION** 2013 2014 3/31/15 (\$MILL)

Cash Assets	66.2	42.3	95.5
Other	617.1	733.5	722.1
Current Assets	683.3	775.8	817.6
Debts Payable	241.6	311.6	295.6
Acct Due	368.0	196.7	225.0
Other	368.9	402.4	497.9
Current Liab.	978.5	910.7	1018.5
Fix. Chg. Cov.	537%	637%	645%

**ANNUAL RATES** Past 10 Yrs. Past 5 Yrs. Est'd '12-'14 to '16-'20

Revenues	5.5%	8.0%	4.0%
"Cash Flow"	5.0%	4.0%	4.5%
Earnings	5.0%	5.0%	7.0%
Dividends	1.5%	2.0%	5.0%
Book Value	6.0%	4.5%	4.5%

**QUARTERLY REVENUES (\$ mill.)<sup>A</sup>**

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	1084.0	1225.5	576.4	552.6	3438.5
2013	1034.2	1309.0	857.9	685.2	3886.3
2014	1255.1	1964.3	942.7	778.8	4940.9
2015	1258.8	1540.1	955	776.1	4530
2016	1300	2000	1000	800	5100

**EARNINGS PER SHARE<sup>A B E</sup>**

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	.68	1.12	.31	--	2.10
2013	.85	1.23	.36	.08	2.50
2014	.95	1.38	.45	.23	2.96
2015	.96	1.35	.47	.22	3.00
2016	1.00	1.45	.51	.24	3.20

**QUARTERLY DIVIDENDS PAID<sup>C</sup>**

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.34	.34	.34	.345	1.37
2012	.345	.345	.345	.35	1.39
2013	.35	.35	.35	.37	1.42
2014	.37	.37	.37	.39	1.50
2015	.39	.39			

**BUSINESS:** Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to more than three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for 2014: 65%, residential; 30%, commercial; 3%, industrial; and 2% other. 2014 depreciation rate 3.0%. Has around 4,760 employees. Officers and directors own 1.6% of common stock (12/14 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

**Atmos Energy had a tough time making progress on the earnings-per-share front in the first two quarters of fiscal 2015.** (Years end on September 30th.) The nonregulated segment experienced a drop in realized margins, reflecting lower natural gas price volatility. During the same period in fiscal 2014, strong demand in the natural gas market caused by substantially colder-than-normal weather led to a more attractive business environment. It should also be noted that the weighted number of diluted shares outstanding was higher. But the natural gas distribution unit benefited partly from higher rates, particularly in the Mid-Tex, Kentucky/Mid-States, Colorado-Kansas, and West Texas divisions. Greater transportation revenues and higher revenue-related taxes helped here, too. Finally, the performance of the regulated pipeline operation enjoyed the benefits of the Gas Reliability Infrastructure Program (GRIP) filings approved in 2014 and 2015. **We anticipate more of the same during the second half.** Consequently, the bottom line might be about \$3.00 a share for the year as a whole. That would be

slightly above the fiscal 2014 figure. Regarding fiscal 2016, however, share net may advance to \$3.20, assuming that operating margins expand further. **Meanwhile, there has been much activity in the rate-filing arena.** In fact, through the first six months of this fiscal year, the Dallas-headquartered company completed seven regulatory proceedings resulting in a \$14.4 million increase in annual operating income. What's more, at the time of this writing, there were 10 rate-making initiatives in progress seeking an additional \$114.4 million of annual operating income. Of course, there are no guarantees that Atmos will receive everything it desires. **Various investors should find something to like here.** The equity offers a decent amount of current dividend income that's well covered by corporate profits. Future, steady increases in the payout are probable, also. Moreover, the Timeliness rank sits at 2 (Above Average). Other appealing qualities include the 1 (Highest) rank for Safety and excellent score for Price Stability.

*Frederick L. Harris, III* June 5, 2015

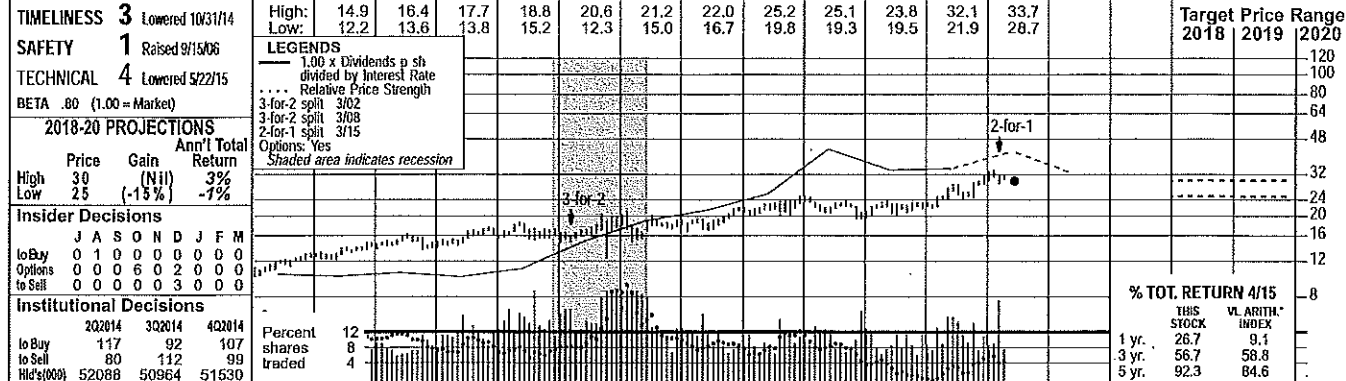
Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	90

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LACLEDE GROUP NYSE-LG		RECENT PRICE	52.49	P/E RATIO	16.4	(Trailing: 16.2 Median: 14.0)	RELATIVE P/E RATIO	0.86	DIV'D YLD	3.5%	VALUE LINE										
<b>TIMELINESS</b> 3	Raised 2/27/15	High: 32.5	34.3	37.5	36.0	55.8	48.3	37.8	42.8	44.0	48.5	55.2	55.8	Target Price	Range						
<b>SAFETY</b> 2	Raised 6/20/03	Low: 26.0	26.9	29.1	28.8	31.9	29.3	30.8	32.9	36.5	37.4	44.0	49.1	2018	2019						
<b>TECHNICAL</b> 4	Lowered 5/22/15	<b>LEGENDS</b> ..... 1.00 x Dividends p sh divided by Interest Rate ..... Relative Price Strength Options: Yes Shaded area indicates recession										128									
<b>BETA</b> .70	(1.00 = Market)	<b>2018-20 PROJECTIONS</b> Price Gain Ann'l Total High 75 (+4.5%) 12% Low 55 (+3.5%) 5%										96									
<b>Insider Decisions</b> J A S O N D J F M to Buy 0 0 0 0 0 0 0 0 0 0 0 0 Options 0 1 2 0 0 0 0 0 0 0 0 0 to Sell 0 2 2 0 0 0 0 0 0 0 0 0												80									
<b>Institutional Decisions</b> 202014 302014 4Q2014 to Buy 125 113 85 to Sell 53 67 99 Hlds(000) 32190 34204 34804												64									
Percent shares traded 15 10 5												48									
<b>% TOT. RETURN 4/15</b> THIS STOCK VS. ARITH. INDEX 1 yr. 13.6 9.1 3 yr. 48.1 58.8 5 yr. 66.9 84.6												40									
<b>© VALUE LINE PUB. LLC 18-20</b>												32									
1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Revenues per sh <sup>A</sup>	60.00		
26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	51.15	55.80	"Cash Flow" per sh <sup>A</sup>	6.35		
2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	5.00	5.30	Earnings per sh <sup>A B</sup>	4.20		
1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.15	3.30	Div'ds Decl'd per sh <sup>C</sup>	2.20		
1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.92	Cap'l Spending per sh	5.55		
2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	4.20	4.40	Book Value per sh <sup>D</sup>	48.10		
14.96	14.89	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.20	39.80	Common Shs Outs't'g <sup>E</sup>	45.00		
18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.00	43.00	Avg Ann'l P/E Ratio	15.5		
15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	Bold figures are Value Line estimates		Relative P/E Ratio	.95		
.90	.97	.74	1.09	.78	.83	.86	.73	.75	.86	.89	.87	.82	.92	1.20	1.04			Avg Ann'l Div'd Yield	3.5%		
5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%						
<b>CAPITAL STRUCTURE as of 3/31/15</b> Total Debt \$2063.9 mill. Due in 5 Yrs \$100.0 mill. LT Debt \$1736.3 mill. LT Interest \$70.0 mill. (Total interest coverage: 4.7x)						1597.0	1997.6	2021.6	2209.0	1895.2	1735.0	1603.3	1125.5	1017.0	1627.2	2200	2400	Revenues (\$mill) <sup>A</sup>		2700	
<b>Leases, Uncapitalized Annual rentals \$12.0 mill.</b> Pension Assets-9/14 \$506.6 mill. Oblig. \$692.5 mill.						40.1	50.5	49.8	57.6	64.3	54.0	63.8	62.6	52.8	84.6	135	140	Net Profit (\$mill)		190	
<b>Pfd Stock None</b> Common Stock 43,318,933 shs. as of 4/30/15						34.1%	32.5%	33.4%	31.3%	33.6%	33.4%	31.4%	29.6%	25.0%	27.6%	29.0%	30.0%	Income Tax Rate		30.0%	
<b>MARKET CAP: \$2.3 billion (Mid Cap)</b>						2.5%	2.5%	2.5%	2.6%	3.4%	3.1%	4.0%	5.6%	5.2%	5.2%	6.2%	5.9%	Net Profit Margin		7.0%	
<b>CURRENT POSITION</b> 2013 2014 3/31/15 (\$MILL)						48.1%	49.5%	45.3%	44.4%	42.9%	40.5%	38.9%	36.1%	46.6%	55.1%	54.0%	53.0%	Long-Term Debt Ratio		51.0%	
Cash Assets 53.0 16.1 46.9 Other 422.9 588.8 790.3 Current Assets 475.9 604.9 837.2						51.8%	50.4%	54.6%	55.5%	57.1%	59.5%	61.1%	63.9%	53.4%	53.4%	44.9%	46.0%	47.0%	Common Equity Ratio		49.0%
Accts Payable 140.2 176.7 247.6 Debt Due 74.0 287.1 327.6 Other 139.0 319.0 278.5 Current Liab. 353.2 782.8 853.7 Fix. Chg. Cov. 337% 423% 477%						707.9	798.9	784.5	878.1	906.3	899.9	937.7	941.0	1959.0	3359.4	3400	3645	Total Capital (\$mill)		4400	
<b>ANNUAL RATES</b> Past Past Est'd '12-'14 of change (per sh) 10 Yrs. 5 Yrs. to '18-'20						679.5	763.8	793.8	823.2	855.9	884.1	928.7	1019.3	1776.6	2759.7	2895	3045	Net Plant (\$mill)		3520	
Revenues -2.5% -15.5% 7.0% "Cash Flow" 3.0% -2.0% 8.5% Earnings 4.0% -2.0% 10.0% Dividends 2.5% 3.0% 4.5% Book Value 7.0% 7.5% 7.5%						7.6%	8.4%	8.5%	8.1%	8.7%	7.4%	8.1%	7.9%	3.3%	3.1%	4.5%	4.5%	Return on Total Cap'l		5.0%	
<b>Fiscal Year</b> QUARTERLY REVENUES (\$mill) <sup>A</sup> Full Fiscal Year						10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	8.5%	8.5%	Return on Shr. Equity		8.5%	
Dec.31 Mar.31 Jun.30 Sep.30						10.9%	12.5%	11.8%	11.8%	12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	8.5%	8.5%	Return on Com Equity		8.5%	
2012 410.9 358.2 186.9 169.5 1125.5 2013 307.0 397.6 165.3 147.1 1017.0 2014 468.6 694.5 241.8 222.3 1627.2 2015 619.6 877.4 360 343 2200 2016 675 950 400 375 2400						3.1%	5.1%	4.3%	5.2%	5.9%	3.6%	4.9%	4.3%	1.0%	1.5%	3.5%	3.5%	Retained to Com Eq		4.0%	
2012 1.12 1.32 .38 d.03 2.79 2013 1.14 1.34 .25 d.30 2.02 2014 1.09 1.59 .33 d.35 2.35 2015 1.09 2.18 .20 d.32 3.15 2016 1.15 1.90 .30 d.25 3.30						72%	59%	63%	56%	53%	64%	56%	59%	81%	73%	58%	58%	All Div'ds to Net Prof		52%	
<b>Fiscal Year</b> EARNINGS PER SHARE <sup>A B F</sup> Full Fiscal Year						<b>BUSINESS:</b> Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City. Has roughly 1.6 million customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility terms sold and transported in fiscal 2014: 2.0 bill. Revenue mix for regulated operations: residential, 66%; commercial and industrial, 24%; transportation, 2%; other, 8%. Has around 3,152 employees. Officers and directors own 3.2% of common shares (1/15 proxy). Chairman: William E. Nasser; CEO: Suzanne Silherwood, Inc.; Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelactedagroup.com.															
Dec.31 Mar.31 Jun.30 Sep.30						<b>Laclede reported solid fiscal second-quarter results (ended March 31st).</b> Indeed, earnings per share reached \$2.18, aided by contributions from the Alagasco merger and synergies being realized through combination efforts with Missouri Gas. Too, cooler-than-usual winter weather played a role in the outstanding results. The second half of the fiscal year appears likely to be weaker than our original projections, as a warmer April and the timing of expenses, including increased maintenance costs, should hamper second-half results. Still, given the latest performance, we raised our 2015 share-net estimate by a nickel, to \$3.15.															
Mar.31 Jun.30 Sep.30 Dec.31						<b>Finances appear to be in decent shape.</b> Although like many industry peers, Laclede's long-term debt constitutes more than 50% of total capital, this is at a fairly manageable level. Too, a good portion of the debt is fixed-rate, which means interest expenses don't fluctuate much. This, in turn, helps to add some stability to earnings.															
2011 .405 .405 .405 .405 1.62 2012 .415 .415 .415 .415 1.66 2013 .425 .425 .425 .425 1.70 2014 .44 .44 .44 .44 1.76 2015 .46 .46						<b>The dividend is a top draw.</b> The payout is well covered by earnings, and the yield is attractive. We expect the dividend to rise at a decent clip over the next few years, although the payout ratio will likely be well below historical highs.															
<b>Cal-endar</b> QUARTERLY DIVIDENDS PAID <sup>C</sup> Full Year						<b>This issue has moderate appeal at this time.</b> Indeed, long-term appreciation potential is below average, and the prospects for payout growth are modest. Nonetheless, when factoring the Above-Average Safety rank and a lower-than-market Beta, Laclede shares offer reasonable total return possibilities on a risk-adjusted basis. This issue should appeal to those with an income objective, though waiting for a price dip appears to be prudent at this juncture.															
2011 .405 .405 .405 .405 1.62 2012 .415 .415 .415 .415 1.66 2013 .425 .425 .425 .425 1.70 2014 .44 .44 .44 .44 1.76 2015 .46 .46						<b>The longer-term picture is favorable for Laclede.</b> Rates cases have been filed for an increase in infrastructure replacement, including \$5.5 million at Laclede and \$2.9 million at Missouri Gas. This should lead to decent earnings growth, as the company would benefit from increased pipeline reliability. The integration of Alagasco appears to be on the right track, and further synergies look to be achieved going forward. All told, we think Laclede can earn \$4.20 a share by 2018-2020.															
2011 .405 .405 .405 .405 1.62 2012 .415 .415 .415 .415 1.66 2013 .425 .425 .425 .425 1.70 2014 .44 .44 .44 .44 1.76 2015 .46 .46						(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes nonrecurring losses: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. (C) Dividends historically paid in early January, April, July, and October. (D) Dividend reinvestment plan available. (E) Incl. deferred charges. In '14: \$383.8 mill., \$8.85/sh. (E) In millions. (F) Qly. egs. may not sum due to rounding or change in shares outstanding.															
2011 .405 .405 .405 .405 1.62 2012 .415 .415 .415 .415 1.66 2013 .425 .425 .425 .425 1.70 2014 .44 .44 .44 .44 1.76 2015 .46 .46						<b>Company's Financial Strength</b> B++ <b>Stock's Price Stability</b> 100 <b>Price Growth Persistence</b> 40 <b>Earnings Predictability</b> 85															

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**NEW JERSEY RES. NYSE-NJR** RECENT PRICE **29.84** P/E RATIO **17.0** (Trailing: 18.3) RELATIVE P/E RATIO **0.89** DIV'D YLD **3.1%** **VALUE LINE**



1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
11.33	14.71	25.61	22.06	31.14	30.44	38.10	39.81	36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	40.60	41.75	Revenues per sh <sup>A</sup>	45.65
.93	1.00	1.06	1.07	1.19	1.25	1.31	1.37	1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.20	2.50	"Cash Flow" per sh	2.65
.55	.60	.65	.70	.79	.85	.88	.93	.78	1.35	1.20	1.23	1.29	1.36	1.37	2.10	1.75	1.80	Earnings per sh <sup>B</sup>	1.85
.37	.38	.39	.40	.41	.43	.45	.48	.51	.56	.62	.68	.72	.77	.81	.86	.92	.94	Div'ds Decl'd per sh <sup>C</sup>	.98
.60	.62	.55	.51	.57	.72	.64	.64	.73	.86	.90	1.05	1.13	1.28	1.33	1.52	.95	.95	Cap'l Spending per sh	.95
3.79	4.14	4.40	4.35	5.13	5.62	5.30	7.50	7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.47	12.30	13.20	Book Value per sh <sup>D</sup>	15.65
79.83	79.17	79.99	83.00	81.70	83.22	82.64	82.88	83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.00	85.00	Common Shs Outs'tg <sup>E</sup>	85.00
15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.6	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	14.0
.87	.96	.73	.80	.80	.81	.89	.87	1.15	.74	.99	.95	1.05	1.07	.90	.60			Relative P/E Ratio	.90
4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%			Avg Ann'l Div'd Yield	3.5%

**CAPITAL STRUCTURE** as of 3/31/15  
 Total Debt \$881.5 mill. Due in 5 Yrs \$315.2 mill.  
 LT Debt \$699.2 mill. LT Interest \$16.3 mill.  
 Incl. \$57.9 mill. capitalized leases.  
 (LT interest earned: 7.5%; total interest coverage: 7.5x)  
 Pension Assets-9/14 \$268.6 mill.  
 Pfd Stock None  
 Common Stock 85,581,223 shs. as of 5/5/15  
**MARKET CAP: \$2.6 billion** (Mid Cap)

CURRENT POSITION (\$MILL)	2013	2014	3/31/15
Cash Assets	3.0	2.2	103.3
Other	742.9	680.5	642.3
Current Assets	745.9	682.7	745.6
Accts Payable	332.8	330.3	329.5
Debt Due	434.2	335.5	182.3
Other	84.8	125.3	143.3
Current Liab.	851.8	791.1	655.1
Fix. Chg. Cov.	700%	700%	700%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Past Est'd '11-'13 to '16-'20
Revenues	2.5%	-3.5%	3.5%
"Cash Flow"	5.0%	4.5%	3.5%
Earnings	6.5%	5.5%	2.5%
Dividends	6.5%	8.5%	3.0%
Book Value	8.0%	4.5%	6.5%

Fiscal Year Ends	QUARTERLY REVENUES (\$mill.) <sup>A</sup>				Full Fiscal Year
	Dec.31	Mar.31	Jun.30	Sep.30	
2012	642.4	612.9	425.1	568.5	2248.9
2013	736.0	960.9	767.5	733.7	3198.1
2014	878.4	1579.6	688.3	591.9	3738.2
2015	824.1	1013.1	825	787.8	3450
2016	850	1060	835	805	3550

Fiscal Year Ends	EARNINGS PER SHARE <sup>A,B</sup>				Full Fiscal Year
	Dec.31	Mar.31	Jun.30	Sep.30	
2012	.55	.90	.05	d.14	1.36
2013	.43	.82	.12	d.01	1.37
2014	.47	1.81	.05	d.23	2.10
2015	.65	1.16	.10	d.16	1.75
2016	.66	1.17	.11	d.14	1.80

Cal-endar	QUARTERLY DIVIDENDS PAID <sup>C</sup>				Full Year
	Mar.31	Jun.30	Sep.30	Dec.31	
2011	.18	.18	.18	.18	.72
2012	.19	.19	.19	.40	.97
2013	--	.20	.20	.20	.60
2014	.21	.21	.21	.23	.86
2015	.23	.23			

**BUSINESS:** New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 504,300 customers at 9/30/14 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2014 volume: 260 bill. cu. ft. (4% interruptible, 27% residential and

**New Jersey Resources posted mixed financial results for its March quarter.** Indeed, revenues declined almost 36%, on a year-to-year basis. This downturn reflected a 46.1% drop in the nonutility business, and to a lesser extent a 5% fall in utility volumes. On the upside, the majority of the reduced revenues are stemming from the downturn in commodity fuel prices. This is evident in NJR's system throughput, which increased 21%, to 297.8 billion cubic feet. On the profitability front, the diminished top line weighed on both fixed- and variable-cost absorption and, consequently, operating expenses rose 740 basis points as a percentage of revenues. After excluding losses on derivative instruments, tax adjustments, and the effect of economic hedging, the company's net financial earnings declined about 36%, to \$1.16 a share. This was better than our earlier expectation. **As a result, we have raised our 2015 bottom-line estimate by \$0.20, to \$1.75 a share.** This would still represent an annual earnings decline of more than 15%. Nonetheless, it does fall more in line with management's recently raised guidance

commercial and electric utility, 69% incentive programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2014 dep. rate: 3.0%. Has 968 empls. Off./dir. own about 1.4% of common (12/14 Proxy). Chrmn., CEO & Pres.: Laurence M. Downes. Inc.: NJ Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

range of \$1.65-\$1.75. The main detractor to this year's results will likely be lower energy services income. That said, NJR continues to benefit from the New Jersey Natural Gas division, which added 4,079 new customer accounts so far this year; about half of those came from newly constructed homes in its service territory. The company anticipates adding 15,000-17,000 new accounts in 2015 and 2016, combined. **Capital expenditures augur well for New Jersey Resources' prospects.** It continues to focus on updating its regulated utility infrastructure, in an effort to raise system safety, reliability, and integrity. The Southern Reliability Link is a 28-mile, 30-inch main transmission pipeline that is in the planning and approval phase. Finally, the company recently completed its 20mw Carroll Area Wind Farm, and continues to work on the 48mw Alexander Wind Farm in Kansas. All told, these projects represent about \$500 million-\$600 million in capital projects. **Still, at this juncture, these shares do not stand out.** NJR's dividend yield is below average for a utility.

*Bryan J. Fong* June 5, 2015

(A) Fiscal year ends Sept. 30th. (B) Diluted earnings. Qly eggs may not sum to total due to change in shares outstanding. Next earnings report due late July. (C) Dividends historically paid in early Jan., April, July, and October. 1Q '13 div'd paid in 4Q '12. ■ Dividend reinvestment plan available. (D) Includes regulatory assets in 2014: \$377.6 million, \$4.48/share. (E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	60

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NISOURCE INC. NYSE-N		RECENT PRICE	P/E RATIO	Trailing: 27.8	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
TIMELINESS — Suspended 6/5/15 SAFETY 3 Lowered 1/14/02 TECHNICAL — Suspended 6/5/15 BETA .85 (1.00 = Market)		47.04	25.4	(Median: 19.0)	1.34	2.2%	
High: 22.8 Low: 19.7 25.5 20.4 24.8 19.5 25.4 17.5 19.8 10.4 15.8 7.8 18.0 14.1 24.0 17.7 26.2 22.3 33.5 24.8 44.9 32.1 47.8 40.9		2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016		Target Price Range 2018 2019 2020			
LEGENDS — 1.20 x Dividends p sh divided by Interest Rate ..... Relative Price Strength Options: Yes Shaded area indicates recession		2018-20 PROJECTIONS Price Gain Ann'l Total Return High 50 (+5%) 4% Low 35 (-25%) -4%		% TOT. RETURN 4/15 THIS STOCK VL ARITH. INDEX 1 yr. 22.5 9.1 3 yr. 90.9 58.8 5 yr. 216.5 84.6			
Insider Decisions J A S O N D J F M to Buy 0 0 0 0 0 0 0 0 0 0 0 0 to Sell 0 0 0 0 0 0 0 0 0 0 0 0 Options 0 0 0 0 0 0 0 0 0 0 0 0		Institutional Decisions 2Q2014 3Q2014 4Q2014 to Buy 172 181 181 to Sell 183 188 198 Hrs(000) 254205 253531 252482		© VALUE LINE PUB. LLC '18-20			
NiSource acquired Columbia Energy on November 1, 2000, paying approximately \$6 billion in cash and stock. Columbia shareholders who chose cash received \$70 a share, plus a security with a face value of \$2.60. Those who chose stock received \$74 a share in NiSource common stock. Shareholders' selections were prorated to reflect a 30% stock portion of the transaction. In 2003, NiSource sold Columbia's exploration and production business.		2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016		Revenues per sh 24.90 "Cash Flow" per sh 5.10 Earnings per sh ^ 2.60 Div'd Decl'd per sh ^ 1.20 Cap'l Spending per sh 5.55 Book Value per sh c 25.55 Common Shs Outst'g ^ 325.00 Avg Ann'l P/E Ratio 16.0 Relative P/E Ratio 1.00 Avg Ann'l Div'd Yield 2.8%			
CAPITAL STRUCTURE as of 3/31/15 Total Debt \$8734.6 mill. Due in 5 Yrs \$2598.8 mill. LT Debt \$7957.9 mill. LT Interest \$450 mill. (Interest cov. earned: 2.8x) (57% of Cap'l)		7899.1 7490.0 7939.8 8874.2 6649.4 6422.0 6019.1 5061.2 5657.3 6470.6 6850 7200		Revenues (\$mill) 8100 Net Profit (\$mill) 810 Income Tax Rate 37.5% AFUDC % to Net Profit 2.0% Long-Term Debt Ratio 56.0% Common Equity Ratio 44.0% Total Capital (\$mill) 18810 Net Plant (\$mill) 21025 Return on Total Cap'l 6.0% Return on Shr. Equity 10.0% Return on Com Equity 10.0% Retained to Com Eq 5.5% All Div's to Net Prof 46%			
Leases, Uncapitalized Annual rentals \$22.7 mill. Pension Assets-12/14 \$2.33 bill. Oblig. \$2.75 bill.		7899.1 7490.0 7939.8 8874.2 6649.4 6422.0 6019.1 5061.2 5657.3 6470.6 6850 7200		Revenues (\$mill) 8100 Net Profit (\$mill) 810 Income Tax Rate 37.5% AFUDC % to Net Profit 2.0% Long-Term Debt Ratio 56.0% Common Equity Ratio 44.0% Total Capital (\$mill) 18810 Net Plant (\$mill) 21025 Return on Total Cap'l 6.0% Return on Shr. Equity 10.0% Return on Com Equity 10.0% Retained to Com Eq 5.5% All Div's to Net Prof 46%			
Pfd Stock None Common Stock 317,377,794 shs. as of 4/23/15		7899.1 7490.0 7939.8 8874.2 6649.4 6422.0 6019.1 5061.2 5657.3 6470.6 6850 7200		Revenues (\$mill) 8100 Net Profit (\$mill) 810 Income Tax Rate 37.5% AFUDC % to Net Profit 2.0% Long-Term Debt Ratio 56.0% Common Equity Ratio 44.0% Total Capital (\$mill) 18810 Net Plant (\$mill) 21025 Return on Total Cap'l 6.0% Return on Shr. Equity 10.0% Return on Com Equity 10.0% Retained to Com Eq 5.5% All Div's to Net Prof 46%			
MARKET CAP: \$14.9 billion (Large Cap)		7899.1 7490.0 7939.8 8874.2 6649.4 6422.0 6019.1 5061.2 5657.3 6470.6 6850 7200		Revenues (\$mill) 8100 Net Profit (\$mill) 810 Income Tax Rate 37.5% AFUDC % to Net Profit 2.0% Long-Term Debt Ratio 56.0% Common Equity Ratio 44.0% Total Capital (\$mill) 18810 Net Plant (\$mill) 21025 Return on Total Cap'l 6.0% Return on Shr. Equity 10.0% Return on Com Equity 10.0% Retained to Com Eq 5.5% All Div's to Net Prof 46%			
CURRENT POSITION 2013 2014 3/31/15 (\$MILL) Cash Assets 26.8 25.4 42.0 Other 2132.4 2441.1 2219.0 Current Assets 2159.2 2466.5 2261.0 Accts Payable 619.0 670.6 563.9 Debt Due 1240.8 1843.5 776.7 Other 1318.6 1440.8 1417.8 Current Liab. 3178.4 3954.9 2758.4 Fix. Chg. Cov. 267% 274% 283%		7899.1 7490.0 7939.8 8874.2 6649.4 6422.0 6019.1 5061.2 5657.3 6470.6 6850 7200		Revenues (\$mill) 8100 Net Profit (\$mill) 810 Income Tax Rate 37.5% AFUDC % to Net Profit 2.0% Long-Term Debt Ratio 56.0% Common Equity Ratio 44.0% Total Capital (\$mill) 18810 Net Plant (\$mill) 21025 Return on Total Cap'l 6.0% Return on Shr. Equity 10.0% Return on Com Equity 10.0% Retained to Com Eq 5.5% All Div's to Net Prof 46%			
ANNUAL RATES Past Past Est'd '12-'14 of change (per sh) 10 Yrs. 5 Yrs. to '18-'20 Revenues -3.0% -8.5% 5.5% "Cash Flow" -.5% 1.5% 7.0% Earnings -1.0% 7.0% 9.0% Dividends -1.0% 1.5% 3.5% Book Value 1.0% 1.0% 5.5%		7899.1 7490.0 7939.8 8874.2 6649.4 6422.0 6019.1 5061.2 5657.3 6470.6 6850 7200		Revenues (\$mill) 8100 Net Profit (\$mill) 810 Income Tax Rate 37.5% AFUDC % to Net Profit 2.0% Long-Term Debt Ratio 56.0% Common Equity Ratio 44.0% Total Capital (\$mill) 18810 Net Plant (\$mill) 21025 Return on Total Cap'l 6.0% Return on Shr. Equity 10.0% Return on Com Equity 10.0% Retained to Com Eq 5.5% All Div's to Net Prof 46%			
QUARTERLY REVENUES (\$mill.) Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year 2012 1648.9 1039.1 962.9 1410.3 5061.2 2013 1782.2 1201.5 1076.8 1596.8 5657.3 2014 2320.5 1335.1 1123.9 1691.1 6470.6 2015 2149.7 1450 1250 2000.3 6850 2016 2400 1450 1350 2000 7200		7899.1 7490.0 7939.8 8874.2 6649.4 6422.0 6019.1 5061.2 5657.3 6470.6 6850 7200		Revenues (\$mill) 8100 Net Profit (\$mill) 810 Income Tax Rate 37.5% AFUDC % to Net Profit 2.0% Long-Term Debt Ratio 56.0% Common Equity Ratio 44.0% Total Capital (\$mill) 18810 Net Plant (\$mill) 21025 Return on Total Cap'l 6.0% Return on Shr. Equity 10.0% Return on Com Equity 10.0% Retained to Com Eq 5.5% All Div's to Net Prof 46%			
EARNINGS PER SHARE ^ Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year 2012 .66 .23 .06 .42 1.37 2013 .69 .23 .16 .49 1.57 2014 .85 .25 .10 .49 1.67 2015 .85 .25 .15 .60 1.85 2016 .95 .30 .20 .60 2.05		7899.1 7490.0 7939.8 8874.2 6649.4 6422.0 6019.1 5061.2 5657.3 6470.6 6850 7200		Revenues (\$mill) 8100 Net Profit (\$mill) 810 Income Tax Rate 37.5% AFUDC % to Net Profit 2.0% Long-Term Debt Ratio 56.0% Common Equity Ratio 44.0% Total Capital (\$mill) 18810 Net Plant (\$mill) 21025 Return on Total Cap'l 6.0% Return on Shr. Equity 10.0% Return on Com Equity 10.0% Retained to Com Eq 5.5% All Div's to Net Prof 46%			
QUARTERLY DIVIDENDS PAID ^ # Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year 2011 .23 .23 .23 .23 .92 2012 .23 .23 .24 .24 .94 2013 .24 .24 .25 .25 .98 2014 .25 .25 .26 .26 1.02 2015 .26 .26		7899.1 7490.0 7939.8 8874.2 6649.4 6422.0 6019.1 5061.2 5657.3 6470.6 6850 7200		Revenues (\$mill) 8100 Net Profit (\$mill) 810 Income Tax Rate 37.5% AFUDC % to Net Profit 2.0% Long-Term Debt Ratio 56.0% Common Equity Ratio 44.0% Total Capital (\$mill) 18810 Net Plant (\$mill) 21025 Return on Total Cap'l 6.0% Return on Shr. Equity 10.0% Return on Com Equity 10.0% Retained to Com Eq 5.5% All Div's to Net Prof 46%			

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, (4¢); gains (losses) on disc. ops.: '05, 10¢; '06, (11¢); '07, 3¢; '08, (\$1.14). Next egs. report due late July. Qtr'y egs. may not sum to total due to rounding.  
 (B) Div'ds historically paid in mid-Feb., May, Aug., Nov. = Div'd reinv. avail.  
 (C) Incl. intang in '14: \$3930.9 million, \$12.45/sh. (D) In mill.  
 Company's Financial Strength B+  
 Stock's Price Stability 90  
 Price Growth Persistence 60  
 Earnings Predictability 75  
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 John E. Seibert III June 5, 2015

N.W. NAT'L GAS NYSE:NMN				RECENT PRICE	PIE RATIO	Trailing: 20.9 Median: 18.0	RELATIVE PIE RATIO	DIV'D YLD	VALUE LINE										
<b>TIMELINESS 3</b> Raised 5/15/15 <b>SAFETY 1</b> Raised 3/18/05 <b>TECHNICAL 4</b> Lowered 5/15/15 BETA .70 (1.00 = Market)				High: 34.1 Low: 27.5	39.6 32.4	43.7 32.8	52.8 39.8	55.2 37.7	46.5 37.7	50.9 41.1	49.0 39.6	50.8 41.0	46.6 40.0	52.6 40.1	52.3 43.8	Target Price Range 2018 2019 2020			
<b>2018-20 PROJECTIONS</b> Price Gain Ann'l Total High 60 (+35%) 11% Low 50 (+10%) 7%																			
<b>Insider Decisions</b> J A S O N D J F M to Buy 0 0 0 0 0 0 0 0 0 Options 0 0 0 0 1 1 0 0 3 to Sell 0 0 0 0 1 2 2 0 4				<b>Institutional Decisions</b> 2Q2014 3Q2014 4Q2014 to Buy 84 79 79 to Sell 53 65 66 Hld's(%) 16493 16110 16761 Percent shares traded 15 10 5															
<b>1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016</b>													<b>© VALUE LINE PUB. LLC 18-20</b>						
18.17 21.09 25.78 25.07 23.57 25.69 33.01 37.20 39.13 39.16 38.17 30.56 31.72 27.14 26.02 28.35 29.55 3.72 3.68 3.86 3.65 3.85 3.92 4.34 4.76 5.41 5.31 5.20 5.18 5.00 4.94 5.04 5.05 4.75 5.25 1.70 1.79 1.88 1.62 1.76 1.86 2.11 2.35 2.76 2.57 2.83 2.73 2.39 2.22 2.24 2.16 1.90 2.30 1.23 1.24 1.25 1.26 1.27 1.30 1.32 1.39 1.44 1.52 1.60 1.68 1.75 1.79 1.83 1.85 1.87 1.91 4.78 3.46 3.23 3.11 4.90 5.52 3.48 3.56 4.48 3.92 5.09 9.35 3.76 4.91 5.13 4.40 5.80 6.15 17.12 17.93 18.56 18.88 19.52 20.64 21.28 22.01 22.52 23.71 24.88 26.08 26.70 27.23 27.77 28.12 28.85 29.95 25.09 25.23 25.23 25.59 25.94 27.55 27.58 27.24 26.41 26.50 26.53 28.58 26.76 26.92 27.08 27.28 27.50 27.75 14.5 12.4 12.9 17.2 15.8 16.7 17.0 15.9 16.7 18.1 15.2 17.0 19.0 21.1 19.4 20.7 20.7 20.7 .83 .81 .66 .94 .90 .88 .91 .86 .89 1.09 1.01 1.08 1.19 1.34 1.09 1.09 1.09 5.0% 5.6% 5.1% 4.5% 4.6% 4.2% 3.7% 3.7% 3.1% 3.3% 3.7% 3.6% 3.9% 3.8% 4.2% 4.1%													Revenues per sh 31.25 "Cash Flow" per sh 6.45 Earnings per sh <sup>A</sup> 3.30 Div'ds Decl'd per sh <sup>B</sup> 2.10 Cap'l Spending per sh 6.80 Book Value per sh <sup>D</sup> 33.85 Common Shs Outst'g <sup>C</sup> 28.00 Avg Ann'l P/E Ratio 17.0 Relative P/E Ratio 1.05 Avg Ann'l Div'd Yield 3.3%						
<b>CAPITAL STRUCTURE as of 3/31/15</b> Total Debt \$827.9 mill. Due in 5 Yrs \$350.0 mill. LT Debt \$621.7 mill. LT Interest \$45.0 mill. (Total interest coverage: 2.5x)				910.5 1013.2 1033.2 1037.9 1012.7 812.1 848.8 730.6 758.5 754.0 780 820 58.1 65.2 74.5 68.5 75.1 72.7 63.9 59.9 60.5 58.7 78.0 82.0 36.0% 36.3% 37.2% 36.9% 38.3% 40.5% 40.4% 42.4% 40.8% 41.5% 40.0% 40.0% 6.4% 6.4% 7.2% 6.6% 7.4% 8.9% 7.5% 8.2% 8.0% 7.8% 6.7% 7.8% 47.0% 46.3% 46.3% 44.9% 47.7% 46.1% 47.3% 48.5% 47.6% 44.8% 44.5% 44.5% 53.0% 53.7% 53.7% 55.1% 52.3% 53.9% 52.7% 51.5% 52.4% 55.2% 55.5% 55.5% 1108.4 1116.5 1106.8 1140.4 1261.8 1284.8 1356.2 1424.7 1433.6 1389.0 1435 1495 1373.4 1425.1 1495.9 1549.1 1670.1 1854.2 1893.9 1973.6 2062.9 2121.6 2205 2295 6.5% 7.1% 8.5% 7.7% 7.3% 7.0% 6.2% 5.7% 5.8% 5.8% 5.0% 5.5% 9.9% 10.3% 12.5% 10.9% 11.4% 10.5% 8.9% 8.2% 8.1% 7.6% 6.5% 7.5% 9.9% 10.9% 12.5% 10.9% 11.4% 10.5% 8.9% 8.2% 8.1% 7.6% 6.5% 7.5% 3.7% 4.5% 6.0% 4.5% 5.0% 4.0% 2.4% 1.6% 1.5% 1.1% 1.5% 1.5% 63% 59% 52% 59% 56% 61% 73% 80% 81% 85% 98% 83%												Revenues (\$mill) 875 Net Profit (\$mill) 92.5 Income Tax Rate 38.0% Net Profit Margin 10.6% Long-Term Debt Ratio 44.0% Common Equity Ratio 56.0% Total Capital (\$mill) 1685 Net Plant (\$mill) 2580 Return on Total Cap'l 6.5% Return on Shr. Equity 10.0% Return on Com Equity 10.0% Retained to Com Eq 3.5% All Div'ds to Net Prof 64%			
<b>CURRENT POSITION</b> 2013 2014 3/31/15 (\$MILL) Cash Assets 9.5 9.5 5.2 Other 321.0 353.1 286.8 Current Assets 330.5 362.6 292.0 Accts Payable 96.1 91.4 62.9 Debt Due 248.2 274.7 206.2 Other 88.5 103.3 101.6 Current Liab. 432.8 469.4 370.7 Fix. Chg. Cov. 316% 321% 251%				<b>BUSINESS:</b> Northwest Natural Gas Co. distributes natural gas to 90 communities, 704,000 customers, in Oregon (89% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 35%; commercial, 22%; industrial, gas transportation, and other, 43%. Employs 1,092. BlackRock Inc. owns 9.2% of shares; officers and directors, 2.1% (4/15 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.															
<b>ANNUAL RATES</b> Past Past Est'd '12-'14 of change (per sh) 10 Yrs. 5 Yrs. to '18-'20 Revenues 1.0% -6.5% 2.0% "Cash Flow" 3.0% -1.0% 4.5% Earnings 2.5% -4.0% 7.0% Dividends 3.5% 3.5% 2.5% Book Value 3.5% 3.0% 3.5%				<b>Warmer-than-usual winter weather caused underwhelming results at Northwest Natural Gas.</b> Too, the company had a negative outcome from Oregon regulators, which caused a pretax charge of \$15 million for disallowed environmental remediation expense recoveries. These together caused earnings to fall to \$1.04 a share. Though we think the rest of the year will show improvement, we are lowering our 2015 per-share estimate by \$0.50, to \$1.90.															
<b>QUARTERLY REVENUES (\$mill.)</b> Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year 2012 309.6 104.0 87.5 229.5 730.6 2013 277.9 131.7 88.2 260.7 758.5 2014 293.4 133.1 87.2 240.3 754.0 2015 261.7 148.3 100 270 780 2016 280 150 105 285 820				<b>Northwest Natural Gas continues to show signs of growth.</b> The customer growth rate in the Portland area was 1.3%, and employment there continues to improve. We think 2016 should show a sizable jump in earnings, assuming improvements come from more normal weather and increased returns from capital investments. We think that 2015 is the last year of declining earnings and that \$2.30 a share is likely in 2016.															
<b>EARNINGS PER SHARE <sup>A</sup></b> Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year 2012 1.51 .05 d.39 1.05 2.22 2013 1.40 .08 d.31 1.07 2.24 2014 1.40 .04 d.32 1.04 2.16 2015 1.04 .10 d.30 1.06 1.90 2016 1.40 .10 d.30 1.10 2.30				<b>The Mist plant expansion appears to be headed forward.</b> Indeed, it received approval from Portland General Electric and will provide storage to the natural gas-fired plants in Port Westward. This will provide up to 2.5 billion cubic feet of storage and will likely cost around \$125 million, with a potential in-service date in the 2018-2019 winter season. This long-term project should allow for ample growth once completed. We are assuming it comes in on time. Construction and permitting can take longer than expected at times, though the Mist underground storage facility and related pipelines should increase revenues.															
<b>QUARTERLY DIVIDENDS PAID <sup>D</sup></b> Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year 2011 .435 .435 .435 .445 1.75 2012 .445 .445 .445 .455 1.79 2013 .455 .455 .455 .460 1.83 2014 .460 .460 .460 .465 1.85 2015 .465 .465				<b>The dividend is a top draw.</b> The slide in the share price has allowed the yield to top 4.2%, which is above average for a natural gas utility. Given the payout ratio remains high when compared to historical levels, we expect dividend expansion will be somewhat muted over the coming years.															
<b>(A)</b> Diluted earnings per share. Excludes non-recurring items: '00, \$0.11; '06, (\$0.06); '08, (\$0.03); '09, 6¢; May not sum due to rounding. Next earnings report due in early August.				<b>(B)</b> Dividends historically paid in mid-February, May, August, and November.				<b>(D)</b> Includes Intangibles. In 2014: \$368.9 million, \$13.52/share.				<b>(C)</b> In millions.				<b>Company's Financial Strength</b> A <b>Stock's Price Stability</b> 95 <b>Price Growth Persistence</b> 40 <b>Earnings Predictability</b> 100			

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SOUTH JERSEY INDS. NYSE-SJ				RECENT PRICE	P/E RATIO	Trailing: 18.5 Median: 17.0	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																												
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<td>.50</td> <td>.54</td> <td>.57</td> <td>.61</td> <td>.68</td> <td>.79</td> <td>.86</td> <td>1.23</td> <td>1.05</td> <td>1.14</td> <td>1.19</td> <td>1.35</td> <td>1.45</td> <td>1.52</td> <td>1.52</td> <td>1.57</td> <td>1.65</td> <td>1.80</td> <td>2.50</td> </tr> <tr> <td>Div'ds Decl'd per sh <sup>B</sup></td> <td>.36</td> <td>.37</td> <td>.37</td> <td>.38</td> <td>.39</td> <td>.41</td> <td>.43</td> <td>.46</td> <td>.51</td> <td>.56</td> <td>.61</td> <td>.68</td> <td>.75</td> <td>.83</td> <td>.90</td> <td>.96</td> <td>1.02</td> <td>1.10</td> <td>1.35</td> </tr> <tr> <td>Cap'l Spending per sh</td> <td>1.09</td> <td>1.11</td> <td>1.41</td> <td>1.74</td> <td>1.18</td> <td>1.34</td> <td>1.60</td> <td>1.26</td> <td>.94</td> <td>1.04</td> <td>1.83</td> <td>2.79</td> <td>3.20</td> <td>4.01</td> <td>4.84</td> <td>5.01</td> <td>3.55</td> <td>3.80</td> <td>4.60</td> </tr> <tr> <td>Book Value per sh <sup>C</sup></td> <td>3.37</td> <td>3.62</td> <td>3.91</td> <td>4.84</td> <td>5.63</td> <td>6.20</td> <td>6.75</td> <td>7.55</td> <td>8.12</td> <td>8.67</td> <td>9.12</td> <td>9.54</td> <td>10.33</td> <td>11.63</td> <td>12.64</td> <td>13.65</td> <td>15.00</td> <td>15.95</td> <td>18.40</td> </tr> <tr> <td>Common Shs Outst'g <sup>D</sup></td> <td>44.61</td> <td>46.00</td> <td>47.44</td> <td>48.83</td> <td>52.92</td> <td>55.52</td> <td>57.96</td> <td>58.65</td> <td>59.22</td> <td>59.46</td> <td>59.59</td> <td>59.75</td> <td>60.43</td> <td>63.31</td> <td>65.43</td> <td>68.33</td> <td>70.00</td> <td>72.00</td> <td>76.00</td> </tr> <tr> <td>Avg Ann'l P/E Ratio</td> <td>13.3</td> <td>13.0</td> <td>13.6</td> <td>13.5</td> <td>13.3</td> <td>14.1</td> <td>16.6</td> <td>11.9</td> <td>17.2</td> <td>15.9</td> <td>15.0</td> <td>16.8</td> <td>18.4</td> <td>16.9</td> <td>18.9</td> <td>18.0</td> <td>17.0</td> <td>16.0</td> <td>14.0</td> </tr> <tr> <td>Relative P/E Ratio</td> <td>.76</td> <td>.85</td> <td>.70</td> <td>.74</td> <td>.76</td> <td>.74</td> <td>.88</td> <td>.64</td> <td>.91</td> <td>.96</td> <td>1.00</td> <td>1.07</td> <td>1.15</td> <td>1.08</td> <td>1.06</td> <td>.95</td> <td>.95</td> <td>.95</td> <td>.90</td> </tr> <tr> <td>Avg Ann'l Div'd Yield</td> <td>5.4%</td> <td>5.2%</td> <td>4.7%</td> <td>4.6%</td> <td>4.3%</td> <td>3.7%</td> <td>3.0%</td> <td>3.2%</td> <td>2.8%</td> <td>3.1%</td> <td>3.4%</td> <td>3.0%</td> <td>2.8%</td> <td>3.2%</td> <td>3.1%</td> <td>3.4%</td> <td>3.4%</td> <td>3.4%</td> <td>3.9%</td> </tr> <tr> <td colspan="4">CAPITAL STRUCTURE as of 3/31/15</td> <td colspan="16"> <table border="1"> <thead> <tr> <th>Year</th> <th>1999</th> <th>2000</th> <th>2001</th> <th>2002</th> <th>2003</th> <th>2004</th> <th>2005</th> <th>2006</th> <th>2007</th> <th>2008</th> <th>2009</th> <th>2010</th> <th>2011</th> <th>2012</th> <th>2013</th> <th>2014</th> <th>2015</th> <th>2016</th> <th>2017</th> </tr> </thead> <tbody> <tr> <td>Total Debt</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> 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<th>2014</th> <th>2015</th> <th>2016</th> <th>2017</th> </tr> </thead> <tbody> <tr> <td>Revenues (\$mill)</td> <td>921.0</td> <td>931.4</td> <td>956.4</td> <td>962.0</td> <td>845.4</td> <td>925.1</td> <td>828.6</td> <td>706.3</td> <td>731.4</td> <td>887.0</td> <td>970.0</td> <td>1075.0</td> <td>1400.0</td> <td>195.0</td> <td>195.0</td> <td>195.0</td> <td>195.0</td> <td>195.0</td> <td>195.0</td> </tr> <tr> <td>Net Profit (\$mill)</td> <td>48.6</td> <td>72.0</td> <td>61.8</td> <td>67.7</td> <td>71.3</td> <td>81.0</td> <td>87.0</td> <td>93.3</td> <td>97.1</td> <td>104.0</td> <td>120.0</td> <td>135.0</td> <td>195.0</td> <td>195.0</td> <td>195.0</td> <td>195.0</td> <td>195.0</td> <td>195.0</td> <td>195.0</td> </tr> <tr> <td>Income Tax Rate</td> <td>41.5%</td> <td>41.3%</td> <td>41.9%</td> <td>47.7%</td> <td>23.0%</td> <td>15.2%</td> <td>22.4%</td> <td>10.8%</td> <td>10.8%</td> <td>20.0%</td> <td>25.0%</td> <td>25.0%</td> <td>25.0%</td> <td>25.0%</td> <td>25.0%</td> <td>25.0%</td> 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<td>53.0%</td> </tr> <tr> <td>Total Capital (\$mill)</td> <td>710.3</td> <td>801.1</td> <td>839.0</td> <td>848.0</td> <td>856.4</td> <td>910.1</td> <td>1048.3</td> <td>1337.6</td> <td>1507.4</td> <td>1791.9</td> <td>1975.0</td> <td>2150.0</td> <td>2650.0</td> <td>2650.0</td> <td>2650.0</td> <td>2650.0</td> <td>2650.0</td> <td>2650.0</td> <td>2650.0</td> </tr> <tr> <td>Net Plant (\$mill)</td> <td>877.3</td> <td>920.0</td> <td>948.9</td> <td>982.6</td> <td>1073.1</td> <td>1193.3</td> <td>1352.4</td> <td>1578.0</td> <td>1859.1</td> <td>2134.1</td> <td>2250.0</td> <td>2350.0</td> <td>2750.0</td> <td>2750.0</td> <td>2750.0</td> <td>2750.0</td> <td>2750.0</td> <td>2750.0</td> <td>2750.0</td> </tr> <tr> <td>Return on Total Cap'l</td> <td>8.3%</td> <td>10.1%</td> <td>8.6%</td> <td>8.9%</td> <td>9.0%</td> <td>9.5%</td> <td>8.9%</td> <td>7.4%</td> <td>6.8%</td> <td>6.4%</td> <td>6.5%</td> <td>7.0%</td> <td>8.0%</td> <td>8.0%</td> <td>8.0%</td> <td>8.0%</td> <td>8.0%</td> <td>8.0%</td> 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Chg. Cov.</td> <td>370%</td> <td>432%</td> <td>455%</td> </tr> </tbody> </table> </td> </tr> <tr> <td colspan="4">ANNUAL RATES</td> <td colspan="16"> <table border="1"> <thead> <tr> <th>Year</th> <th>Past 10 Yrs</th> <th>Past 5 Yrs</th> <th>Est'd '12-'14</th> </tr> </thead> <tbody> <tr> <td>Revenues</td> <td>-1.0%</td> <td>-5.5%</td> <td>7.5%</td> </tr> <tr> <td>"Cash Flow"</td> <td>8.0%</td> <td>7.5%</td> <td>8.0%</td> </tr> <tr> <td>Earnings</td> <td>8.0%</td> <td>6.5%</td> <td>8.6%</td> </tr> <tr> <td>Dividends</td> <td>8.5%</td> <td>10.0%</td> <td>7.0%</td> </tr> <tr> <td>Book Value</td> <td>8.5%</td> <td>8.0%</td> <td>6.5%</td> </tr> </tbody> </table> </td> </tr> <tr> <td colspan="4">QUARTERLY REVENUES (\$mill)</td> <td colspan="16"> <table border="1"> <thead> <tr> <th>Year</th> <th>Mar.31</th> <th>Jun.30</th> <th>Sep.30</th> <th>Dec.31</th> <th>Full Year</th> </tr> </thead> <tbody> <tr> <td>2012</td> <td>274.8</td> <td>121.9</td> <td>112.0</td> <td>197.6</td> <td>706.3</td> </tr> <tr> <td>2013</td> <td>255.6</td> <td>122.6</td> <td>128.8</td> <td>224.4</td> <td>731.4</td> </tr> <tr> <td>2014</td> <td>350.2</td> <td>133.3</td> <td>122.4</td> <td>281.1</td> <td>887.0</td> </tr> <tr> <td>2015</td> <td>383.0</td> <td>155</td> <td>145</td> <td>287</td> <td>970</td> </tr> <tr> <td>2016</td> <td>415</td> <td>175</td> <td>165</td> <td>320</td> <td>1075</td> </tr> </tbody> </table> </td> </tr> <tr> <td colspan="4">EARNINGS PER SHARE <sup>A</sup></td> <td colspan="16"> <table border="1"> <thead> <tr> <th>Year</th> <th>Mar.31</th> <th>Jun.30</th> <th>Sep.30</th> <th>Dec.31</th> <th>Full Year</th> </tr> </thead> <tbody> <tr> <td>2012</td> <td>.83</td> <td>.14</td> <td>.07</td> <td>.49</td> <td>1.52</td> </tr> <tr> <td>2013</td> <td>.76</td> <td>.16</td> <td>d.02</td> <td>.62</td> <td>1.52</td> </tr> <tr> <td>2014</td> <td>1.01</td> <td>.15</td> <td>d.05</td> <td>.47</td> <td>1.57</td> </tr> <tr> <td>2015</td> <td>.86</td> <td>.16</td> <td>.03</td> <td>.60</td> <td>1.65</td> </tr> <tr> <td>2016</td> <td>.93</td> <td>.18</td> <td>.04</td> <td>.65</td> <td>1.80</td> </tr> </tbody> </table> </td> </tr> <tr> <td colspan="4">QUARTERLY DIVIDENDS PAID <sup>B=C</sup></td> <td colspan="16"> <table border="1"> <thead> <tr> <th>Year</th> <th>Mar.31</th> <th>Jun.30</th> <th>Sep.30</th> <th>Dec.31</th> <th>Full Year</th> </tr> </thead> <tbody> <tr> <td>2011</td> <td>--</td> <td>.183</td> <td>.183</td> <td>.384</td> <td>.75</td> </tr> <tr> <td>2012</td> <td>--</td> <td>.202</td> <td>.202</td> <td>.423</td> <td>.83</td> </tr> <tr> <td>2013</td> <td>--</td> <td>.222</td> <td>.222</td> <td>.458</td> <td>.90</td> </tr> <tr> <td>2014</td> <td>--</td> <td>.237</td> <td>.237</td> <td>.488</td> <td>.96</td> </tr> <tr> <td>2015</td> <td>--</td> <td>.251</td> <td></td> <td></td> <td></td> </tr> </tbody> </table> </td> </tr> <tr> <td colspan="4">BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 366,854 customers in New Jersey's southern counties. Gas revenue mix '14: residential, 43%; commercial, 19%; cogeneration and electric generation, 17%; industrial, 21%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJJ Midstream. Has about 700 employees. Off./dir. own .8% of common shares; BlackRock, Inc., 9.5%; The Vanguard Group, Inc., 6.9% (3/15 proxy). Chrmn. &amp; CEO: Edward Graham. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Web: www.sjindustries.com.</td> <td colspan="16"> <p><b>South Jersey Industries completed a 2-for-1 stock split in early May.</b> As a result, the number of shares outstanding rose to just under 69 million. The company cited healthy operating performance and favorable growth prospects as factors supporting the decision to effect the split. Our per-share figures have been adjusted accordingly.</p> <p><b>The company reported mixed results for the March quarter.</b> The top line advanced roughly 9%, on a year-over-year basis. This was the result of impressive growth at the utility operation, which more than offset lower revenues from the nonutility side. Operating expenses also increased, however, and earnings per share of \$0.86 were no match for the prior-year tally.</p> <p><b>We expect favorable comparisons in the coming quarters, and higher revenues and share earnings for full-year 2015.</b> The utility ought to be an important performance driver going forward. South Jersey Gas should continue to experience healthy customer growth, as natural gas remains the fuel of choice within its service territory. This business will likely continue to gain from customer conversions to natural gas, given its cost effectiveness compared to alternatives. On the non-utility side, the company's wholesale and retail commodity businesses should also post solid results, driven by demand for fuel management services from four large gas-fired merchant generating facilities, and SJJ's portfolio of transportation assets. The energy services business ought to benefit from the healthy performance of its energy production portfolio, too.</p> <p><b>This stock is neutrally ranked for year-ahead relative price performance.</b> Looking further out, we expect healthy growth in revenues and share earnings for the company from 2016 onward. On top of that, South Jersey Industries earns high marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. All things considered, this good-quality stock offers solid risk-adjusted total return potential for the pull to late decade. Conservative, income-oriented investors may find something to like here. Dividend growth looks to be a strong point here.</p> <p><i>Michael Napoli, CFA</i> <span style="float: right;">June 5, 2015</span></p> </td> </tr> <tr> <td colspan="4">(A) Based on GAAP egs. through 2006, economic egs. thereafter. GAAP EPS: '07, \$1.05; '08, \$1.29; '09, \$0.97; '10, \$1.11; '11, \$1.49; '12, \$1.49; '13, \$1.28; '14, \$1.46. Excl. non-recur. gain (loss): '01, \$0.07; '08, \$0.16; '09, (\$0.22); '10, (\$0.24); '11, \$0.04; '12, (\$0.03); '13, (\$0.24); '14, (\$0.11). Earnings may not sum due to rounding. Next egs. report due in August.</td> <td colspan="16">(B) Div's paid early April, July, Oct., and late Dec. = Div. reinvest. plan avail. (C) Incl. reg. assets. In 2014: \$357.2 mill., \$5.25 per shr. (D) In mill., adj. for split.</td> </tr> <tr> <td colspan="4">Company's Financial Strength</td> <td colspan="16">A</td> </tr> <tr> <td colspan="4">Stock's Price Stability</td> <td colspan="16">95</td> </tr> <tr> <td colspan="4">Price Growth Persistence</td> <td colspan="16">60</td> </tr> <tr> <td colspan="4">Earnings Predictability</td> <td colspan="16">95</td> </tr> <tr> <td colspan="4">© 2015 Value Line Publishing LLC. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.</td> <td colspan="16">To subscribe call 1-800-VALUELINE</td> </tr> </tbody> </table>										Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Revenues per sh	8.80	11.22	17.65	10.35	13.17	14.75	15.89	15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.85	14.95	18.40	"Cash Flow" per sh	.92	.97	.95	1.06	1.12	1.22	1.25	1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.70	2.90	4.00	Earnings per sh <sup>A</sup>	.50	.54	.57	.61	.68	.79	.86	1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.65	1.80	2.50	Div'ds Decl'd per sh <sup>B</sup>	.36	.37	.37	.38	.39	.41	.43	.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.10	1.35	Cap'l Spending per sh	1.09	1.11	1.41	1.74	1.18	1.34	1.60	1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	3.55	3.80	4.60	Book Value per sh <sup>C</sup>	3.37	3.62	3.91	4.84	5.63	6.20	6.75	7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	15.00	15.95	18.40	Common Shs Outst'g <sup>D</sup>	44.61	46.00	47.44	48.83	52.92	55.52	57.96	58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.00	72.00	76.00	Avg Ann'l P/E Ratio	13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.0	16.0	14.0	Relative P/E Ratio	.76	.85	.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.95	.95	.90	Avg Ann'l Div'd Yield	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.4%	3.4%	3.9%	CAPITAL STRUCTURE as of 3/31/15				<table border="1"> <thead> <tr> <th>Year</th> <th>1999</th> <th>2000</th> <th>2001</th> <th>2002</th> <th>2003</th> <th>2004</th> <th>2005</th> <th>2006</th> <th>2007</th> <th>2008</th> <th>2009</th> <th>2010</th> <th>2011</th> <th>2012</th> <th>2013</th> <th>2014</th> <th>2015</th> <th>2016</th> <th>2017</th> </tr> </thead> <tbody> <tr> <td>Total Debt</td> 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Debt	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	LT Debt	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	Leases, Uncapitalized	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	Penston Assets	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	Oblig.	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	Pfd Stock None				<table border="1"> <thead> <tr> <th>Year</th> <th>1999</th> <th>2000</th> <th>2001</th> <th>2002</th> <th>2003</th> <th>2004</th> <th>2005</th> <th>2006</th> <th>2007</th> 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Equity</td> <td>12.4%</td> <td>16.3%</td> <td>12.8%</td> <td>13.1%</td> <td>13.1%</td> <td>14.2%</td> <td>13.9%</td> <td>12.7%</td> <td>11.7%</td> <td>11.2%</td> <td>11.5%</td> <td>11.5%</td> <td>14.0%</td> <td>14.0%</td> <td>14.0%</td> <td>14.0%</td> <td>14.0%</td> <td>14.0%</td> <td>14.0%</td> </tr> <tr> <td>Return on Com Equity</td> <td>12.4%</td> <td>16.3%</td> <td>12.8%</td> <td>13.1%</td> <td>13.1%</td> <td>14.2%</td> <td>13.9%</td> <td>12.7%</td> <td>11.7%</td> <td>11.2%</td> <td>11.5%</td> <td>11.5%</td> <td>14.0%</td> <td>14.0%</td> <td>14.0%</td> <td>14.0%</td> <td>14.0%</td> <td>14.0%</td> <td>14.0%</td> </tr> <tr> <td>Retained to Com Eq</td> <td>6.2%</td> <td>10.2%</td> <td>6.7%</td> <td>6.7%</td> <td>6.4%</td> <td>7.1%</td> <td>6.7%</td> <td>5.8%</td> <td>4.8%</td> <td>4.3%</td> <td>4.5%</td> <td>5.0%</td> <td>6.5%</td> <td>6.5%</td> <td>6.5%</td> <td>6.5%</td> <td>6.5%</td> <td>6.5%</td> <td>6.5%</td> </tr> <tr> <td>All Div's to Net Prof</td> <td>50%</td> <td>37%</td> <td>48%</td> <td>49%</td> <td>51%</td> <td>50%</td> <td>52%</td> <td>55%</td> <td>59%</td> <td>61%</td> <td>60%</td> <td>59%</td> <td>53%</td> <td>53%</td> <td>53%</td> <td>53%</td> <td>53%</td> <td>53%</td> <td>53%</td> </tr> </tbody> </table>																Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Revenues (\$mill)	921.0	931.4	956.4	962.0	845.4	925.1	828.6	706.3	731.4	887.0	970.0	1075.0	1400.0	195.0	195.0	195.0	195.0	195.0	195.0	Net Profit (\$mill)	48.6	72.0	61.8	67.7	71.3	81.0	87.0	93.3	97.1	104.0	120.0	135.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	Income Tax Rate	41.5%	41.3%	41.9%	47.7%	23.0%	15.2%	22.4%	10.8%	10.8%	20.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	Net Profit Margin	5.3%	7.7%	6.5%	7.0%	8.4%	8.8%	10.5%	13.2%	13.3%	11.7%	12.4%	12.6%	13.9%	13.9%	13.9%	13.9%	13.9%	13.9%	13.9%	Long-Term Debt Ratio	44.9%	44.7%	42.7%	39.2%	36.5%	37.4%	40.5%	45.0%	45.1%	48.0%	47.0%	46.5%	47.0%	47.0%	47.0%	47.0%	47.0%	47.0%	47.0%	Common Equity Ratio	55.1%	55.3%	57.3%	60.8%	63.5%	62.6%	59.5%	55.0%	54.9%	52.0%	53.0%	53.5%	53.0%	53.0%	53.0%	53.0%	53.0%	53.0%	53.0%	Total Capital (\$mill)	710.3	801.1	839.0	848.0	856.4	910.1	1048.3	1337.6	1507.4	1791.9	1975.0	2150.0	2650.0	2650.0	2650.0	2650.0	2650.0	2650.0	2650.0	Net Plant (\$mill)	877.3	920.0	948.9	982.6	1073.1	1193.3	1352.4	1578.0	1859.1	2134.1	2250.0	2350.0	2750.0	2750.0	2750.0	2750.0	2750.0	2750.0	2750.0	Return on Total Cap'l	8.3%	10.1%	8.6%	8.9%	9.0%	9.5%	8.9%	7.4%	6.8%	6.4%	6.5%	7.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	Return on Shr. Equity	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	11.5%	11.5%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	Return on Com Equity	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	11.5%	11.5%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	Retained to Com Eq	6.2%	10.2%	6.7%	6.7%	6.4%	7.1%	6.7%	5.8%	4.8%	4.3%	4.5%	5.0%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	All Div's to Net Prof	50%	37%	48%	49%	51%	50%	52%	55%	59%	61%	60%	59%	53%	53%	53%	53%	53%	53%	53%	MARKET CAP: \$1.8 billion (Mid Cap)				<table border="1"> <thead> <tr> <th>Year</th> <th>2013</th> <th>2014</th> <th>3/31/15</th> </tr> </thead> <tbody> <tr> <td>Cash Assets</td> <td>3.8</td> <td>4.2</td> <td>7.2</td> </tr> <tr> <td>Other</td> <td>479.1</td> <td>562.5</td> <td>573.0</td> </tr> <tr> <td>Current Assets</td> <td>482.9</td> <td>566.7</td> <td>580.2</td> </tr> <tr> <td>Accs Payable</td> <td>259.8</td> <td>273.0</td> <td>221.2</td> </tr> <tr> <td>Debt Due</td> <td>374.9</td> <td>395.6</td> <td>422.3</td> </tr> <tr> <td>Other</td> <td>130.3</td> <td>181.6</td> <td>178.1</td> </tr> <tr> <td>Current Liab.</td> <td>765.0</td> <td>850.2</td> <td>821.6</td> </tr> <tr> <td>Fix. Chg. Cov.</td> <td>370%</td> <td>432%</td> <td>455%</td> </tr> </tbody> </table>																Year	2013	2014	3/31/15	Cash Assets	3.8	4.2	7.2	Other	479.1	562.5	573.0	Current Assets	482.9	566.7	580.2	Accs Payable	259.8	273.0	221.2	Debt Due	374.9	395.6	422.3	Other	130.3	181.6	178.1	Current Liab.	765.0	850.2	821.6	Fix. Chg. Cov.	370%	432%	455%	ANNUAL RATES				<table border="1"> <thead> <tr> <th>Year</th> <th>Past 10 Yrs</th> <th>Past 5 Yrs</th> <th>Est'd '12-'14</th> </tr> </thead> <tbody> <tr> <td>Revenues</td> <td>-1.0%</td> <td>-5.5%</td> <td>7.5%</td> </tr> <tr> <td>"Cash Flow"</td> <td>8.0%</td> <td>7.5%</td> <td>8.0%</td> </tr> <tr> <td>Earnings</td> <td>8.0%</td> <td>6.5%</td> <td>8.6%</td> </tr> <tr> <td>Dividends</td> <td>8.5%</td> <td>10.0%</td> <td>7.0%</td> </tr> <tr> <td>Book Value</td> <td>8.5%</td> <td>8.0%</td> <td>6.5%</td> </tr> </tbody> </table>																Year	Past 10 Yrs	Past 5 Yrs	Est'd '12-'14	Revenues	-1.0%	-5.5%	7.5%	"Cash Flow"	8.0%	7.5%	8.0%	Earnings	8.0%	6.5%	8.6%	Dividends	8.5%	10.0%	7.0%	Book Value	8.5%	8.0%	6.5%	QUARTERLY REVENUES (\$mill)				<table border="1"> <thead> <tr> <th>Year</th> <th>Mar.31</th> <th>Jun.30</th> <th>Sep.30</th> <th>Dec.31</th> <th>Full Year</th> </tr> </thead> <tbody> <tr> <td>2012</td> <td>274.8</td> <td>121.9</td> <td>112.0</td> <td>197.6</td> <td>706.3</td> </tr> <tr> <td>2013</td> <td>255.6</td> <td>122.6</td> <td>128.8</td> <td>224.4</td> <td>731.4</td> </tr> <tr> <td>2014</td> <td>350.2</td> <td>133.3</td> <td>122.4</td> <td>281.1</td> <td>887.0</td> </tr> <tr> <td>2015</td> <td>383.0</td> <td>155</td> <td>145</td> <td>287</td> <td>970</td> </tr> <tr> <td>2016</td> <td>415</td> <td>175</td> <td>165</td> <td>320</td> <td>1075</td> </tr> </tbody> </table>																Year	Mar.31	Jun.30	Sep.30	Dec.31	Full Year	2012	274.8	121.9	112.0	197.6	706.3	2013	255.6	122.6	128.8	224.4	731.4	2014	350.2	133.3	122.4	281.1	887.0	2015	383.0	155	145	287	970	2016	415	175	165	320	1075	EARNINGS PER SHARE <sup>A</sup>				<table border="1"> <thead> <tr> <th>Year</th> <th>Mar.31</th> <th>Jun.30</th> <th>Sep.30</th> <th>Dec.31</th> <th>Full Year</th> </tr> </thead> <tbody> <tr> <td>2012</td> <td>.83</td> <td>.14</td> <td>.07</td> <td>.49</td> <td>1.52</td> </tr> <tr> <td>2013</td> <td>.76</td> <td>.16</td> <td>d.02</td> <td>.62</td> <td>1.52</td> </tr> <tr> <td>2014</td> <td>1.01</td> <td>.15</td> <td>d.05</td> <td>.47</td> <td>1.57</td> </tr> <tr> <td>2015</td> <td>.86</td> <td>.16</td> <td>.03</td> <td>.60</td> <td>1.65</td> </tr> <tr> <td>2016</td> <td>.93</td> <td>.18</td> <td>.04</td> <td>.65</td> <td>1.80</td> </tr> </tbody> </table>																Year	Mar.31	Jun.30	Sep.30	Dec.31	Full Year	2012	.83	.14	.07	.49	1.52	2013	.76	.16	d.02	.62	1.52	2014	1.01	.15	d.05	.47	1.57	2015	.86	.16	.03	.60	1.65	2016	.93	.18	.04	.65	1.80	QUARTERLY DIVIDENDS PAID <sup>B=C</sup>				<table border="1"> <thead> <tr> <th>Year</th> <th>Mar.31</th> <th>Jun.30</th> <th>Sep.30</th> <th>Dec.31</th> <th>Full Year</th> </tr> </thead> <tbody> <tr> <td>2011</td> <td>--</td> <td>.183</td> <td>.183</td> <td>.384</td> <td>.75</td> </tr> <tr> <td>2012</td> <td>--</td> <td>.202</td> <td>.202</td> <td>.423</td> <td>.83</td> </tr> <tr> <td>2013</td> <td>--</td> <td>.222</td> <td>.222</td> <td>.458</td> <td>.90</td> </tr> <tr> <td>2014</td> <td>--</td> <td>.237</td> <td>.237</td> <td>.488</td> <td>.96</td> </tr> <tr> <td>2015</td> <td>--</td> <td>.251</td> <td></td> <td></td> <td></td> </tr> </tbody> </table>																Year	Mar.31	Jun.30	Sep.30	Dec.31	Full Year	2011	--	.183	.183	.384	.75	2012	--	.202	.202	.423	.83	2013	--	.222	.222	.458	.90	2014	--	.237	.237	.488	.96	2015	--	.251				BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 366,854 customers in New Jersey's southern counties. Gas revenue mix '14: residential, 43%; commercial, 19%; cogeneration and electric generation, 17%; industrial, 21%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJJ Midstream. Has about 700 employees. Off./dir. own .8% of common shares; BlackRock, Inc., 9.5%; The Vanguard Group, Inc., 6.9% (3/15 proxy). Chrmn. & CEO: Edward Graham. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Web: www.sjindustries.com.				<p><b>South Jersey Industries completed a 2-for-1 stock split in early May.</b> As a result, the number of shares outstanding rose to just under 69 million. The company cited healthy operating performance and favorable growth prospects as factors supporting the decision to effect the split. Our per-share figures have been adjusted accordingly.</p> <p><b>The company reported mixed results for the March quarter.</b> The top line advanced roughly 9%, on a year-over-year basis. This was the result of impressive growth at the utility operation, which more than offset lower revenues from the nonutility side. Operating expenses also increased, however, and earnings per share of \$0.86 were no match for the prior-year tally.</p> <p><b>We expect favorable comparisons in the coming quarters, and higher revenues and share earnings for full-year 2015.</b> The utility ought to be an important performance driver going forward. South Jersey Gas should continue to experience healthy customer growth, as natural gas remains the fuel of choice within its service territory. This business will likely continue to gain from customer conversions to natural gas, given its cost effectiveness compared to alternatives. On the non-utility side, the company's wholesale and retail commodity businesses should also post solid results, driven by demand for fuel management services from four large gas-fired merchant generating facilities, and SJJ's portfolio of transportation assets. The energy services business ought to benefit from the healthy performance of its energy production portfolio, too.</p> <p><b>This stock is neutrally ranked for year-ahead relative price performance.</b> Looking further out, we expect healthy growth in revenues and share earnings for the company from 2016 onward. On top of that, South Jersey Industries earns high marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. All things considered, this good-quality stock offers solid risk-adjusted total return potential for the pull to late decade. Conservative, income-oriented investors may find something to like here. Dividend growth looks to be a strong point here.</p> <p><i>Michael Napoli, CFA</i> <span style="float: right;">June 5, 2015</span></p>																(A) Based on GAAP egs. through 2006, economic egs. thereafter. GAAP EPS: '07, \$1.05; '08, \$1.29; '09, \$0.97; '10, \$1.11; '11, \$1.49; '12, \$1.49; '13, \$1.28; '14, \$1.46. Excl. non-recur. gain (loss): '01, \$0.07; '08, \$0.16; '09, (\$0.22); '10, (\$0.24); '11, \$0.04; '12, (\$0.03); '13, (\$0.24); '14, (\$0.11). Earnings may not sum due to rounding. Next egs. report due in August.				(B) Div's paid early April, July, Oct., and late Dec. = Div. reinvest. plan avail. (C) Incl. reg. assets. In 2014: \$357.2 mill., \$5.25 per shr. (D) In mill., adj. for split.																Company's Financial Strength				A																Stock's Price Stability				95																Price Growth Persistence				60																Earnings Predictability				95																© 2015 Value Line Publishing LLC. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.				To subscribe call 1-800-VALUELINE															
Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
Revenues per sh	8.80	11.22	17.65	10.35	13.17	14.75	15.89	15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.85	14.95	18.40																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
"Cash Flow" per sh	.92	.97	.95	1.06	1.12	1.22	1.25	1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.70	2.90	4.00																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
Earnings per sh <sup>A</sup>	.50	.54	.57	.61	.68	.79	.86	1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.65	1.80	2.50																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
Div'ds Decl'd per sh <sup>B</sup>	.36	.37	.37	.38	.39	.41	.43	.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.10	1.35																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
Cap'l Spending per sh	1.09	1.11	1.41	1.74	1.18	1.34	1.60	1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	3.55	3.80	4.60																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
Book Value per sh <sup>C</sup>	3.37	3.62	3.91	4.84	5.63	6.20	6.75	7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	15.00	15.95	18.40																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
Common Shs Outst'g <sup>D</sup>	44.61	46.00	47.44	48.83	52.92	55.52	57.96	58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.00	72.00	76.00																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
Avg Ann'l P/E Ratio	13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.0	16.0	14.0																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
Relative P/E Ratio	.76	.85	.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.95	.95	.90																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
Avg Ann'l Div'd Yield	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.4%	3.4%	3.9%																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
CAPITAL STRUCTURE as of 3/31/15				<table border="1"> <thead> <tr> <th>Year</th> <th>1999</th> <th>2000</th> <th>2001</th> <th>2002</th> <th>2003</th> <th>2004</th> <th>2005</th> <th>2006</th> <th>2007</th> <th>2008</th> <th>2009</th> <th>2010</th> <th>2011</th> <th>2012</th> <th>2013</th> <th>2014</th> <th>2015</th> <th>2016</th> <th>2017</th> </tr> </thead> <tbody> <tr> <td>Total Debt</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> <td>\$1281.8</td> </tr> <tr> <td>LT Debt</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> <td>\$859.5</td> </tr> <tr> <td>Leases, Uncapitalized</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> <td>\$7.0</td> </tr> <tr> <td>Penston Assets</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> <td>\$180.5</td> </tr> <tr> <td>Oblig.</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> <td>\$265.4</td> </tr> </tbody> </table>																Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total Debt	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	\$1281.8	LT Debt	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	\$859.5	Leases, Uncapitalized	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	Penston Assets	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	\$180.5	Oblig.	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4	\$265.4																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																										
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Equity	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	11.5%	11.5%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	Return on Com Equity	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	11.5%	11.5%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	Retained to Com Eq	6.2%	10.2%	6.7%	6.7%	6.4%	7.1%	6.7%	5.8%	4.8%	4.3%	4.5%	5.0%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	All Div's to Net Prof	50%	37%	48%	49%	51%	50%	52%	55%	59%	61%	60%	59%	53%	53%	53%	53%	53%	53%	53%																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																										
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Net Profit (\$mill)	48.6	72.0	61.8	67.7	71.3	81.0	87.0	93.3	97.1	104.0	120.0	135.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
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Long-Term Debt Ratio	44.9%	44.7%	42.7%	39.2%	36.5%	37.4%	40.5%	45.0%	45.1%	48.0%	47.0%	46.5%	47.0%	47.0%	47.0%	47.0%	47.0%	47.0%	47.0%																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
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Total Capital (\$mill)	710.3	801.1	839.0	848.0	856.4	910.1	1048.3	1337.6	1507.4	1791.9	1975.0	2150.0	2650.0	2650.0	2650.0	2650.0	2650.0	2650.0	2650.0																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
Net Plant (\$mill)	877.3	920.0	948.9	982.6	1073.1	1193.3	1352.4	1578.0	1859.1	2134.1	2250.0	2350.0	2750.0	2750.0	2750.0	2750.0	2750.0	2750.0	2750.0																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		
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EARNINGS PER SHARE <sup>A</sup>				<table border="1"> <thead> <tr> <th>Year</th> <th>Mar.31</th> <th>Jun.30</th> <th>Sep.30</th> <th>Dec.31</th> <th>Full Year</th> </tr> </thead> <tbody> <tr> <td>2012</td> <td>.83</td> <td>.14</td> <td>.07</td> <td>.49</td> <td>1.52</td> </tr> <tr> <td>2013</td> <td>.76</td> <td>.16</td> <td>d.02</td> <td>.62</td> <td>1.52</td> </tr> <tr> <td>2014</td> <td>1.01</td> <td>.15</td> <td>d.05</td> <td>.47</td> <td>1.57</td> </tr> <tr> <td>2015</td> <td>.86</td> <td>.16</td> <td>.03</td> <td>.60</td> <td>1.65</td> </tr> <tr> <td>2016</td> <td>.93</td> <td>.18</td> <td>.04</td> <td>.65</td> <td>1.80</td> </tr> </tbody> </table>																Year	Mar.31	Jun.30	Sep.30	Dec.31	Full Year	2012	.83	.14	.07	.49	1.52	2013	.76	.16	d.02	.62	1.52	2014	1.01	.15	d.05	.47	1.57	2015	.86	.16	.03	.60	1.65	2016	.93	.18	.04	.65	1.80																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																														
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BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 366,854 customers in New Jersey's southern counties. Gas revenue mix '14: residential, 43%; commercial, 19%; cogeneration and electric generation, 17%; industrial, 21%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJJ Midstream. Has about 700 employees. Off./dir. own .8% of common shares; BlackRock, Inc., 9.5%; The Vanguard Group, Inc., 6.9% (3/15 proxy). Chrmn. & CEO: Edward Graham. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Web: www.sjindustries.com.				<p><b>South Jersey Industries completed a 2-for-1 stock split in early May.</b> As a result, the number of shares outstanding rose to just under 69 million. The company cited healthy operating performance and favorable growth prospects as factors supporting the decision to effect the split. Our per-share figures have been adjusted accordingly.</p> <p><b>The company reported mixed results for the March quarter.</b> The top line advanced roughly 9%, on a year-over-year basis. This was the result of impressive growth at the utility operation, which more than offset lower revenues from the nonutility side. Operating expenses also increased, however, and earnings per share of \$0.86 were no match for the prior-year tally.</p> <p><b>We expect favorable comparisons in the coming quarters, and higher revenues and share earnings for full-year 2015.</b> The utility ought to be an important performance driver going forward. South Jersey Gas should continue to experience healthy customer growth, as natural gas remains the fuel of choice within its service territory. This business will likely continue to gain from customer conversions to natural gas, given its cost effectiveness compared to alternatives. On the non-utility side, the company's wholesale and retail commodity businesses should also post solid results, driven by demand for fuel management services from four large gas-fired merchant generating facilities, and SJJ's portfolio of transportation assets. The energy services business ought to benefit from the healthy performance of its energy production portfolio, too.</p> <p><b>This stock is neutrally ranked for year-ahead relative price performance.</b> Looking further out, we expect healthy growth in revenues and share earnings for the company from 2016 onward. On top of that, South Jersey Industries earns high marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. All things considered, this good-quality stock offers solid risk-adjusted total return potential for the pull to late decade. Conservative, income-oriented investors may find something to like here. Dividend growth looks to be a strong point here.</p> <p><i>Michael Napoli, CFA</i> <span style="float: right;">June 5, 2015</span></p>																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																	
(A) Based on GAAP egs. through 2006, economic egs. thereafter. GAAP EPS: '07, \$1.05; '08, \$1.29; '09, \$0.97; '10, \$1.11; '11, \$1.49; '12, \$1.49; '13, \$1.28; '14, \$1.46. Excl. non-recur. gain (loss): '01, \$0.07; '08, \$0.16; '09, (\$0.22); '10, (\$0.24); '11, \$0.04; '12, (\$0.03); '13, (\$0.24); '14, (\$0.11). Earnings may not sum due to rounding. Next egs. report due in August.				(B) Div's paid early April, July, Oct., and late Dec. = Div. reinvest. plan avail. (C) Incl. reg. assets. In 2014: \$357.2 mill., \$5.25 per shr. (D) In mill., adj. for split.																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																	
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UGI CORP. NYSE-UGI		RECENT PRICE	36.56	P/E RATIO	18.4	(Trailing: 19.4 Median: 14.0)	RELATIVE P/E RATIO	0.97	DIV'D YLD	2.5%	VALUE LINE								
<b>TIMELINESS</b>	2 Raised 3/27/15	High: 13.8	20.0	19.3	19.8	19.2	18.3	21.7	22.4	22.4	28.8	39.7	38.6	Target Price Range	2018	2019	2020		
<b>SAFETY</b>	2 Raised 9/17/04	Low: 10.0	12.8	13.5	15.2	12.5	14.1	15.9	16.0	17.3	21.9	26.8	31.5						
<b>TECHNICAL</b>	4 Lowered 5/22/15	<b>LEGENDS</b> — 1.30 x Dividends p sh divided by Interest Rate ..... Relative Price Strength 3-for-2 split 4/03 2-for-1 split 5/05 3-for-2 split 9/14 Options: Yes Shaded area indicates recession																	
<b>BETA</b>	.95 (1.00 = Market)	<b>2018-20 PROJECTIONS</b> Price Gain Ann'l Total High 3.5 (-5%) 1% Low 2.5 (-3.0%) -6%																	
<b>Insider Decisions</b>	J A S O N D J F M	to Buy 0 0 0 0 0 0 1 0 0 0 0 Options 0 5 0 0 0 3 1 1 0 0 to Sell 0 6 2 0 0 3 0 1 0																	
<b>Institutional Decisions</b>	202014 302014 402014	to Buy 150 154 181 to Sell 135 156 152 Hld's(000) 136174 134645 133925																	
<b>1999</b>	<b>2000</b>	<b>2001</b>	<b>2002</b>	<b>2003</b>	<b>2004</b>	<b>2005</b>	<b>2006</b>	<b>2007</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>© VALUE LINE PUB. LLC</b>	<b>18-20</b>
11.27	14.50	20.09	17.76	23.62	24.63	31.10	33.01	34.24	41.27	35.25	34.01	36.31	38.56	42.10	47.92	41.55	45.60	Revenues per sh <sup>A</sup>	51.30
1.08	1.16	1.32	1.36	1.59	1.63	2.09	2.05	2.26	2.48	2.82	2.87	2.75	2.75	3.05	4.05	4.15	4.30	"Cash Flow" per sh	4.95
.30	.35	.47	.60	.76	.81	1.15	1.10	1.18	1.33	1.57	1.59	1.37	1.17	1.59	1.92	1.95	2.10	Earnings per sh <sup>AB</sup>	2.65
.33	.34	.35	.36	.38	.40	.43	.46	.48	.50	.52	.60	.68	.71	.74	.79	.88	.92	Div's Decl'd per sh <sup>C</sup>	1.01
.57	.58	.64	.76	.79	.87	1.01	1.21	1.39	1.44	1.85	2.11	2.15	2.01	2.84	2.64	2.80	2.90	Cap'l Spending per sh	3.05
2.03	2.04	2.08	2.55	4.45	5.43	6.35	6.95	8.26	8.80	9.78	11.10	11.79	13.21	14.59	15.39	16.90	18.40	Book Value per sh <sup>D</sup>	23.25
122.72	121.47	122.83	124.66	128.10	153.63	157.20	158.18	159.97	161.09	162.78	164.38	167.75	169.06	170.88	172.73	177.00	180.00	Common Shs Outst'g <sup>E</sup>	180.00
15.9	13.6	12.1	11.4	12.6	13.4	13.8	14.0	15.1	13.3	10.3	10.9	15.0	16.4	15.4	15.8	15.8	15.8	Avg Ann'l P/E Ratio	12.0
.91	.88	.62	.62	.72	.71	.73	.76	.80	.80	.69	.69	.94	1.04	.87	.83	.83	.83	Relative P/E Ratio	.75
6.9%	7.0%	6.2%	5.3%	3.9%	3.7%	2.7%	3.0%	2.7%	2.9%	3.2%	3.5%	3.3%	3.7%	3.0%	2.6%	2.6%	2.6%	Avg Ann'l Div'd Yield	3.1%
<b>CAPITAL STRUCTURE as of 3/31/15</b> Total Debt \$3518.6 mill. Due in 5 Yrs \$1379 mill. LT Debt \$2958.2 mill. LT Interest \$237 mill. (Total Interest coverage: 4.2x)																			
<b>Leases, Uncapitalized Annual rentals \$72.6 mill.</b> Pension Assets-9/14 \$472 mill. Oblig. \$595 mill.																			
<b>Pfd Stock None</b>																			
Common Stock 172,497,596 shares as of 4/30/15																			
<b>MARKET CAP: \$6.3 bill. (Mid. Cap)</b>																			
<b>CURRENT POSITION</b> 2013 2014 3/31/15 (\$MILL)																			
Cash Assets 389.3 419.5 445.5 Other 1238.0 1243.5 1513.5 Current Assets 1627.3 1663.0 1959.0 Accrs Payable 472.3 459.8 440.8 Debt Due 295.1 288.0 560.4 Other 657.5 683.1 848.5 Current Liab. 1424.9 1430.9 1849.7 Fix. Chg. Cov. 338% 338% 338%																			
<b>ANNUAL RATES</b> Past Past Est'd '12-'14 of change (per sh) 10 Yrs. 5 Yrs. to '18-'20																			
Revenues 7.0% 3.0% 3.0% "Cash Flow" 9.0% 7.5% 5.5% Earnings 8.0% 3.0% 9.0% Dividends 7.0% 8.0% 5.0% Book Value 13.5% 10.0% 8.5%																			
<b>QUARTERLY REVENUES (\$ mill.)<sup>A</sup></b> Full Fiscal Year																			
Fiscal Year Ends Dec.31 Mar.31 Jun.30 Sep.30																			
2012 1690 2427 1277 1125 6519.2 2013 2018 2542 1374 1259 7194.7 2014 2316 3163 1486 1311 8277.3 2015 2005 2456 1510 1379 7350 2016 2055 3175 1560 1410 8200																			
<b>EARNINGS PER SHARE<sup>AB</sup></b> Full Fiscal Year																			
Fiscal Year Ends Dec.31 Mar.31 Jun.30 Sep.30																			
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<b>QUARTERLY DIVIDENDS PAID<sup>C</sup></b> Full Year																			
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2011 .17 .17 .17 .17 .68 2012 .175 .175 .18 .18 .71 2013 .18 .18 .19 .19 .74 2014 .19 .19 .20 .22 .80 2015 .22 .22																			
<b>BUSINESS:</b> UGI Corp. operates six business segments: AmeriGas Propane (accounted for 18.7% of net income in 2014), International Propane (14.3%), Gas Utility (35.2%), Midstream & Marketing (34.9%), and Corp. & Other less than -3%. UGI Utilities distributes natural gas and electricity to over 600,000 customers mainly in Pennsylvania; 26%-owned AmeriGas Partners is the largest U.S. propane marketer, serving about 1.3 million users in 50 states. Acquired remaining 80% interest in Antargaz (3/04); Energy Transfer Partners (1/12). Wellington Management Co. holds 10.8% of stock; officers/directors, 2.4% (12/14 proxy). Has 8,400 empl. CEO: John L. Walsh, Inc., PA. Address: 460 N. Gulph Rd., King of Prussia, PA 19406. Telephone: 610-337-1000. Internet: www.ugicorp.com.																			
<b>UGI Corp.'s financial results could certainly be better this year.</b> Indeed, the company's March-period top line declined more than 22%. This downturn reflected lower contributions from the AmeriGas Propane, UGI International, Gas Utility, and Midstream & Marketing segments. The weak revenues can largely be attributed to the year-over-year decline in propane and natural gas pricing as well as from reduced retail gallons sold at the AmeriGas Propane unit. On the profitability front, operating & administrative costs increased 340 basis points as a percentage of the top line. This was largely offset by the sharp reduction in cost of sales. On balance, UGI's bottom line remained unchanged when compared to 2014's figure, at \$1.23 a share. This was relatively in line with our earlier call.																			
<b>Consequently, we have left our 2015 and 2016 share-net estimates unchanged for the time being.</b> In fiscal 2015 (ends September 30th) this would represent a modest 1.5% annual increase. This ought to be supported by the regulated gas utility division, which has added approximately 11,000 new heating custom-																			
ers over the first six months of fiscal 2015. A number of capital projects and an acquisition augur well for long-term prospects. The PennEast pipeline project is progressing nicely through the FERC preapproval process. That 100-plus-mile expansion will link the Northeast, PA Marcellus region with major customer markets in Pennsylvania and New Jersey. Meanwhile, UGI recently announced plans for a 1,000-megawatt plant in Sunbury, PA and a 1,300-megawatt plant in Jessup, PA, know as Sunbury and Invenergy, respectively. All of those facilities are expected to be operational in late 2017. Too, the \$400 million-\$450 million (EUR) purchase of the Total LPG Distribution business in France (Totalgaz) received final regulatory approval from the French Competition Authority. This deal should help to grow UGI's geographic footprint.																			
These shares are ranked to outpace the broader market averages. However, the dividend yield is somewhat below average for a utility, and the equity is trading above our Target Price Range, thus limiting appreciation potential.																			
Bryan J. Fong June 5, 2015																			
<b>Company's Financial Strength</b> B++ <b>Stock's Price Stability</b> 90 <b>Price Growth Persistence</b> 75 <b>Earnings Predictability</b> 75																			

(A) Fiscal year ends Sept. 30. Quarterly sales and earnings may not sum to total due to rounding and/or change in share count. (B) Diluted earnings. Excludes nonrecur. items: '99, July, and Oct. Div. reinvest. plan available. (C) Dividends historically paid in early Jan., April, July, and Oct. (D) Incl. inlang. At 9/14: \$3,409.5 mill., \$19.73/sh. (E) In mill., adjusted for stock splits.

WGL HOLDINGS NYSE-WGL		RECENT PRICE	PIE RATIO	Trailing: 18.5	RELATIVE PIE RATIO	DIV'D YLD	VALUE LINE
<b>TIMELINESS</b> 3 Raised 3/27/15 <b>SAFETY</b> 1 Raised 4/2/93 <b>TECHNICAL</b> 4 Lowered 5/15/15 <b>BETA</b> .80 (1.00 = Market)		56.17	19.2	(Median: 15.0)	1.01	3.3%	
<b>2018-20 PROJECTIONS</b> Price High 55 Low 45 Gain (N/I) (-2.0%) Ann'l Total Return 3% (-7%)		31.4 26.7	34.8 28.8	33.6 27.0	35.9 29.8	37.1 22.4	35.5 28.6
<b>Insider Decisions</b> J A S O N D J F M to Buy 0 0 0 0 0 0 0 0 0 0 to Sell 0 0 0 0 0 0 0 0 0 0 Options 0 0 0 0 0 0 0 0 0 0		37.1 22.4	35.5 28.6	40.0 31.0	45.0 34.7	45.0 36.0	47.0 38.0
<b>Institutional Decisions</b> 202614 302614 402614 to Buy 93 99 94 to Sell 86 84 116 Hlds(000) 34353 34118 31805		45.0 36.0	47.0 38.0	56.8 35.4	59.1 50.9		
<b>MARKET CAP: \$2.8 billion (Mid Cap)</b>		59.1 50.9					
<b>CURRENT POSITION (SMILL)</b> Cash Assets 3.5 Other 816.5 Current Assets 820.0 Accts Payable 270.7 Debt Due 440.1 Other 239.3 Current Liab. 950.1 Fix. Chg. Cov. 535%		59.1 50.9					
<b>ANNUAL RATES</b> Revenues 2.5% "Cash Flow" 2.5% Earnings 3.5% Dividends 2.5% Book Value 4.0%							
<b>QUARTERLY REVENUES (\$mill.)<sup>A</sup></b> Dec.31 Mar.31 Jun.30 Sep.30							
<b>EARNINGS PER SHARE<sup>A,B</sup></b> Dec.31 Mar.31 Jun.30 Sep.30							
<b>QUARTERLY DIVIDENDS PAID<sup>C</sup></b> Mar.31 Jun.30 Sep.30 Dec.31							
<b>LEGENDS</b> 1.00 x Dividends p sh divided by Interest Rate Relative Price Strength Options: Yes Shaded area indicates recession							
<b>©VALUE LINE PUB. LLC</b>							
<b>REVENUES</b> 2013 2014 2015 2016 20.92 22.19 29.80 32.63							
<b>CASH FLOW</b> 2013 2014 2015 2016 2.74 3.20 3.24 2.63							
<b>EARNINGS</b> 2013 2014 2015 2016 1.47 1.79 1.88 1.14							
<b>DIVIDENDS</b> 2013 2014 2015 2016 1.22 1.24 1.26 1.27							
<b>CAPITAL SPENDING</b> 2013 2014 2015 2016 3.42 2.67 2.68 3.34							
<b>BOOK VALUE</b> 2013 2014 2015 2016 14.72 15.31 16.24 15.78							
<b>COMMON SHARES OUTSTG<sup>E</sup></b> 2013 2014 2015 2016 46.47 46.47 48.54 48.56							
<b>PIE RATIO</b> 2013 2014 2015 2016 17.3 14.6 14.7 23.1							
<b>RELATIVE PIE RATIO</b> 2013 2014 2015 2016 .99 .95 .75 1.26							
<b>AVG ANN'L DIV'D YIELD</b> 2013 2014 2015 2016 4.8% 4.6% 4.6% 4.8%							
<b>CAPITAL STRUCTURE as of 3/31/15</b> Total Debt \$1170.5 mill. Due in 5 Yrs \$95.0 mill. LT Debt \$950.5 mill. LT Interest \$37.7 mill. (LT interest earned: 6.2x; total interest coverage: 5.7x) Pension Assets-9/14 \$1,244.3 mill. Oblig. \$1,260.3 mill. Preferred Stock \$28.2 mill. Pfd. Div'd \$1.3 mill.							
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July 17, 2015

## WATER UTILITY INDUSTRY

1780

INDUSTRY TIMELINESS: 40 (of 96)

The Water Utility Industry consists of nine stocks, eight of which are regulated entities. The structure of the water utility market varies widely from that of the electric utility model.

Drought conditions in California continue to bring attention to this sector.

Most utilities deferred doing major overhauls of their aging infrastructure for the past few decades. As a result, many are now spending to replace old pipelines as well as meet all EPA standards.

The industry ranks 40 out the 96 that *Value Line* follows. This is up from 64 at the time of our last April report.

### The American Water Utility Market

Many investors assume that the water utilities are similar to their electric generating counterparts. Both need regulatory approval for the prices they charge customers, but otherwise the two industries can be very different. For example, most electric power companies are publicly traded. Conversely, it takes almost 53,000 municipally-owned water systems to service about 300 million Americans. If we included the small and very small systems, which are classified as serving 25 to 500 people, the number of water districts soars above 150,000. The remaining water is supplied by only about 10 or so companies that issue stock and can be owned by private investors. Of the eight we follow, four have a market capitalization of over \$1 billion, with the remaining four averaging about \$500 million. The total is about \$19 billion or equal to the market cap of one very large electric utility, such as Con Edison.

The small number of public companies limits the amount investors can participate in this industry. Indeed, water stocks' P/E's are much higher than electric utilities. This is probably due to accounts willing to pay a premium to diversify into another regulated industry, which is relatively stable. Another reason is that regulators appear to have fewer conflicts with water companies compared to the electric utilities. In the residential sector, water bills are almost always lower than electricity bills. Thus, any increase is coming from a low base and the impact isn't as substantial.

### California's Long Drought

The state remains short on water as a result of an historic lack of rainfall. Governor Brown has had to implement a new policy intended to get urban dwellers to reduce water consumption 25%. For customers going over their limit, much higher rates and penalties will be applied. For investors, the two main questions are "What will happen when a utility experiences a 25% drop in demand?" And, "Are there any regulated water businesses that would benefit from the present environment?" The answer to both questions is "No". California regulators have worked in tandem with the three companies we follow that operate in the state. They had already changed the methodology on how utilities generate profits. By introducing decoupling, a water company can do fine even when there is a sharp decline in sales. This gets everyone on the same page. A water operator receives more of a service fee. Conservation can be pushed hard and the water utilities won't have to take a hit. As we mentioned earlier, all of the regulated

corporations would never be allowed to enjoy windfall profits at the expense of the service area (which is also populated with people who vote.)

The one company that could benefit from the shortage of water is *Consolidated Water*. It is publicly traded and is not regulated. As a builder and operator of desalination plants, it is well positioned to provide many countries in the world with potable water. The one negative is that *Consolidated* is a very small company with a market capitalization of between \$175 million and \$200 million.

### Large Construction Programs

Years of deferring expenditures to maintain pipelines, wastewater facilities, and other structures has left the water infrastructure in the U.S. in very poor condition. Just about every company we follow is in the midst of a major construction program aimed at replacing and upgrading these assets. Fortunately, regulators have been working with the utilities, enabling them to earn a reasonable return on their investments. Moreover, as a whole, the industry has been able to maintain its financial integrity by not issuing too much debt. And, even though these capital expenditures will be ongoing, we are not worried about any of the companies, at this point.

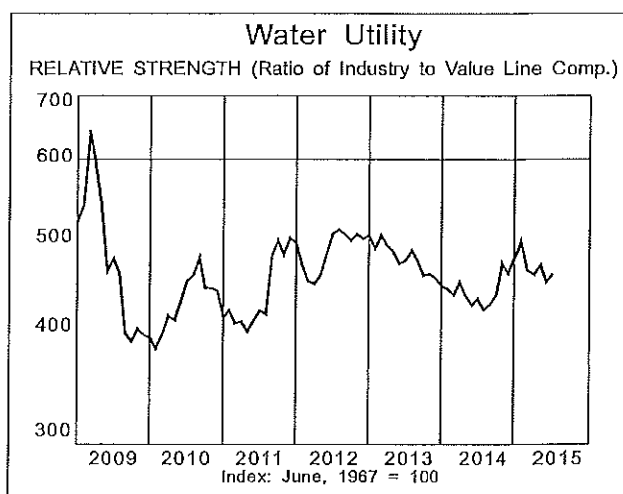
### Conclusion

In this group, *American States Water* and *American Water Works* are ranked to outperform the market in the year ahead. These are the two largest companies in the industry. Both have at least average finances and better-than-average long-term dividend growth prospects. Another positive is that the dividend yield spread between the upper and lower end on stocks in the industry is very tight. This means that the quality equities are cheap on a relative basis.

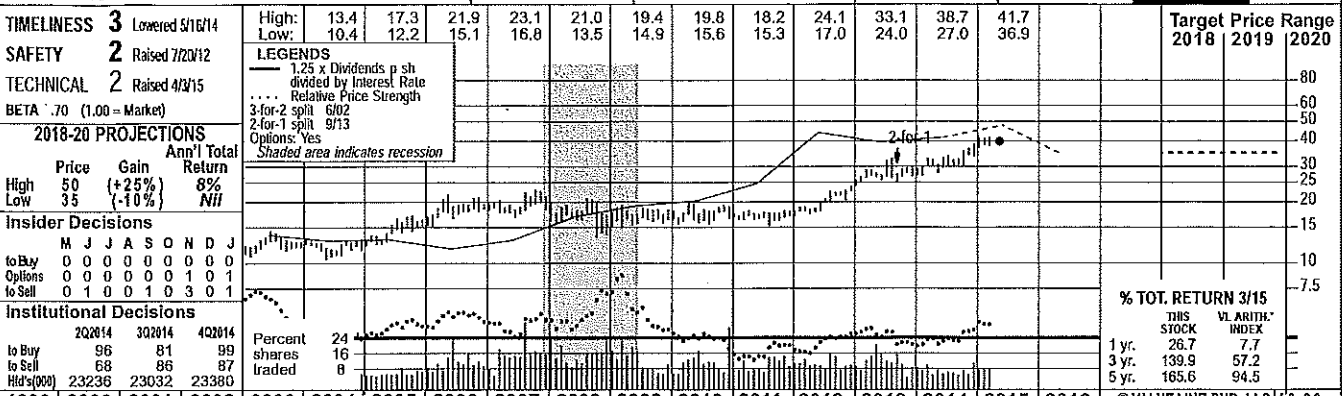
The other six regulated water companies are neutrally ranked. *Consolidated Water*, which we mentioned earlier, currently is not timely.

Income-oriented investors may also like group. The average yield is around 2.6%, which is 50 basis points higher the average stock in the *Value Line* universe.

James A. Flood



<b>AMER. STATES WATER</b>	NYSE:AWR	RECENT PRICE <b>39.76</b>	P/E RATIO <b>24.0</b> (Trailing: 25.5; Median: 21.0)	RELATIVE P/E RATIO <b>1.24</b>	DIV'D YLD <b>2.2%</b>	<b>VALUE LINE</b>
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Year	2009	2010	2011	2012	2013	2014	2015	2016	18-20										
Revenues per sh	6.45	6.08	6.53	6.89	6.93	6.81	7.03	7.88	8.75	9.21	9.74	10.71	11.12	12.12	12.19	12.17	12.35	13.35	15.35
"Cash Flow" per sh	1.13	1.10	1.26	1.27	1.04	1.11	1.32	1.45	1.65	1.69	1.70	2.11	2.13	2.48	2.65	2.65	2.70	2.80	3.70
Earnings per sh <sup>A</sup>	.60	.64	.67	.67	.39	.53	.66	.67	.81	.78	.81	1.11	1.12	1.41	1.61	1.57	1.60	1.65	2.15
Div'd Decl'd per sh <sup>B</sup>	.43	.43	.43	.44	.44	.44	.45	.46	.48	.50	.51	.52	.55	.64	.76	.83	.88	.93	1.12
Cap'l Spending per sh	2.15	1.51	1.59	1.34	1.88	2.51	2.12	1.95	1.45	2.23	2.09	2.12	2.13	1.77	2.52	1.90	2.05	2.10	2.40
Book Value per sh	5.91	6.37	6.61	7.02	6.98	7.51	7.86	8.32	8.77	8.97	9.70	10.13	10.84	11.80	12.72	13.24	13.80	14.25	15.45
Common Shs Outst'g <sup>C</sup>	26.87	30.24	30.24	30.36	30.42	33.50	33.60	34.10	34.46	37.06	37.26	37.70	38.53	38.72	38.29	38.00	37.50		37.50
Avg Ann'l P/E Ratio	17.1	15.9	16.7	18.3	31.9	23.2	21.9	27.7	24.0	22.6	21.2	15.7	15.4	14.3	17.2	22.2	22.2	22.2	20.5
Relative P/E Ratio	.97	1.03	.86	1.00	1.82	1.23	1.17	1.50	1.27	1.36	1.41	1.00	.97	.91	.97	1.17	1.17	1.17	1.30
Avg Ann'l Div'd Yield	4.2%	4.2%	3.9%	3.6%	3.5%	3.6%	3.1%	2.6%	2.5%	2.9%	2.9%	3.0%	3.2%	3.1%	2.7%	2.4%	2.4%	2.4%	2.7%

**CAPITAL STRUCTURE as of 12/31/14**  
 Total Debt \$326.1 mill. Due in 5 Yrs \$41.6 mill.  
 LT Debt \$325.8 mill. LT Interest \$21.5 mill.  
 (LT interest earned; 5.7 x: total interest coverage: 5.4 x)  
 Leases, Uncapitalized: Annual rentals \$0.4 mill.  
 Pension Assets-12/14 \$140.6 mill. Oblig. \$185.2 mill.  
 Pfd Stock None.  
 Common Stock 38,220,567 shs. as of 2/23/15  
**MARKET CAP: \$1.5 billion (Mid Cap)**

Current Position	2012	2013	12/31/14
Cash Assets	23.5	36.2	76.0
Other	160.5	153.4	133.5
Current Assets	184.0	191.6	209.5
Accts Payable	40.6	49.8	41.9
Debt Due	3.3	6.3	.3
Other	49.8	44.8	57.1
Current Liab.	93.7	100.9	99.3
Fix. Chg. Cov.	488%	531%	533%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	5.5%	6.5%	4.0%
"Cash Flow"	7.5%	8.5%	6.0%
Earnings	9.0%	13.0%	6.5%
Dividends	4.0%	6.5%	8.0%
Book Value	5.5%	6.5%	4.0%

Cal-endar	QUARTERLY REVENUES (\$mill.)				Full Year
	Mar.31	Jun.30	Sep.30	Dec.31	
2012	107.6	114.3	133.5	111.5	466.9
2013	110.6	120.7	130.9	109.9	472.1
2014	102.0	115.6	138.3	109.9	465.8
2015	103	117	140	110	470
2016	105	125	150	120	500

Cal-endar	EARNINGS PER SHARE <sup>A</sup>				Full Year
	Mar.31	Jun.30	Sep.30	Dec.31	
2012	.27	.40	.49	.26	1.41
2013	.35	.43	.53	.30	1.61
2014	.28	.39	.54	.36	1.57
2015	.30	.45	.55	.30	1.60
2016	.31	.46	.57	.31	1.65

Cal-endar	QUARTERLY DIVIDENDS PAID <sup>B</sup>				Full Year
	Mar.31	Jun.30	Sep.30	Dec.31	
2011	.13	.14	.14	.14	.55
2012	.14	.14	.1775	.1775	.64
2013	.1775	.1775	.2025	.2025	.76
2014	.2025	.2025	.213	.213	.83
2015	.213				

**American States Water's earnings growth should be modest through 2016.** The company's main subsidiary, Golden State Water Co., has been coming close to earning the allowable return on its common equity for the past two years. Thus, there isn't much room for bottom-line expansion in the near term. All told, we only expect share net to increase 2% this year, followed by a 3% increase in 2016.

**Growth in the military business should bolster long-term profits.** Through its ASUS subsidiary, the company provides water to nine armed forces bases under six 50-year contracts. This operation, in which returns are not capped by state regulators, has been responsible for 20% to 25% of American States' share earnings. Over the next five years, up to 50 more bases may privatize their water and wastewater systems. As ASUS has performed successfully in this sector, we expect it to win a proportionate amount of these contracts.

**Operating in California has not been a negative for the company.** Regulators in the state have worked well with the in-

dustry in response to the record-breaking drought now plaguing the region. Usually, a decrease in water usage translates into reduced revenues for a utility, making conservation almost not in their interest. In a process known as decoupling, GSWC is allowed to structure fees that result in it not being penalized to incentivize households to use less water. Indeed, over the past six years, water usage has declined 16%-17%. Moreover, California permits utilities to collect increased expenses as they are incurred, not after the fact, as many other state regulators require.

**Management believes that a 5% dividend growth rate is sustainable over the next 3- to 5-year period.** Though this is below historical levels, the expected increase in the annual payout is not far off the industry average. With the help from nonregulated businesses, we think there is potential upside to this figure.

**American Water shares do not stand out for either short- or long-term potential performance.** The stock's strong showing has eliminated much of its attractiveness.

*James A. Flood*  
 April 17, 2015

(A) Primary earnings. Excludes nonrecurring gains/(losses): '04, '07, '08, '10, '11, '12, '13, '14, '15, '16, '17, '18, '19, '20. Next earnings report due mid-May. Quarterly earnings may vary due to rounding.  
 (B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.  
 (C) In millions, adjusted for splits.  
 Company's Financial Strength A  
 Stock's Price Stability 85  
 Price Growth Persistence 70  
 Earnings Predictability 85  
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**AMERICAN WATER** NYSE-AWK RECENT PRICE **54.68** P/E RATIO **20.5** (Trailing: 23.0 Median: NMF) RELATIVE P/E RATIO **1.06** DIV'D YLD **2.4%** **VALUE LINE**

**TIMELINESS** 2 Raised 1/23/15  
**SAFETY** 3 New 7/25/08  
**TECHNICAL** 2 Raised 4/10/15  
**BETA** .70 (1.00 = Market)

**LEGENDS**  
 --- 0.25 x Dividends p sh divided by Interest Rate  
 .... Relative Price Strength  
 Options: Yes  
 Shaded area indicates recession

**2018-20 PROJECTIONS**

Price	Gain	Ann'l Total Return
High 80	(+4.5%)	12%
Low 50	(-10%)	7%

**Insider Decisions**

M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0
Options	3	0	4	0	0	3	0	0
to Sell	3	0	0	6	0	0	3	0

**Institutional Decisions**

202014	3Q2014	4Q2014	
to Buy	208	206	223
to Sell	194	189	201
Hld's(000)	146101	146606	143322

Percent shares traded: 21, 14, 7

**% TOT. RETURN 3/15**

THIS STOCK	W. ARNH. INDEX
1 yr. 22.4	7.7
3 yr. 72.3	57.2
5 yr. 188.3	94.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008 <sup>B</sup>	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB, LLC	18-20
--	--	--	--	--	--	--	13.08	13.84	14.61	13.98	15.49	15.18	16.25	16.28	16.78	17.70	18.50	Revenues per sh	21.40
--	--	--	--	--	--	--	.65	d.47	2.87	2.89	3.56	3.73	4.27	4.36	4.75	4.65	5.10	"Cash Flow" per sh	6.15
--	--	--	--	--	--	--	d.97	d2.14	1.10	1.25	1.53	1.72	2.11	2.06	2.39	2.60	2.80	Earnings per sh <sup>A</sup>	3.25
--	--	--	--	--	--	--	--	--	.40	.82	.86	.91	1.21	.84	1.21	1.33	1.42	Div'd Decl'd per sh <sup>Ⓜ</sup>	1.70
--	--	--	--	--	--	--	4.31	4.74	6.31	4.50	4.38	5.27	5.25	5.50	5.33	5.55	5.55	Cap'l Spending per sh	6.25
--	--	--	--	--	--	--	23.86	28.39	25.64	22.91	23.59	24.11	25.11	26.52	27.39	27.60	29.60	Book Value per sh <sup>D</sup>	34.55
--	--	--	--	--	--	--	160.00	160.00	160.00	174.63	175.00	175.66	176.99	178.25	179.46	179.50	179.50	Common Shs Outst'g <sup>C</sup>	185.00
--	--	--	--	--	--	--	--	--	18.9	15.6	14.6	16.8	16.7	19.9	20.1	20.1	20.1	Avg Ann'l P/E Ratio	20.0
--	--	--	--	--	--	--	--	--	1.14	1.04	.93	1.05	1.06	1.12	1.06	1.06	1.06	Relative P/E Ratio	1.25
--	--	--	--	--	--	--	--	--	1.9%	4.2%	3.8%	3.1%	3.4%	2.0%	2.5%	2.5%	2.5%	Avg Ann'l Div'd Yield	2.6%

**CAPITAL STRUCTURE** as of 12/31/14  
 Total Debt \$5959.3 mil. Due in 5 Yrs \$1294.5 mil.  
 LT Debt \$5448.2 mil. LT Interest \$278.0 mil.  
 (Total interest coverage: 3.0x) (53% of Cap'l)

Leases, Uncapitalized: Annual rentals \$14.0 mil.  
 Pension Assets 12/14 \$1428.2 mil.  
 Oblig. \$1746.5 mil.  
 Pfd Stock \$17.2 mil. Pfd Div'd \$ .5 mil

Common Stock 179,787,780 shs.  
 as of 2/19/2015

**MARKET CAP: \$9.8 billion (Large Cap)**

2003	2004	2005	2006	2007	2008 <sup>B</sup>	2009	2010	2011	2012	2013	2014	2015	2016
2093.1	2214.2	2336.9	2440.7	2710.7	2666.2	2876.9	2901.9	3011.3	3175	3325	3960	660	
d155.8	d342.3	187.2	209.9	267.8	304.9	374.3	369.3	429.8	465	505	505	600	
--	--	37.4%	37.9%	40.4%	39.5%	40.7%	39.1%	39.4%	39.5%	38.5%	37.5%	37.5%	
--	--	--	--	--	--	6.2%	5.1%	1.4%	5.0%	5.0%	6.0%	6.0%	
58.1%	50.9%	53.1%	56.8%	55.7%	53.9%	52.4%	52.4%	53.5%	53.0%	55.0%	55.0%	55.0%	
43.9%	49.1%	46.9%	43.1%	43.2%	44.2%	46.1%	47.8%	47.4%	46.5%	47.0%	45.0%	45.0%	
8692.8	9245.7	8750.2	9289.0	9561.3	9580.3	9635.5	9940.7	10363.8	10955	11500	13300	15000	
8720.6	9318.0	9991.8	10524	11059	11021	11739	12391	13029.3	13600	14250	15000	15000	
NMF	NMF	3.7%	3.8%	4.4%	4.8%	5.4%	5.1%	5.5%	5.0%	5.5%	6.0%	6.0%	
NMF	NMF	4.6%	5.2%	6.5%	7.2%	8.4%	7.8%	8.7%	8.5%	8.5%	9.0%	9.0%	
NMF	NMF	4.6%	5.2%	6.5%	7.2%	8.4%	7.8%	8.7%	8.5%	8.5%	9.0%	9.0%	
NMF	NMF	3.0%	1.8%	2.8%	3.5%	3.6%	4.7%	4.3%	4.0%	4.5%	4.5%	4.5%	
--	--	34%	65%	56%	52%	57%	40%	43%	53%	51%	51%	51%	

**BUSINESS:** American Water Works Company, Inc. is the largest investor-owned water and wastewater utility in the U.S., providing services to over 15 million people in over 47 states and Canada. (Regulated presence in 16 states). Nonregulated business assists municipalities and military bases with the maintenance and upkeep as well. Regulated operations made up 88.8% of 2014 revenues.

New Jersey is its largest market accounting for 22.7% of regulated revenues. Has roughly 6,400 employees. BlackRock, Inc., owns 10.0% of outstanding shares; Vanguard, 6.3%; officers & directors, less than 1.0%. (4/14 Proxy). Pres. & CEO: Susan Story. Chairman: George Mackenzie. Addr.: 1025 Laurel Oak Road, Voorhees, NJ 08043. Tel.: 856-346-8200. Internet: www.amwater.com.

**CURRENT POSITION**

(\$ MILL.)	2012	2013	12/31/14
Cash Assets	24.4	27.0	23.1
Other	475.0	523.3	638.3
Current Assets	499.4	550.3	661.4
Accts Payable	279.6	264.1	285.8
Debt Due	385.9	644.5	511.1
Other	329.3	326.9	444.1
Current Liab.	994.8	1235.5	1241.0
Fix. Chg. Cov.	297%	307%	300%

**ANNUAL RATES of change (per sh)**

	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	--	3.0%	4.5%
"Cash Flow"	--	32.5%	6.0%
Earnings	--	--	7.5%
Dividends	--	--	8.0%
Book Value	--	-5%	5.0%

**American Water Works recently completed another successful year.** Thanks to a strong fourth quarter, the company posted a hefty 16% year-over-year share-net gain in 2014.

**We expect this trend to continue.** One of the strengths of American Water is in its ability to make many small tuck-in acquisitions and integrate them into existing operations. In addition to the synergies realized from these purchases, management continues to place a significant emphasis on driving down costs. (Last year's key expense ratio fell from 38.5% to 36.7%.) Since, like most members of this industry, the company needs to make large expenditures to improve its infrastructure, it will have to spend roughly \$1 billion annually for the foreseeable future. Higher investment increases American Water's assets that it is allowed to earn a return on. Though comparison with last year's impressive results will be difficult, we expect the company to record healthy earnings-per-share gains of 8% in both 2015 and 2016.

**American Water stands out in comparison to most of its peers.** For com-

ers, this is a market in which size matters. AWK's market capitalization represents more than half that of all of the nine stocks in this industry combined. As smaller municipally-run water districts realize that they don't have the financial wherewithal required to maintain their systems, American Water should be the main beneficiary. As the largest buyer of pipes, meters, etc., it is able to get better pricing. Moreover, being so diversified geographically, the utility already is familiar with all federal and state regulations.

**The balance sheet should remain about average.** American Water probably won't be able to generate sufficient cash to cover its large construction budget through late decade. So, more debt will be required. As a result, we don't expect the Financial Strength rating to be raised.

**These shares are ranked to outperform the market averages in the year ahead.** But despite all of the company's positive attributes, the equity's total return potential through 2016-2018 is below average for the typical stock in the Value Line universe.

**QUARTERLY REVENUES (\$ MILL.)**

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	618.5	745.6	831.8	681.0	2876.9
2013	636.1	724.3	829.2	712.3	2901.9
2014	679.0	754.8	846.1	731.4	3011.3
2015	700	805	880	790	3175
2016	735	840	920	830	3325

**EARNINGS PER SHARE <sup>A</sup>**

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.28	.66	.87	.30	2.11
2013	.32	.57	.84	.33	2.06
2014	.39	.62	.86	.52	2.39
2015	.45	.70	1.00	.45	2.60
2016	.50	.75	1.05	.50	2.80

**QUARTERLY DIVIDENDS PAID <sup>Ⓜ</sup>**

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.22	.23	.23	.23	.91
2012	.23	.23	.25	.50	1.21
2013	--	.28	.28	.28	.84
2014	.28	.31	.31	.31	1.21
2015	.31				

**James A. Flood**  
 April 17, 2015

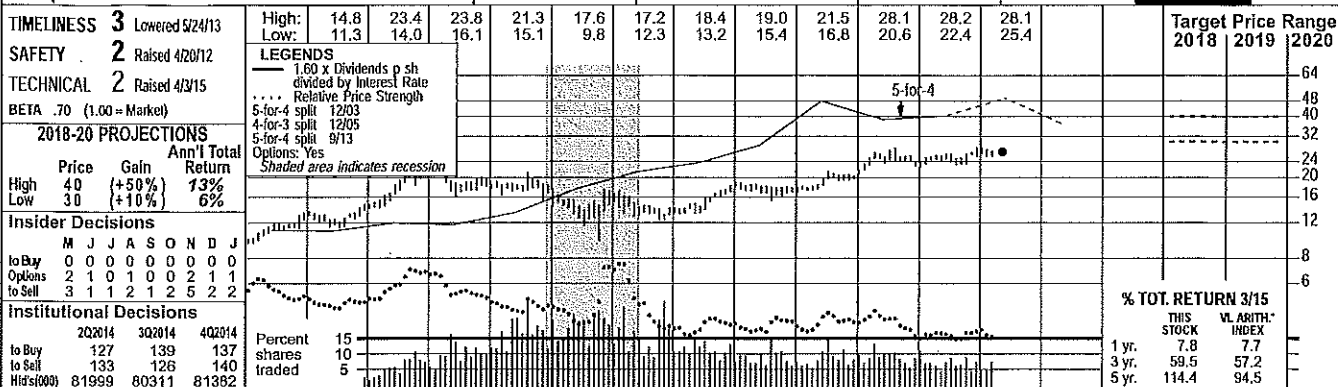
Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	20

(A) Diluted earnings. Excludes nonrecurring losses: '08, \$4.62; '09, \$2.63; '11, \$0.07. Discontinued operations: '06, (\$0.04); '11, \$0.03; '12, (\$0.10); '13, (\$0.01); '14, (\$0.05). Next earnings report due early May. Quarterly earnings may not sum due to rounding. (B) Dividends paid in March, June, September, and December. (C) Div. reinvestment available. (D) Includes intangibles. In 2014: \$1.21 billion, \$6.73/share. (E) Pro forma numbers for '06 & '07.

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**AQUA AMERICA** NYSE-WTR RECENT PRICE **26.81** P/E RATIO **21.6** (Trailing: 22.2 Median: 24.0) RELATIVE P/E RATIO **1.12** DIV'D YLD **2.6%** **VALUE LINE**



1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC 18-20																		
1.93	1.97	2.16	2.28	2.38	2.78	3.08	3.23	3.61	3.71	3.93	4.21	4.10	4.32	4.32	4.37	4.55	4.70	Revenues per sh	5.70																	
.58	.61	.69	.76	.77	.87	.97	1.01	1.10	1.14	1.29	1.42	1.45	1.51	1.82	1.90	2.35	2.50	"Cash Flow" per sh	3.05																	
.33	.37	.41	.43	.46	.51	.57	.56	.57	.58	.62	.72	.83	.87	1.16	1.20	1.25	1.30	Earnings per sh <sup>A</sup>	1.65																	
.22	.23	.24	.26	.28	.29	.32	.35	.38	.41	.44	.47	.50	.54	.58	.63	.71	.77	Div'd Decl'd per sh <sup>B</sup>	.98																	
.72	.93	.87	.96	1.06	1.23	1.47	1.64	1.43	1.58	1.66	1.89	1.90	1.98	1.73	1.84	1.95	2.00	Cap'l Spending per sh	2.00																	
2.74	3.08	3.32	3.49	4.27	4.71	5.04	5.57	5.85	6.26	6.50	6.81	7.21	7.90	8.63	9.27	9.65	10.05	Book Value per sh	11.40																	
133.50	139.78	142.47	141.49	154.31	158.97	161.21	165.41	166.75	169.21	170.61	172.46	173.60	175.43	177.93	178.59	178.50	175.00	Common Shs Outst'g <sup>C</sup>	170.00																	
21.2	18.2	23.6	23.6	24.5	25.1	31.8	34.7	32.0	24.9	23.1	21.1	21.3	21.9	21.2	20.2	<i>Bold figures are Value Line estimates</i>	20.2	Avg Ann'l P/E Ratio	21.5																	
1.21	1.18	1.21	1.29	1.40	1.33	1.69	1.87	1.70	1.50	1.54	1.34	1.34	1.39	1.19	1.06		1.06	Relative P/E Ratio	1.35																	
3.0%	3.3%	2.5%	2.5%	2.5%	2.3%	1.8%	1.8%	2.1%	2.8%	3.1%	3.1%	2.8%	2.8%	2.4%				Avg Ann'l Div'd Yield	2.6%																	
<b>CAPITAL STRUCTURE as of 12/31/14</b>																		496.8	533.5	602.5	627.0	670.5	726.1	712.0	757.8	768.6	779.9	800	825	Revenues (\$mill)	970					
Total Debt \$1630.7 mill. Due in 5 Yrs \$436.9 mill.																		91.2	92.0	95.0	97.9	104.4	124.0	144.8	153.1	205.0	213.9	225	230	Net Profit (\$mill)	280					
LT Debt \$1560.7 mill. LT Interest \$70.0 mill.																		38.4%	39.6%	38.9%	39.7%	39.4%	39.2%	32.9%	39.0%	10.0%	10.5%	18.0%	20.0%	Income Tax Rate	27.0%					
(Total interest coverage: 3.9x)																		--	--	--	--	--	--	--	--	1.1%	2.4%	2.0%	2.5%	AFUDC % to Net Profit	3.0%					
<b>Pension Assets-12/14 232.4 mill.</b>																		52.0%	51.6%	55.4%	54.1%	55.6%	56.6%	52.7%	52.7%	48.9%	49.5%	50.0%	50.0%	Long-Term Debt Ratio	50.0%					
Obliq. \$281.2 mill.																		48.0%	48.4%	44.6%	45.9%	44.4%	43.4%	47.3%	47.3%	51.1%	51.5%	50.5%	50.0%	Common Equity Ratio	50.0%					
<b>Pfd Stock None</b>																		1680.4	1904.4	2191.4	2306.6	2495.5	2706.2	2646.8	2929.7	3003.6	3216.1	3370	3505	Total Capital (\$mill)	3955					
Common Stock 176,823,519 shares as of 2/12/15																		2280.0	2506.0	2792.8	2997.4	3227.3	3469.3	3612.9	3936.2	4167.3	4402.0	4550	4700	Net Plant (\$mill)	5000					
<b>MARKET CAP: \$4.7 billion (Mid Cap)</b>																		6.9%	6.4%	5.9%	5.7%	5.6%	5.9%	6.9%	6.6%	8.0%	7.5%	8.0%	7.5%	Return on Total Cap'l	8.5%					
																		11.2%	10.0%	9.7%	9.3%	9.4%	10.6%	11.6%	11.0%	13.4%	12.9%	13.0%	13.0%	Return on Shr. Equity	14.5%					
																		11.2%	10.0%	9.7%	9.3%	9.4%	10.6%	11.6%	11.0%	13.4%	12.9%	13.0%	13.0%	Return on Com Equity	14.5%					
<b>CURRENT POSITION</b>																		4.9%	3.7%	3.2%	2.8%	2.7%	3.7%	4.6%	4.3%	6.7%	6.1%	5.5%	5.5%	Retained to Com Eq	6.0%					
<b>(SMILL)</b>																		56%	63%	67%	70%	72%	65%	60%	61%	50%	53%	57%	53%	All Div'ds to Net Prof	59%					
Cash Assets																		5.5	5.1	4.1																
Receivables																		92.9	95.4	97.0																
Inventory (AvgCst)																		11.8	11.4	12.8																
Other																		150.7	59.8	38.6																
Current Assets																		260.9	171.7	152.5																
Accts Payable																		55.5	65.8	60.0																
Debt Due																		125.4	123.0	70.0																
Other																		93.3	78.1	95.3																
Current Liab.																		274.2	266.9	225.3																
Fix. Chg. Cov.																		413%	388%	389%																

**BUSINESS:** Aqua America, Inc. is the holding company for water and wastewater utilities that serve approximately three million residents in Pennsylvania, Ohio, North Carolina, Illinois, Texas, New Jersey, Florida, Indiana, and five other states. Has 1,617 employees. Acquired AquaSource, 7/03; Consumers Water, 4/99; and others. Water supply revenues '14: residential, 68%; commercial,

17%; industrial & other, 15%. Officers and directors own .8% of the common stock; Vanguard Group, 6.6%; State Street Capital Corp., 6.3%; Blackrock, Inc, 6.1% (4/14 Proxy). Chairman & Chief Executive Officer: Nicholas DeBenedictis. Incorporated: Pennsylvania. Address: 762 West Lancaster Avenue, Bryn Mawr, Pennsylvania 19010. Telephone: 610-525-1400. Internet: www.aquaamerica.com.

**Aqua America has healthy long-term dividend growth prospects.** Based upon our projections of the company's ability to internally generate cash, we estimate that the annual payout may increase roughly 9% per annum through 2018-2020. This is a much higher rate than that of the typical stock in the industry.

**Earnings gains will probably moderate both this year and next.** Excluding the \$0.11-a-share gain from the sale of its operations in Fort Wayne, Aqua's share net rose 3.4% in 2014. Considering that 2013 was an exceptional year, the comparison was actually good. Due to some rate relief, synergies from acquisitions, and the ability to earn returns on capital investments with little regulatory lag, we expect the utility to record 4% bottom-line increases in both 2015 and 2016.

**Expansion via acquisitions is a major part of the company's strategy.** Most water systems in the U.S. are small and municipally owned. Over the past two decades, Aqua has made over 300 purchases, including 16 in 2014. As these smaller water districts realize that they do not have the finances to modernize their

aging infrastructures, they will continue to look toward merging with larger companies. With a significant amount of redundancies, cost savings from synergies can be significant in this industry.

**Low energy prices could impact non-regulated operations.** Hydraulic fracking has become a major presence in Aqua's service areas. With each well requiring five million gallons of water, transporting it by truck is both burdensome and expensive. Extending pipeline systems directly to the wells can be very profitable for water utilities. Revenues from this sector should decline, however, as drillers shut wells until the energy market recovers.

**Investors willing to sacrifice some returns for more certainty may like these shares.** On the plus side, Aqua America stock has a decent well-protected dividend yield, favorable payout growth prospects, a solid balance sheet, the highest (95) mark for Stock Price Stability, well-defined earnings, and a 2 (Above Average) Safety rank. All told, we believe that the potential total returns are adequate on a risk-adjusted basis.

James A. Flood April 17, 2015

(A) Diluted eps. Excl. nonrec. gains (losses): '99, (9¢); '00, 2¢; '01, 2¢; '02, 4¢; '03, 3¢; '12, 18¢. Excl. gain from disc. operations: '12, 7¢; '13, 9¢; '14, 11¢. May not sum due to rounding.

Next earnings report due mid-May.  
(B) Dividends historically paid in early March, June, Sept. & Dec. ■ Div'd. reinvestment plan available (5% discount).

(C) In millions, adjusted for stock splits.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	95

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# CALIFORNIA WATER NYSE-CWT

RECENT PRICE **24.76** P/E RATIO **19.2** (Trailing: 23.1 Median: 20.0) RELATIVE P/E RATIO **0.99** DIV'D YLD **2.7%** **VALUE LINE**

**TIMELINESS** 3 Raised 5/20/14

**SAFETY** 3 Lowered 7/27/07

**TECHNICAL** 2 Raised 4/3/15

BETA .75 (1.00 = Market)

2018-20 PROJECTIONS

Price Gain Ann'l Total  
High 35 (+40%) 11%  
Low 25 (Nil) 3%

Insider Decisions

Institutional Decisions

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
7.98	8.08	8.13	8.67	8.18	8.59	8.72	8.10	8.88	9.90	10.82	11.05	12.00	13.34	12.23	12.50	12.80	13.25	Revenues per sh	16.80
1.37	1.26	1.10	1.32	1.26	1.42	1.52	1.36	1.56	1.86	1.93	2.07	2.32	2.07	2.21	2.50	2.60	2.65	"Cash Flow" per sh	3.20
.77	.66	.47	.83	.61	.73	.74	.67	.75	.95	.98	.91	.86	1.02	1.02	1.19	1.20	1.20	Earnings per sh A	1.55
.54	.55	.56	.56	.56	.57	.57	.58	.58	.59	.60	.62	.63	.64	.64	.65	.67	.69	Div'd Decl'd per sh B	.97
1.72	1.23	2.04	2.91	2.19	1.87	2.01	2.14	1.84	2.41	2.66	2.97	2.83	3.04	2.58	2.75	2.50	2.60	Cap'l Spending per sh	3.10
6.71	6.45	6.48	6.86	7.22	7.83	7.90	9.07	9.25	9.72	10.13	10.45	10.76	11.28	12.54	13.22	13.75	14.25	Book Value per sh C	16.00
25.87	30.29	30.36	30.36	33.86	38.73	36.78	41.31	41.33	41.45	41.53	41.67	41.82	41.98	47.74	47.81	48.00	48.00	Common Shs Outst'g D	50.00
17.8	19.6	27.1	19.8	22.1	20.1	24.9	29.2	26.1	19.8	19.7	20.3	21.3	17.9	20.1	19.3	19.3	19.3	Avg Ann'l P/E Ratio	20.0
1.01	1.27	1.39	1.08	1.26	1.06	1.33	1.58	1.39	1.19	1.31	1.29	1.34	1.14	1.13	1.02	1.02	1.02	Relative P/E Ratio	1.25
4.0%	4.3%	4.4%	4.5%	4.2%	3.9%	3.1%	2.9%	3.0%	3.1%	3.1%	3.2%	3.4%	3.5%	3.1%	2.8%	2.8%	2.8%	Avg Ann'l Div'd Yield	3.2%
<b>CAPITAL STRUCTURE as of 12/31/14</b>																		840	
Total Debt \$504.9 mill. Due in 5 Yrs \$206.7 mill.																		77.5	
LT Debt \$419.2 mill. LT Interest \$20.0 mill.																		36.0%	
(LT Interest earned: 4.2x; total Int. cov.: 4.0x)																		5.0%	
(40% of Cap'l)																		41.5%	
Pension Assets-12/14 \$306.3 mill.																		58.5%	
Oblig. \$390.6 mill.																		1370	
Pfd Stock None																		1820	
Common Stock 47,800,997 shs. as of 2/9/15																		7.0%	
<b>MARKET CAP: \$1.2 billion (Mid Cap)</b>																		9.5%	
<b>CURRENT POSITION</b>																		3.5%	
2012 2013 12/31/14																		63%	
<b>(\$ MILL)</b>																			
Cash Assets 38.8 27.5 19.6																			
Other 107.8 112.0 134.5																			
Current Assets 146.6 139.5 154.1																			
Accts Payable 46.8 55.1 59.4																			
Debt Due 136.3 54.7 85.7																			
Other 59.7 56.8 72.6																			
Current Liab. 242.8 166.6 217.7																			
Fix. Chg. Cov. 296% 301% 299%																			
<b>ANNUAL RATES</b>																			
Past Past Est'd '11-'13																			
of change (per sh) 10 Yrs. 5 Yrs. to '18-'20																			
Revenues 4.0% 7.0% 5.0%																			
"Cash Flow" 6.0% 6.5% 5.5%																			
Earnings 5.5% 4.0% 7.5%																			
Dividends 1.0% 1.5% 7.0%																			
Book Value 5.5% 4.5% 5.5%																			
<b>QUARTERLY REVENUES (\$ MILL)</b>																			
Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year																			
2012 116.8 143.6 178.1 121.5 560.0																			
2013 111.4 154.6 184.4 133.7 584.1																			
2014 110.5 158.4 191.2 137.4 597.5																			
2015 115 165 195 140 615																			
2016 120 170 200 145 635																			
<b>EARNINGS PER SHARE A</b>																			
Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year																			
2012 .03 .31 .56 .12 1.02																			
2013 .01 .28 .61 .12 1.02																			
2014 d.11 .36 .70 .24 1.19																			
2015 Nil .32 .73 .15 1.20																			
2016 Nil .31 .74 .15 1.20																			
<b>QUARTERLY DIVIDENDS PAID B</b>																			
Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year																			
2011 .154 .154 .154 .154 .62																			
2012 .1575 .1575 .1575 .1575 .63																			
2013 .16 .16 .16 .16 .64																			
2014 .1625 .1625 .1625 .1625 .65																			
2015 .1675																			

**BUSINESS:** California Water Service Group provides regulated and nonregulated water service to 477,900 customers in 85 communities in the state of California. Accounts for over 94% of total customers. Also operates in Washington, New Mexico, and Hawaii. Main service areas: San Francisco Bay area, Sacramento Valley, Salinas Valley, San Joaquin Valley & parts of Los Angeles. Acquired Rio Grande Corp; West Hawaii Utilities (9/08). Revenue breakdown, '14: residential, 68%; business, 19%; industrial, 5%; public authorities, 3%; other 5%. '14 reported depreciation rate: 4.0%. Has 1,105 employees. President, Chairman, and CEO: Peter C. Nelson. Inc.: OE. Address: 1720 North First St., San Jose, CA 95112-4588. Tel.: 408-367-8200. Internet: www.calwatergroup.com.

**State regulators (CPUC) have been working well with California Water Services during the region's historic drought.** The more water it sells, the more revenues a water utility generates. Due to the ongoing lack of rainfall, the CPUC has implemented "decoupling." This mechanism encourages conservation, without having a major impact on a water utility's profits.

**The company had a much better-than-expected fourth quarter.** Fueled by rate relief implemented last year and reduced expenses, California Water's earnings per share doubled to \$0.24, on a year-over-year basis in the December interim. This resulted in a hefty 17% bottom-line gain in 2014.

**We expect profits to be flattish over the next two years.** The bulk of the earnings gains resulting from higher rates were reflected in California Water's earnings in 2014. Based on state regulations, California water utilities can only file for adjustments for increased expenses once every three years. With most of the recent cost reductions probably not sustainable, we estimate that the company's share earnings will barely budge from last year's tally of \$1.19, and come in at \$1.20 for both 2015 and 2016.

**The latest dividend hike was a bit of a disappointment.** We had been looking for a 4.6% increase in the quarterly payout to \$0.17 a share, instead it was only raised by 3.1% to \$0.1675.

**California Water's finances are in fine shape.** The equity-to-total capital ratio was at an industry high of 60% at year-end 2014. Much of this can be attributed to a large equity offering in 2013. Capital expenditures to replace an aging pipeline infrastructure will probably increase in the years ahead. Because of the strong balance sheet, we don't anticipate any major equity offerings out to the late decade. Additional debt may be required, but we believe the utility's financial metrics will remain above the industry averages.

**These shares are not of particular interest at this juncture.** On the plus side, CWT's yield is higher than most of the stocks in the water industry. Over the pull to 2018-2020, however, the stock has below-average total return potential.

*James A. Flood*  
*April 17, 2015*

(A) Basic EPS. Excl. nonrecurring gain (loss): '00, (4¢); '01, 2¢; '02, 4¢; '11, 4¢. Next earnings report due mid-May. (B) Dividends historically paid in late Feb., May, Aug., and Nov. (C) Incl. intangible assets. In '14: \$7.3 mill., \$0.15/sh. (D) In millions, adjusted for splits. (E) Excludes non-reg. rev.

Company's Financial Strength B++  
Stock's Price Stability 95  
Price Growth Persistence 40  
Earnings Predictability 90

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CONNECTICUT WATER NDQ-CTWS											RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO		DIV'D YLD		VALUE LINE												
											36.82	18.7	(Trailing: 19.2)	0.97	2.9%															
											High: 29.8	28.2	27.7	25.6	29.0	26.4	27.9	29.1	32.8	36.4	37.5	38.6	Target Price Range							
											Low: 23.8	21.9	20.3	22.4	19.3	17.3	20.0	23.3	26.2	27.8	31.0	35.1	2018	2019						
TIMELINESS	3	Lowered 11/21/14															80													
SAFETY	3	New 1/10/13															60													
TECHNICAL	2	Raised 3/27/15															50													
BETA	.65	(1.00 = Market)															40													
2018-20 PROJECTIONS															30															
Price Gain Ann'l Total															25															
High 50 (+35%) 10%															20															
Low 35 (-5%) 2%															15															
Insider Decisions															10															
M J J A S O N D J															7.5															
to Buy 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0																														
Options 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0																														
to Sell 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0																														
Institutional Decisions															%															
202014 302014 4Q2014															TOT. RETURN 3/15															
to Buy 40 50 36															THIS STOCK															
to Sell 32 34 46															VL. ARTH. INDEX															
Hld's(000) 4304 4299 4296															1 yr. 9.5 7.7															
															3 yr. 40.9 57.2															
															5 yr. 84.5 94.5															
© VALUE LINE PUB. LLC 18-20																														
1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Revenues per sh	12.50											
5.87	5.70	5.93	5.77	5.91	6.04	5.81	5.68	7.05	7.24	6.93	7.65	7.93	9.47	8.29	8.45	8.75	9.00	"Cash Flow" per sh	3.60											
1.65	1.73	1.78	1.78	1.89	1.91	1.62	1.52	1.90	1.95	1.93	2.04	2.11	2.64	2.63	3.00	3.20	3.35	Earnings per sh <sup>A</sup>	2.25											
1.03	1.09	1.13	1.12	1.15	1.16	.88	.81	1.05	1.11	1.19	1.13	1.13	1.53	1.66	1.92	2.00	2.10	Div'd Decl'd per sh <sup>B</sup>	1.30											
.79	.79	.80	.81	.83	.84	.85	.86	.87	.88	.90	.92	.94	.96	.98	1.01	1.05	1.09	Cap'l Spending per sh	2.85											
1.42	1.43	1.86	1.98	1.49	1.58	1.96	1.96	2.24	2.44	3.28	3.06	2.61	2.79	3.02	4.11	4.60	4.15	Book Value per sh <sup>D</sup>	24.15											
8.61	8.92	9.25	10.06	10.46	10.94	11.52	11.60	11.95	12.23	12.67	13.05	13.50	20.95	17.92	18.84	20.10	21.15	Common Shs Outst'g <sup>C</sup>	12.00											
7.26	7.28	7.65	7.94	7.97	8.04	8.17	8.27	8.38	8.46	8.57	8.68	8.76	8.85	11.04	11.12	11.20	11.35	Avg Ann'l P/E Ratio	19.0											
18.2	18.2	21.5	24.3	23.5	22.9	28.6	29.0	23.0	22.2	18.4	20.7	23.0	19.4	18.4	17.7	17.7	17.7	Relative P/E Ratio	1.20											
1.04	1.18	1.10	1.33	1.34	1.21	1.52	1.57	1.22	1.34	1.23	1.32	1.44	1.23	1.03	1.03	1.03	1.03	Avg Ann'l Div'd Yield	2.8%											
4.2%	4.0%	3.3%	3.0%	3.0%	3.1%	3.4%	3.6%	3.6%	3.6%	4.1%	3.9%	3.6%	3.2%	3.2%	3.0%	3.0%	3.0%	Revenues (\$mill)	150											
CAPITAL STRUCTURE as of 12/31/14															47.5	46.9	59.0	61.3	59.4	66.4	69.4	83.8	91.5	94.0	98.0	102	Net Profit (\$mill)	27.0		
Total Debt \$181.0 mill. Due in 5 Yrs \$19.3 mill.															7.2	6.7	8.8	9.4	10.2	9.8	9.9	13.6	18.3	21.3	23.0	24.0	Income Tax Rate	30.0%		
LT Debt \$176.6 mill. LT Interest \$7.0 mill.															--	23.5%	32.4%	27.2%	19.5%	35.2%	41.3%	32.0%	28.0%	14.5%	18.0%	19.5%	AFUDC % to Net Profit	2.0%		
(Total interest coverage: 4.4x)															--	--	--	1.7%	--	--	--	1.7%	2.0%	2.4%	2.5%	2.5%	Long-Term Debt Ratio	47.5%		
(46% of Cap'l)															44.9%	44.4%	47.8%	46.9%	50.6%	49.5%	53.2%	49.0%	46.9%	45.7%	45.5%	47.5%	Common Equity Ratio	52.5%		
Leases, Uncapitalized: Annual rentals \$.1 mill.															172.3	174.1	193.2	198.5	221.3	225.6	254.2	364.6	373.6	386.8	420	455	Total Capital (\$mill)	550		
Pension Assets-12/14 \$61.6 mill.															247.7	268.1	284.3	302.3	325.2	344.2	362.4	447.9	471.9	506.9	535	560	Net Plant (\$mill)	675		
Oblig. \$79.8 mill.															5.0%	4.9%	5.5%	5.9%	5.5%	5.4%	4.9%	4.8%	5.9%	6.4%	6.5%	6.5%	Return on Total Cap'l	6.0%		
Pfd Stock \$0.8 mill. Pfd Divd NMF															7.5%	6.9%	8.7%	9.0%	9.3%	8.6%	8.3%	7.3%	9.2%	10.2%	10.0%	10.0%	Return on Shr. Equity	9.5%		
Common Stock 11,152,627 shs.															7.6%	7.0%	8.7%	9.1%	9.4%	8.7%	8.3%	7.3%	9.2%	10.2%	10.0%	10.0%	Return on Com Equity	9.5%		
as of 3/1/15															3%	NMF	1.6%	1.9%	2.3%	1.6%	1.4%	2.8%	3.9%	4.5%	4.5%	4.5%	Retained to Com Eq	4.0%		
MARKET CAP: \$400 million (Small Cap)															95%	105%	82%	79%	76%	81%	63%	62%	59%	53%	53%	52%	All Div'ds to Net Prof	58%		
CURRENT POSITION (\$MILL)																														
Cash Assets															13.2	18.4	2.5													
Accounts Receivable															11.5	12.3	12.0													
Other															11.7	16.2	21.7													
Current Assets															36.4	46.9	36.2													
Accts Payable															10.0	10.8	10.0													
Debt Due															3.0	4.1	4.4													
Other															2.9	7.8	9.2													
Current Liab.															15.9	22.7	23.6													
Fix. Chg. Cov.															408%	375%	375%													
ANNUAL RATES of change (per sh)															Past 10 Yrs	Past 5 Yrs	Est'd '11-'13 to '18-'20													
Revenues															4.0%	5.0%	5.5%													
"Cash Flow"															3.0%	6.5%	5.5%													
Earnings															2.5%	8.0%	6.5%													
Dividends															1.5%	2.0%	4.6%													
Book Value															6.0%	8.0%	4.5%													
QUARTERLY REVENUES (\$mill.)															Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year										
2012															18.5	21.3	24.5	19.5	83.8											
2013															19.7	22.6	27.6	21.6	91.5											
2014															20.3	25.4	27.6	20.7	94.0											
2015															21.5	26.5	29.0	21.0	98.0											
2016															22.5	27.5	30.0	22.0	102.0											
EARNINGS PER SHARE <sup>A</sup>															Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year										
2012															.22	.47	.67	.16	1.53											
2013															.24	.39	.86	.17	1.66											
2014															.27	.67	.76	.22	1.92											
2015															.35	.60	.80	.25	2.00											
2016															.36	.62	.85	.27	2.10											
QUARTERLY DIVIDENDS PAID <sup>B</sup>															Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year										
2011															.233	.233	.238	.238	.942											
2012															.238	.238	.2425	.2425	.962											
2013															.2425	.2425	.2475	.2475	.98											
2014															.2475	.2475	.2575	.2575	1.01											
2015															.2575															
BUSINESS: Connecticut Water Service, Inc. is a non-operating holding company, whose income is derived from earnings of its wholly-owned subsidiary companies (regulated water utilities). In 2014, 93% of net income was derived from these activities. Provides water services to 400,000 people in 77 municipalities throughout Connecticut and Maine. Acquired The Maine Water Company, January, 2012; Biddeford and Saco Water, December, 2012. Incorporated: Connecticut. Has 265 employees. Chairman/President/Chief Executive Officer: Eric W. Thornburg. Officers and directors own 2.3% of the common stock; BlackRock, Inc. 7.0%; (4/15 proxy). Address: 93 West Main Street, Clinton, CT 06413. Telephone: (860) 669-8636. Internet: www.cwwater.com.																														
<b>Connecticut Water Services will be hard-pressed to repeat last year's impressive performance.</b> Share net rose 16% in 2014, thanks mostly to an agreement with regulators regarding a rebate from the IRS. Still, we estimate that the utility can string together two consecutive solid years in 2015 and 2016. Margins are improving as the company is successfully integrating two acquisitions made in 2012. Moreover, the Biddeford and Saco operation in Maine was recently granted a significant rate increase. As a result, we think Connecticut Water can still grow earnings 4%-5% per annum over the next two years.																														
<b>Capital expenditures are scheduled to be large in the short term.</b> In addition, to having to replace older pipes (like almost every other water utility), the company has agreed to supply water to two new customers. Funds are being spent to extend the infrastructure in Connecticut to service the town of Mansfield and the University of Connecticut's Storrs campus, which is the size of a small city. Overall, we expect the capital budget to average over \$50 million a year through 2016,																														
which represents a 10% increase over the relatively large outlays made in 2014. Starting in 2017, however, construction should take a breather.																														
<b>The balance sheet is strong enough to handle the increased spending.</b> The equity-to-total capital ratio will most likely decline from its very healthy level of 54.5% to 52.5% by year-end 2016. Despite the dip, this percentage is high for a water utility.																														
<b>Dividend growth prospects have improved.</b> Over the past five- and 10-year periods, the company has only raised its annual payout by 1.5% and 2.0%, respectively. This rate lagged the industry mean by a wide margin. We expect this gap to narrow substantially in the long term. Indeed, dividend hikes through late decade will probably average 4.5%.																														
<b>Shares of Connecticut Water do not hold much appeal at their recent price.</b> Despite having a high yield, the stock is expected to only perform in line with the market averages in the year ahead. Potential returns through late decade are even less attractive.																														
James A. Flood															April 17, 2015															
(A) Diluted earnings. Next earnings report due mid-May. Quarterly earnings do not add in 2012 due to rounding.																														
(B) Dividends historically paid in mid-March.																														
(C) In millions, adjusted for split.																														
(D) Includes intangibles. In 2014: \$31.7 mil.																														
Company's Financial Strength															B+															
Stock's Price Stability															85															
Price Growth Persistence															50															
Earnings Predictability															85															
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<b>CONSOL. WATER CO. NDQ: CWCO</b>										<b>RECENT PRICE</b> 12.43	<b>P/E RATIO</b> 20.7 (Trailing: 29.6 Median: 27.0)	<b>RELATIVE P/E RATIO</b> 1.07	<b>DIV'D YLD</b> 2.4%	<b>VALUE LINE</b>												
<b>TIMELINESS</b> 4 Lowered 3/27/15	<b>SAFETY</b> 3 New 1/17/14	<b>TECHNICAL</b> 3 Raised 4/3/15	<b>BETA</b> .90 (1.00 = Market)	<b>2018-20 PROJECTIONS</b>	<b>Insider Decisions</b>	<b>Institutional Decisions</b>											<b>Target Price</b>	<b>Range</b>								
<b>High:</b> 15.5	<b>Low:</b> 8.7	<b>22.5</b>	<b>13.6</b>	<b>31.8</b>	<b>19.8</b>	<b>37.5</b>	<b>23.3</b>	<b>29.8</b>	<b>7.6</b>	<b>21.3</b>	<b>6.4</b>	<b>15.1</b>	<b>8.1</b>	<b>11.7</b>	<b>7.3</b>	<b>9.2</b>	<b>6.7</b>	<b>16.9</b>	<b>7.5</b>	<b>14.5</b>	<b>8.4</b>	<b>12.7</b>	<b>9.6</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>
<p><b>LEGENDS</b>                  2.00 x Dividends per sh divided by Interest Rate                  Relative Price Strength                  2-for-1 split 8/05                  Options: Yes                  Shaded area indicates recession</p>																										
<b>Price</b>	<b>Gain</b>	<b>Ann'l Total Return</b>																								
<b>High</b> 30	<b>Low</b> 18	<b>(+140%)</b>	<b>27%</b>																							
<p><b>Percent shares traded</b>                  202014 302014 402014                  to Buy 35 32 28                  to Sell 54 31 28                  Hld's(000) 6207 6127 5703</p>																										
<p><b>© VALUE LINE PUB. LLC 18-20</b></p>																										
1.25	1.24	1.41	1.52	1.68	2.02	1.12	2.71	3.41	4.52	3.99	3.49	3.79	4.49	4.35	4.46	4.75	5.00	4.46	5.95	Revenues per sh	5.95					
.43	.46	.52	.50	.63	.77	.37	.87	1.20	.95	1.18	.86	.83	1.17	.96	.80	1.05	1.10	.80	1.60	"Cash Flow" per sh	1.60					
.31	.34	.35	.32	.42	.49	.23	.59	.79	.50	.74	.43	.42	.64	.58	.42	.60	.65	.40	1.10	Earnings per sh <sup>A</sup>	1.10					
.08	.17	.20	.21	.21	.23	.12	.24	.20	.33	.28	.30	.30	.30	.30	.30	.30	.30	.30	.30	Div'd Decl'd per sh <sup>B</sup>	.40					
.24	.30	.24	.39	.19	.24	.77	1.83	.54	.46	.18	.09	.96	.31	.29	.32	.60	.60	.60	.60	Cap'l Spending per sh	.60					
1.96	2.30	2.45	2.64	3.89	4.20	2.54	7.49	8.21	8.36	8.53	8.69	8.83	9.20	9.44	9.59	9.85	10.20	10.20	13.65	Book Value per sh	13.65					
6.38	7.73	7.84	7.99	11.37	11.51	23.46	14.13	14.40	14.53	14.54	14.55	14.57	14.59	14.69	14.72	14.75	15.00	15.00	16.00	Common Shs Outst'g <sup>C</sup>	16.00					
11.7	10.4	13.9	21.6	19.3	23.1	NMF	43.0	35.4	37.8	19.0	26.9	22.4	12.4	20.0	27.4	20.0	27.4	20.0	21.0	Avg Ann'l P/E Ratio	21.0					
.67	.68	.71	1.18	1.10	1.22	NMF	2.32	1.88	2.27	1.27	1.71	1.41	.79	1.12	1.44	1.12	1.44	1.12	1.30	Relative P/E Ratio	1.30					
2.2%	4.9%	4.2%	3.1%	2.6%	2.0%	.7%	.9%	.7%	1.7%	2.0%	2.6%	3.2%	3.8%	2.6%	2.6%	2.6%	2.6%	2.6%	1.6%	Avg Ann'l Div'd Yield	1.6%					
<p><b>CAPITAL STRUCTURE</b> as of 12/31/14                  Total Debt \$9.0 mill. Due in 5 Yrs \$9.0 mill.                  LT Debt None LT Interest None</p>																										
<p><b>Leases, Uncapitalized:</b> Annual rentals \$ .7 mill.</p>																										
<p><b>No Defined Benefit Pension Plan</b></p>																										
<p><b>Pfd Stock</b> NMF 36,840 shares out. Div'd NMF</p>																										
<p><b>Common Stock</b> 14,715,899 shs. as of 3/9/14</p>																										
<p><b>MARKET CAP:</b> \$175 million (Small Cap)</p>																										
<p><b>CURRENT POSITION</b></p>																										
<p><b>Cash Assets</b> 42.5 42.2 40.7  <b>Accs Receivable</b> 14.3 18.9 11.8  <b>Other</b> 4.5 6.5 6.9  <b>Current Assets</b> 61.3 67.6 59.4  <b>Accs Payable</b> 5.9 7.2 6.0  <b>Debt Due</b> 1.6 5.2 9.0  <b>Other</b> 1.2 11.2 1.2  <b>Current Liab.</b> 8.7 23.6 16.2  <b>Fix. Chg. Cov.</b> 832% NMF NMF</p>																										
<p><b>ANNUAL RATES of change (per sh)</b></p>																										
<p><b>Revenues</b> 10.5% 3.5% 5.0%  <b>"Cash Flow"</b> 6.0% -0.5% 7.0%  <b>Earnings</b> 4.5% -2.5% 10.5%  <b>Dividends</b> 4.0% 3.5% 4.0%  <b>Book Value</b> 12.0% 2.5% 6.0%</p>																										
<p><b>QUARTERLY REVENUES (\$ mill.)</b></p>																										
<p><b>2012</b> 16.7 16.2 15.8 16.8 65.5  <b>2013</b> 16.6 16.6 15.4 15.2 63.8  <b>2014</b> 16.3 16.9 17.0 15.4 65.6  <b>2015</b> 17.5 17.5 18.5 16.5 70.0  <b>2016</b> 18.5 18.5 19.5 18.5 75.0</p>																										
<p><b>EARNINGS PER SHARE <sup>A</sup></b></p>																										
<p><b>2012</b> .17 .13 .09 .25 .64  <b>2013</b> .26 .19 .06 .07 .58  <b>2014</b> .04 .19 .13 .06 .42  <b>2015</b> .16 .22 .16 .06 .69  <b>2016</b> .18 .24 .17 .06 .65</p>																										
<p><b>QUARTERLY DIVIDENDS PAID <sup>B</sup></b></p>																										
<p><b>2011</b> .075 .075 .075 .075 .30  <b>2012</b> .075 .075 .075 .075 .30  <b>2013</b> .075 .075 .075 .075 .30  <b>2014</b> .075 .075 .075 .075 .30  <b>2015</b> .075 .075 .075 .075 .30</p>																										

**BUSINESS:** Consolidated Water Co. Ltd. develops and operates seawater desalination plants and water distribution systems in areas where naturally occurring supplies of potable water are scarce or nonexistent. Its desalination process involves reverse osmosis tech. It provides water in the Cayman Islands, Belize, the Bahamas, the British Virgin Islands, and Bali. At 12/31/14, it operat-

**Consolidated Water's investment in the British Virgin Islands (BVI) is having a negative impact on earnings.**

For almost a decade, the BVI government and the water company have been engaged in several legal disputes, with the most recent being centered on the OC-BVI desalination facility. As an equity investment, Consolidated must determine the market value of OC-BVI at the end of each year. Due to the ongoing conflicts with the BVI, the company had to write down the investment by about \$0.06 in 2014. Moreover, the initial seven-year contract is due for renewal in 2017. Even though the BVI will most likely re-sign, Consolidated may be forced to take additional writedowns in 2015 and 2016. Consequently, **Our earnings estimates for this year and next are somewhat tentative.** The retail water operations in the Caymans remain the bread and butter of the company's business. Prospects in this sector seem good, though the island's officials are making some noise about restructuring the deal. Profits from bulk water sales in the Bahamas are being hurt as conservation resulted in demand falling 17% last

year. All told, we estimate that the company's share net will be \$0.60 this year, and \$0.65 in 2016.

**Otherwise, Consolidated is involved in two very promising new ventures.** Bali is one of the premier tourist destinations in the world, with many high-end hotels. Unfortunately, it has hardly any potable water. The company built a desalination plant that recently started operations and is in the process of ramping up. As the isle's population continues to grow, we expect this to be a very profitable long-term venture. In addition, plans to build a \$600 million facility in Mexico (CWCO will own a 12% stake) that would provide water to two growing cities, San Diego and Tijuana, are going smoothly and construction may begin soon. **These shares are not timely.** Moreover, the unresolved situation in the BVI adds uncertainty. Investors willing to live with a fair amount of risk may find this an interesting holding to 2018-2020, however, as CWCO could benefit greatly from the growing scarcity of water in its operating areas.

James A. Flood

April 17, 2015

(A) Fully diluted earnings. Next earnings report due mid-May. Quarterly share earnings do not sum in 2014 due to rounding.  
 (B) Dividends historically paid in late January.

April, July and October. ■ Dividend reinvestment plan available.  
 (C) In millions adjusted for stock split.

Company's Financial Strength	B+
Stock's Price Stability	35
Price Growth Persistence	10
Earnings Predictability	50



MIDDLESEX WATER NDQ-MSEX		RECENT PRICE	P/E RATIO	Trailing: 20.3 Median: 21.0	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE	Target Price	Range
TIMELINESS 3	Lowered 4/11/14	High: 21.8	22.97	19.6	1.02	3.4%	2018	2019	2020
SAFETY 2	New 10/21/11	Low: 16.7							
TECHNICAL 2	Raised 4/3/15	23.5							
BETA .75	(1.00 = Market)	20.5							
2018-20 PROJECTIONS		20.2							
Price	Gain	19.8							
High	30	17.9							
Low	25	19.3							
Insider Decisions		19.4							
Institutional Decisions		19.6							
CAPITAL STRUCTURE as of 12/31/14		22.5							
Pension Assets-12/14 \$51.6 mill.		23.7							
MARKET CAP: \$375 million (Small Cap)		23.5							
ANNUAL RATES of change (per sh)		23.5							
QUARTERLY REVENUES (\$ mill.)		23.5							
EARNINGS PER SHARE		23.5							
QUARTERLY DIVIDENDS PAID		23.5							

**BUSINESS:** Middlesex Water Company engages in the ownership and operation of regulated water utility systems in New Jersey, Delaware, and Pennsylvania. It also operates water and wastewater systems under contract on behalf of municipal and private clients in NJ and DE. Its Middlesex System provides water services to 60,000 retail customers, primarily in Middlesex County, New Jersey. In 2014, the Middlesex System accounted for 60% of operating revenues. At 12/31/14, the company had 282 employees. Incorporated: NJ. President, CEO, and Chairman: Dennis W. Doll. Officers & directors own 3.5% of the common stock; BlackRock Institutional Trust Co., 6.6% (4/15 proxy). Add: 1500 Ronson Road, Iselin, NJ 08830. Tel.: 732-634-1500. Internet: www.middlesexwater.com.

**Middlesex Water had a surprisingly good 2014.** For the second straight year, the company was able to post a double-digit gain in earnings per share. This was impressive considering that the utility is still in recovery mode following the 2013 loss of two major customers — a Hess refinery and the borough of Sayreville. **Bottom-line gains should moderate.** The rate relief that was granted in New Jersey and Delaware will not have as positive an impact on profits as was the case last year. On the positive side, an agreement to distribute water at the Dover Air Force Base (a major military installation) should provide a consistent source of revenues. Overall, we expect Middlesex's 2015 share net to barely rise, from \$1.13 to \$1.15 in 2015. Next year will probably be better, as we think per-share earnings can increase 4%, to \$1.20.

**We are not expecting Middlesex to change its remarkably consistent dividend policy through 2016.** Since 2004, the utility has raised the payout by exactly \$0.01 a share each and every year. With a dividend growth rate of 1.5% over both the past five- and 10-year periods, the company has lagged the industry mean by a substantial margin. When this tradition started, the dividend to net profits percentage was relatively high, meaning there was little room for increases. This figure fell to 57% in 2014, so Middlesex appears to have the flexibility to distribute a greater share of profits to shareholders. **The balance sheet may not be big, but it is strong.** At the end of last year, Middlesex's equity-to-total capital ratio was close to 59%, the second highest in the industry. And, while this metric will most likely decline as debt is added to help fund the upgrading of the pipeline network, the utility's finances should remain very sound by late decade. **Middlesex stock has the highest yield of any member in the water industry.** At 3.4%, the equity has a payout that is almost 80 basis points above the group average. Indeed, it is the only one that has a yield above 3%. Basically, investors are demanding a premium to own shares in this company. Despite the generous current income, the stock's potential returns through 2018-2020 are still subpar.

James A. Flood  
April 17, 2015

(A) Diluted earnings. May not sum due to rounding. Next earnings report due mid-May.  
(B) Dividends historically paid in mid-Feb., May, Aug., and November. Div'd reinvestment plan available.  
(C) In millions, adjusted for splits.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	40

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## SJW CORP. NYSE-SJW

**RECENT PRICE 30.62** **P/E RATIO 24.3** (Trailing: 12.1 Median: 24.0) **RELATIVE P/E RATIO 1.26** **DIV'D YLD 2.6%** **VALUE LINE**

<b>TIMELINESS</b> 4 Lowered 12/19/14	High: 19.6	27.8	45.3	43.0	35.1	30.4	28.2	26.8	26.9	30.1	33.7	35.7	Target Price Range 2018 2019 2020
<b>SAFETY</b> 3 New 4/22/11	Low: 14.6	16.1	21.2	27.7	20.0	18.2	21.6	20.9	22.6	24.5	25.5	29.8	

**TECHNICAL** 2 Raised 3/27/15  
**BETA** .80 (1.00 = Market)

**2018-20 PROJECTIONS**

Price	Gain	Ann'l Total Return
High 45	(+45%)	12%
Low 30	(Nil)	2%

**Insider Decisions**

	M	J	J	A	S	O	N	D	J
to Buy	1	1	0	1	1	0	0	1	0
Options to Sell	0	0	0	0	0	0	0	1	0

**Institutional Decisions**

	2Q2014	3Q2014	4Q2014
to Buy	45	38	49
to Sell	4D	45	47
Hld's(000)	10965	10784	10867

**LEGENDS**  
 1.50 x Dividends p sh divided by Interest Rate  
 .... Relative Price Strength  
 3-for-1 split 3/04  
 2-for-1 split 3/06  
 Options: No  
 Shaded area indicates recession

**% TOT. RETURN 3/15**

	THIS STOCK	VL ARTH' INDEX
1 yr.	7.3	7.7
3 yr.	39.2	57.2
5 yr.	39.8	94.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
6.40	6.74	7.45	7.97	8.20	9.14	9.86	10.35	11.25	12.12	11.88	11.62	12.85	14.01	13.73	15.76	14.15	14.05	Revenues per sh	17.60
1.43	1.23	1.49	1.55	1.75	1.89	2.21	2.38	2.30	2.44	2.21	2.38	2.80	2.97	2.90	4.50	3.45	3.55	"Cash Flow" per sh	3.90
.87	.58	.77	.78	.91	.87	1.12	1.19	1.04	1.08	.81	.84	1.11	1.18	1.12	2.54	1.35	1.40	Earnings per sh <sup>A</sup>	1.75
.40	.41	.43	.46	.49	.51	.53	.57	.61	.65	.66	.68	.69	.71	.73	.75	.78	.81	Div'd Decl'd per sh <sup>B=C</sup>	1.05
1.77	1.89	2.63	2.06	3.41	2.31	2.83	3.87	6.62	3.79	3.17	5.65	3.75	5.67	4.68	5.00	4.95	4.95	Cap'l Spending per sh	4.90
7.88	7.90	8.17	8.40	9.11	10.11	10.72	12.48	12.90	13.99	13.66	13.75	14.20	14.71	15.92	17.75	18.30	19.05	Book Value per sh	21.30
18.27	18.27	18.27	18.27	18.27	18.27	18.27	18.28	18.36	18.18	18.50	18.55	18.59	18.67	20.17	20.29	20.50	21.00	Common Shs Outst'g <sup>C</sup>	23.00
15.5	33.1	18.5	17.3	15.4	19.6	19.7	23.5	33.4	26.2	28.7	29.1	21.2	20.4	24.3	11.0	11.0	11.0	Avg Ann'l P/E Ratio	22.0
.88	2.15	.95	.94	.88	1.04	1.05	1.27	1.77	1.58	1.91	1.85	1.33	1.30	1.37	.58	.58	.58	Relative P/E Ratio	1.40
3.0%	2.1%	3.0%	3.4%	3.5%	3.0%	2.4%	2.0%	1.7%	2.3%	2.8%	2.8%	2.9%	3.0%	2.7%	2.7%	2.7%	2.7%	Avg Ann'l Div'd Yield	2.8%

**CAPITAL STRUCTURE as of 12/31/14**

Total Debt \$398.2 mill. Due in 5 Yrs \$21.2 mill.	180.1	189.2	206.6	220.3	216.1	215.6	239.0	261.5	276.9	319.7	290	295	Revenues (\$mill)	405
LT Debt \$384.4 mill. LT Interest \$18.1 mill. (Total interest coverage: 2.9x) (52% of Cap'l)	20.7	22.2	19.3	20.2	15.2	15.8	20.9	22.3	23.5	51.8	27.5	29.0	Net Profit (\$mill)	40.0
Leases, Uncapitalized: Annual rentals \$5.5 mill.	41.6%	40.8%	39.4%	39.5%	40.4%	38.8%	41.1%	41.1%	38.7%	32.5%	37.0%	36.0%	Income Tax Rate	38.0%
Pension Assets-12/14 \$91.4 mill. Oblig. \$128.7 mill.	1.6%	2.1%	2.7%	2.3%	2.0%	--	--	--	2.0%	1.0%	1.0%	1.0%	AFUDC % to Net Profit	1.5%
Pfd Stock None.	42.6%	41.8%	47.7%	46.0%	49.4%	53.7%	55.0%	51.1%	51.6%	52.5%	52.5%	52.5%	Long-Term Debt Ratio	53.5%
Common Stock 20,336,409 shs. as of 2/13/15	57.4%	58.2%	52.3%	54.0%	50.6%	46.3%	43.4%	45.0%	48.9%	48.4%	47.5%	47.5%	Common Equity Ratio	46.5%
<b>MARKET CAP: \$625 million (Small Cap)</b>	341.2	391.8	453.2	470.9	499.6	550.7	607.9	610.2	656.2	744.6	790	845	Total Capital (\$mill)	1025
<b>CURRENT POSITION</b> 2012 2013 12/31/14 (\$MILL.)	484.0	541.7	645.5	684.2	718.5	785.5	756.2	831.6	898.7	963.0	1010	1065	Net Plant (\$mill)	1200
Cash Assets	7.6%	7.0%	5.7%	5.8%	4.4%	4.3%	4.9%	5.0%	5.0%	8.3%	5.0%	5.0%	Return on Total Cap'l	5.5%
Other	10.6%	9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	8.1%	7.3%	14.4%	7.5%	7.5%	Return on Shr. Equity	8.0%
Current Assets	10.6%	9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	8.1%	7.3%	14.4%	7.5%	7.5%	Return on Com Equity	8.0%
Accs Payable	5.6%	5.2%	3.5%	3.3%	1.2%	1.2%	3.1%	3.3%	2.8%	10.1%	3.0%	3.0%	Retained to Com Eq	3.5%
Debt Due	47%	46%	57%	59%	80%	80%	61%	59%	62%	28%	58%	58%	All Div'ds to Net Prof	59%
Other														
Current Liab.														
Fix. Chg. Cov.														

**ANNUAL RATES of change (per sh)**

	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	5.5%	4.0%	4.0%
"Cash Flow"	6.0%	4.0%	4.5%
Earnings	3.5%	.5%	6.5%
Dividends	4.5%	3.5%	5.5%
Book Value	5.5%	2.5%	5.0%

**QUARTERLY REVENUES (\$ mill.)**

Cal-endar	Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	51.1	65.6	82.4	62.4	261.5
2013	50.1	74.2	85.2	67.4	276.9
2014	54.6	70.4	125.4	69.3	319.7
2015	56.0	73.0	89.0	72.0	290
2016	57.0	74.0	90.0	74.0	295

**EARNINGS PER SHARE <sup>A</sup>**

Cal-endar	Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	.06	.28	.53	.31	1.18
2013	.07	.37	.44	.24	1.12
2014	.04	.34	1.88	.28	2.54
2015	.05	.40	.53	.37	1.35
2016	.05	.40	.57	.38	1.40

**QUARTERLY DIVIDENDS PAID <sup>B=C</sup>**

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.173	.173	.173	.173	.69
2012	.1775	.1775	.1775	.1775	.71
2013	.1825	.1825	.1825	.1825	.73
2014	.1875	.1875	.1875	.1875	.75
2015	.1950				

**BUSINESS:** SJW Corporation engages in the production, purchase, storage, purification, distribution, and retail sale of water. It provides water service to approximately 229,000 connections that serve a population of approximately one million people in the San Jose area and 12,000 connections that serve approximately 36,000 residents in a service area in the region between San Antonio and Austin, Texas. The company offers nonregulated water-related services. Also owns and operates commercial real estate investments. Has about 395 employees. Officers & directors (including Nancy O. Moss) own 27.9% of outstanding shares. Chrm.: Charles J. Toeniskoetter, Inc.: CA. Address: 110 W. Taylor Street, San Jose, CA 95110. Tel.: (408) 279-7800. Int: www.sjwater.com.

**SJW's main operating service area is in the midst of an historic drought.** The vast majority of the utility's revenues are derived from its water operations in the thriving San Jose area of California. The lack of rain and snow in the mountains has led to the state placing severe restrictions on water usage for conservation purposes. This should result in a steep decline in demand for water. To date, regulators have worked with water utilities using a mechanism known as "decoupling." Basically, this process doesn't meaningfully penalize utilities for encouraging residents to reduce consumption.

**SJW's earnings have been skewed.** In 2014, the company's profits more than doubled due to a one-time event. The utility received a large payment in the third quarter for past expenses that it was forced to absorb. Since the funds were received as compensation for normal business expenses, we did not classify it as a nonrecurring event.

**SJW's bottom line should post decent gains over the next two years.** We think that the company's share net can reach \$1.35 in 2015. If 2014 had been a normal year, the year-over-year comparison would have been favorable. Next year's per-share earnings will probably only show a modest \$0.05-a-share increase to \$1.40, however. During 2015 and 2016, opposite forces will be at work pulling the utility's profits in different directions. On the positive side, SJW will be earning a return on the funds spent modernizing its pipeline infrastructure. Conversely, margins may be restrained by the scarcity of surface water, which would force SJW to pay more to either extract more ground water or purchase it from other sources.

**The recent dividend increase was adequate.** Though the 4% hike was positive in that it was higher than the company's historical growth rate, we thought that there was room for a 5% raise. This would have put the company's growth rate more in line with the industry norm.

**These shares are ranked to underperform the broader market averages in the year ahead.** Moreover, total return potential over the next three- to five-year period is subpar, as well.

*James A. Flood*  
April 17, 2015

(A) Diluted earnings. Excludes nonrecurring losses: '03, \$1.97; '04, \$3.78; '05, \$1.09; '06, \$16.36; '08, \$1.22; '10, \$0.46. Next earnings report due mid-May. Quarterly earnings may not add due to rounding.

(B) Dividends historically paid in early March, June, September, and December. Div'd reinvestment plan available.

(C) In millions, adjusted for stock splits.

Company's Financial Strength B+  
 Stock's Price Stability 80  
 Price Growth Persistence 30  
 Earnings Predictability 70

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YORK WATER NDQ:YORW		RECENT PRICE	PIE RATIO	Trailing: 27.0 Median: 25.0	RELATIVE PIE RATIO	DIV'D YLD	VALUE LINE			
TIMELINESS 3	Raised 3/27/15	24.01	24.5		1.27	2.5%				
SAFETY 2	New 7/19/13	High: 14.0	17.9	21.0	18.5	16.5	18.0			
TECHNICAL 2	Lowered 4/17/15	Low: 11.0	11.7	15.3	15.5	9.7	12.8			
BETA .70	(1.00 = Market)							Target Price Range 2020		
2018-20 PROJECTIONS		Price	Gain	Ann'l Total Return				2018	2019	
High	30	+25%	8%							
Low	20	-15%	-7%							
Insider Decisions								% TOT. RETURN 3/15		
Institutional Decisions								THIS STOCK VS. ARITH. INDEX		
CAPITAL STRUCTURE as of 12/31/14		Total Debt \$84.8 mill. Due in 5 Yrs \$30.5 mill. LT Debt \$84.8 mill. LT interest \$5.1 mill. (Total interest coverage: 4.0x)						1 yr. 22.2 3 yr. 51.6 5 yr. 103.2		
Pension Assets 12/14 \$30.6 mill.		Oblig. \$40.9 mill. (45% of Cap'l)						18-20		
Pfd Stock None								Revenues per sh 4.75		
Common Stock 12,837,661 shs. as of 3/9/14								"Cash Flow" per sh 1.75		
MARKET CAP: \$300 million (Small Cap)								Earnings per sh A 1.15		
CURRENT POSITION (\$MILL)								Div'd Decl'd per sh B 1.79		
Cash Assets 4.0								Cap'l Spending per sh 1.15		
Accounts Receivable 6.4								Book Value per sh 9.60		
Other 1.2								Common Shs Outs't'g C 12.00		
Current Assets 11.6								Avg Ann'l PIE Ratio 22.5		
Accts Payable 1.1								Relative PIE Ratio 1.40		
Debt Due .1								Avg Ann'l Div'd Yield 3.0%		
Other 4.3								Revenues (\$mill) 57.0		
Current Liab. 5.5								Net Profit (\$mill) 14.0		
Fix. Chg. Cov. 414%								Income Tax Rate 36.5%		
								AFUDC % to Net Profit 1.0%		
								Long-Term Debt Ratio 48.0%		
								Common Equity Ratio 52.0%		
								Total Capital (\$mill) 220		
								Net Plant (\$mill) 280		
								Return on Total Cap'l 8.0%		
								Return on Shr. Equity 12.0%		
								Return on Com Equity 12.0%		
								Retained to Com Eq 3.5%		
								All Div'ds to Net Prof 69%		
ANNUAL RATES of change (per sh)								BUSINESS: The York Water Company is the oldest investor-owned regulated water utility in the United States. It has operated continuously since 1816. As of December 31, 2014, the company's average daily availability was 35.2 million gallons and its service territory had an estimated population of 190,000. Has more than 65,100 customers. Residential customers accounted for 63% of 2014 revenues; commercial and industrial (29%); other (8%). It also provides sewer billing services. Incorporated: PA. York had 105 full-time employees at 12/31/14. President/CEO: Jeffrey R. Hines. Officers/directors own 1.1% of the common stock (4/15 proxy). Address: 130 East Market Street York, Pennsylvania 17401. Telephone: (717) 845-3601. Internet: www.yorkwater.com.		
Past 10 Yrs.	4.5%	Past 5 Yrs.	3.0%	Est'd '11-'13 to '18-'20	5.5%					
Revenues	4.5%	Cash Flow	6.5%	Earnings	5.5%					
Earnings	5.5%	Dividends	4.5%	Book Value	7.0%					
Dividends	4.5%									
Book Value	7.0%									
Cal-endar	QUARTERLY REVENUES (\$ mill.)				Full Year					
	Mar.31	Jun.30	Sep.30	Dec.31						
2012	9.6	10.4	11.0	10.4	41.4					
2013	10.1	10.7	10.9	10.7	42.4					
2014	10.6	11.8	12.0	11.5	45.9					
2015	11.0	12.0	12.5	12.5	48.0					
2016	11.5	12.5	13.0	13.0	50.0					
Cal-endar	EARNINGS PER SHARE A				Full Year					
	Mar.31	Jun.30	Sep.30	Dec.31						
2012	.15	.17	.22	.18	.72					
2013	.17	.18	.19	.21	.75					
2014	.16	.22	.23	.28	.89					
2015	.19	.25	.26	.25	.95					
2016	.20	.26	.28	.26	1.00					
Cal-endar	QUARTERLY DIVIDENDS PAID B				Full Year					
	Mar.31	Jun.30	Sep.30	Dec.31						
2011	.131	.131	.131	.131	.524					
2012	.134	.134	.134	.134	.535					
2013	.138	.138	.138	.138	.552					
2014	.1431	.1431	.1431	.1431	.572					
2015	.1495	.1495								

(A) Diluted earnings. Next earnings report due mid-May.  
 (B) Dividends historically paid in mid-January, April, July, and October.

(C) In millions, adjusted for splits.

James A. Flood

April 17, 2015

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	100

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**PUBLIC UTILITY COMMISSION  
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OREGON**

**STAFF EXHIBIT 210**

**Security Market Trends  
(What News Are Investors Experiencing?)**

**Exhibits in Support  
of Opening Testimony**

**October 16, 2015**

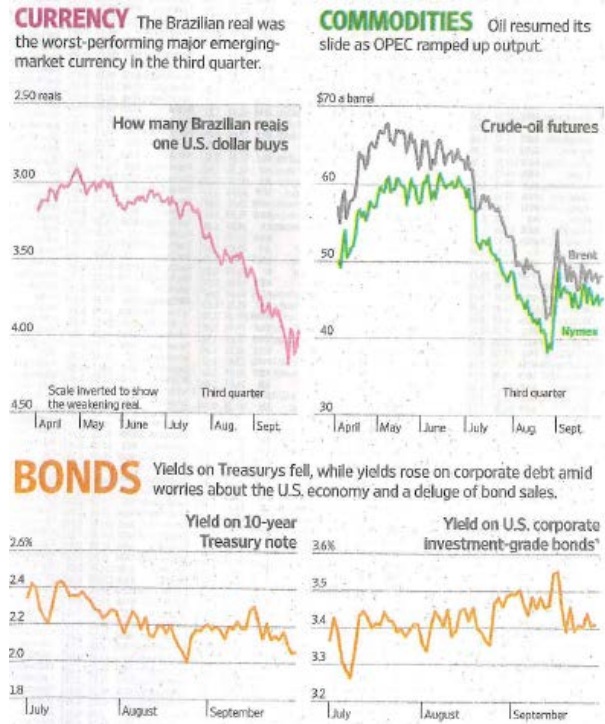
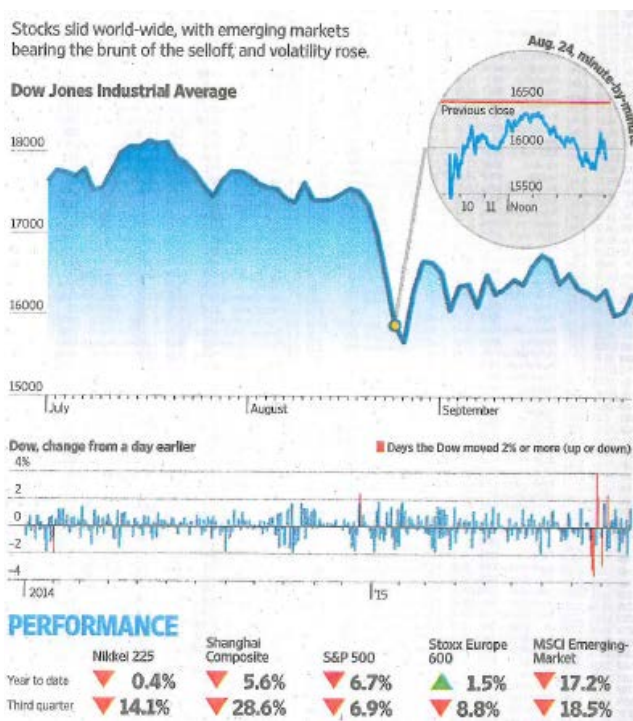
## Wall Street Journal Quarterly Overview — October 1, 2015:

Worries about the ripple effects from China's economic slowdown hammered global markets in the third quarter and sent investors into safer assets such as U.S. government bonds. A rout in commodities deepened, pulling many emerging market currencies to record lows against the dollar.

July 15 — Greece passed austerity measures to secure bailout

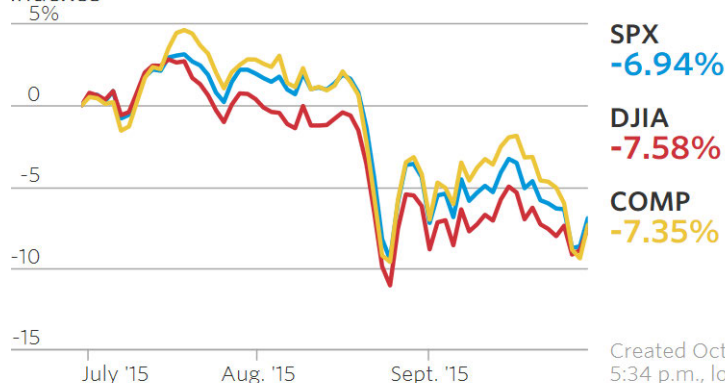
Aug. 11 — China unexpectedly devalued its currency, rattling markets

Sept. 17 — Federal Reserve kept interest rates near zero.



## A Quarter to Forget

Change in the third quarter in the S&P 500 (blue), DJ Industrials (red) and Nasdaq composite (yellow) stock indexes



Source: WSJ Market Data Group

U.S. stocks limped into October, following the worst quarter for benchmark indexes since 2011.



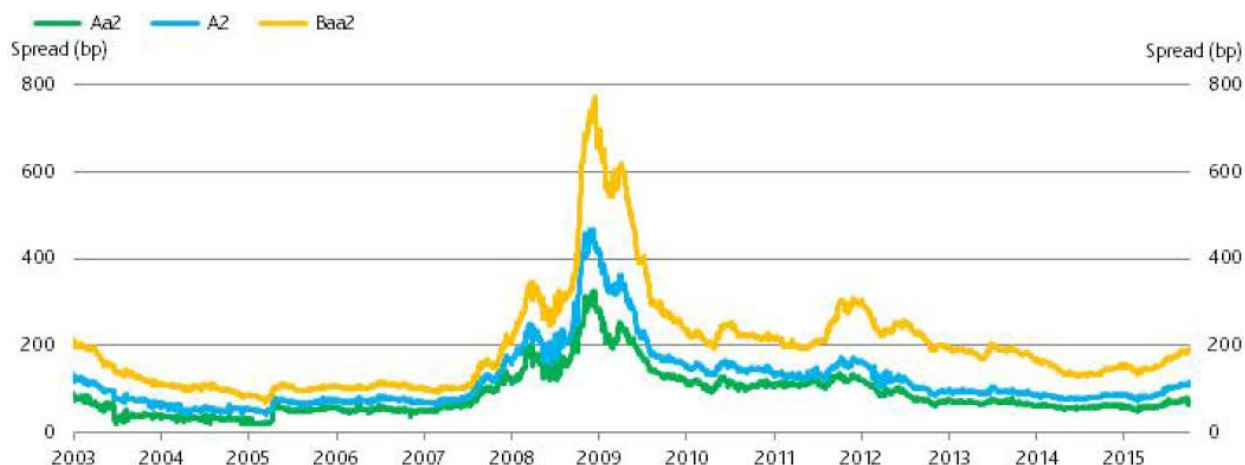
## Spreads

Excerpts from Moody's Capital Market Research, Inc. (CMR) — Oct. 1, 2015

Analyses from Moody's Capital Markets Research, Inc. (CMR) focus on explaining signals from the credit and equity markets. This publication addresses whether market signals, in the opinion of the group's analysts, accurately reflect the risks and investment opportunities associated with issuers and sectors. CMR research thus complements the fundamentally-oriented research offered by Moody's Investors Service (MIS), the rating agency.

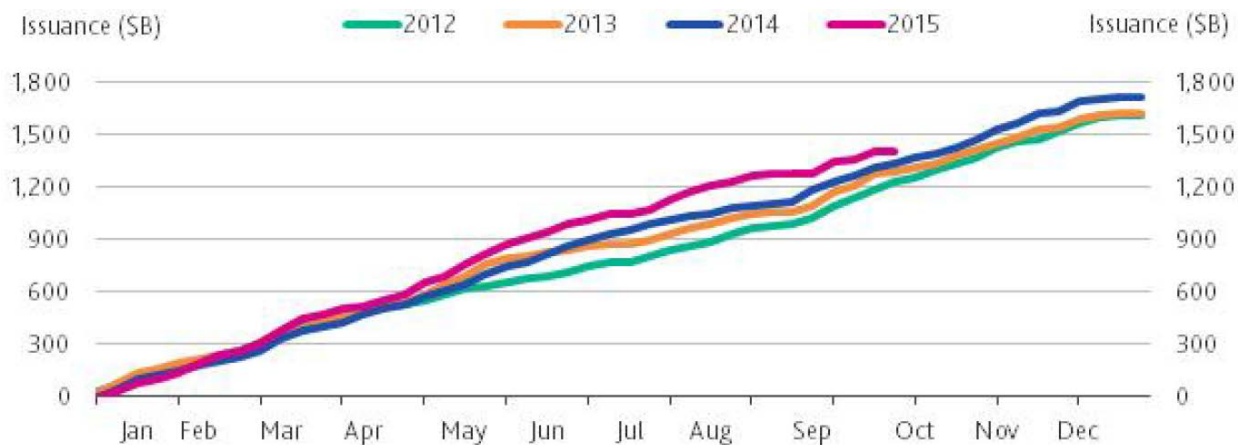
CMR is part of Moody's Analytics, which is one of the two operating businesses of Moody's Corporation. Moody's Analytics (including CMR) is legally and organizationally separated from Moody's Investors Service and operates on an arm's length basis from the ratings business. CMR does not provide investment advisory services or products.

5-Year Median Credit Spreads – High Grade



Source: Moody's

Market Cumulative Issuance of USD Denominated Corporate & Financial Institutions



Source: Moody's / Dealogic



USD denominated investment grade issuances examined for corporate and financial institutions was \$10.9B on a weekly and \$1.036T on an annual basis. North American median Credit Default Spreads (CDS).

### CDS Implied Ratings Rises:

Issuer	Sep. 30	Sep. 23	Senior Ratings
SunGard Data Systems Inc.	Baa3	Ba2	B3
Freescale Semiconductor, Inc.	A3	Baa2	Caa1
Alcatel-Lucent USA, Inc.	Baa3	Ba2	B2
Ford Motor Credit Company LLC	Baa3	Ba1	Baa3
Wal-Mart Stores, Inc.	Aa3	A1	Aa2
Microsoft Corporation	Aa3	A1	Aaa
Johnson & Johnson	Aa1	Aa2	Aaa
Target Corporation	Aa2	Aa3	A2
Union Pacific Corporation	Aa2	Aa3	A3
Simon Property Group, L.P.	A1	A2	A2

### CDS Implied Ratings Declines:

Issuer	Sep. 30	Sep. 23	Senior Ratings
Caterpillar Inc.	Baa2	A3	A2
Archer-Daniels-Midland Company	Baa1	A2	A2
Eastman Chemical Company	Baa3	Baa1	Baa2
Molson Coors Brewing Company	Baa2	A3	Baa2
Bank of America Corporation	Baa2	Baa1	Baa1
John Deere Capital Corporation	A3	A2	A2
Caterpillar Financial Services Corporation	Baa2	Baa1	A2
Time Warner Inc.	Baa1	A3	Baa2
Dow Chemical Company (The)	Baa3	Baa2	Baa2
Kinder Morgan Energy Partners, L.P.	Ba3	Ba2	Baa3

### CDS Spread Increases:

Issuer	Senior Ratings	Sep. 30	Sep. 23	Spread Diff
Peabody Energy Corporation	Caa2	6,130	5,090	1,039
Sprint Communications, Inc.	B1	904	661	244
iHeartCommunications, Inc.	Ca	3,842	3,625	217
Chesapeake Energy Corporation	Ba1	1,248	1,036	212
Cablevision Systems Corporation	B1	580	396	184
Toys 'R' US, Inc.	Caa2	2,112	1,970	142
United States Steel Corporation	B1	1,329	1,190	139
Williams Companies, Inc. (The)	Baa3	370	234	136
MBIA Insurance Corporation	B3	1,937	1,831	106
Freeport-McMoRan Inc.	Baa3	669	567	103

(Continued on next page)



### CDS Spread Decreases

Issuer	Senior Ratings	Sep. 30	Sep. 23	Spread Diff
HealthSouth Corporation	B1	293	333	-40
Alcatel-Lucent USA, Inc.	B2	116	155	-39
Commercial Metals Company	Ba2	231	267	-36
AutoNation, Inc.	Baa3	452	476	-25
Juniper Networks, Inc.	Baa2	99	116	-18
SunGard Data Systems Inc.	B3	137	153	-17
Freescale Semiconductor, Inc.	Caa1	69	85	-16
Crown Castle International Corp.	Ba3	292	308	-15
Navistar International Corp.	Caa1	609	623	-14
Dole Food Company, Inc.	Caa1	260	272	-13

Data Source: Moody's

## Market Isn't Buying Fed on Inflation

by Min Zeng — WSJ — Oct. 1, 2015

The lack of inflation made itself felt in the bond market this quarter.

While Treasury bonds chalked up a price rally this quarter, their sibling—Treasury inflation protected securities — have taken a heavy beating, set for the biggest quarterly loss in a year.

Treasury debt overall has handed investors a total return — including price gains and interest payments — of 1.82% between the end of June and Tuesday, according to data from Barclays PLC. TIPS have lost 1.2% during the same period.

The key driver: inflation expectation in the bond market has plunged to five-year low amid worries over **sluggish global growth and disinflationary pressure**. U.S. consumer price index for August rose 0.2% on an annualized base and excluding food and energy, the reading was 1.8%. Inflation has been running below the Fed's 2% target for 40th consecutive months.

Treasury bonds, especially long-term debt, are vulnerable if consumer prices rise as that will chip away their fixed returns. TIPS offer protection against inflation by boosting principal repayments once inflation breaches a certain threshold.

Over the past few months, worries over **slower growth in China, lower commodity prices and plunging emerging-market currencies all deflated inflation fear**, encouraging investors to favor U.S. Treasury debt over TIPS. **A gauge of inflation expectation, the yield spread between a 10-year Treasury note and 10-year TIPS, tumbled to the lowest level since 2009 earlier this week. The yield spread suggested Wednesday that U.S. Inflation will run at an annualized 1.42% on average within a decade, well below the Fed's target of 2%.**

"TIPs have cheapened up relentlessly in recent weeks given the global disinflationary pressure," said Lynn Chen, senior portfolio manager at Aberdeen Asset Management, which has \$483.3 billion assets under management.

Investors pulled \$60 million of net cash out of U.S. bond mutual funds and ETFs focusing on TIPS for the week ending Sept 23, according to Lipper. The sector has suffered outflows for eight of the past nine weeks.

Ms. Chen said the selloff has made TIPS more attractive, though she said she is not stepping in to buy at the moment given the global uncertainties.

TIPS "are always good to own as part of a broadly diversified portfolio as they hedge against unexpected inflation," said Gemma Wright-Casparius, senior portfolio manager at The Vanguard Group. "They appear attractive, but with the Fed likely to hike in the fourth quarter of 2015, I would wait before buying."

## FOMC Leaves Rates Untouched

by Robb Soukup — SNI Financial LC — Sep. 17, 2015

The Federal Open Market Committee on Sept. 17 said it was **leaving** the **federal funds rate** unchanged.

The **target range** for the federal funds rate **remains at between zero and 0.25%**, the committee said in its policy statement. There had been widespread **speculation** ahead of the meeting that the **bank could lift rates for the first time in nine years**. **But policymakers demurred**, saying the committee will not lift rates until it sees "further improvement in the labor market and is reasonably confident that inflation will move back to its 2% objective over the medium term."

Policymakers continued to emphasize improvements in the committee's assessment of the broader economy. It noted improving housing, as well as "solid" job gains paired with declining unemployment.

It added that it anticipates that "economic activity will expand at a moderate pace," with continued improvements in labor markets. The committee members also said that while they expect to continue to see low inflation numbers in the short-run, they **expect that inflation will rise closer to its 2% target over the medium term**.

The committee stressed that even **when** it does decide to **begin policy normalization**, it will **likely leave rates below levels it would view as normal in the long-run**.

**Nine members** of the committee **voted** in **favor** of the **policy action**; **Federal Reserve Bank of Richmond** President Jeffrey Lacker voted against it. Lacker "preferred to raise the target range for the federal funds rate by 25 basis points at the meeting," according to the statement.

## Risks Grow for Slow but Steady U.S. Expansion

by Jon Hilsenrath and Nick Timiraos – WSJ – Aug. 24, 2015

Market turmoil and China's troubles threaten to undermine outlook for world's largest economy



Federal Reserve Chairwoman Janet Yellen, shown in Washington last month, faces a tougher decision whether to begin raising interest-rates later this year after the recent stock-market declines

The **U.S. has been the tortoise in a global race for economic growth, plodding out a slow but steady expansion** while China signals exhaustion and the rest of the world wobbles. Now, market turmoil and China's troubles threaten to undermine the already unspectacular U.S. outlook.

Few economists see a U.S. recession. In fact, some recent developments, including lower oil prices, will help U.S. consumers and businesses.

But an **uneven global growth outlook is pushing the value of the dollar higher**, making U.S. goods more expensive overseas and harder to export. That could restrain the U.S. economy in the months ahead. Stock-market declines could further hurt U.S. consumer sentiment and spending, if the drops are sustained, and they make businesses even less willing to invest.

Federal Reserve officials now need to decide if they should alter their planned course on interest rates. Officials have been signaling for months that at least one increase in short-term rates is likely this year, possibly as soon as September.

Now, Fed officials might rethink the timing and pace of their plans, thanks to an uncertain growth and inflation outlook. In futures markets, **investors put the odds of a rate increase in September at just 24%, according to the Chicago Mercantile Exchange; a week ago, it was rated a tossup.**

The stakes are high. Asset values could tumble without the support of continued low rates. Investors also worry policy makers lack tools to intervene in the economy should it sink again.

**Atlanta Fed President Dennis Lockhart, who said earlier this month he was inclined to move rates up in September, said in a speech on Monday that he sees an increase this year, but he avoided attaching a date to it.**

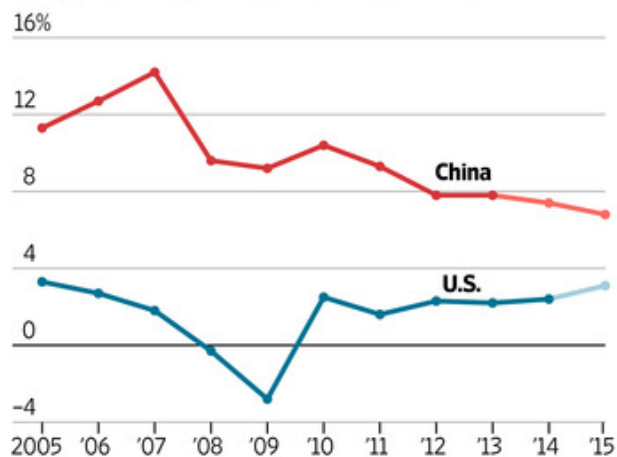
**“The Fed should not be raising rates,” said Lawrence Summers, a Harvard University professor and former Obama administration adviser, in an interview.** “It should be thinking about its contingency plans if financial distress becomes serious. It should signal that it won’t be raising rates until and unless it sees clear evidence of inflation breaking above 2% or clear evidence of euphoria in financial markets.”

**Such views increase public pressure on Fed Chairwoman Janet Yellen to stand pat. Merely talking about rate increases in the absence of inflation or a financial boom would be counterproductive at this point, Mr. Summers said.**

## Tortoise or Hare?

The U.S. has posted steady but unremarkable growth over the past six years, while China’s rapidly expanding economy has downshifted. Stronger U.S. growth has led to a surge in the dollar, causing heartburn for American exporters.

**GDP, percentage change from a year earlier**



Note: GDP estimates, China 2014-15, U.S. 2015

Sources: International Monetary Fund (GDP); WSJ Market Data Group (dollar index)

**Performance of the WSJ U.S. dollar index**



THE WALL STREET JOURNAL.

Investors, struggling to make sense of a resilient U.S. economy buffeted by threats from abroad, went both ways on **Monday**. The **Dow Jones Industrial Average dropped more than 1000 points at its open, reversed course, drifted lower again and closed down almost 600 points.**

“People are scratching their heads how the economy is doing better as markets are doing worse,” said David Rosenberg, chief economist at money-management firm

Gluskin Sheff & Associates. “The markets and the economy don’t always have to correlate at any given point in time.”

**The U.S. has managed 2.1% annual growth since emerging from recession in 2009, rarely veering much above or below that pace**, even when China slowed and Japan and Europe experienced secondary downturns.

The sluggish U.S. expansion has unfolded amid unprecedented support from the Fed, which has kept its benchmark federal-funds rate pinned near zero since December 2008 and launched several rounds of bond-buying programs to boost investment.

Economists surveyed by The Wall Street Journal expect the Commerce Department to report later this week that U.S. economic output expanded at a 3.3% annual rate in the second quarter, faster than previously reported.

Recent reports on retail sales and housing investment suggest output is expanding at a pace of 2.4% in the third quarter, according to analysts at Macroeconomic Advisers, a research firm.

The modest rebound Fed officials expected earlier in the year for now at least appears to be playing out. Weighing against threats from abroad are domestic sectors like autos and housing. Sales of previously owned homes are running at their highest levels since 2007, and home prices have rebounded strongly.

Home Depot reported last week that sales at stores open at least one year rose 4.2% in the second quarter and 5.7% in the U.S. The company raised its earnings guidance for the second time this year, and executives last week called out improvements in their division that caters to contractors, which they said reflected the continued rebound in home prices.

“When consumers believe their home is an investment and not an expense, they spend differently, and we’re seeing that spend pattern,” Carol Tomé, the company’s finance chief, told analysts.

Meantime, falling gasoline prices have delivered a boost to restaurants and bars, which have reported their best sales growth in years, and are ramping up hiring amid increased competition for workers. Chipotle Mexican Grill Inc. announced plans Sunday to hire 4,000 employees in a single day next month, around 7% of its workforce.

**Falling gasoline prices are more meaningful than Wall Street’s gyrations to most working-class Americans**, “who don’t care where Apple stock is trading,” said [Andy Puzder](#), chief executive of CKE Restaurants Inc., which operates the Carl’s Jr. and Hardee’s burger chains. He said the closely held company plans to add a substantial number of restaurants in the U.S. this year.

Many U.S. companies find themselves trying to navigate a two-tiered global outlook, marked by small gains at home and new worries in China and Asia, a stark contrast from China’s boom days of a few years ago.

Examples of the global disconnect were ample in recent U.S. company earnings reports:



Attendance at Disney parks in the U.S. rose a steady 4% in the quarter ended in June, while it declined in Hong Kong.

Ford Motor Corp.'s North American revenue rose 4.1% in the first half of the year, while it dropped 14.5% in Asia.

At Wynn Resorts, the global gaming company, gamblers cut back 27.6% in slot-machine use in Macau, China, in the latest quarter, while inching up their use by 1.6% in Las Vegas.

"In Las Vegas, we are enjoying a comfortable business. I think that is the right word for it," said [Steve Wynn](#), the chief executive of the gaming company, in a conference call with analysts last month. His big bets on Macau, meanwhile, were "more of a question than a certainty."

China by itself is not an obvious threat to the U.S. economy. **China accounts for 21% of U.S. imports of goods and services.** That gives it big influence on U.S. consumer prices and wages. **However, it accounts for only 7% of U.S. exports.** Because exports themselves aren't a big driver of U.S. growth, the hit from a slowdown of sales to China is bound to be small. **But broader spillovers from China's slowdown could pose challenges for U.S. companies and the economy.**

Many companies are still investing heavily in the world's second-largest economy. Wynn, for example, is planning to open a \$4.1 billion, 1,700 room hotel called Wynn Palace in Macau in March. Disney recently announced plans to open a new theme park in Shanghai. If growth doesn't materialize in these and other ventures, it could knock the profitability of multinationals.

Then there is the U.S. dollar, which has appreciated nearly 8% against a broad basket of currencies so far this year, according to the Fed. The move was amplified earlier this month, when Beijing allowed the yuan to depreciate.

**Economists at Goldman Sachs estimate a worsening U.S. trade position will subtract 0.75 to 1.00 percentage point from the already slow U.S. growth rate in the coming year,** worse than the 0.6 percentage point that trade pulled from growth in the past year. That is **not enough to short-circuit the recovery,** but it is **enough to keep restraining it.**

A **stronger dollar also holds down inflation** by restraining the price of imported goods, which were down 10.4% in July from a year earlier. Besides the 2007-2009 global financial crisis, declines of that magnitude haven't occurred in government records going back to 1982.

The Fed has said it won't raise short-term interest rates until officials are "reasonably confident" that inflation will rise toward 2% after running below it for more than three years. The stronger dollar and falling oil prices are bound to undermine that confidence.

The timing of an interest-rate increase is only one variable officials must consider in the weeks ahead. Another is the pace of rate increases the central bank plans for the years ahead.

In forecasts released in June, Fed officials estimated the benchmark Fed funds rate would be 1.625% by the end of 2016 and 2.875% by the end of 2017. **Yields on two-year Treasury notes were 0.601% on Monday, suggesting investors don't believe officials will move nearly as much as projected.**

But keeping rates low carries its own set of risks. One is that it could stoke a new financial bubble.

The **U.S. stock market, now in correction territory, is hardly screaming bubble. But other sectors look stretched.** U.S. regulators, for instance, have expressed concern recently about commercial real estate. "Now is not the time to be overly aggressive in bidding," said Chris Finlay, CEO of Lloyd Jones Capital, a boutique firm in Miami that invests primarily in multifamily properties.

In a note to clients, Mr. Finlay warned that too much capital was chasing apartments. The firm recently bid on a distressed \$6 million apartment complex in Tallahassee, Fla., that was just 85% occupied. The sale drew 21 bidders – normally such a sale would draw around five or six, he said – and the winning bid offered a \$500,000 nonrefundable cash down payment before conducting due diligence.

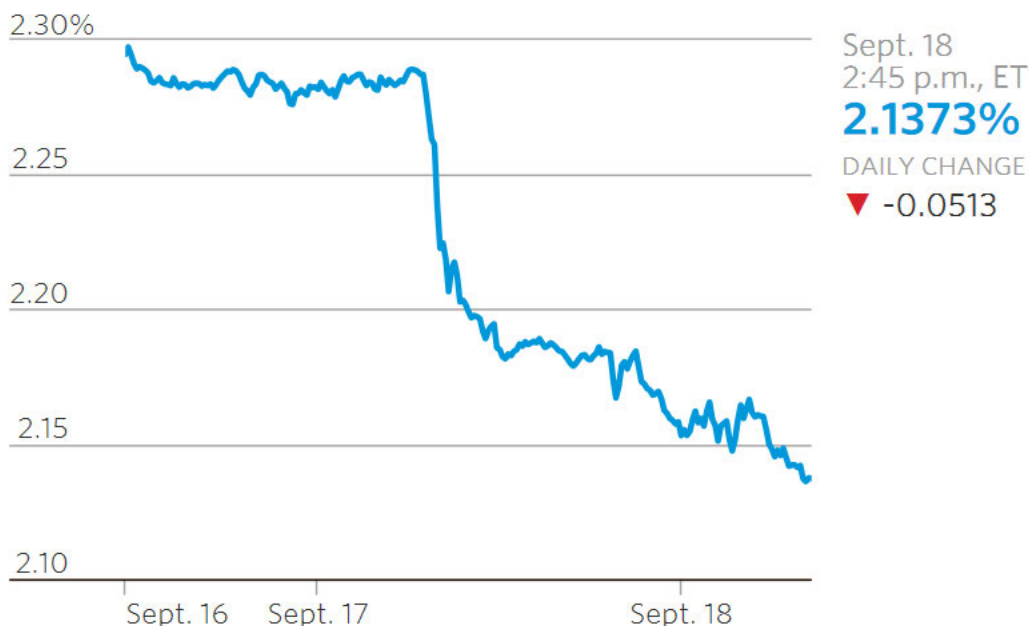
"That's just not good business sense," said Mr. Finlay.

## Global Government Bond Yields Fall on Fed, ECB Outlook

by Ming Zeng — WSJ — [min.zeng@wsj.com](mailto:min.zeng@wsj.com) — Sep. 18, 2015

Fed's decision to hold the line on rates deters move into riskier assets

### Yield on the 10-Year Treasury Note



Source: WSJ Market Data Group

Government bond yields on both sides of the Atlantic tumbled Friday as stocks declined one day after the Federal Reserve left short-term interest rates unchanged and generated anxiety in financial markets.

The Fed's decision to hold short-term rates near zero for a longer period failed to boost investors' confidence to buy riskier assets. Instead, the Fed's signal Thursday over concerns about the global economy, especially the slowdown in China, pushed down global stocks Friday and boosted the relative safety in sovereign bonds in rich countries.

"It was the first time the Fed was so specific about external factors" in influencing the U.S. monetary policy outlook and the "lingering issue of a rate increase" remains unresolved, said John Briggs, head of strategy for Americas at RBS Securities. "Investors are confused and concerned," he said.

An additional boost for bonds came from comments from **European Central Bank** Executive Board member Benoît Coeuré, who **said Friday that the bank has flexibility to extend bond buying beyond September 2016 if needed**. The comment bolstered expectations that more monetary stimulus may be up before the end of this year, which energized buyers into the euro-zone's bond markets.

**Lower bond yields in Europe make higher-yielding U.S. Treasury debt more attractive for buyers**, highlighting investors' struggle to obtain assets that offer liquidity

and income amid sluggish global growth, subdued inflation and continued uncertainty over when the Fed would start its first tightening campaign since 2006.

**In recent trading, the yield on the benchmark 10-year Treasury note was 2.146%, compared with 2.215% Thursday**, according to Tradeweb. Yields fall as bond prices rise.

The **yield on the two-year note fell to 0.682% from 0.702% Thursday**.

The **two-year yield posted the biggest one-day drop Thursday since December 2010 following the Fed's decision**. Yields on short-term notes, such as those maturing between two years and five years, are highly sensitive to changes in the Fed's interest-rate policy outlook. The yield on the two-year note had closed Wednesday at a four-year high of 0.811%.

The Fed's ultra-loose monetary policy since the financial crisis has pushed up Treasury bond prices to historically elevated levels and bond investors are concerned that the value of bonds may fall once the Fed shifts gear into a tightening mode. **Higher interest rates typically make newly minted bonds more attractive and shrink the value of outstanding bonds**.

Fed officials signaled that a rate increase before the end of the year is still on the table, but expectation in the financial markets is growing that the Fed might wait until 2016 to raise rates, which drove buyers into bonds.

Fed-funds futures, used by investors and traders to place bets on central bank policy, showed Friday that bettors see a 14% likelihood of a rate increase for the Fed's October policy meeting, according to data from CME Group. The odds of a rate increase at the December meeting were 41%.

Lower long-term Treasury bond yields are compounding expectations by investors and traders who predict that yields should rise this year to reflect an improving U.S. economy and a pending shift by the Fed on monetary policy.

These bets panned out earlier this year as the 10-year yield reached 2.5% in June, the highest intraday level since September 2014. The yield has since tumbled as worries over China's economy and stock market have stoked demand for haven bonds.

"It is hard to bet against long-term Treasury bonds," said David Coard, head of fixed-income trading in New York at Williams Capital Group. "I need to remind myself again and again that we are not living in normal time. **Yields are not going to spike given the global uncertainty**."

**U.S. bond yields remain more attractive among high-income countries**. Friday, the 10-year German bond yield fell to 0.657%, the 10-year U.K. bond yield declined to 1.831% and the 10-year French bond yield slid to 0.952%, according to Tradeweb.

**Another appeal to buy long-term bonds: tame inflation**. The value of long-term bonds is less influenced by the Fed's short-term interest-rate policy and more influenced by global growth and the inflation outlook. Inflation is the main threat because it chips away bonds' fixed return over time.

**Lower commodities have reduced inflation expectations in the U.S.** where the Fed has failed to push inflation higher to its 2% target. **China's surprise decision last month to weaken the Chinese yuan has sent many emerging-market currencies tumbling against the dollar**, adding to **disinflationary pressure** and **increasing the appeal of long-term Treasury bonds**.

Some investors see one risk to buy long-term debt: sales of long-term Treasury debt by foreign central banks to raise cash to support local economies, fight against capital outflow or support flagging economic growth.

**China**, the largest foreign owner of U.S. government securities, **shed Treasury debt holdings in July**, according to data from the Treasury earlier this week. Traders and analysts said China has sold long-term Treasury bonds following its move to weaken the yuan in August, which had prevented bond yields from falling significantly amid a recent stock-market swoon.

"This is a short term concern but there are other factors that would provide support for long-term bonds," said Patrick Maldari, money manager at Aberdeen Asset Management, which has \$483.3 billion in global assets under management.

## U.S. 10-Year Note Closes Below 2%

by Ming Zeng – WSJ – Aug. 24, 2015

**A Deepening rout in global stocks and commodities sending investors to the safe harbor of U.S. debt. Chinese** stocks nosedived Monday with the benchmark **Shanghai Composite Index dropping 8.49%**.

**Rising demand for haven assets on Monday** sent the yield on the **benchmark 10-year U.S. government note below 2%** for the first time since April as a rout in global stock and crude oil markets deepened.

The flight for safety has been gathering speed over the past few weeks, underscoring growing anxiety over China's slowing economy and its **stock market rout**, which has rippled through markets globally and clouded the global economic outlook.

The uncertainty over whether the Federal Reserve will raise interest rates next month or wait longer to act has contributed to growing volatility in riskier assets, driving many to shed their risk appetites and shift focus to preserve capital.

"This is a **flight to quality** and the actual level that the Treasury yield achieves in this environment is not meaningful," said David Keeble, global head of fixed-income strategy at Crédit Agricole. "This is a time when you dig a deep hole, close your eyes and put your fingers in your ears."

On Monday, U.S. stocks and European equities fell sharply as a rout in Chinese shares accelerated, wiping out gains for the year. U.S. oil prices tumbled by 5.5% on Monday and settled below \$40 a barrel for the first time since February 2009. A gauge of 10-year inflation expectation in the U.S. bond market fell to the lowest level since 2009.

As investors sought shelter in Treasury debt, the yield on the benchmark 10-year Treasury note fell to 1.997% in late-afternoon trading from 2.052% on Friday. It marks the lowest closing level since April 28. Yields fall as prices rise.

Growing turmoil is heaping pressure on global central banks to act. If policy makers take actions to soothe investors' fears about markets and growth, demand for haven assets could wane, sending yields higher, say some traders. On Sunday, The Wall Street Journal reported that China's central bank is **preparing to bolster liquidity** in the country's banking system.

Ray Uy, senior portfolio manager at Invesco Ltd., which has \$803.6 billion in assets under management, says with rising volatility and a lot of uncertainties, "it is risky to step into markets that are getting hit" even though some asset classes are getting cheaper from the market rout.

The **10-year yield**, a foundation for global finance and a key indicator of investors' sentiment toward growth and inflation, has **plunged from 2.5% in June**. Anxiety has been growing over the global economy amid lower commodities prices, plunging emerging-market assets and a selloff in both stocks and bonds sold by lower-rated U.S. companies, known as junk bonds.

**China's surprising move to devalue the yuan earlier this month** amid tumbling exports heightened concerns over the pace of the world's second-largest economy,



which has been a big buyer of commodities, including iron ore, copper and oil. Last Friday, a report showed a gauge of China's manufacturing sector dropped to its lowest level in 6 1/2 years.

Rising volatility in financial markets and falling inflation expectations are complicating the Fed's plan to raise interest rates for the first time since 2006. The U.S. economy has been strengthening after a soft patch earlier this year. Solid jobs growth has bolstered the case for the Fed to start moving away from crisis-era monetary stimulus. **The Fed's ultra-loose monetary policy has boosted prices of a wide range of financial assets over the past years and now investors are concerned whether these assets may fall in value once the Fed shifts gears into a tightening mode.**

The nonfarm jobs report for August is due to be released in early September. Analysts say a strong report may allow the central bank to act at its Sept. 16-17 policy meeting. Yet many investors say global uncertainties and rising volatility in many asset markets could make the Fed wait longer to act. They are concerned that a rate increase could jolt sentiment and roil already jumpy markets.

**Fed-funds futures**, used by investors and traders to place bets on central bank policy, **showed Monday that investors and traders see a 24% likelihood of a rate increase at the September 2015 meeting, according to data from the CME Group. A couple of weeks ago, the odds were around 50%.**

"There are fears that global growth is going to come crashing down," said **Thomas Roth, executive director in the U.S. government bond trading group at Mitsubishi UFJ Securities (USA) Inc. in New York.** **"A week ago we were thinking the U.S. economy was strong enough for a Fed rate hike and now we fear a global recession. It is amazing how quickly things can change."**

As expectations on the Fed to tighten next month pulled back, the **yield on the two-year Treasury note fell to 0.568% Monday**, the lowest closing level since July 8, from 0.629% Friday. The yield is **highly sensitive to changes in the Fed's interest rate policy outlook.**

## China's Central Bank Cuts Interest Rates

by Lingling Wei – WSJ – Aug. 25, 2015

Grace Zhu and Mark Magnier contributed to this article.

PBOC cut interest rates by one-quarter of a percentage point, and lowered banks' reserve-requirement ratio.



The PBOC also dropped a key control on rates for some bank deposits, allowing lenders greater freedom to compete for business.

China stepped up its credit-easing efforts by slashing interest rates and flooding its banking system with new liquidity, its second such combo move in two months aimed at battling a deepening economic slowdown and its [worst stock-market selloff in decades](#).

The **People's Bank of China** announced the one-two punch late Tuesday after the **country's main stock index fell another 7.6%, bring losses to more than \$1 trillion in market value over the past four trading days**. The stock rout was triggered by growing doubts among investors over the government's ability to avoid a hard landing of the world's No. 2 economy.

Concerns over China's economic health have also **roiled global markets** in recent days, prompting the Chinese central bank to take action. In a statement posted on its website, the **PBOC** – dubbed “Yang Ma,” or Big Mama, within China – noted the “big fluctuations” in financial markets around the world, which prompted it to “make flexible use” of monetary-policy tools to ensure steady growth.

**China has targeted year-over-year economy growth of about 7% for 2015**, which already would be the slowest pace in a quarter century. New data since July has called its ability to hit that target into question. In particular, a private-sector gauge of factory activity fell to a 77-month low in August. Meanwhile, a **surprise 2% devaluation** earlier this month of the country's currency, the **yuan**, was interpreted by investors as a sign that economic growth is slowing more than Beijing had anticipated.

An interest-rate cut by China's central bank added fuel to a rally in European stocks and U.S. stock futures despite another sharp drop in Chinese shares.

“China's economy will get worse before it gets better,” said Yu Yongding, a prominent Chinese economist and a former adviser to the central bank.

Chinese companies are struggling with high debt loads and low prices, said Mr. Yu. Persistently low factory-output prices and still-low consumer prices have put disinflationary pressure on the Chinese economy and led to worries that China could enter deflation, which pushes up borrowing costs and makes it more difficult for businesses to service debt.

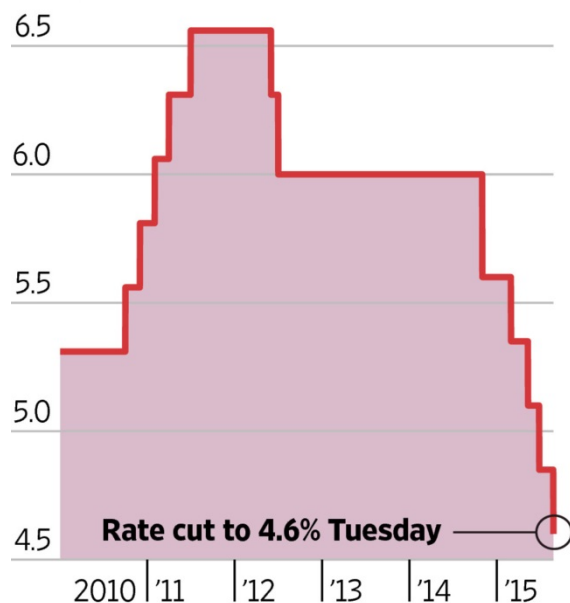
“China has entered a stage of deflation,” he said, pointing to the factory and consumer-price data. To maintain economic stability **in the short** run, Mr. Yu said, “it's inevitable for the Chinese central bank to **ease credit**.”

The issue for investors is whether the latest easing steps will help restore – or further hurt – their confidence in Beijing’s handling of the economy and markets. “One key question is whether these measures will gain much traction at a time of slipping confidence and weakening growth momentum,” said Eswar Prasad, a Cornell University professor and former China head for the International Monetary Fund.

## Cut-Rate Cash

China’s central bank cut interest rates after days of market turmoil.

### One-year benchmark lending rate



Source: People’s Bank of China

THE WALL STREET JOURNAL.

nearly 2% weaker in a move it said was intended to bring the yuan’s value more in line with market expectations. The surprise action prompted investors to sell the yuan both on the mainland and in what is known as the Hong Kong offshore market in expectations it would go still lower.

China limits the yuan’s daily trading on the mainland to a tight band, but under a new policy its value is supposed to be determined more by daily trading moves. To contain those moves, PBOC has frequently bought the yuan and sold the U.S. dollar to prevent the Chinese currency from falling too much. Analysts at Orient Securities Co., a Shanghai brokerage, estimate that the PBOC has spent more than \$40 billion of China’s roughly \$3.7 trillion foreign-exchange reserves. It could become costlier if the market continues to drive the yuan down.

The interference also has had the effect of draining yuan funds out of the market – threatening to cause a shortage of funds at Chinese banks that already are battling with rising bad-loan levels and falling profitability. The Wall Street Journal reported on

**With Tuesday’s moves, the Chinese central bank has cut interest rates for the fifth time since November and broadly lowered for the third time the amount of deposits banks are required to hold in reserve.** It is rare for the PBOC to simultaneously cut interest rates and banks’ reserve requirements. The last time it made the combo move was June 27, soon after Chinese stocks started to sell off.

In the past two months, China has accelerated monetary easing to shore up stock prices and stabilize the economy. But some of its efforts – especially its heavy intervention in the stock market and recent currency moves – have also called into question the government’s ability to effectively manage the economy.

So far, the steps have largely failed to lift market sentiment as investors kept pushing down share prices. The central bank’s recent handling of the Chinese yuan also raised eyebrows among investors and economists.

On Aug. 11, the PBOC **unexpectedly devalued the yuan** by setting its official rate

Sunday that the PBOC was planning to **flood the financial system with new liquidity** in a bid to counter that liquidity squeeze.

The half-percentage reduction in banks' **reserve requirements**, which will become effective Sept. 6, will pump about 678 billion yuan, or roughly \$105.7 billion, worth of funds into China's banking system. After the interest-rate cuts, which will be effective Wednesday, China's benchmark one-year lending rate will be lowered to 4.6% from 4.85% previously, and the one-year deposit rate will fall to 1.75% from 2%.

PBOC officials hope that the new funds will encourage Chinese lenders to make more loans to help the part of the economy that can generate jobs and boost productivity. However, based on recent official data, credit to those areas slumped in July, while lending to financial institutions surged amid the government's efforts to prop up the stock market.

In a nod to reforms, the PBOC on Tuesday also dropped a key control on rates for some bank deposits, allowing lenders greater freedom to compete for business. However, the central bank still refrained from fully giving up its control on deposit rates for fear of driving up interest rates and prompting more risk-taking behavior by banks amid a slowing economy, according to people close to the central bank.

In the statement, the **PBOC** said China faces an "arduous task" to **maintain growth and press ahead with overhauling the economy**.

## Chinese Retail Investors Flee Plunging Markets

by Wei Gu – WSJ – Aug. 5, 2015



More than 20 million pulled out in July, as Shanghai Composite Index took biggest monthly dive in six years.

Left – Inside a Qingdao brokerage house Friday, as **China's market ended its worst month since 2009 and bid farewell to more than 20 million individual investors.**

**China's market selloff can safely be**

**declared a rout.**

Nearly a third of the country's individual investors – more than 20 million people – fled the plunging stock markets last month. The number of retail investors holding stocks in their accounts slid to 51 million at the end of July from 75 million at the end of June, according to China Securities Depository & Clearing Corp., the government agency that tracks accounts. As they ran, the Shanghai Composite Index suffered its **biggest monthly decline in six years**, falling 14% to **finish 29% below its June 12 peak.**

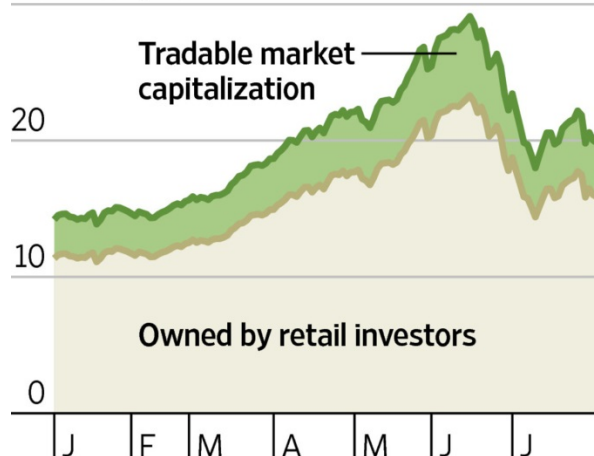
**Unlike in the U.S., where institutions dominate stock trading, retail investors are king in China, owning around 80% of listed stocks' tradable shares, according to investment bank CICC.**

## Losing Wealth

The pain of China's market selloff has been felt mostly by retail investors.

### A-share market capitalization

30 trillion yuan



Note: Based on CICC estimate of retail participation at 80% of free float

Source: Wind Info

THE WALL STREET JOURNAL.

Earlier this year ZZ Xu, a Shanghai restaurateur, put money in the stock market rather than in his business, believing he could get a faster return. He got out before the July rout with his finances intact – indeed, with a profit in the millions of dollars – but his **faith badly shaken.** Mr. Xu recently signed a new lease for a restaurant in Shanghai, and has moved some of the money he held in stocks back into his businesses.

“Now I **realize I can lose a lot of money very quickly,**” he said, noting that threats to stocks include China's slowing growth and the eventual end of government rescue efforts.

Those **frantic rescue efforts** couldn't keep back the share-price plunge in Shanghai and Shenzhen, which began in mid-June, from continuing through most of July. When the month ended, **investors in**

**China were sitting on a paper loss since that June 12 peak of 6.8 trillion yuan (\$1.1 trillion),** according to CICC.

Though the crash could mean that there are some bargains out there, it is hardly surprising that **China's turbulent stock markets are drawing fewer new entrants.** The number of investors opening **new accounts** in the week ending July 24 was **down 20% from the corresponding week in June.**

**"Families that haven't invested aren't jumping in,"** said Li Gan of China's Southwestern University of Finance and Economics, whose recently released China Household Finance Survey covers 28,000 households. "The market lacks new blood."

Still, some investors do plan a return to stocks.

"Where else can I put my money?" said Helen Lu. "Real estate is so expensive and beyond our reach, and there are no other good investment channels." Yields on bank savings accounts, still the most popular place for Chinese to put their money, are low. So the Shanghai-based medical executive's family put most of their 600,000 yuan in savings in China stocks, only to see the value of their portfolio fall by as much as 60%. Having sold on one of the rebounds, they are now looking to invest again through friends who run funds.

The **Chinese are big savers, setting aside as much as 50% of their disposable income,** according to the World Bank. The **government had hoped to channel some of that from banks to the capital markets,** but for now that hope looks rather forlorn



## Debt-Market Tumult Hits Corporate-Bond Sales

by Mike Cherney — Sep. 28, 2015

Three companies reduced or put off planned bond sales in response to soft investor demand.



Westfield Corp., part owner of the London shopping mall - Left, canceled a sale of 10-year bonds.

**Bond-market turmoil mounted Monday, as three companies reduced or put off planned bond sales in response to soft investor demand, damped by concerns that a global economic slowdown is taking shape.**

Santander Holdings USA Inc., the U.S. arm of Spanish bank Banco Santander SA, canceled a planned sale that had been expected at \$1 billion or more, a person familiar with the deal said. Chattanooga, Tenn.-based shopping-center company CBL & Associates Properties Inc. pulled a \$300 million bond sale. Westfield Corp. another shopping-center firm, canceled the sale of 10-year bonds, though the company was able to sell \$1 billion in five-year debt at higher yields than initially expected.

The market weakness is the latest sign of building worries about the pace of global economic growth. The deals pulled Monday came from companies carrying investment-grade ratings; bankers had little trouble selling similar bonds earlier in the year.

"I have never seen the investment-grade primary markets this schizophrenic before," said Ron Quigley, managing director and head of fixed-income syndicate at Mischler Financial Group. "One day the window is open, the next it's slammed shut."

**U.S. corporate-bond issuance in 2015 is up 15% from the comparable year-ago period, according to Securities Industry and Financial Markets Association data, after setting records in each of the past three years.**

But the market action over the past month reflects **anxiety among some investors that slower growth in China and persistently low commodity prices will push some companies into financial distress and dim global economic prospects. Bond investors in recent months have demanded higher yields relative to Treasuries to own U.S. corporate debt**, indicating some worry about companies' ability to pay back their debt.

"We're starting to become a little more cautious in terms of our views," said Christopher Coolidge, a portfolio manager at Brandywine Global Investment Management, which oversees \$65 billion. "We're **OK heading into the end of the year, but next year I think is going to be pretty tough for the U.S. economy.**"

Bonds backed by mining giant Glencore PLC dropped sharply after an analyst report from Investec Securities renewed questions about whether the Switzerland-based company will be able to reduce its debt load amid soft commodity prices. The prices of some Glencore bonds fell as much as 25%, a large drop for a company that still commands investment-grade ratings.

“I’ve never seen bonds react so violently to a research report,” said Tim Doubek, senior portfolio manager at Columbia Threadneedle Investments, which oversees about \$500 billion.

[Hewlett-Packard](#) Co. could represent another test. The company is prepping a sizable bond sale that was expected to sell as early as Monday, some investors and analysts said. H-P could still sell the bonds later in the week.

An H-P spokeswoman declined to comment. Representatives for Westfield and Santander didn’t respond to requests for comment.

CBL pulled its bond sale “in light of today’s capital-market conditions,” the company said in a statement. “We decided to **postpone the offering until market conditions become more favorable.**”

Corporate-debt markets had been consistently wide open in recent years, as investors bet that slow but steady economic growth in the U.S. would support corporate earnings.

Monday’s events come after companies in the junk-bond market, where companies have lower credit ratings, were **forced** last week to **increase yields on new debt sales**. Altice NV paid higher yields on a bond offering backing its purchase of Cablevision Systems Corp. and had to reduce the size of its deal from \$6.3 billion to \$4.8 billion. Olin Corp. also **reduced the size of its bond sale and boosted interest payments** to fund its acquisition of Dow Chemical Co.’s chlorine-products unit.

**Junk bonds, which are viewed as a more sensitive indicator of economic conditions because the companies are more indebted and have less cushion to withstand a downturn, logged a poor day Monday.** The SPDR Barclays High Yield Bond ETF was down about 1.4% on the day, almost as bad as the 1.9% drop in the Dow Jones Industrial Average stock benchmark.

## China Shares Wipe Out All Gains This Year

by Chao Deng and Anjuani Trivedi – WSJ – Aug. 24, 2015  
Rose Yu and Yifan Xie contributed to this article.

A number of currencies in the region fell to multiyear lows; **China shares finish down 8.5%**

Chinese stocks suffered their worst single-day loss in more than eight years, spurring a fresh phase of a global selloff that dragged the Dow Jones Industrial Average to an 18-month low.

The plunge in China shines an unwelcome spotlight on the country's financial condition just as its leaders are putting on two big events meant to showcase China's global standing.

Chinese government media dubbed it "**Black Monday**," a surprisingly bleak description to come from the People's Daily, which normally tries to cushion bad news. The **Shanghai Composite Index's 8.5% loss was its biggest percentage decline since February 2007**, leaving the market down 0.8% for the year and down 38% from its mid-June peak. At that point, stocks were up 60% for the year, having doubled over the preceding 12 months.

"Compared with the selloff in June and July, when investors still harbored hope of government rescue measures, this time investors are completely despairing, because the previous government stabilization measure have failed," said Amy Lin, analyst at Capital Securities.

Coming on top of a global downturn on Friday, it spurred more selling across Asia, Europe and the U.S. The **Dow Industrials tumbled 588.40 points, or 3.6%**, to 15871.35, the lowest level since February 2014. **Minutes after the open of U.S. trading, the blue-chip index plummeted more than 1,000 points but later pared losses.**

Driving the global selloff is the concern that the once-highflying Chinese economy **may be slowing significantly**, which has **triggered steep losses** in global stock markets, commodities and emerging-market currencies. China's **surprise currency devaluation** two weeks ago – which could make its exports more competitive – and a string of weak data signal the economy may be feebler than expected, despite a campaign to rev up growth that has included interest-rate cuts and measures to boost lending.

The **smaller Shenzhen market fell 7.7%** to 1882.46, putting it down 40% from its June peak. Both indexes have fallen past bottoms hit in early July. In the days leading up to that low point, the government intervened to stem the selling.

Investors were poised for another pounding on Tuesday, with New Zealand's stock market opening 2.3% lower and futures for Australian shares also pointing down.

Mark Lu, 30 years old, said after the government started buying stocks to boost the market, he followed suit. "I have never thought of the plunge," he said. "It totally ran counter to the government's intention."

Mr. Lu said he is planning to load up on more stocks, as he believes the market is nearing the bottom. "I know it sounds like a gamble," he said. "But sometimes the Chinese market is indeed a casino."

The decline comes at an embarrassing time for China's leaders. The government already has shut down parts of central Beijing in preparation for a Sept. 3 parade that will feature about 12,000 troops and nearly 200 aircraft. Marking the 70th anniversary of the end of World War II, it is meant to highlight how far the country has come since then.

The other big event, the world track-and-field championships, serves as a reminder of a recent high point in China. The competition is being held in the stadium known as the Bird's Nest, built for the 2008 Olympics, when the country was coming off three years of nearly 13% annual growth.

Shanghai's performance is increasingly a factor for investors in global markets, even though China's mainland market isn't yet fully accessible to foreigners.

Stock markets across the region – from Japan to Australia – slid more than 4%, and a number of currencies in the region fell to multiyear lows.

Traders are looking to China's next easing move after The Wall Street Journal reported that the central bank is preparing to **flood the banking system** with liquidity to increase lending.

One measure analysts are expecting is a cut to banks' reserve-ratio requirements, the third such cut in an easing cycle that began last November. Such a move, allowing banks to keep a lower share of their deposits on reserve at the central bank, could potentially free up hundreds of billions of yuan in funds from banks to make loans.

**Some 2,153 stocks trading in Shanghai and Shenzhen fell by the 10% daily limit allowed by regulators**, according to Wind Information Co. That means at least **two-thirds of mainland shares were effectively un-tradable** – bargain hunters have to wait until at least the next trading day. Among the hardest-hit stocks in China were brokerages. Citic Securities Co., one of China's biggest, was down by its 10% limit Monday and has fallen more than 50% this year.

The global stock rout hit **India**, which had been one of the best-performing emerging markets in the world. India's S&P **BSE Sensex fell 5.9%**, its largest one-day percentage drop since January 2009. For the year, the benchmark is down 6.4%, at 25741.56 – its lowest point in 13 months.

**Hong Kong's Hang Seng Index**, which last week slipped into bear-market territory – defined as a drop of more than 20% from a recent high – **slid a further 5.2%** to 21251.57. A benchmark of Hong Kong-listed Chinese companies fell below 10000 for the first time in more than a year, finishing off 5.8% at 9602.29.

Hong Kong Financial Secretary John Tsang held a news conference in a bid to calm jitters. "Hong Kong's financial market is still operating in an orderly manner and in a smooth fashion," he said.

**Japan's Nikkei** Stock Average was **down 4.6%**, **Australia's S&P ASX 200** was **off 4.1%** and **South Korea's Kospi** was **down 2.5%**. **Taiwan's Taiex**, Asia's worst-performing stock index this year—down 20%—**fell 4.8%**.

In **currencies**, **losses accelerated** as nervous investors pulled out cash. The Malaysian ringgit led the way, falling to a fresh 17-year low, while the Thai baht fell to a six-year low and the South Korean won to a four-year low, all when measured **against the U.S. dollar**. Indonesia's rupiah weakened to a multiyear low, while the Philippine peso fell to its weakest in almost five years.

"The global tone towards emerging markets is getting worse, and [investors'] risk aversion is broadening," said Rajeev DeMello, head of Asian fixed income in Singapore at Schroders, which has \$487.4 billion under management.

The ringgit spiraled down after Swiss authorities **opened a criminal probe** into the relationship between "suspicious transactions" in the country's banking sector and state investment fund 1Malaysia Development Bhd. The currency was down 1.5% against the dollar and is down 21% for the year.

Asian bond prices fell relatively modestly, with heavier selling in high-yield corporate debt, including that of Chinese property businesses and Indonesian companies. But if the rout continues, investors could start turning to their more-liquid assets to cover losses or meet margin calls – when brokerages ask borrowers to add more money to their trading accounts or to unwind their bets if the market has fallen below certain thresholds.

"If the stock rout continues, that will create a systemic selloff, as investors will need to raise cash to cover margin calls amid equity falls," said Ben Sy, Asia head of fixed income at J.P. Morgan Private Bank in Hong Kong. "Fixed income is the only area for them to raise cash."

**U.S. oil prices tumbled**. Futures for West Texas Intermediate fell by 2.8% to **\$39.33**, after falling below the \$40 mark Friday for the first time since 2009. Brent, the international benchmark, fell 2.4% to \$44.35. It is down 23% in 2015. **Gold was flat** at \$1,159.80 a troy ounce, after hitting seven-week highs last week.





## Fear Index' Grabs Headlines as Stocks Swing

by Jo Craven McGinty — WSJ — Sep. 18, 2015

Volatility gauge yields clues on how investors are insuring their portfolios



Left Traders monitor the **CBOE Volatility Index**, or 'fear gauge,' at moments of market turbulence.

When **Robert E. Whaley** settles into his home office, you can count on two things: His television will be tuned to CNBC, and he'll be tracking the stock market's "fear index" on his computer.

Mr. Whaley, a **professor of finance** at **Vanderbilt University**, may not be a household name. But chances are you've heard of the volatility index he designed, known to market watchers as the **VIX**.

The VIX is the **most popular measure of expected short-term volatility on Wall Street**. The index is **computed in real time on trading days**, and **when it shoots up, it suggests investors fear market prices are about to move wildly**.

The **historical average of the VIX is around 20**. **Lower numbers signal that investors are confident in the strength of their investments**. **Higher numbers signal investor anxiety**. For example, **during the 2008 financial crisis, the index hit a dizzying 80**, and **last month, it made news when it spiked above 50 for the first time since 2009** before returning to near its long-run average.

"What you're scared of is a drop in the value of your pension fund," said Mr. Whaley. "The **higher the VIX gets, the more fear you have the market will drop**."

The VIX reflects investors' sentiment by **tracking how much they are paying for "out-of-the-money" stock options — particularly "put" options**, which provide a **cushion against falling market prices**.

Mr. **Whaley compared it to buying insurance for a beach house**.

"**If a hurricane is forming and there is potential for the hurricane to hit land in the next few weeks, you are likely to pay a whole lot for insurance**," he said. "You want to protect the value of the home."

If investors fear a storm is brewing in the stock market, they could sell their stock, but with trading fees and other costs that would be expensive. Or they could opt to protect their investment.



## View of Volatility

The 'fear index' has traded around a historical average of 20, but it has spiked over the past decade amid bouts of market tumult.

### CBOE Market Volatility Index (VIX)



Source: FactSet

THE WALL STREET JOURNAL.

**“Instead of selling your stocks, you can go out and buy insurance, and the insurance you would buy would be put options on the S&P 500.”** Mr. Whaley said.

A **“put” option gives someone the right to sell stock at an agreed-upon price by a certain date.** The stock price specified in the contract is called the **“strike” price.** And **if it is lower than the market value of the underlying stock, the options are “out of the money.”** (A **“call” option is the opposite; it gives someone the right to buy stock at an agreed-upon price by a certain date.**)

“VIX is driven by the price of out-of-the-money calls and puts, but the calls don’t really matter,” Mr. Whaley said. “If you look at **trading activity in the market, it is predominantly puts.** You’re **only concerned about the downside risk.**”

Put options benefit investors in the event that the market price of a stock tumbles below the strike price. If it does, the investor who bought the put will collect the difference between the two values.

For example, suppose the market price of the S&P 500 portfolio was \$1,951 per share, and the strike price of a put option was \$1,950. If the market price falls below that threshold to, say, \$1,945 before the option contract expires, the investor who purchased the put will collect \$5 per share. (*This doesn't account for the cost to purchase the put option.*)

If the market price doesn't fall below the strike price before the contract expires, there is no payout.

"If the stock stays above \$1,950, you'd have a situation you have with any insurance," Mr. Whaley said. "You pay for it and never collect. You lose the premium. What you bought is the satisfaction that if there had been a drop, you would have been covered."

**Options contracts are sold by market makers who accept risk to facilitate trading. The fees they charge for the options contracts offset their own risk of having to pay off investors if the stocks do tank. So when nervous investors begin to clamor for puts, market makers raise the price.**

That is what sends the VIX skyward.

"The **more demand, the higher the price, and the higher the prices, the higher the VIX,**" Mr. Whaley said.

Investment firms like Zacks notice the VIX, but because they look further into the future, the level of the fear gauge doesn't alter their overall strategy, according to Bryant Sheehy, who is business development director for Zacks.

"It's more of a way to add some sexiness to editorial articles," he said, referring to headline-grabbing shifts in the VIX. "It's one more data point we can mention to talk about a tough market and what opportunities are now coming up.

But **for speculators** — the storm chasers of the stock market — **the VIX serves as a weather vane, pointing out when they should plunge into the market in search of short-term trading profits.**

"**Volatility is opportunity**, not risk," said Tim West, who publishes market analysis on tradingview.com, a social network for investors and traders. "Most people get that backwards."

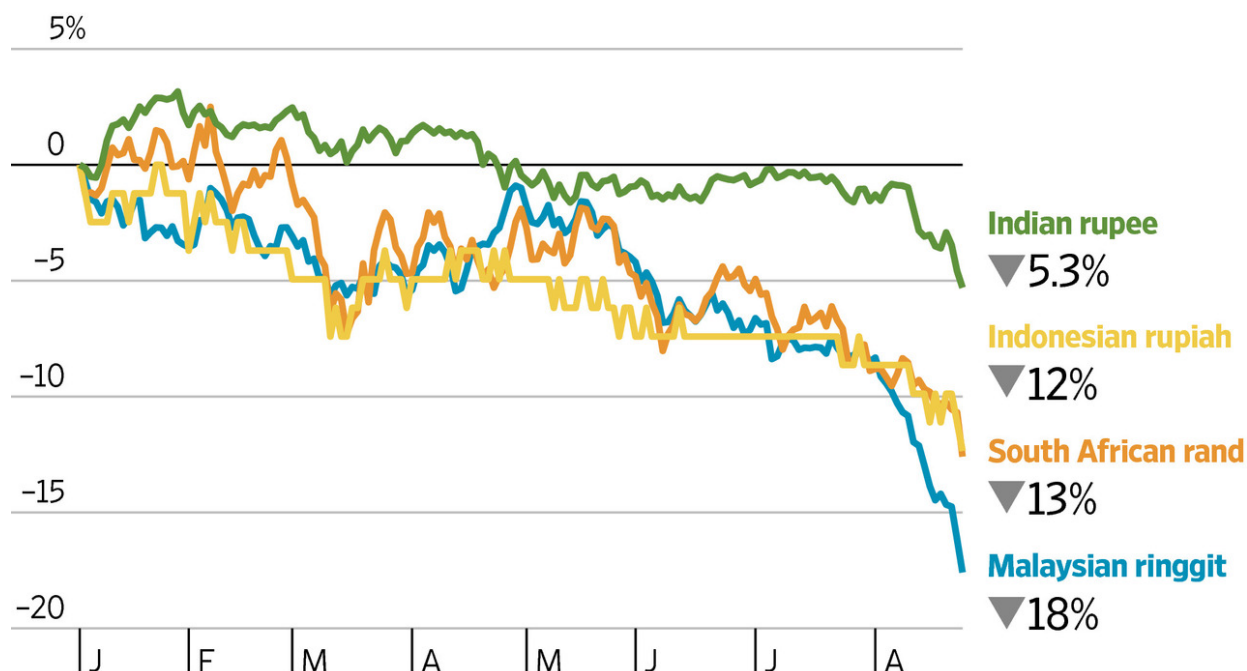
## Emerging Markets Hit Hard as Global Rout Continues

by Andrey Ostroukh and Patrick McGroarty – WSJ – Aug. 25, 2015  
James Marson, Raymond Zhong, and Jeff Lewis contributed to this article.

Growing anxieties about China cause investors to pull money from developing markets

### Submerging

Performance of select emerging market currencies against the U.S. dollar this year.



Source: FactSet

THE WALL STREET JOURNAL.

[Bad news from China](#) has sparked a firestorm in the developing countries that feed its vast industrial machine, leaving a swath of economies with few good ways to escape a crunch.



In **Indonesia**, coal once bound for China is piled up in port. In **South Africa**, mines that fed China's voracious demand for metals are firing workers. In financial markets, investors have responded by pulling out.

On Monday, the currencies of **Russia**, Indonesia, South Africa, **Brazil** and other commodity exporters tumbled to multiyear lows against the U.S. dollar. Stock indexes collapsed.

South Africa's mines are among the industries in emerging markets impacted by the slowing of China's economy. Nations such as **Thailand**, Indonesia and **Malaysia** have seen imports decline and their currencies fall.

The Russian ruble hit a seven-month low Monday, and by the end of the main trading session in Moscow it slid to its weakest-ever closing level of 70.9 to the dollar. A year ago, a dollar bought only around 36 rubles.

The weak currencies in these economies present a glum dilemma: Raise rates to defend them, and the economy takes a hit from tighter credit; let them fall, and inflation erodes household budgets. Meanwhile, dollar-denominated debt becomes a bigger burden for many cash-strapped governments and companies.

"We were all fully aware **emerging markets were vulnerable**," said Malcolm Charles, a portfolio manager at Investec Asset Management in Cape Town, which has \$120 billion under management. Now, he said, "I can only see red on my screen. There's a complete pricing-out of risk assets."

The blowout in Russia is emblematic of the fragility of economies relying on high raw materials prices supported by China's long-sturdy demand – and of the tight constraints faced by those countries' policy makers.

Chinese woes helped trigger a plunge in the price of Russia's principal export and main source of foreign-currency income, crude oil. That, in turn, has pummeled the ruble.

The weak ruble has pumped **inflation** above 15%, meaning the central bank has little space to cut interest rates further to try to revive the economy, which contracted 4.6% in the second quarter compared with last year.

And Russian authorities have all but given up spending foreign-currency reserves to help support the ruble rate, something the central bank did for years. It let the ruble float freely late last year after spending nearly \$80 billion of its reserves in an attempt to prop it up, only to see the ruble weaken substantially. Russia has \$363 billion of

Russia is doubly vulnerable because it has turned to China as relations with the West have soured over the past two years. Russia is the second-largest supplier of oil to China, after Saudi Arabia, and Moscow has sought to increase trade and investment ties with China, especially in its big energy projects.

Large chunks of the emerging world have staked their growth on supplying China. "There are piles of coal in ports," said Supriatna Suhala, executive director of the Indonesian Coal Mining Association. Big coal miners, he said, have sent workers home to make ends meet.

In Thailand, a major supplier of rubber to China's tire factories, Perk Lertwangpong, a rubber farmer and former president of the Rubber Planter Cooperatives, said he expects exports to fall by a fifth in 2015 compared with last year.

Indonesia, which sells coal, minerals and palm oil to China, was riding high not long ago. Economic growth in 2012 was around 6%. This year, the stock market is down more than 20%. Its currency, the rupiah, is down 12.5% for the year and is hovering at its lowest level since the Asian financial crisis that began in 1997.

Latin America, too, rode the coattails of surging Chinese demand for commodities like soybeans, copper and iron ore during the past 15 years. The peso currencies in both oil-exporting Mexico and Colombia hit record lows on Monday. **Mexico's peso is down 23% in the past year, Colombia's is off an eye-popping 60%, and Brazil's real has plunged nearly 36%.**

Revenue at Rio de Janeiro-based Vale SA, the world's biggest iron-ore producer, fell 29.7% in the second quarter from a year earlier as weaker demand from China pushed the price of the commodity lower. China is Vale's – and Brazil's – biggest customer. The mining company has been selling off noncore assets, including four giant ore-carrying ships, as it tries to shore up its finances.

In South Africa, the rand on Monday plummeted to all-time lows of beyond 14 to the dollar. Inflation is rising. Economists warn growth could miss already-lackluster forecasts, leading to a second consecutive sub-2% expansion this year.

Yet South Africa's central bank raised rates last month to bolster its currency despite economic distress. The bank said Monday that if the rand plunges more aggressively, it would “consider becoming involved in foreign exchange markets to ensure orderly market conditions.”

Hardest hit are the [gold, platinum and iron mines](#) whose riches built South Africa into the continent's most developed economy. Beijing's demand for those metals pushed China past the U.S. as South Africa's top trading partner in 2009.

The reversal since then has been severe. AngloGold Ashanti Ltd. last week reported a loss of \$142 million in the second quarter. Platinum miner Lonmin PLC said it would cut 6,000 jobs, nearly a fifth of its workforce, through 2017. Glencore PLC is cutting 380 jobs at a South African coal mine.

“There's a big crunch,” said Anton van der Merwe, a director at I-Cat Environmental Solutions, a contractor that services roads and purifies water at some of South Africa's biggest mines.

As miners have laid off workers and trimmed costs, I-Cat has pursued new clients, such as telecoms. The closely held company is still making money, Mr. van der Merwe said. But profits were a fifth lower than expected in the first half of its current fiscal year.

“At the end of the day, it's affecting everybody,” he said of the turmoil emanating from China.

The weak currencies have a silver lining, especially for those countries with more-dynamic manufacturing sectors: exports. From Mexican-made cars to Colombian-grown flowers, exports from Latin America are becoming far cheaper in dollar terms and will gain competitiveness. That is especially important to Mexico, a rival to China in their mano-a-mano battle for a share of the U.S. import market.

Indonesian Trade Minister Tom Lembong said straitened circumstances could aid the country's efforts to become less resource-reliant. “Short term, we have to let the market do its work,” Mr. Lembong said. “The depreciation of the rupiah has already done what it's supposed to do. We've swung from at least four years of trade deficits to, this year, a trade surplus.”



In Russia, the weakening of the ruble in line with the oil price is protecting the federal budget from severe strains. Russia gets around half its federal budget revenues from oil and gas sales. Chris Weafer, senior partner at Macro-Advisory, a Moscow-based consultancy, said the weaker ruble will cause consumers and businesses to postpone investment and spending decisions, worsening the outlook for the economy of the next six months. But, he said, longer-term the decision to let the ruble weaken could help boost growth. Russians have reacted calmly to the renewed ruble weakness, a contrast to the currency's shock collapse in December, which set off panic buying of dollars and durable goods. President [Vladimir Putin](#) remains widely popular despite the hit of inflation to household budgets

Banks reported no unusual increase in foreign-currency sales beyond the usual demand of the holiday season. M. Video, a leading electronics retailer, said it had seen no increase in sales. "We just stopped caring," said Natalia Muravyova, a 30-year-old telecommunications consultant. "There's a feeling that you can't do anything anymore, that nothing depends on you. So you sort of watch from the distance."

Ms. Muravyova said she had long given up holidays with her husband and child to Europe, and instead went to Crimea.





## More Utility Losses Won't Be a Shocker

by Spencer Jakab – WSJ – Jun 25, 2015

Utilities have slumped this year as bond yields have risen; more carnage is likely. Utilities stocks as a group are down nearly 12% so far this year.



Left – Transmission lines from NRG Energy's Joliet Station power plant in Illinois.

A traditional preserve of widows and orphans became a widow maker this year.

Utilities stocks as a group **have dropped by nearly 12%** as the year's halfway mark looms. The culprit isn't some hostile rate regulator or even bad weather – it's the bond market's reaction to what the

Federal Reserve might do later in 2015.

**Investors craving regular income have long looked to regulated utilities as a source of dependable quarterly checks. Six-plus years into the era of near-zero interest rates, they have been more appealing than usual. At the end of 2006, a popular exchange-traded fund tracking the sector, the Utilities Select SPDR Fund, had a dividend yield of 4.1%. That was lower than the 4.7% offered at the time by the benchmark 10-year Treasury note, but wasn't unusual.** Utilities payouts can keep up with inflation.

Fast forward to the **end of last year**, and the **utility ETF's yield was** less attractive than before. But at **3.2%**, it **handily eclipsed the Treasury note's yield of 1.9%**.

For the sector, though, that was the end of a good run that most strategists earlier said wouldn't continue in **2014. Bets that utilities stocks would fall surged at the start of 2014, as most economists predicted a rise in bond yields, making bond-like stocks unattractive. Instead yields went the other direction and the utility fund outpaced the S&P 500 by 13 percentage points.**

That was quite the contrast to the prior year. Between April and August 2013, the time of the bond market's so-called **taper tantrum**, the utilities ETF lagged behind the market by the same amount.

(Continued on next page)

## High-Wire Act

Utilities' trailing price/earnings ratio relative to S&P 500



Source: FactSet | WSJ.com

One reason utilities are so choppy lately is a concept called **duration**, a measure of **how sensitive prices are to moves in interest rates**. The **longer the duration**, the **more a bond's price moves**. **Utilities stocks have a theoretical duration of about 23 years**. A leading bond index, meanwhile, has a duration of five years.

And the carnage may not be over. **Utilities stocks' price/earnings ratio relative to the S&P 500 has dropped to around 91% today, from about 107% at the start of the year. But that remains well above the 73% average seen between 2000 and 2006.**

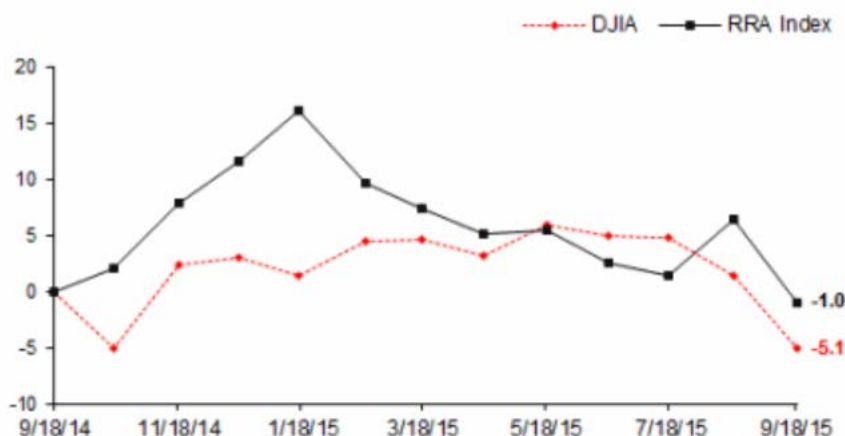
That still leaves utilities looking overcharged as rate increases draw closer.

## Utilities Regain Favor, Broad Markets Withdraw as Fed Postpones Rate Move by Brian Collins — Regulatory Research Associates (RRA)

An affiliate of SNL Financial LC — Sep. 21, 2015

Regulatory Research Associates (RRA), an affiliate of SNL Energy, noted in a recent Financial Focus research report that most broad market indices suffered, while utilities were resurgent, as **investors sailed for safe harbor** with the Fed voting down a September rate action. RRA indicated that while the Fed may be attempting to stabilize markets, investor anxiety around a potential global slowdown and U.S. economic fallout was compounded by the Fed's rate restraint. The RRA Utility Index was up 2.5%, as the DJIA and S&P 500 fell 0.3% and 0.2%, respectively; the NASDAQ held onto a 0.1% increase for the week. Thus far in 2015, the RRA Index, DJIA, and S&P 500 are down 12.1%, 8.1%, and 4.9%, respectively, while the NASDAQ is up 1.9%. Over the previous 12 months, the RRA Index was down 1%, while the other indices we track were mixed, with performance within a range of -5% to +5%

Index (%) Price Change - 09/18/14 to 09/18/15



Source: SNL Energy

Index Performance	Price Change through 09/18/15 (%)		
	Week	Year-to-Date	Last 12 mos.
RRA	2.5	-12.1	-1.0
DJIA	-0.3	-8.1	-5.1
S&P 500	-0.2	-4.9	-2.7
NASDAQ Composite	0.1	1.9	5.1

Source: SNL Energy

## Wall Street Says Fed's Rate Decision is Good for Utilities

by Darren Sweeney — SNL Financial LC — Sep 18, 2015

Rycia Mantua contributed to this article.

After much debate and concern in the power and electric utility industry about whether the Federal Reserve will raise interest rates for the first time in nine years, the Federal Open Market Committee on Sept. 17 said it was leaving the federal funds rate unchanged. Wall Street, for the most part, agrees this is good for the sector.

"Given the interest-rate sensitivity of electric utility stocks, we regard the Fed's inaction as a positive for the sector, although renewed uncertainty regarding a rate hike is likely to occur as we get later in the year," BMO Capital Markets Corp. analyst Michael Worms wrote in a Sept. 18 research flash.

In response to the decision, BMO reiterated its "outperform" ratings on American Electric Power Co. Inc., Calpine Corp., Duke Energy Corp., Edison International and NextEra Energy Inc.

Edison International's stock led utility and power equities Sept. 17, according to data compiled by SNL Energy. The company's stock closed at \$61.10 on Sept. 17, up 2.33% from a \$59.71 close on Sept. 16.

**KeyBanc** Capital Markets Inc. agreed that the **Fed's stance is "supportive of well-positioned utilities."**

"We continue to believe well-positioned utilities offer near-term outperformance potential during what we expect to be a period of monetary policy patience," analyst Paul Ridzon wrote in a Sept. 18 research report.

### Top 10 power stock performances for Sept. 17

Company (ticker)	Close (\$)		Change (%)
	9/16/2015	9/17/2015	
Edison International (EIX)	59.71	61.10	2.33
American Electric Power Co. Inc. (AEP)	54.63	55.87	2.27
Talen Energy Corp. (TLN)	12.91	13.19	2.17
Ameren Corp. (AEE)	39.69	40.54	2.14
Eversource Energy (ES)	46.71	47.66	2.03
El Paso Electric Co. (EE)	34.96	35.65	1.97
Abengoa Yield Plc (ABY)	21.61	22.01	1.85
TerraForm Power Inc. (TERP)	35.02	35.64	1.77
Unitil Corp. (UTL)	17.19	17.48	1.69
NiSource Inc. (NI)	33.23	33.79	1.69

Data compiled Sept. 17, 2015.

Includes power companies in SNL Energy's coverage universe trading on U.S. exchanges.

Source: SNL Energy



KeyBanc said it is maintaining its view that the initial interest rate hike will likely be pushed into 2016.

In addition to AEP and NextEra Energy, **KeyBanc lists its well-positioned utilities as ALLETE Inc., CMS Energy Corp., DTE Energy Co., MDU Resources Group Inc., NiSource Inc., Portland General Electric Co., Pepco Holdings Inc. and Sempra Energy.**

At least one industry executive had hoped that the Fed would go ahead and raise the interest rate.

During a panel discussion Sept. 16 at the Bank of America Merrill Lynch 2015 Power & Gas Leaders Conference in Boston, **Dominion Resources Inc.** Executive Vice President and CFO Mark McGettrick said he hoped the Fed would "go ahead and do it because it's been dragging on and dragging on."

"The overhang — whether it be on the yieldco or MLP or utility sector — up and down, it's been going on for a year now. So, let's go ahead and get it done," McGettrick said.

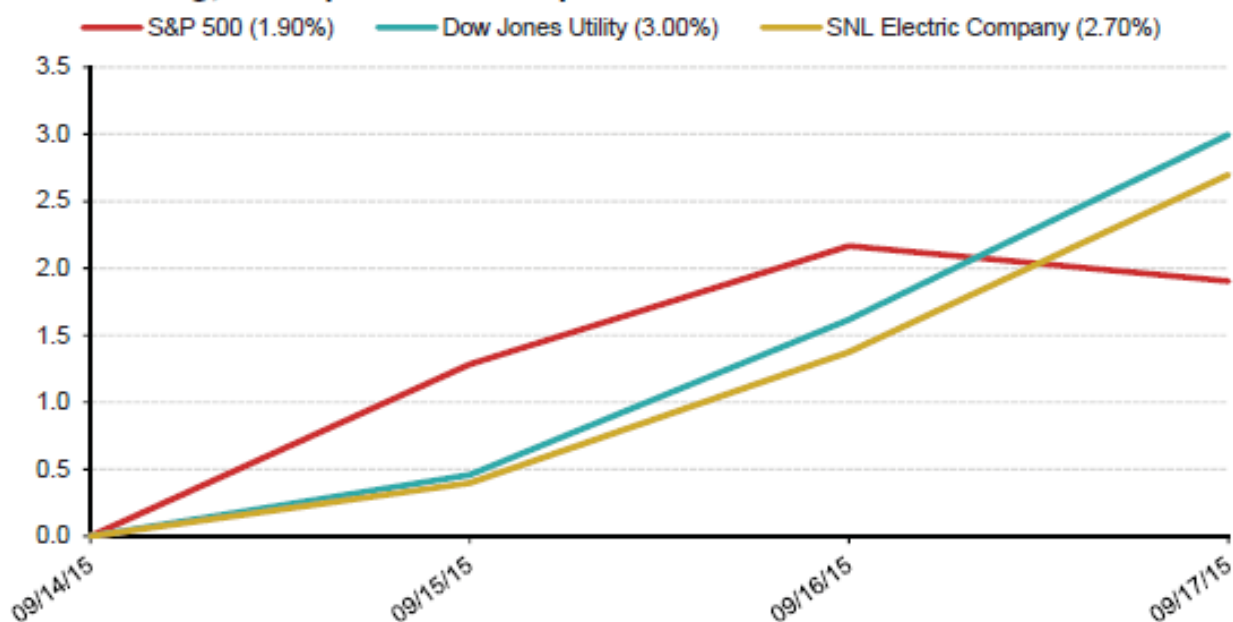
Both McGettrick and NextEra Energy Chairman, President and CEO James Robo said their companies were poised to weather the hike, which was anticipated to be as much as 25 basis points.

Robo noted that NextEra's yieldco vehicle, NextEra Energy Partners, would actually be "less sensitive" to interest rates than the parent company.

"I think whether [the Fed] raises rates 25 basis points isn't going to matter much for the physical economy," Robo added.

McGettrick made similar comments when comparing the impact of an interest rate hike to Dominion's MLP, Dominion Midstream Partners LP.

### Select energy index performance Sept. 14-17



Data compiled Sept. 17, 2015.

SNL electric company index includes all publicly traded (NYSE, NYSE MKT, NASDAQ, OTC) electric utilities and transmission only companies in SNL's coverage universe.

Source: SNL Energy



"I just can't believe that interest rates in the environment we're in today are going to have any significant downside compared to what we've seen already with the commodity sensitivity that's out there in just a general MLP, yieldco space," he said. "I think companies ... that have strong sponsors, have strong balance sheets, can ride through any of the interest rate sensitivities that might be out there and have the longevity with the assets they have to grow in a number of different ways that a lot of our other competitors don't have."

KeyBanc Capital Markets Inc. Managing Director Andy Redinger said Sept. 16 at the Solar Power International conference in Anaheim, Calif., that yieldcos will be "least affected" by an interest rate hike.

"If you're a yield investor, this is where you'll want to be," he said.

Guggenheim Securities LLC analyst Shahriar Pourreza wrote in a Sept. 16 report that he believes the anticipated rate increase caused the utility sell-off between February and July of this year and said a rate increase "should remove a material technical overhang on the sector."

Moody's, in a Sept. 16 report, said higher interest rates result in higher borrowing costs for the utility industry, which is a credit negative.

"Unregulated utilities are most vulnerable to rising interest rates since they must recoup costs via the market," Moody's said in a news release announcing the report's release. "Regulated utilities can recover interest costs by passing additional costs through to customers, but require regulatory approval before doing so. Public power companies are the least vulnerable, owing to their ability to raise rates without regulatory approval."



CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 211**

**Frequency of General Rate Case Filings  
by U.S. Investor Owned Regulated  
Gas Utilities**

**Exhibits in Support  
of Opening Testimony**

**October 16, 2015**

Frequency of General Rate Cases by Investor Owned Regulated Utilities

#	Abbreviated Gas Utility	Ticker	Y Indicates a General Rate Case in that Year															Peers	
			2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	UG 288 AVA
A	Avista	AVA																No	No
	Avista (WA)									Y			Y	Y	Y				
	Avista (OR)					Y						Y	Y			Y	Y		
	Avista (ID)		Y	Y			Y					Y	Y	Y	Y			Y	
B	Cascade	MDU																No	No
	Cascade (WA)									Y									
	Cascade (OR)												Y				Y		
1	AGL	GAS																Yes	Sensitivity
	AGL (GA)						Y												
	Chattanooga Gas (TN)											Y							
	Elizabethtown Gas (NJ)																		
	Elkton Gas (MD)										Y								
	Florida City Gas (FL)																		
	Nicor Gas (IL)						Y				Y								
	Virginia Nat Gas (VA)								Y					Y					
2	Atmos	ATO																Yes	No
	Atmos (CO)											Y				Y	Y	Y	
	Atmos (KS)					Y					Y		Y		Y				
	Atmos (KY) / Mid-States									Y			Y		Y				
	Atmos (LA)																		
	Atmos (MS)													Y					
	Atmos (TX)														Y				
	Atmos (TN)											Y	Y		Y				
3	Laclede	LG																Yes	No
	Alagasco (AL)																		
	Laclede Gas (MO)								Y		Y		Y		Y				
4	New Jersey Nat Gas Co	NJR																Yes	No
	Missouri Gas Energy (MO)															Y			
5	NiSource	NI									Y		Y					Yes	No
	Columbia (KY)				Y					Y		Y			Y				
	Columbia (MD)										Y		Y		Y		Y		
	Columbia MA								Y			Y		Y	Y				
	Columbia (PA)											Y		Y	Y				
	Columbia (OH)																		
	Columbia (VA)												Y						
	NIPSCO (IN)												Y						
6	Northwest Natural	NWN																Yes	Yes
	NWN (OR)				Y							Y							
	NWN (WA)		Y			Y					Y								
7	Piedmont	PNY																Yes	Yes
	Piedmont Nat Gas (NC)		Y		Y											Y			
	Piedmont Nat Gas (SC)				Y														
	Piedmont Nat Gas (TN)					Y						Y							
8	South Jersey	SJI				Y									Y			Yes	No
	Southwest Gas																	Yes	No
9	SW Gas (AZ)	SWX	Y				Y			Y		Y							
	SW Gas (CA)				Y					Y				Y					
	SW Gas (NV)					Y					Y			Y					
10	UGI	UGI																No	No
	UGI Utility (PA)																		
	UGI Penn Nat Gas (PA)											Y							
	UGI Central Penn (PA)											Y							
	UGI Central Penn (MD)																		
11	WGL	WGL																Yes	No
	Wa Gas/Light Co (DC)			Y		Y						Y							
	Wa Gas/Light Co (MD)		Y							Y			Y						
	Wa Gas/Light Co (VA)									Y			Y						

CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
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OREGON**

**STAFF EXHIBIT 212**

**SNL Overview of Energy Utility Rate Case  
ROEs 2015 Midyear Update**

**Exhibits in Support  
of Opening Testimony**

**October 16, 2015**

**STAFF EXHIBIT 212**

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CASE: UG 288  
WITNESS: MATT MULDOON

**PUBLIC UTILITY COMMISSION  
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**STAFF EXHIBIT 213**

**AVISTA Investor Presentation  
Second Quarter 2015 Earnings Webcast**

**Exhibits in Support  
of Opening Testimony**

**October 16, 2015**



**Welcome**

**Second Quarter 2015  
Earnings Webcast**

**August 5, 2015**



# Call Participants



**Scott Morris**  
Chairman, President  
and CEO



**Mark Thies**  
Sr. VP and CFO



**Dennis Vermillion**  
Sr. VP, Avista Corp.  
President, Avista Utilities



**Kelly Norwood**  
VP, State and Federal  
Regulation



**Christy Burmeister-Smith**  
VP, Controller and  
Principal Accounting Officer

# Forward-Looking Statements

*This presentation contains forward-looking statements, including statements regarding our current expectations for future financial performance and cash flows, capital expenditures, financing plans, our current plans or objectives for future operations and other factors, which may affect the company in the future. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond our control and many of which could have significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.*

*For a further discussion of these factors and other important factors, please refer to our Annual Report on Form 10-K for the year ended Dec. 31, 2014 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2015. The forward-looking statements contained in this presentation speak only as of the date hereof. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on our business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.*

# Net Income (Loss) and Diluted EPS

<i>(\$ in thousands, except per-share data)</i>	<b>Q2 2015</b>	<b>Q2 2014</b>	<b>YTD 2015</b>	<b>YTD 2014</b>
Operating Revenues (continuing operations)	\$337,332	\$312,580	\$783,822	\$759,158
Income from Operations (continuing operations)	\$57,360	\$62,731	\$146,935	\$153,073
Net Income from continuing operations attributable to Avista Corp. Shareholders	\$25,050	\$31,254	\$71,499	\$78,730
Net Income from discontinued operations attributable to Avista Corp. Shareholders	\$196	\$69,617	\$196	\$70,640
<b>Total Net Income attributable to Avista Corp. Shareholders</b>	<b>\$25,246</b>	<b>\$100,871</b>	<b>\$71,695</b>	<b>\$149,370</b>

## **Net Income (Loss) per diluted share by Business Segment attributable to Avista Corp. Shareholders**

Avista Utilities	\$24,478	\$26,685	\$68,862	\$74,681
Alaska Electric Light and Power Company	\$925	—	\$3,559	—
Ecova (discontinued operations)	\$196	\$69,696	\$196	\$70,807
Other	\$(353)	\$4,490	\$(922)	\$3,882

## **Earnings (Loss) per diluted share by Business Segment attributable to Avista Corp. Shareholders**

Avista Utilities	\$0.39	\$0.44	\$1.10	\$1.24
Alaska Electric Light and Power Company	\$0.02	—	\$0.06	—
Ecova (discontinued operations)	—	\$1.15	—	\$1.17
Other	\$(0.01)	\$0.08	\$(0.02)	\$0.07
<b>Total Earnings per diluted share attributable to Avista Corp. Shareholders</b>	<b>\$0.40</b>	<b>\$1.67</b>	<b>\$1.14</b>	<b>\$2.48</b>
Earnings per diluted share from continuing operations	\$0.40	\$0.52	\$1.14	\$1.31
Earnings per diluted share from discontinued operations	—	\$1.15	—	\$1.17
<b>Total Earnings per diluted share attributable to Avista Corp. Shareholders</b>	<b>\$0.40</b>	<b>\$1.67</b>	<b>\$1.14</b>	<b>\$2.48</b>



# Driving effective regulatory outcomes

## Continued recovery of costs and capital investments

### Washington



- May 4, 2015, filed a partial settlement agreement on cost of capital, net power supply costs and rate spread and rate design. Cost of capital based on 48.5% equity ratio and 9.5% return on equity.
- Original electric and natural gas revenue increase request filed Feb. 9, 2015, was reduced from \$33.2 million to \$17.0 million, and from \$12.0 million to \$11.3 million, respectively. Agreement included \$12.4 million reduction to net power supply costs.
- Unsettled issues include capital investments and recovery of increased utility operating costs.

### Oregon



- May 1, 2015, filed a general rate case designed to increase natural gas revenues by \$8.6 million.
- Request based on 50% equity ratio and 9.9% return on equity.
- Approved revenue increase of \$5.0 million took effect April 16, 2015, following approval of the all-party settlement agreement April 9, 2015. New rates based on 51% equity ratio and 9.5% return on equity.

### Idaho

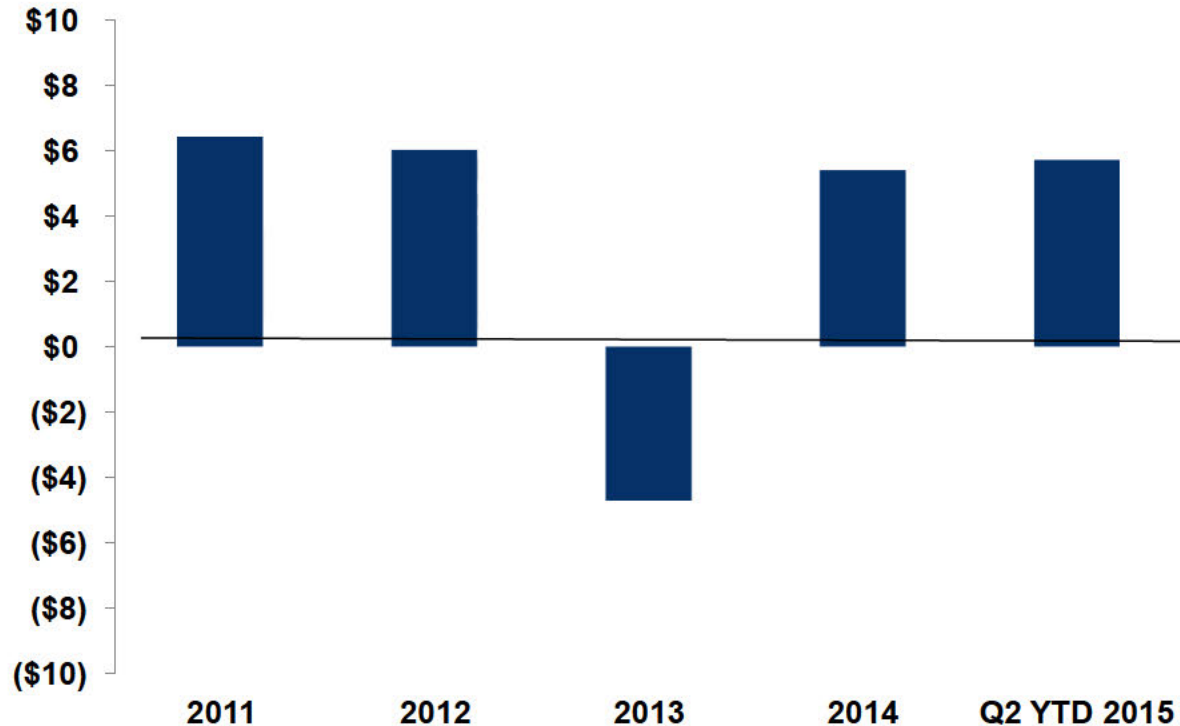


- Filed a two-year electric and natural gas rate request on June 1, 2015.
- Request designed to increase annual electric revenues by \$13.2 million and annual natural gas revenues by \$3.2 million, effective Jan. 1, 2016.
- The request is also designed to increase annual electric revenues by \$13.7 million and annual natural gas revenues by \$1.7 million, effective Jan. 1, 2017.
- Request based on 50% equity ratio and 9.9% return on equity.

# Washington Electric Energy Recovery Mechanism (ERM)

## Annual Benefit/(Expense) to Avista

(\$ millions)



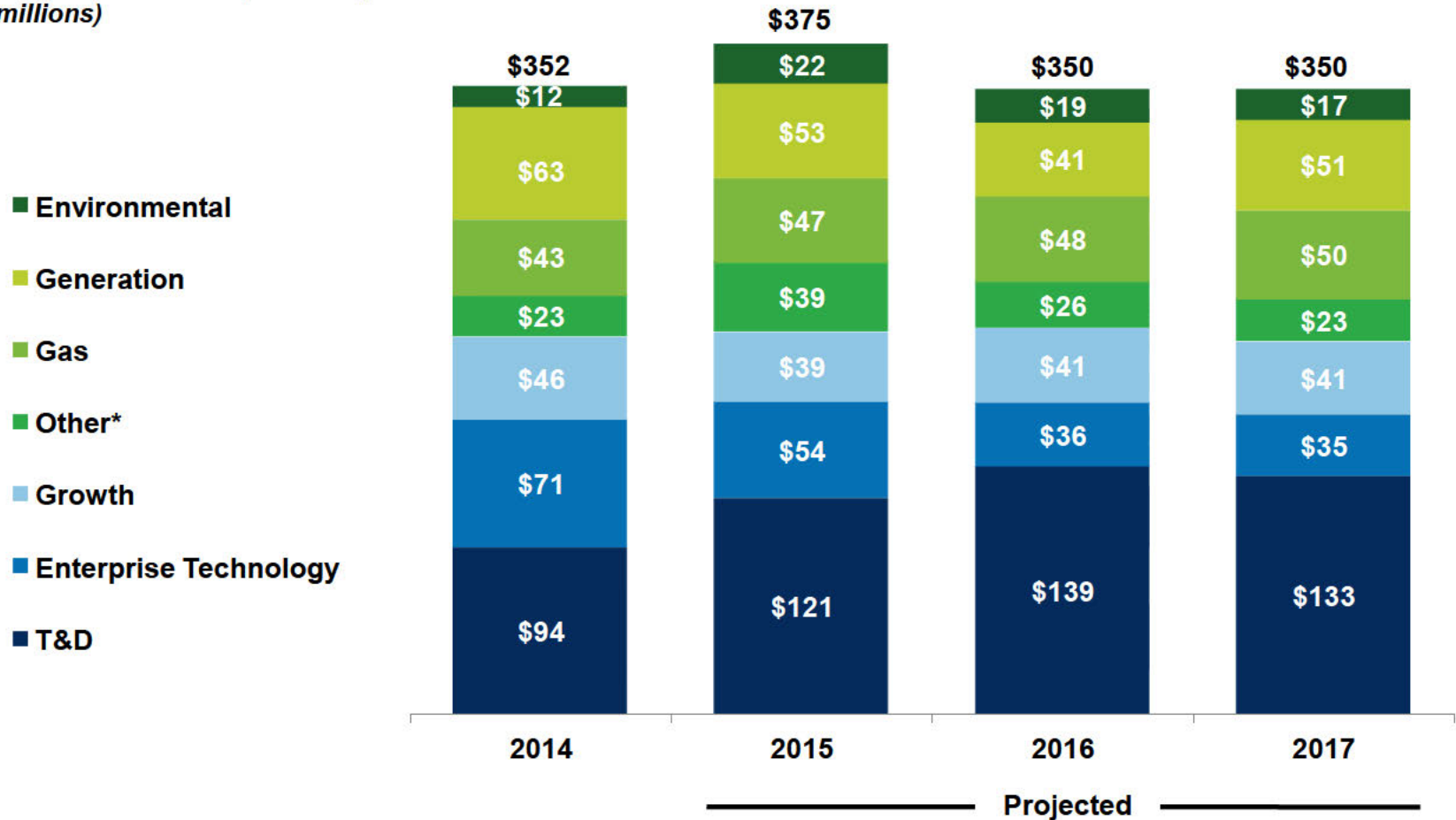
Power supply costs above or below the level in retail rates

\$0 +/- \$4 Million	100% Company
\$4-\$10 Million Expense	50% Company
\$4-\$10 Million Benefit	25% Company
> +/- \$10 Million	10% Company

# Significant investments to upgrade all systems

## 5% to 6% rate base growth

**Avista Utilities Capital Expenditures\*\***  
(\$ millions)



\* Other includes Facilities and Fleet

\*\* Excludes planned capital expenditures at AEL&P of \$15 million in 2015, 2016 and 2017

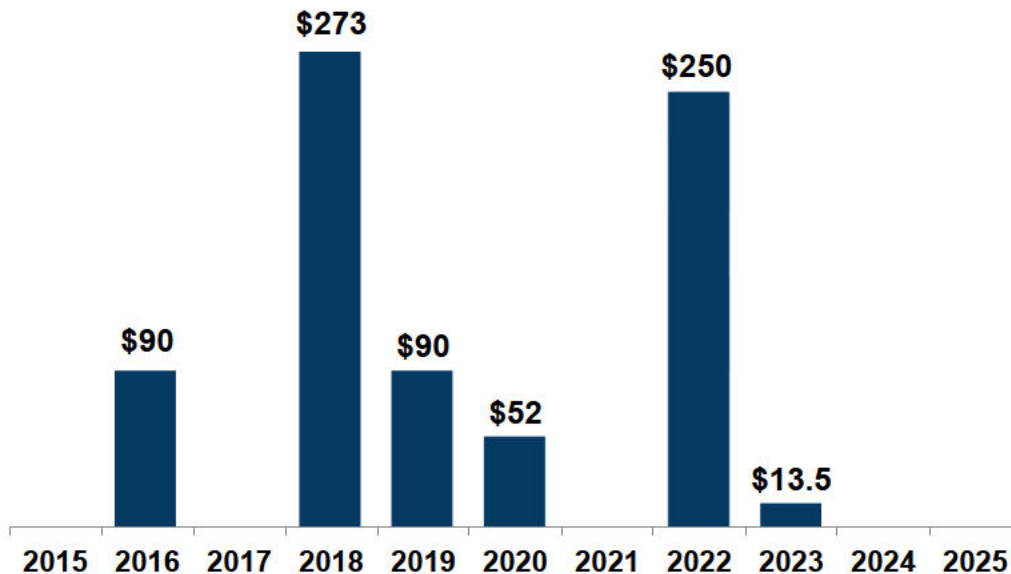


# Prudent balance sheet and liquidity

## \$275.6 million of available liquidity at Avista Corp. as of June 30, 2015

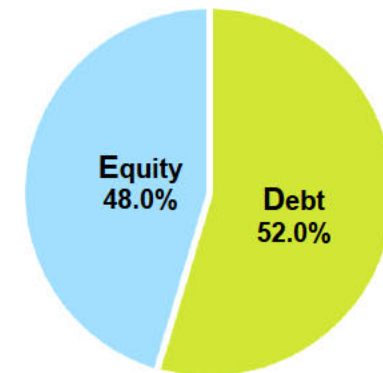
- We expect to issue up to \$125 million of long-term debt at Avista Corp. in 2015
- We do not expect to issue any equity in 2015, other than small amounts under the employee benefit plans

**No significant maturities until 2018**  
(\$ millions)



Additional long-term debt maturities beyond 2025 not shown

**Consolidated Capital Structure**  
June 30, 2015



# Growth for 2015

2015 Earnings Guidance	
Avista Utilities	\$1.81 - \$1.95
AEL&P	\$0.08 - \$0.12
Other	\$(0.03) - \$(0.01)
<b>Consolidated</b>	<b>\$1.86 - \$2.06</b>

## Guidance Assumptions

- Our outlook for Avista Utilities assumes, among other variables, normal precipitation and temperatures for the remainder of the year and includes the expected impact from decoupling in Washington. Also, for Avista Utilities we are estimating that we will have a provision for earnings sharing for our Washington electric operations and our Idaho operations.
- For Avista Utilities we are expecting below normal hydroelectric generation for the third quarter and normal hydroelectric generation for the fourth quarter of the year. Due to the strong generation through April, we are expecting hydroelectric generation to be about 94% of normal for the full year. Due to significantly warmer weather and reduced heating loads in the first quarter of 2015, we expect a reduction to annual consolidated earnings of approximately \$0.08 per diluted share.
- Our outlook for AEL&P assumes, among other variables, normal precipitation, temperatures and hydroelectric generation for the remainder of the year.
- Our guidance range for Avista Utilities encompasses expected variability in power supply costs and the application of the ERM to that power supply cost variability.
- The midpoint of our guidance range for Avista Utilities does not include any benefit or expense under the ERM. In 2015, we expect to be in a benefit position under the ERM within the 90% customer/10% company sharing band, which is expected to add approximately \$0.06 per diluted share.
- In addition, because we did not reach the targeted level of repurchases for our stock repurchase programs, we expect earnings dilution of approximately \$0.03 per diluted share in 2015.

# Questions?



***Kettle Falls Generating Station***



# Contact Information

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**Replay** Available at (888) 843-7419  
Passcode 40193445#

**Webcast** Archived on [www.avistacorp.com](http://www.avistacorp.com)

CASE: UG 288  
WITNESS: JUDY JOHNSON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 300**

**Information Technology, Distribution O&M**

**Opening Testimony**

**October 16, 2015**

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Judy Johnson. My business address is 201 High Street, SE Suite  
3 100, Salem, Oregon 97301-3612.

4 **Q. Please describe your educational background and work experience.**

5 A. My Witness Qualification Statement is found in Exhibit Staff/301.

6 **Q. What is the purpose of your testimony?**

7 A. The purpose of my testimony is to justify my adjustments to Information  
8 Technology Plant and Distribution O&M.

9 **Q. Did you prepare exhibits for this docket?**

10 A. Yes. I prepared Exhibit Staff/ 301, consisting of one page showing my witness  
11 qualifications. I also prepared Exhibit Staff/302, consisting of two pages,  
12 Confidential Exhibit Staff/303, consisting of two pages, Exhibit Staff/304,  
13 consisting of five pages, and Confidential Exhibit Staff/305, consisting of two  
14 pages.

15 **Q. How is your testimony organized?**

16 A. My testimony is organized as follows:

17	Issue 1, -----Information Technology Plant.....	2
18	Issue 2, -----Distribution O&M .....	6



1

**ISSUE 1, INFORMATION TECHNOLOGY PLANT**

2

**Q. Were you aware that Avista had been working on a technology project called Project Compass?**

3

4

A. Yes. The Company has been working on Project Compass for several years. It went into service in February of 2015.

5

6

**Q. Have you reviewed this project in prior cases?**

7

A. Yes, Staff has looked at this project in the prior two Avista rate cases (i.e. UG 246 and UG 284).

8

9

**Q. Do you believe that Project Compass is necessary?**

10

A. Yes. Avista's computer systems were old, outdated, and needed to be upgraded.

11

12

**Q. What is in the Company's filing for Project Compass?**

13

A. Avista's filing contains only one reference to the dollars associated with Project Compass. The reference is in Avista/600, Schuh/13, where she states that "Expenditure Request" (ER) 5138 contains \$8.3 million for 2015. It is impossible to tell by Schuh's testimony exactly how much is in the Company's filing for Project Compass. However, Avista's response to Staff Data Request 264 contains Avista's Total System cost for Project Compass (see Exhibit Staff/302).

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**Q. Are you proposing an adjustment in this case for Project Compass?**

21

A. Yes, based on Avista's response to Staff Data Requests 264 and confidential response to 265C, which are shown in Exhibit Staff/302 and Confidential

22

23

Exhibit Staff/303.

1 **Q. Please explain your proposed adjustment for Project Compass.**

2 A. Staff reviewed the Washington Utilities and Transportation Commission's  
3 (WUTC) Staff testimony (Docket UE-150204/UG-150205, Testimony of David  
4 C. Gomez, pages 52-56) (see Exhibit Staff/304) on Project Compass. In his  
5 testimony, WUTC witness Gomez states that he determined Project Compass  
6 had gone over its budget. Staff then asked the Company questions about the  
7 budget overruns in Staff Data Request 264 (Exhibit Staff/302). The Company's  
8 response provided Total System numbers. However, Avista also gave  
9 Oregon's allocation percentage for Project Compass of 8.072 percent and from  
10 this Staff was able to calculate that the Company had exceeded its budget by  
11 34 percent or \$27 million on a Total System basis. Staff used the information  
12 provided as part of Staff Data Request 302 to calculate the cost overruns and  
13 used the Oregon allocation percentage to calculate how much of the overrun  
14 was allocated to Oregon.

15 **Q. Do you consider a \$27 million cost overrun for Project Compass to be**  
16 **an excessive amount? Please explain your answer.**

17 A. Yes, Staff considers that to be an excessive cost overrun amount for this  
18 project. While computer costs are well known to spiral out of control, Staff  
19 believes Avista should have had better cost controls in place that would have  
20 kept the cost overruns to a minimum. The testimony of WUTC witness Gomez  
21 sets forth extensive discussion regarding one of the contractor's, EP2M/Five  
22 Point/Ernst & Young, performance of its obligations under the contract (See  
23 Staff/304, pages 52 and 53 showing Docket UE-150204/UG-150205,

1 Testimony of David C. Gomez, pages 52-53). Staff examined Mr. Gomez's  
2 concerns that Avista failed "to recognize, evaluate, identify, document and  
3 mitigate the possible risks to Project Compass resulting from the apparent  
4 conflict of interest arising from Five Point's acquisition of EP2M less than six  
5 months after award of a contract" and "the Company's lack of documentation of  
6 the prudence of its decision, above alternatives, to enter into an Extension  
7 Agreement with Ernst & Young for the added resources needed to complete  
8 Project Compass". After evaluating and considering the WUTC witness's  
9 testimony, Staff concluded that Avista had contributed to the cost overruns of  
10 Project Compass and should be held partially responsible.

11 Staff, therefore, has removed \$1.175 million in rate base which represents  
12 one-half of Oregon's share of the cost overruns. Staff chose one-half because  
13 Avista should be held partially responsible for the project's sizable cost overrun  
14 and a 50 percent adjustment equally shares the overrun costs between the  
15 Company and its customers.

16 **Q. Do you have additional concerns about the costs associated with**  
17 **Project Compass? If so, please explain your answer.**

18 A. Staff discovered that bonuses were given to employees involved in Project  
19 Compass. At a minimum, Staff would propose removing 50 percent of the  
20 bonuses under the Commission's standard for allowance of bonuses in a rate  
21 case. However, Staff decided to remove the Company's total share of the  
22 bonuses associated with this project on an Oregon allocated basis, which  
23 amounts to \$0.068 million. Staff does not believe that when a project has cost

1           overruns of 34 percent it is prudent to give out bonuses. Staff's total  
2           adjustment is \$1.234 million.

3       **Q. Did you make a similar adjustment in prior cases?**

4       A. No. Staff only learned of the cost overruns in this case and has proposed an  
5           adjustment to hold the Company partially responsible.

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**ISSUE 2, DISTRIBUTION O&M**

2

**Q. Why is Staff making an adjustment to Distribution O&M costs?**

3

A. Staff recently discovered through Data Request 262 (Confidential Staff Exhibit/305) that Avista had gone through a Reduction in Force (RIF) in 2013 without notifying Oregon Staff ahead of time.

4

5

6

**Q. Why is the RIF an issue?**

7

A. When a company institutes a RIF, there are two things that will happen. The first is that, depending on how many employees are involved in the RIF, labor expenses for the company should be permanently decreased. The second is that there are costs associated with the RIF that the company expects to collect from customers.

8

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**Q. Were these the same circumstances for Avista's 2013 RIF?**

13

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**Q. What is Staff's concern in the current case that involves a past RIF?**

21

22

23

A. Staff asked Avista in Data Request 262 to provide more detail about the decrease and increase in costs associated with the RIF. The Company replied to Data Request 262 (Confidential Exhibit Staff/305) that the savings to Oregon

1 customers should be \$0.264 million annually. Staff is taking Avista's  
2 assurances that the savings are included in this case as true although the  
3 Company has been unable to demonstrate that the savings were actually there  
4 by showing a reduction in ongoing expenses. In Avista/100, Morris/7-8, the  
5 Company shows a graph that depicts "...non-fuel Operations and Maintenance  
6 and Administration and General Expenses are growing at a faster pace than  
7 sales".

8 The piece that is the most worrying is the increase in costs of \$0.550 million  
9 due to the severance pay-out, which was not removed from this rate case as a  
10 one-time occurrence. Staff can find no evidence that Avista has removed it.  
11 Generally, with a cost of this type of action, a utility company will submit an  
12 application for a deferral when the program begins and then at a later time after  
13 the program ends will amortize the deferral. Because Avista did not inform  
14 Oregon Staff of the RIF and did not ask for a deferral, Staff believes it was  
15 considered as just another cost and collected on an on-going basis from  
16 customers. Staff plans to review UG 246 and UG 284 to see if an adjustment  
17 should have been made. If Staff determines that the Company has kept the  
18 \$0.550 million in rates and over-collected the amount, Staff will initiate talks  
19 with the Company to find a solution. The Company should have made an  
20 adjustment to remove this one-time cost from expenses.

21 **Q. Does Avista believe that it has removed this cost?**

22 A. Apparently, yes. In the Company's response to Staff Data Request 262, on  
23 page two, Avista states "Severance payments are not included in rates in



1 Oregon as per the Settlement Stipulation, UG-246, Order No. 14-026 on page  
2 5". When Staff reviewed Order No. 14-026 it was discovered that the Order is  
3 only a single page and therefore cannot have a page 5. Staff then examined  
4 the main order in Docket UG-246 which is Order No. 14-017. This Order  
5 contains the Stipulation. The Order and the Stipulation were thoroughly  
6 examined by two different Staff and no reference to removing severance  
7 payments was found. Staff can only conclude that the Company is mistaken.

8 **Q. Has Staff removed this cost?**

9 A. Yes. Staff has made an adjustment to lower expenses by \$0.550 million to  
10 remove the one-time cost from expenses.

11 **Q. Does this conclude your testimony?**

12 A. Yes.

CASE: UG 288  
WITNESS: JUDY JOHNSON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 301**

**Witness Qualifications Statement**

**October 16, 2015**

**WITNESS QUALIFICATIONS STATEMENT**

NAME: Judy A. Johnson

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist  
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE., Suite 100  
Salem, OR. 97301

EDUCATION: MBA with an emphasis in Statistics from  
Eastern Washington University  
Cheney, Washington

BA in Accounting from  
Eastern Washington University  
Cheney, Washington

EXPERIENCE: 3/95-Present I have been employed by the Oregon Public Utility Commission since March of 1995. My current position is as a Senior Economist in Energy, Rates, Finance, and Audit.

6/77-2/95 I was employed by Avista Corporation, an electric and natural gas utility located in Spokane, Washington. The majority of my employment was spent in the Rates and Regulatory Affairs Department as a Senior Rate Analyst. I have prepared testimony and exhibits in numerous electric and natural gas rate cases, primarily in the area of results of operations and cost of service.

CASE: UG 288  
WITNESS: JUDY JOHNSON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 302**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/19/2015
CASE NO.:	UG 288	WITNESS:	Karen K. Schuh
REQUESTER:	PUC Staff - Johnson	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff-264	TELEPHONE:	(509) 495-4710
		EMAIL:	<a href="mailto:larry.labolle@avistacorp.com">larry.labolle@avistacorp.com</a>

**REQUEST:**

Please provide, in as much detail as possible, the following detail about the CSS:

- a. How did the actual cost of CSS compare to what was budgeted?
- b. If there were any cost over-runs, please fully explain them.
- c. Please provide support for the amount of CSS in Oregon.
- d. The amount and date that CSS went into plant-in-service.

**RESPONSE:**

The Company's legacy Customer Information and Work and Asset Management System, which was in service for twenty years, was replaced in a multi-year effort named "Project Compass." The legacy applications replaced included the Company's Customer Service System, Work Management System, and the Electric and Gas Meter Application. The primary replacement systems are Oracle's Customer Care & Billing application and International Business Machine's ("IBM") Maximo work and asset management application. A portion of the Maximo system was enabled in the fall of 2013, and the full System was placed in service in February 2015.

- a. The initial implementation budget for Project Compass was developed in 2012, based on the system requirements information developed as part of the initial project plan. The basis for the initial budget of approximately \$79 million was described in a project report filed in support of testimony describing Project Compass, which was part of the Company's 2013 general rate case in Oregon. In particular, that testimony highlighted the nature of large enterprise-wide software projects like Compass, and the preliminary nature of the estimates. In June of 2014, Avista revised the initial budget to approximately \$98 million, and prepared a report describing the project factors that were resulting in greater workload, development and testing time, and cost. That report, which was filed in support of the Company's 2014 general rate case in Oregon, also described some of the mitigation measures implemented by the Compass project team to manage changes in the workload and time requirements. The report is provided here as Staff\_DR\_264 Attachment A. A final revision to the budget for Project Compass (approximately \$106 million) was made in November 2014, and the new systems were placed into service on February 2, 2015. The final implementation cost was approximately \$106 million.
- b. While the Company expected that the final cost for Project Compass would very likely be greater than the initial budget developed in 2012, Avista does not consider it reasonable to characterize this difference as a "cost overrun." Rather, the amount spent by the Company to implement the new systems represents the true installation cost. As explained

in part a, above, accurately predicting the final implementation cost was not possible at the time the initial budget was developed. The report, provided as Staff\_DR\_264 Attachment A, describes the major activities that required more time and money to complete than was initially estimated.

- c. Avista's customer information and asset management system is a company-wide platform that supports and enables the provision of service to customers receiving electric or natural gas service in any of Avista's service territories. Therefore, this asset is treated as a common asset in terms of both service and jurisdiction, and the net plant balance is allocated to Avista's services and jurisdictions based upon Avista's established allocation methodology. The most current common service and jurisdiction allocation factor for Oregon is 8.702%, which is the allocation factor included in this case for Project Compass net plant. Please see Avista's responses to DRs Staff\_DR\_128 through Staff\_DR\_134, which include information regarding Avista's established allocation methodology.
- d. The table below details the transfers to plant-in-service associated with Project Compass. During 2013 and 2014, portions of the overall project that were in service prior to the whole-system go-live were transferred to plant-in-service. The whole-system Go-Live occurred on February 2, 2015 and the associated capital expense was placed in service in February 2015. Certain trailing capital expenditures were transferred to plant-in-service in the months following February 2015. These trailing expenditures are associated with the activities of Post-Go Live Support and Project Stabilization, where are elements of the capital project.

Period	Transferred to Service (in thousands of \$)
2013	10,390
2014	262
January 2015	
February 2015	85,988
March 2015	3,486
April 2015	2,167
May 2015	2,206
June 2015	2,872
July 2015	108



CASE: UG 288  
WITNESS: JUDY JOHNSON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 303**

**Confidential Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**STAFF EXHIBIT 303**  
**IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE**  
**ORDER NO. 15-141 IN UG 288**

CASE: UG 288  
WITNESS: JUDY JOHNSON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 304**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

1 In addition, the Commission has made it clear that the company bears the burden of  
2 demonstrating prudence.<sup>89</sup>

3

4 **Q. Why is Staff contesting the prudence of Avista's additional capital costs for**  
5 **Project Compass?**

6 A. Avista's explanation, contained in the testimony and exhibits of Mr. Kensok, does not  
7 tell the whole story behind the reasons for Project Compass' cost overrun and  
8 implementation delay. The Company's responses to Staff's discovery requests<sup>90</sup>  
9 reveal that the primary contributor to the added capital costs was the performance of  
10 Project Compass' System Integrator (SI)<sup>91</sup> for the Oracle Customer Care & Billing  
11 (CC&B) solution: EP2M/Five Point/Ernst & Young.<sup>92</sup>

12 Staff's recommendation to disallow Avista's capital costs relating to the  
13 extended timeline are based on the following issues, which I discuss below: 1) the  
14 failure on the part of Avista to recognize, evaluate, identify, document and mitigate  
15 the possible risks to Project Compass resulting from the apparent conflict of interest  
16 arising from five Point's acquisition of EP2M less than six months after award of a  
17 contract; 2) Avista's failure to cure contractual breaches on the part of the SI early

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<sup>89</sup> Ibid., p. 13 ("As with all issues, the company bears the burden to prove initiation, construction and continuation of the project was prudent"); see *Petition of Puget Sound Power & Light Co. for an Order Regarding the Accounting Treatment of Residential Exchange Benefits*, Docket No. UE-920433, Eleventh Supplemental Order (Sept 21, 1993), p. 19 ("Puget must make an affirmative showing of the reasonableness and prudence of the expenses under review . . . even in the absence of a challenge by another party").

<sup>90</sup> Avista's responses to Staff Data Request Nos. 140, 141, 152, 153 and 154. See Gomez, Exh. Nos. (DCG-15C), (DCG-16C), (DCG-16C), (DCG-J 8C), and (DCG-19).

<sup>91</sup> The Company also uses the term "Solution Integrator," which is synonymous in meaning to "System Integrator."

<sup>92</sup> Staff's reference here to multiple companies is the result of two separate mergers and acquisitions of Avista's SI during the tenure of this project. EP2M was acquired by Five Point in January of 2013, and Ernst and Young acquired Five Point on June 1, 2014.

1 enough in the project, which could have avoided the need for an extension of the  
2 project's timeline and added cost; and 3) the Company's lack of documentation of  
3 the prudence of its decision, above other alternatives, to enter into an Extension  
4 Agreement with Ernst & Young (EY) for the added resources needed to complete  
5 Project Compass.<sup>93</sup>

6

7 **Q. What was the function of the CC&B System Integrator for Project Compass?**

8 A. The CC&B SI for Project Compass is tasked with aligning the product standard  
9 configuration components of Oracle's off-the-shelf CC&B software to meet key  
10 business goals, minimizing the need for product extensions and, to the greatest extent  
11 possible, modifying Avista's business processes to align with best practices inherent  
12 in the product workflow. Additionally, the SI actively supports cooperation with the  
13 other concurrent system projects like Maximo Asset Management.<sup>94</sup>

14

15 **Q. Please explain the conflict of interest that arose when Five Point acquired**  
16 **EP2M.**

17 A. Prior to its acquisition of EP2M, Five Point was operating in the capacity of an agent  
18 of Avista in the procurement of SI services for Project Compass.<sup>95</sup> In its confidential

---

<sup>93</sup> Gomez, Exh. No. \_\_ (DCG-16C), Avista's supplemental response to Staff Data Request No. 141, Attachment A, Project Change Request (PCR) FP 23N -Revised and Extended EY SI Services and Project Change Request (PCR) FP 24N - Extension, completion, and true up of EY resources - all signatures.

<sup>94</sup> Gomez, Exh. No. \_\_ (DCG-15C), Avista's confidential response to Staff Data Request No. 140, Attachment A, EP2M 04 -EP2M Avista Project SOW 7.9.2012, Page 15, Section 4.1 Project Objective.

<sup>95</sup> Gomez, Exh. No. \_\_ (DCG-31C), UE-140188, Kensok, Exh. No. JMK-2, Attachment 10, "Project Compass Guidebook" dated January 27, 2012, shows Five Point personnel (Greg Galluzzi and Gary Weseloh) actively involved in contract negotiations and development of statements of work with SI vendors including EP2M which received the contract award.

1 response to Staff Data Request No. 140, the Company acknowledges it knew of the  
2 merger and acquisition at the time it occurred, which was in January 2013. Avista  
3 then states that "the interests of its customers were insulated from any potential  
4 conflict of interest by the rigorous and objective processes it established for  
5 developing vendor proposals, evaluating and scoring proposals, making final vendor  
6 selections, and in negotiating the final contracts, purchase agreements, and purchase  
7 prices."<sup>96</sup> Avista's assertion that its procurement process was not compromised and  
8 did not impact project results is an after-the-fact statement that cannot be confirmed.

9

10 **Q. Why is the integrity of the procurement process so important in the selection of**  
11 **an SI for Project Compass?**

12 A. The integrity of the procurement process is an important consideration in the vendor  
13 performance risk assumed by the Company for this project. This is especially the  
14 case given that Avista's award to EP2M resulted in a Firm Fixed Price Contract for  
15 deliverables contained in the SI's Statement of Work (SOW).<sup>97</sup> The nature of such  
16 contracts places the primary cost risk onto the seller, in this case EP2M. Therefore,  
17 the bid of an offeror (here EP2M) has to be responsive to the requirements contained  
18 in the scope of work only and not affected by other influences. Otherwise, an  
19 unacceptable level of performance risk is introduced that the awarded amount is  
20 below the offeror's costs and the project under-resourced.<sup>98</sup>

---

<sup>96</sup> Gomez, Exh. No. \_\_ (DCG-15C), Avista's confidential response to Staff Data Request No. 140.

<sup>97</sup> Ibid., Attachment A, 01 - EP2M Deal Sheet 6.29.2012 and 04 - EP2M Avista Project SOW 7.9.2012.

<sup>98</sup> Ibid., Attachment B, provides monthly Project status reports, prepared for the Executive Steering Committee for the calendar year 2014. On the very first monthly report of the year (page 5 of 2664), project management



2 **Q. Do you believe that the conflict of interest that arose after EP2M's acquisition**  
3 **by Five Point resulted in an awarded amount that was below cost and in a**  
4 **project that was under resourced?**

5 A. Staff cannot say with certainty that the SI bid was affected in any way by Five  
6 Point's acquisition of EP2M or that Five Point's decision to buy EP2M was  
7 somehow motivated by the prospect of an awarded contract by Avista. Staff only  
8 need point to Five Point's integral and active involvement in Project Compass' SI  
9 procurement contained in Mr. Kensok's Exhibit No. JMK-2 in UE-140188 and Five  
10 Point's subsequent performance problems commencing early in the project as a  
11 successor to EP2M as evidence of questions that should have been asked of Five  
12 Point by Avista's project management and Executive Steering Committee. Avista  
13 has not provided documentation that such questions were addressed.

15 **Q. You point to Avista's failures to cure contractual breaches as another reason to**  
16 **disallow the costs of the extended timeline for Project Compass. Please explain.**

17 A. In Avista's confidential response to Staff Data Request No. 152,<sup>99</sup> it provides a  
18 lengthy explanation regarding its "due diligence in evaluating the consequences of a  
19 decision to enforce contract provisions against Five Point," which contradicts its  
20 earlier narrative in Mr. Kensok's testimony and exhibit regarding the circumstances  
21 surrounding the project's extended timeline and added costs being the result of

---

reports as an issue that "Five Point has been challenged with resources to deliver integration and configuration code to meet Project deliverable dates."  
<sup>99</sup> Gomez, Exh.No. (DCG-17C).

1 greater than anticipated complexity. In its response to Staff Data Request No. 152,  
2 the Company refers Staff to the reports it provided in its Attachments B and C to  
3 Staff's Data Request No. 140 as evidence that it prudently evaluated its options,  
4 including termination of the contract, to address the SI's non-performance in  
5 delivering usable code for System Integration Testing, a critical path item for the  
6 project. Staff's review of these reports located no evidence of such discussions or  
7 analysis. Nor does Staff find evidence that such options were explored or discussed  
8 in the materials presented to the Board in May/June 2014 to extend the project  
9 timeline and add another \$20.0 million to the project's budget.<sup>100</sup>

10  
11 **Q. Why does Staff believe that an early and aggressive response by Avista to**  
12 **the SI's contractual breach might have led to different results for Project**  
13 **Compass?**

14 Avista's contract with the SI was performance based. This means that the Company  
15 structured its payments with EP2M/Five Point on the successful completion of SOW  
16 deliverable milestones based on mutually agreed upon acceptance criteria. The  
17 contract's payment structure also included "holdback" amounts for deliverables. The  
18 holdback amounts would be payable upon successful delivery of the completed  
19 solution by the SI. Based on Avista's response to Staff Data Request No. 152, Staff  
20 concludes that the Company continued to make payments to a vendor that was  
21 clearly not performing. As a result, the Company lost any leverage to compel the SI  
to cure its breach, particularly the further along the project moved toward its Go-

---

<sup>100</sup> A copy of the presentation made to the Company's Finance Committee of its Board of Directors, supporting

the revision of the Go Live date and implementation budget, were provided by Avista in response to Staff Data Request No. 153, Confidential Attachment A. See Gomez, Exh. No. \_\_ (DCG-18C).

CASE: UG 288  
WITNESS: JUDY JOHNSON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 305**

**Confidential Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**STAFF EXHIBIT 305**  
**IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE**  
**ORDER NO. 15-141 IN UG 288**

CASE: UG 288  
WITNESS: MING PENG

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 400**

**Depreciation**

**Opening Testimony**

**October 16, 2015**



1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Ming Peng. I am employed by the Public Utility Commission of  
3 Oregon (OPUC) as a Utility and Energy Analyst 3 in the Energy Rates, Finance  
4 and Audit Division. My business address is 201 High Street, SE Suite 100,  
5 Salem, Oregon 97301-3612.

6 **Q. Please describe your educational background and work experience.**

7 A. My Witness Qualification Statement is found in Exhibit Staff/401.

8 **Q. What is the purpose of your testimony?**

9 A. I reviewed the depreciation expense and depreciation reserve portions of  
10 Avista Corporation's (AVA or Company) revenue requirement rate case filing  
11 as documented by witness Smith in Avista/500-502 and witness Schuh in  
12 Avista/600.

13 **Q. What exhibits do you include as part of your testimony?**

14 A. I have prepared the following exhibits:  
15 Exhibit Staff/401, Witness Qualification Statement, consisting of three pages,  
16 and Exhibit Staff/402, AVA Data Response No. 152, consisting of two pages.

17 **Q. How is your testimony organized?**

18 A. My testimony is organized as follows:

19 Issue 1. Analysis of Capital Recovery Parameters.....2  
20  
21 Issue 2. Depreciation Effect on Revenue Requirement.....6

1                                 **ISSUE 1. Analysis of Capital Recovery Parameters**

2           **Q. What is depreciation?**

3           A. “Depreciation” is defined by the National Association of Regulatory Utility  
4           Commissioners (NARUC) in relevant part as follows:

5                                 *As applied to the depreciable plant of utilities, the term depreciation*  
6                                 *means the loss in service value not restored by current maintenance, incurred*  
7                                 *in connection with the consumption or prospective retirement of utility plant in*  
8                                 *the course of service from causes that are known to be in current operation,*  
9                                 *against which the company is not protected by insurance, and the effect of*  
10                                *which can be forecast with reasonable accuracy. Among the causes to be*  
11                                *considered are wear and tear, decay, action of the elements, inadequacy,*  
12                                *obsolescence, changes in the art, changes in demand, and the requirement of*  
13                                *public authorities.*<sup>1</sup>

14           **Q. Where can the current authorized depreciation rates be found for AVA?**

15           A. The current authorized depreciation rates for the Company can be found in  
16           Commission Order 13-168 (Docket UM 1626).

17           **Q. How did you analyze the depreciation expense, and what information did**  
18           **you review for the Company’s rate case filing?**

19           A. To check if the depreciation calculation is properly conducted by using the  
20           authorized depreciation parameters in Commission Order 13-168, I performed  
21           the following analytical review procedures:

---

<sup>1</sup> NARUC “Public Utility Depreciation Practices,” p 318.

1           1. I sent one set of data requests (DR 152) to AVA on May 29, 2015. I asked  
2 the company to provide the following information:

3                   *the calculation in Excel format with the cell reference links and*  
4                   *formulae for exhibits AVISTA/502, Smith, and for AVISTA/600, Schuh. The*  
5                   *data set could include, but not limited to, the following:*  
6

- 7           1)     *CAP SUMMARY- OR - 12.31.15 EOP (w 2016 AMA Growth) – linked*
- 8           2)     *EOP and Full Year Depreciation Adjustments – linked*
- 9           3)     *Filed - 2015 OR Gas Rev Req Model*
- 10          4)     *Transportation Depreciation Study Support*
- 11          5)     *UM 1626 Settled Exhibit 102 Attachment A-linked*

12  
13          2. I verified the calculations from AVA's data responses to DR 152, including:

14               (1) checked the reference links, formulae, and calculations from the  
15 data response.

16               (2) reviewed how the Company derived the "weighted average  
17 depreciation rate" by using the rates in Order 13-168.

18               (3) verified how Company forecasted 2015 and 2016 depreciation  
19 expenses

20               (4) reviewed how the Company's adjustments to depreciation expense  
21 were calculated

22     **Q. Did you make any adjustments and, if so, for what reasons?**  
23

24     **A.** Yes. In the current general rate case (UG 288) filing, I discovered that certain  
25 depreciation rates had not been correctly updated by the Company. AVA  
26 should use depreciation parameters and rates from Order 13-168. To comply  
27 with the Commission Order's authorized depreciation rates for the Company, I  
28 propose the following adjustments and corrections:

29           1. Depreciation & Amortization expenses be reduced by \$281,000 from

- 1           \$3,183,000 to \$2,902,000; and
- 2           2. Accumulated Depreciation & Amortization be reduced by \$173,000 from
- 3           \$8,322,000 to \$8,149,000.

4           The table below shows the comparison of the “aggregated”

5           depreciation rates that derived by using AVA filed and OPUC authorized

6           depreciation rates. The depreciation expense and accumulated depreciation

7           adjustments are based on the calculations by using Oregon PUC authorized

8           depreciation rates.

<b>UG 288 - AVA</b>	<b>OPUC</b>	<b>AVA Filed</b>	<b>Difference</b>
<b>Description</b>	Aggregated	Aggregated	Authorized
	Depreciation Rate	Depreciation Rate	Less Filed
Gas Underground Storage	1.88%	1.59%	0.29%
Distribution			
Direct	2.05%	2.52%	-0.47%
Allocate All Jurisdictions	2.05%	2.52%	-0.47%
Allocate Northern Jurisdictions	2.05%	2.52%	-0.47%
Subtotal			
General Plant	7.00%	3.62%	3.38%
Transport.	8.06%	8.92%	-0.86%
Compass-Hardware	6.66%	23.70%	-17.04%
Hardware	20.00%	23.70%	-3.70%

9

10 **Q. Please describe your activities with regard to reviewing the Company’s**

11 **filing.**

12 **A.** In order to get a better collective understanding of AVA’s depreciation

13 adjustment, I conducted two phone conferences with AVA’s Data Responder

14 David Machado. As I understand it, Mr. Machado works with the Company’s

1 witness Karen Schuh. The conference calls concerned my proposed  
2 depreciation adjustments.

3 **Q. Please describe data responses to Staff's DR 152 provided by AVA.**

4

5 **A.** AVA's data response (Exhibit Staff/402) to DR 152 was on time, relevant and  
6 complete. The Company provided five files relating to DR-152 A.B.C.D.E in  
7 excel format. Further, in its response, AVA stated as follows:  
8  
9

10

11

*Subsequent to the filing of the general rate case, it was discovered that  
12 certain forecast depreciation rates had not been correctly updated.*

13

14

*These depreciation rates have been appropriately updated in the files  
15 submitted in response to this data request, and the "CAP SUMMARY-  
16 OR – 12.31.15 EOP (w 2016 AMA Growth) – linked" file  
17 (Staff\_DR\_152 Attachment A to this response) reflects these updated  
18 depreciation rates. The calculation of forecast depreciation expense  
19 and the forecast accumulated depreciation (depreciation reserve) are  
20 included.*

21

22

In its data response (DR) No. 152, AVA updated its depreciation calculation

23

24

and forecasting by using the depreciation rates authorized by the Commission.

1                    **ISSUE 2, Depreciation Effect on Revenue Requirement**

2           **Q. Describe the depreciation effect on the revenue requirement of a**  
3           **utility.**

4           A. In the traditional rate base rate-of-return environment, customer rates and  
5           utility costs are components of a utility's revenue requirement. NARUC in its  
6           "Public Utility Depreciation Practices", "Depreciation Expense and Its Effect  
7           on the Utility's Financial Performance – Revenue Requirement" states:

8                    *Depreciation has a profound effect on the revenue requirement of a*  
9                    *utility, and for many utilities, depreciation expense represents a large*  
10                   *percentage of total operating expenses. In addition, deferred income taxes,*  
11                   *rate base, and cost of capital are all affected by the depreciation practices of a*  
12                   *utility.*

13           **Q. Please identify Oregon's relevant statute regarding utility depreciation**  
14           **rates.**

15           A. It is ORS 757.140, which states in relevant part:

16                    *(1) Every public utility shall carry a proper and adequate*  
17                    *depreciation account. The Public Utility Commission shall*  
18                    *ascertain and determine the proper and adequate rates of*  
19                    *depreciation of the several classes of property of each public*  
20                    *utility. The rates shall be such as will provide the amounts*  
21                    *required over and above the expenses of maintenance, to keep*  
22                    *such property in a state of efficiency corresponding to the*  
23                    *progress of the industry. Each public utility shall conform its*  
24                    *depreciation accounts to the rates so ascertained and determined*  
25                    *by the commission. The commission may make changes in such*

1                    *rates of depreciation from time to time as the commission may*  
2                    *find to be necessary.*

3                    **Q. How are depreciation rates used in determining the utility's revenue**  
4                    **requirement?**

5                    A. In a general rate case filing, the depreciation expense is calculated by using  
6                    the Commission's authorized depreciation rates (in this case, those set forth in  
7                    Order 13-168), and in traditional FERC classification of generation,  
8                    transmission, distribution and general plant assets.

9                    **Q. Does this conclude your testimony?**

10                  A. Yes.



CASE: UG 288  
WITNESS: MING PENG

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 401**

**Witness Qualifications Statement**

**October 16, 2015**

**WITNESS QUALIFICATIONS STATEMENT**

NAME: Ming Peng (Ms.)

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist  
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100  
Salem, OR. 97301

EDUCATION: M.S. Applied Economics  
University of Idaho, Moscow

B.S. Statistics  
People's University of China, Beijing

C.R.R.A. Certified Rate of Return Analyst  
Society of Utility and Regulatory Financial Analysts

Depreciation studies - the Society of  
Depreciation Professionals

NARUC Annual Regulatory Studies Program  
Michigan State University, East Lansing

EXPERIENCE: 1/11/1999-Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 16 years since January 1999. My roles include: Expert Witness, Case Manager, Economist, Policy Analyst, Econometrician, and Principal Analyst. I have testified in various formal state hearings. I have performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in public utility industry.

Principal Analyst & Case Manager, Settlement leader/negotiator for Depreciation:

For the depreciation rate determination (fixed cost allocation) in revenue requirement, I have served as a principal analyst and case manager for the determination of Energy Property Depreciation Rates (ORS 757.140) for last eight years. In this position, I investigate, analyze and calculate the Cost and Impact on Customer Rates for Coal-plant "Shutdowns", Hydro-plant Shutdowns, "Old Plant Retirement" and "New Plant Investment".

The New Plant Depreciation Rates determinations listed for the following Cases:

UM 1679 and UE 294

1. PGE Port Westward 2, Gas Plant
2. Tucannon River Wind Farm,
3. Carty, Gas plant,

The Power Plant Shutdown Removal & Depreciation Cost for the following:

1. PGE closes Boardman Coal plant (UM 1679 & UE 215) ,
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246)
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under the ORS 757.734 - Recovery of investment in Klamath River dams in OPUC UE 219.

I calculate and determine the depreciation rates including the analyses on all energy assets under the FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants; the energy source I have worked on including "Steam Production Plant", "Hydraulic Production Plant", "Other Production Plant" including "Natural Gas", "Wind", and "Solar" Plants.

I conduct case investigation and energy asset analysis, make rate adjustments, lead settlement negotiation, and prepare and present testimony on behalf of Commission staff related to each of the six energy companies: (1) PacifiCorp, (2) Portland General Electric, (3) Northwest Natural Gas, (4) Idaho Power, (5) Avista Corp, and (6) Cascade Gas under the commission's regulatory jurisdiction.

I also perform an analysis of "Rate Impact Calculation of Oregon Clean Energy Capital Investment, Comparative Advantage of Oregon Clean Energy – Dollar Impact in rates".

Lead Analyst and Case Manager on Financial Dockets:

Prior to my present position, I was a lead analyst and case manager for nine years. My responsibilities in that position included: financial risk analysis on the application of Derivative Instruments filed by utilities while they conduct Financial Hedging and Capital Raising Activities.

I passed the test and become a "Certified Rate of Return Analyst". I was involved with more than 60 PUC UF financial dockets before the Commission for PacifiCorp, Portland General

Electric, Northwest Natural Gas, Idaho Power, Avista Corp, and Cascade Gas, and water companies.

Public Utility & Policy Analyst:

Energy Merger & Acquisition: I have testified in formal state hearings involving Energy Merger & Acquisition, I conducted Acquisition Premiums & Credit Risk Analysis and testified for the Merger case of "PacifiCorp vs. MidAmerican Energy Company" (a subsidiary of Berkshire Hathaway Energy) in UM 1209. My reviews for Energy Merger & Acquisition have also included "PacifiCorp vs. Scottish Power", "PGE vs. Enron".

I testified in UP-158, PGE Fuel Price Forecasting and Property Sales; I reviewed Electricity Load Forecasting, Weather Normalization for energy companies in IRP and rate case filing; I conducted the Statistical Sampling Design and Procedure Design, and testified on Revenue Issues (UM 1288), Analysis for General Rate Case components, and other regulated utility issues.

My work functions have also included Integrated Resource Planning (IRP) filing review for PacifiCorp, PGE and Northwest Natural Gas Companies. I conducted Energy Utility Auditing for cost of capital component on all energy companies and operational audit on Idaho Power Company.

I have conducted Interest Rate and late payment charge Survey and Analysis for state of Oregon (UM 779), conducted Market Competition and Economic Policy Survey Analysis and Report in Oregon Telecommunications Industry (HB 2577) and the report has been published on OPUC web annually for 15 years.

Mentor in the ICER - International Confederation of Energy Regulators

I was also selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. I taught various subjects on Incentive Regulation, comparing the Rate and Economic Impacts of "Cost-Of-Service" regulation in US and "Price-Cap" regulation in Europe, Cost of Capital, Energy Demand and Price Forecasting Models, Least Cost Planning, and policy issues affecting Utility Rates.

CASE: UG 288  
WITNESS: MING PENG

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 402**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	06/01/2015
CASE NO.:	UG 288	WITNESS:	Karen Schuh
REQUESTER:	PUC Staff - Peng	RESPONDER:	David Machado
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 152	TELEPHONE:	(509) 495-4554
		EMAIL:	david.machado@avistacorp.com

**REQUEST:**

152. Please provide the calculation in Excel format with the cell reference links and formulae for exhibits AVISTA/502, Smith, and for AVISTA/600, Schuh. The data set could include, but not limited to, the following:

- 1) CAP SUMMARY- OR - 12.31.15 EOP (w 2016 AMA Growth) – linked
- 2) EOP and Full Year Depreciation Adjustments – linked
- 3) Filed - 2015 OR Gas Rev Req Model
- 4) Transportation Depreciation Study Support
- 5) UM 1626 Settled Exhibit 102 Attachment A-linked

152.1 Please provide the cell reference links and formulae, in Excel format, between the “book rate” Avista used in this filing and the “depreciation rates” the Commission approved in Order 13-168. For the rates Avista used that are not in the Order, such as Intangible Assets, please explain how these rates are determined.

152.2 Please provide the calculation of forecasted depreciation expense and reserve for each year 2015 and 2016 with the cell reference links and formulae.

152.3 Please add cell reference links and formulae on Total Adjustments to Depreciation & Amortization (+3,183) and Accumulated Depreciation & Amortization (-8,322) in “Avista/501, Smith/1 of 11.”

**RESPONSE:**

**152.** Items 1, 2, 4, and 5 listed above are included as Staff\_DR\_152 Attachments A, B, D, and E, respectively. Item 3 listed above, “Filed – 2015 OR Gas Rev Req Model,” was previously provided with our original filing in this general rate case – we have included this file again, in response to this data request, as Staff\_DR\_152 Attachment C.

**152.1.** The cell reference links and formulae, in Excel format, requested in the request are included in the files entitled “EOP and Full Year Depreciation Adjustments – linked” and “UM 1626 Settled Exhibit 102 Attachment A-linked,” which we have included as attachments Staff\_DR\_152 – Attachment B and Staff\_DR\_152 – Attachment D in our response to DR 152.

For depreciation rates that were not included in Order 13-168, Docket UM-1626, the depreciation rates used in the current filing are equal to the depreciation rates identified in the

depreciation study from which the rates included in the aforementioned Order 13-168 were sourced. For depreciation rates associated with new fixed asset accounts that were not present as of the most recent depreciation study, the depreciation rates used in the current filing represent the effective depreciation rate in the base year (average-of-monthly-averages for the twelve months ended December 31, 2014).

Subsequent to the filing of the general rate case, it was discovered that certain forecast depreciation rates had not been correctly updated. These depreciation rates have been appropriately updated in the files submitted in response to this data request, and the “CAP SUMMARY-OR – 12.31.15 EOP (w 2016 AMA Growth) – linked” file (Staff\_DR\_152 Attachment A to this response) reflects these updated depreciation rates. Following the aforementioned updates, the updated balances for Total Adjustments to Depreciation & Amortization and Accumulated Depreciation & Amortization are \$2,900 and (\$8,147), respectively. The impact to revenue requirement is a decrease of \$277,000.

**152.2.** The calculation of forecast depreciation expense and the forecast accumulated depreciation (depreciation reserve) are included within the file entitled “CAP SUMMARY – OR – 12.31.15 EOP (w 2016 AMA Growth) – linked,” which is included as attachment Staff\_DR\_152 – Attachment A in our response to this data request.

**152.3.** The cell references and formulae for the Total Adjustments to Depreciation & Amortization (+3,183) and Accumulated Depreciation & Amortization (-8,322) in “Avista/501, Smith/1 of 11 have previously been included within the originally filed native format Excel file entitled “*Filed – 2015 OR Gas Rev Req Model.*”

For further clarification, within this native format workpaper, the \$3,183 Total Adjustment to Depreciation & Amortization is the sum of cells AT59, AT93, AT143, AT148, and AT160 on the tab entitled “Exh 502-ADJ Detail Input.” Likewise, the (\$8,322) Total Adjustment to Accumulated Depreciation & Amortization is equal to cell AT244 on the “Exh 502-ADJ Detail Input” tab.

Each of the aforementioned cells (AT59, AT93, AT143, AT148, AT160, and AT244) reflect the cross-sum of all adjustments. However, adjustments to depreciation & amortization expense and accumulated depreciation & amortization only occurred within adjustments 2.05, 2.06, and 2.07, which are included in columns Y, Z, and AA in the “Exh 502-ADJ Detail Input” tab. The adjustment balances included in these three adjustments come from the respective adjustments calculated and included within the “CAP SUMMARY-OR – 12.31.15 EOP (w 2016 AMA Growth)” file, which was included in Ms. Schuh’s native format workpapers.



CASE: UG 288  
WITNESS: LINNEA WITTEKIND

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 500**

**D&O Insurance, Various A&G**

**Opening Testimony**

**October 16, 2015**

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Linnea Wittekind. My business address is 201 High Street, SE  
3 Suite 100, Salem, Oregon 97301-3612.

4 **Q. Please describe your educational background and work experience.**

5 A. My Witness Qualification Statement is found in Exhibit Staff/101.

6 **Q. What is the purpose of your testimony?**

7 A. The purpose of my testimony is to recommend two adjustments<sup>1</sup>:

- 8 1. Directors & Officers (D&O) Insurance \$ [REDACTED]
- 9 2. Various A&G \$30,323

10  
11 **Q. Did you prepare an exhibit for this docket?**

12 A. Yes. I in addition to my witness qualification statement, I prepared four exhibits  
13 they are as follows:

- 14 1. Exhibit Staff/502, consisting of 2 pages – Staff Calculations
- 15 2. Exhibit Staff/503, consisting of 1 page – Data Response No. 229
- 16 3. Exhibit Staff/504 consisting of 2 pages – An excerpt from OPUC Order  
17 No. 09-020
- 18 4. Exhibit Staff/505 consisting of 2 pages – An excerpt from OPUC Order  
19 No. 09-020

20 **Q. How is your testimony organized?**

21 A. My testimony is organized as follows:

22 Issue 1, D&O Insurance ..... 3

23 Issue 2, Various A&G..... 5

24

<sup>1</sup> See Exhibit Staff/502 pages 1 & 2 for staff's calculation of the adjustments.

1 **Q. How many data requests did you review as part of your analysis of D&O**  
2 **Insurance and Various A&G issues?**

3 A. I reviewed 18 multi-part standard data requests and four follow up data  
4 requests.

5

**ISSUE 1, D&O INSURANCE****Q. Briefly describe your analysis related to D&O Insurance.**

A. Avista included in its filed case \$ [REDACTED] in total company D&O Insurance expense, which is \$ [REDACTED] on an Oregon-allocated basis. This amount represents the first layer (premium layer) as well as first, second, third, fourth, fifth excess layers in addition to an A-side layer of D&O Insurance<sup>2</sup>. My analysis is that 50 percent of the total cost of all layers of D&O Insurance should be removed from A&G, which is consistent with Commission past practice. Based on my analysis, removing 50 percent of D&O Insurance would result in an Oregon-allocated adjustment of \$ [REDACTED].

**Q. What is your reason for removing 50 percent of D&O Insurance?**

A. In Docket UE 197, Staff proposed that customers and ratepayers share the cost of excess layers of D&O liability insurance. The Commission agreed the cost of D&O liability insurance should be split between ratepayers and shareholders. In fact, the Commission ordered that the Company absorb a greater amount of the cost of D&O insurance than proposed by Staff:

We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost.<sup>3</sup>

Consistent with this ruling, Staff proposed an adjustment in Docket UE 283 removing 50 percent of the entire cost of D&O Insurance. Staff/500,

<sup>2</sup> See Avista's confidential response to Staff Data Request No. 229 included as Exhibit Staff/503.

<sup>3</sup> OPUC Order No. 09-020 at 19-20. An excerpt of the relevant rulings from that Order is included in Exhibit Staff/504.

1 Wittekind/3 Docket UE 283). Staff's adjustment was settled in the second  
2 partial stipulation in that docket, which was adopted by the Commission in  
3 Order No. 14-422.

1

**ISSUE 2, VARIOUS A&G**

2

**Q. Briefly describe your analysis of Various A&G.**

3

A. Avista included in its UG 288 filing \$60,645 in expense for meals, entertainment and employee recognition identified in FERC Accounts 500 – 935. My analysis of these accounts leads me to recommend removal of 50 percent of the meals, entertainment and employee recognition expenses as consistent with Commission past practice.

4

5

**Q. What is your reason for removing 50 percent of these items from Various A&G?**

6

7

A. Because the costs for meals, entertainment and employee recognition are discretionary and not required to provide safe and adequate service to customers, Staff's practice is to recommend a 50 / 50 sharing of expenses between customers and shareholders.

8

9

10

11

12

13

14

In Commission Order No. 09–020 (UE 197), the Commission adopted Staff's recommendation concerning meals and entertainment expenses and ordered the 50 percent sharing between customers and shareholders. The Commission stated on page 21:<sup>4</sup>

15

16

17

18

We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders.

19

20

21

22

**Q. Does this conclude your testimony?**

23

A. Yes.

---

<sup>4</sup> Docket No. UE 197, OPUC Order No. 09-020 at 21. An excerpt of the relevant rulings from that Order is included in Exhibit Staff/505.

CASE: UG 288  
WITNESS: LINNEA WITTEKIND

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 501**

**Witness Qualifications Statement**

**October 16, 2015**



### **WITNESS QUALIFICATIONS STATEMENT**

**NAME:** Linnea Wittekind

**EMPLOYER:** Public Utility Commission of Oregon

**TITLE:** Senior Financial Analyst  
Energy Rates, Finance & Audit Division

**ADDRESS:** 201 High Street SE., Suite 100  
Salem, OR. 97301

**EDUCATION:** B.S. WESTERN OREGON UNIVERSITY  
MAJOR: BUSINESS WITH FOCUS IN ACCOUNTING  
MINOR: ENTREPRENEURSHIP

**EXPERIENCE:** Since November 2009, I have been employed by the Public Utility Commission of Oregon. Responsibilities include research, analysis and recommendations on a wide range of cost, revenue and policy issues for electric and natural gas utilities. I have provided testimony in UE 215, UE 233, UG 221, UG 284, UE 246, UE 294 and UM 1741 and have filed comments in LC 50 as well as various UP and UI dockets. I have also reviewed and analyzed a number of energy efficiency tariff filings. I've written several public meeting memos summarizing my analysis of the energy efficiency tariff filings. I have performed operational audits of NW Natural, Cascade Natural Gas, and Portland General Electric as well as assisted in an operational audit PacifiCorp. Recently I've completed an audit regarding gas accounting best practices and labor benchmarking.

Through the Public Utility Commission of Oregon, I am a member of the NARUC Staff Subcommittee on Accounting & Finance.

I've attended a number of trainings which include, The Basics through the Center for Public Utilities, New Mexico State University, Best Practices in an Era of Renewables and Reduced Emissions through EUCI as well as Benchmarking the Performance of Electric and Gas Distribution Utilities also through EUCI. I've also attended the Advanced Regulatory Studies Program through the Institute of Public Utilities at Michigan State University.

From July 2005 to November 2009, I worked as a Tax Auditor for the Oregon Department of Revenue. In enforcement of tax laws, rules and regulations, I performed income tax audits of individual tax payers and small businesses. Additionally I prepared cost analysis of tax credits and measures. I also represented the department before the Oregon Tax Court for tax deficiency appeals.

CASE: UG 288  
WITNESS: LINNEA WITTEKIND

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 502**

**Confidential Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**STAFF EXHIBIT 502**

**IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE**

**ORDER NO. 15-141 IN UG 288**

**THE EXHIBIT IS AN EXCEL FILE**  
**AND IS INCLUDED ON THE**  
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CASE: UG 288  
WITNESS: LINNEA WITTEKIND

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 503**

**Confidential Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**STAFF EXHIBIT 503**

**IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE**

**ORDER NO. 15-141 IN UG 288**

CASE: UG 288  
WITNESS: LINNEA WITTEKIND

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 504**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

ORDER NO. 09-020

Staff supports Occupational Health Benefits, but disagrees with PGE's proposed increase in funding for the program. Although participation has increased 46 percent between 2006 and 2008, Staff notes that actual program costs have only increased about 1.7 percent. Staff proposes to allow \$224,434 in funding for Occupational Health Benefits for 2009, which is an increase of approximately 19 percent over two years.<sup>67</sup> With respect to the IAM program, designed to reduce employee absences, Staff asserts that PGE has failed to link the program to cost reductions benefitting customers, and therefore costs associated with the program should be disallowed.<sup>68</sup> Staff supports Occupational Fitness, but believes that PGE's requested level of funding is unsupported by the record, which shows a recent decrease in costs.<sup>69</sup> Staff also proposes to remove the Recreation Program from the revenue requirement, as these activities are discretionary, take place outside the workplace, and are not required to provide safe and adequate service to customers.<sup>70</sup> Staff supports the Health Club Partial Reimbursement program, but questions whether increasing classes and activities will almost double program costs as indicated by PGE. Instead, Staff supports allowing a 20 percent increase resulting from increased participation for the test year.<sup>71</sup> Staff proposes to adjust the proposed expense for Service Awards in a manner similar to the adjustment for merit-based bonuses—50 percent to customers and 50 percent to shareholders. Finally, Staff recommends disallowance of expenses for Retiree Association and Retiree Luncheon because they are not required to provide safe and adequate service to customers, and to disallow all other unidentified, and therefore unjustified, expenses.<sup>72</sup>

In response, PGE claims that these benefits represent a comparatively small amount of overall benefits yet are a critical part of an overall package designed to attract and retain qualified employees.

*Resolution*

We concur with Staff's analysis and adopt the calculations contained in Staff/900, Ball/10, to adjust PGE's 2009 revenue requirement through the disallowance of \$319,000.

**g. Insurance**

Staff proposes several adjustments to PGE's requested test-period, insurance-related expense. First, Staff cites falling premiums in the current soft market and recommends no escalation for property and liability premiums.<sup>73</sup> Second, Staff proposes to eliminate 50 percent of the excess Directors' and Officers' (D&O) insurance

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<sup>67</sup> Staff/900, Ball/5-6.

<sup>68</sup> *Id.* at 6-7.

<sup>69</sup> *Id.* at 7.

<sup>70</sup> *Id.* at 8.

<sup>71</sup> *Id.*

<sup>72</sup> *Id.* at 9.

<sup>73</sup> Staff/300, Ball-Dougherty/9; Staff/901, Ball/3.



ORDER NO. 09-020

as a shareholder cost. D&O insurance protects PGE senior management in the event that they are sued, whether by customers, stockholders, or others in conjunction with the performance of their Company duties. According to Staff, “[c]ustomers, who have no say in electing or appointing PGE’s Directors or Officers, should not be held financially responsible in providing 100 percent of insurance coverage against business decisions or improprieties by management which results in lawsuits.”<sup>74</sup> Third, Staff proposes to apply a utility allocation percentage to the overall insurance premiums to allocate the cost between the utility and non-utility aspects of PGE’s operations.<sup>75</sup> Finally, Staff proposes a \$1.75 million adjustment to PGE’s Uninsured Losses based on escalating the five-year historical average by inflation.<sup>76</sup>

PGE contends that D&O liability insurance is a normal cost of doing business, and the entire cost should be included in its revenue requirement. PGE also includes updates to its policies in rebuttal testimony and claims Staff did not properly consider certain policies. PGE further noted that flat insurance rates can still result in increased premiums when property values increase. The Company proposed that the utility allocation factor adjustment should be applied only to a limited number of specific categories.<sup>77</sup>

*Resolution*

We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost. We also adopt Staff’s proposal to hold premiums steady for 2009 property and liability insurance and apply the utility allocation percentage to overall policy premiums. In addition, we adopt Staff’s adjustment to Uninsured Losses. PGE’s 2009 revenue requirement is therefore reduced by \$3.717 million.

**h. Miscellaneous Expenses**

These expenses consist primarily of costs for catering, gifts, promotional items, and civic activities, including lunch meetings and gifts to employees for overtime work or as retirement gifts, sympathy gifts to employees’ families, holiday activities and “team-building days for employees.”

Staff proposes that 50 percent of the meal and entertainment expenses, office refreshments and catering, gifts of flowers, and awards be disallowed. In Staff’s view, these expenses should be shared equally between ratepayers and shareholders. This approach somewhat mirrors the policy associated with bonuses and the handling of meal and entertainment expenses for income tax purposes.<sup>78</sup>

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<sup>74</sup> See Staff/900, Ball/11.

<sup>75</sup> *Id.* at 15.

<sup>76</sup> Staff/300, Ball-Dougherty/11; Staff/900, Ball/14; Staff/901, Ball/4.

<sup>77</sup> PGE Opening Brief at 33-36 and testimony cited therein.

<sup>78</sup> Staff Opening Brief, citing Staff/300, Ball-Dougherty/13-15.

CASE: UG 288  
WITNESS: LINNEA WITTEKIND

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 505**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

as a shareholder cost. D&O insurance protects PGE senior management in the event that they are sued, whether by customers, stockholders, or others in conjunction with the performance of their Company duties. According to Staff, “[c]ustomers, who have no say in electing or appointing PGE’s Directors or Officers, should not be held financially responsible in providing 100 percent of insurance coverage against business decisions or improprieties by management which results in lawsuits.”<sup>74</sup> Third, Staff proposes to apply a utility allocation percentage to the overall insurance premiums to allocate the cost between the utility and non-utility aspects of PGE’s operations.<sup>75</sup> Finally, Staff proposes a \$1.75 million adjustment to PGE’s Uninsured Losses based on escalating the five-year historical average by inflation.<sup>76</sup>

PGE contends that D&O liability insurance is a normal cost of doing business, and the entire cost should be included in its revenue requirement. PGE also includes updates to its policies in rebuttal testimony and claims Staff did not properly consider certain policies. PGE further noted that flat insurance rates can still result in increased premiums when property values increase. The Company proposed that the utility allocation factor adjustment should be applied only to a limited number of specific categories.<sup>77</sup>

#### *Resolution*

We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost. We also adopt Staff’s proposal to hold premiums steady for 2009 property and liability insurance and apply the utility allocation percentage to overall policy premiums. In addition, we adopt Staff’s adjustment to Uninsured Losses. PGE’s 2009 revenue requirement is therefore reduced by \$3.717 million.

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<sup>74</sup> See Staff/900, Ball/11.

<sup>75</sup> *Id.* at 15.

<sup>76</sup> Staff/300, Ball-Dougherty/11; Staff/900, Ball/14; Staff/901, Ball/4.

<sup>77</sup> PGE Opening Brief at 33-36 and testimony cited therein.

<sup>78</sup> Staff Opening Brief, citing Staff/300, Ball-Dougherty/13-15.

ORDER NO. 09-020

Staff also proposes removing 100 percent of civic activities recorded in Administrative & General (A&G) accounts, noting “the Commission has not previously allowed regulated utilities to recover contributions to charities, community affairs, and economic development organizations through rates charged for regulated services. . . . In addition, Commission policy does not require customers to support causes in which they do not believe.”<sup>79</sup>

PGE asserts that these discretionary costs are appropriately included in rates, because these miscellaneous expenses create a business culture that allows the utility to attract and retain qualified workers.<sup>80</sup>

*Resolution*

We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders. We also adopt Staff’s recommendation with respect to contributions to charities, community affairs, and economic development organizations. PGE provides no rationale to change our existing policies, and we conclude that all contributions to charities, community affairs, and economic development organizations should be disallowed. PGE’s 2009 revenue requirement is reduced by \$710,000 to reflect the disallowance of these expenses.

We also acknowledge PGE’s removal of Directors’ Compensation and Officer Vehicles from the proposed 2009 test-year budget. The total revenue-requirement reduction for miscellaneous expenses is \$1.18 million.

**i. Senate Bill 408 Ratio Adjustment**

Senate Bill 408 (SB 408) requires the Commission to establish certain ratios in general ratemaking proceedings, which will be used to determine the amounts of “taxes collected” from customers for the purpose of the SB 408 true-up of “taxes paid” to “taxes collected.” PGE believes that, in setting the tax rate and margin ratios here for SB 408 purposes, the Commission should consider the impact of costs that have been disallowed. PGE explains that, “[t]o do otherwise would effectively allow customers to receive tax benefits from utility costs for which customers are not responsible.”<sup>81</sup>

Staff opposes PGE’s proposal as an attempt to insulate its shareholders from sharing the tax benefit of disallowed expenses with ratepayers when trueing up the amount of taxes collected. Staff believes PGE’s request is inconsistent with the terms of SB 408, as well as Commission rules implementing the bill.<sup>82</sup> According to Staff, the Commission indirectly addressed this issue when it declined PGE’s request for a deferral

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<sup>79</sup> *Id.*, citing Staff/300, Ball-Dougherty/15.

<sup>80</sup> PGE Opening Brief at 37, citing PGE/2700, Piro-Tooman/12.

<sup>81</sup> PGE/2300, Tooman-Tinker/24.

<sup>82</sup> See ORS 757.268 and OAR 860-022-0041.

CASE: UG 288  
WITNESS: MITCHELL MOORE

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 600**

**Plant Capital Additions**

**Opening Testimony**

**October 16, 2015**

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Mitchell Moore. My business address is 201 High Street, SE Suite  
3 100, Salem, Oregon 97301-3612.

4 **Q. Please describe your educational background and work experience.**

5 A. My Witness Qualification Statement is found in Exhibit Staff/601.

6 **Q. What recommendations, if any, do you propose in your testimony?**

7 A. I am responsible for reviewing the capital additions that Avista Corporation  
8 (Avista or Company) proposes in its filing. For reasons I will explain, I  
9 recommend a reduction of approximately \$30 million from the Company's  
10 capital forecast. I will show that Avista's request in this proceeding is  
11 extraordinary and far exceeds its historical rate base growth rate. Avista's level  
12 of capital additions is not supported by the Company's relatively flat growth in  
13 terms of number of customers, as well as an overall decline in gas sales. In  
14 addition, absent compelling evidence showing a need for such extraordinary  
15 growth, the Company should increase its rate base at a measured rate to meet  
16 service and safety requirements while maintaining cost control.

17 **Q. Did you prepare exhibits for this docket?**

18 A. Yes. I prepared the following exhibits:

19 Exhibit Staff/602 Responses to DR #'s 188-189

20 Exhibit Staff/603 Response to DR #190 – HVAC upgrade

21 Exhibit Staff/604 Avista investor update; 2014 Integrated Resource  
22 Plan (IRP) material.

23 Confidential Staff/605 Avista pipeline capacity presentation

1 Exhibit Staff/606 Excel file, Moore workpapers

2 **Q. Please summarize Avista's filing regarding capital additions.**

3 A. Avista proposes to increase its net rate base in Oregon 20.3 percent by adding  
4 approximately \$45.6 million to its Oregon plant base in 2015, and an additional  
5 \$2 million for customer hookups for the first quarter of 2016.<sup>1</sup> Of that amount,  
6 \$16 million is proposed for general plant projects, which include items and  
7 activities such as technology upgrades, website redevelopment, transportation  
8 and tool replacements, as well as the continuation of the Company's long-term  
9 campus restructuring.

10 The largest project in the General Plant additions is the implementation of  
11 Project Compass, the Company's new Customer Information and Asset  
12 system. However, I do not address Project Compass in my testimony, and it is  
13 not part of my adjustment recommendations, except to the extent that the  
14 amount recommended to be allowed for total capital additions in this  
15 proceeding would include Project Compass. In other words, the Company's  
16 increasing its rate base at a measured level would include the expenditures  
17 associated with Project Compass. This project is addressed in Ms. Judy  
18 Johnson's testimony in Staff/300.

19 For Oregon gas distribution projects, Avista proposes adding \$30.2 million in  
20 capital additions.<sup>2</sup> These projects include various programmatic (ongoing)  
21 growth-related work, infrastructure updating, Aldyl-A Pipe replacement, street  
22 and highway replacements, as well as some large discrete projects.

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<sup>1</sup> See Avista/600, Schuh/9-10

<sup>2</sup> Ibid, p.10



1

2

**Q. How did Staff perform its analysis and arrive at its recommended**

3

**adjustments?**

4

A. Staff began with the principle that the Company should make sufficient capital investment to allow it to provide safe and adequate service while being mindful of controlling costs. This principle conflicts with a goal of accelerating rate base growth with the objective of increasing earnings given weak customer growth and reduced demand.

8

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Under normal operating conditions (e.g. absent a natural disaster or other *force majeure*), growth in rate base should happen at a measured pace so that rate-payers are not burdened with sharp rate increases that far outpace the rate of inflation in order to reward its shareholders. It is up to the Company to identify and prioritize appropriate rate base additions to maintain a healthy plant in order to provide safe, reliable service to its customers at just and reasonable rates. Stated differently, it is the Company's prerogative as to how it chooses to manage its investments to both control costs, provide safe and adequate service, and attract capital.

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**Q. Please explain how the capital additions proposed in this proceeding**

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**compare with Avista's plant growth in prior years.**

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A. The capital additions in this filing represent a dramatic increase over the additions made relative to the historical average in the years from 2002-2013. The Company is proposing to grow its net plant base by a significantly higher percentage than the historical average. For example, Avista's current filing

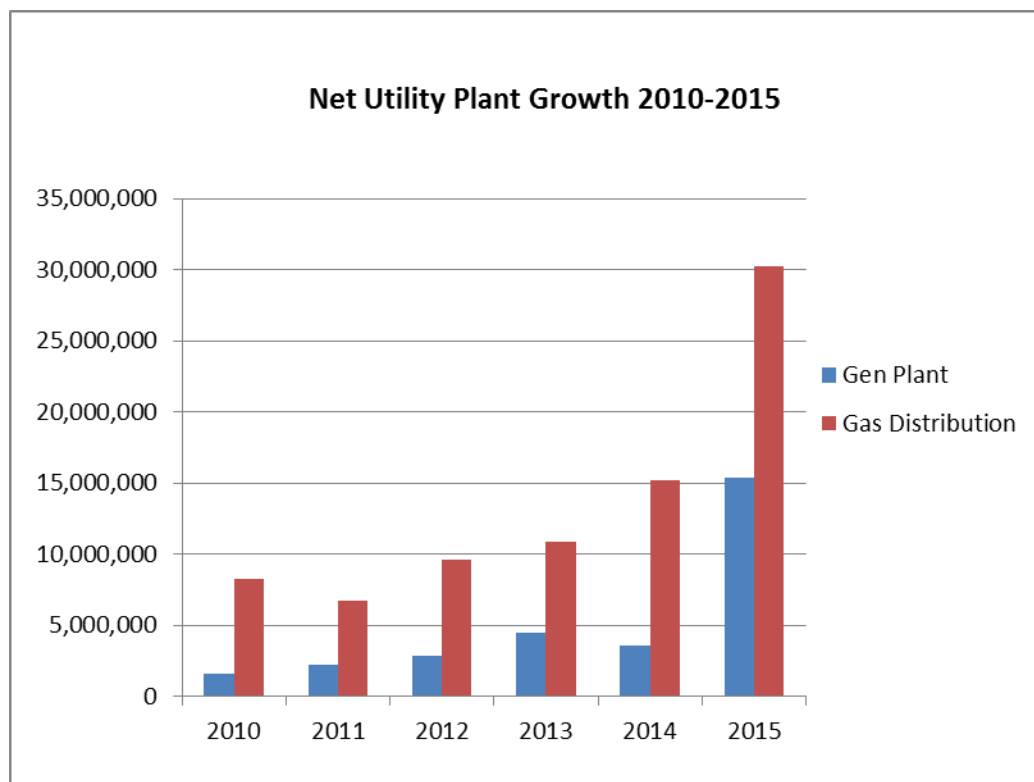
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23

1 represents a 22.6 percent increase over last year's net plant base, and in 2014  
 2 the Company added 11 percent to its plant base. The historical average of net  
 3 plant growth from 2002 through 2013 is 7.75%. In this filing, the Company  
 4 proposes a three-fold increase of its net plant base over the 7.75% historical  
 5 average. Figure 1 below illustrates the relative increase in the current and prior  
 6 year:

7 Figure 1



8  
 9 **Q. What does Staff consider a reasonable rate of growth in rate base?**

10 A. For the purposes of this filing, Staff considered two things: a) the Company's  
 11 historical growth rate from 2002-2013; and b) Avista shareholder presentations

<sup>3</sup> Exhibit Staff/602, Moore/1-2; Data obtained from Company DR responses 188 Attachment C and 189 Attachment C

1 that highlight a 5-6 percent annual growth in rate base as an attractive  
2 investment proposition.<sup>4</sup>

3 From 2002-2013 the average growth in net plant base was 7.75 percent. The  
4 growth over that time period ranged from a high of about 18.9 percent in 2008  
5 to a low of 1.8 percent in 2004.<sup>5</sup> The historical average of 7.75 percent is high  
6 compared to the 5-6 percent system-wide annual growth rate that the Company  
7 asserts in its presentations represents an attractive investment. If 2014 is  
8 added to that average, it rises to 8 percent. This suggests that historically  
9 Oregon rate payers have, on average, borne a higher share of rate base growth  
10 than customers in other jurisdictions. This higher growth rate may be  
11 reasonable if there has been more customer growth in Oregon, or other unique  
12 circumstances in Oregon that require more capital investment than in other  
13 states. For the purposes of this proceeding, it is entirely possible that Oregon's  
14 average net rate base growth rate of 7.75 percent is justifiable, even though it is  
15 higher than the Company's system-wide average growth rate. However, the  
16 growth in net plant base of 22.6 percent represented by this filing is  
17 extraordinary, and is not justified by the evidence presented in this case.

18 **Q. What does Staff recommend for a growth rate in this case?**

19 A. For the purposes of this proceeding, Staff recommends 7.75 percent rate base  
20 addition for 2015. The Company's Project Compass, which came online in  
21 February of this year, represents an atypically large and discrete investment of

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<sup>4</sup> Exhibit Staff/604, Moore/1-4: Avista Corporation Investor Update, June 2015

<sup>5</sup> Exhibit Staff/606, Excel tab: "ROO 2001-2014": data from Avista's annual Results of Operations Report 2002-2013.

1       \$106 million (\$8.3 million Oregon allocation). The implementation of this one-  
2       time project may justify a growth in rate base for this year that, even though  
3       consistent with Oregon's historical average, is higher than the standard 5 to 6  
4       percent system-wide growth rate.

5       **Q. Please discuss the proposed capital additions relative to the Company's**  
6       **growth in Oregon.**

7       A. The Company's capital additions in recent years, and particularly that proposed  
8       in this year's filing, is growing dramatically while customer demand is relatively  
9       flat, and total gas sales have declined. As a consequence, Avista's customer  
10      rates are approximately 37% higher than are Cascade Natural Gas's rates,  
11      which is a similarly-situated Oregon gas utility.<sup>6</sup> Between 2007 and 2014,  
12      Avista's net plant base has doubled from \$106 million to \$211 million.<sup>7</sup> In  
13      contrast, year-end residential customers over that same period have only  
14      increased three percent, commercial customers have increased 2.5 percent,  
15      and industrial customers have increased 11 percent.<sup>8</sup> Moreover, total therms  
16      sold to all classes of customers has decreased 7.7 percent from 2007-2014.<sup>9</sup>  
17      Figures 2 and 3 on the following page illustrate the relationship between  
18      Avista's capital plant additions and its customer and sales growth:

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<sup>6</sup> Exhibit Staff/606, Moore/workpapers; tab "Average Bill"; calculation derived from average December sales to residential and commercial customers.

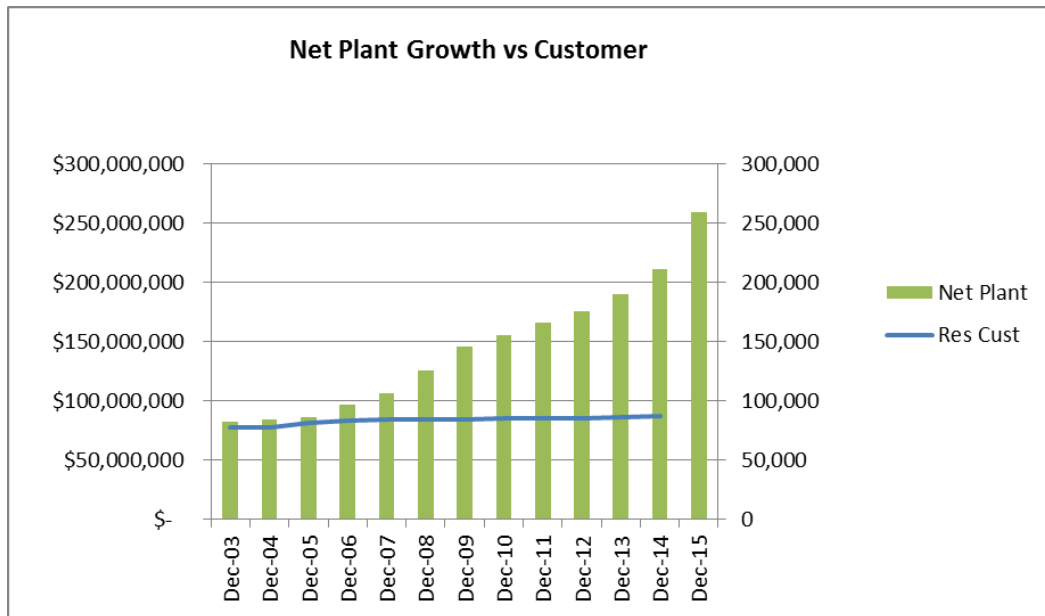
<sup>7</sup> Exhibit Staff/606, Moore/workpapers; tab Avista Results of Operations, 2007 and 2014.

<sup>8</sup> Exhibit Staff/606, Moore/workpapers; tab Staff DR# 193 Att A, SAS forecast data; calculation derived from customer count for month of December each year.

<sup>9</sup> Ibid. calculation derived from therms sold in December each year.

1

Figure 2



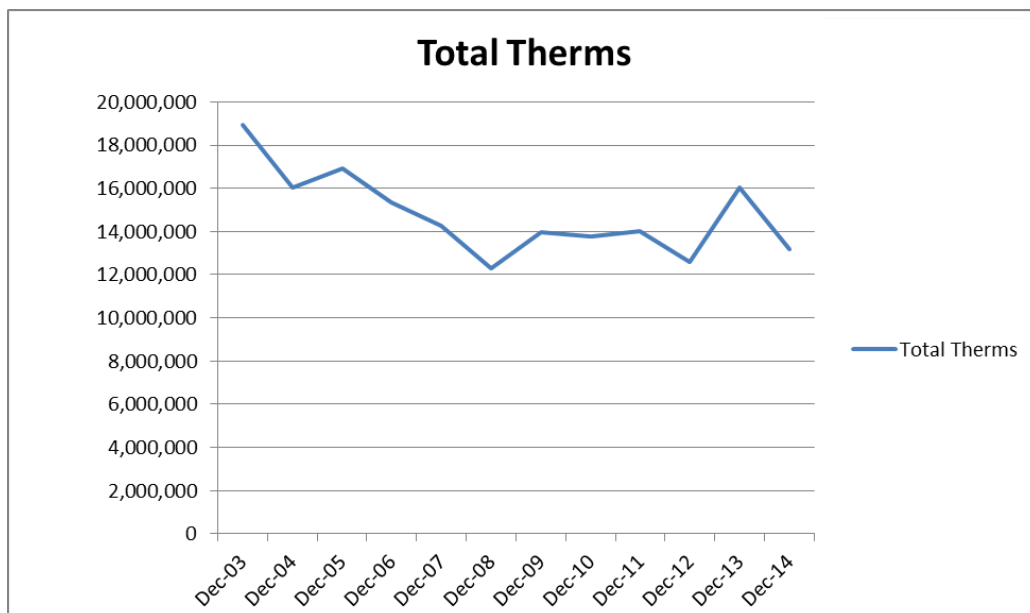
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Figure 3



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1 **Q. Does the Company have a financial incentive to increase its rate base?**

2 A. It certainly appears so. In reports to investors, the Company highlights its utility  
3 infrastructure investment and increasing rate base as a positive aspect of the  
4 Company's overall financial condition driving earnings and dividend growth.<sup>10</sup> In  
5 its Direct Testimony, the Company states that it expects future revenue growth  
6 to be "relatively flat" as result of "weak customer growth and flat use-per-  
7 customer."<sup>11</sup> Therefore, one clear and remaining avenue to achieve earnings  
8 and dividend growth would be increasing rate base.

9 **Q. Is Avista's investment in Oregon growing faster than the Company's**  
10 **system-wide growth?**

11 A. Yes. In its most recent update to investors in June 2015, the Company  
12 presents a five to six percent rate base growth through utility capital  
13 investments. The Company's highlighting a five to six percent rate base growth  
14 in its presentations to investors implies that this level of growth is sufficient to  
15 attract investors. However, as noted above, the growth in net plant in Oregon  
16 from 2002-2013 has been nearly 7.75 percent. In this context, the 20.2 percent  
17 net rate base growth in this filing and the 2014 net increase of 11.2 percent is  
18 truly extraordinary. In addition, it suggests that Oregon rate payers are being  
19 asked to shoulder an outsized share of the Company's system-wide rate-base  
20 growth.

21 **Q. How did the Company develop its projection of rate base in this**  
22 **proceeding?**

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<sup>10</sup> Exhibit Staff/604, Moore/1-4: Avista Corporation Investor Update, June 2015

<sup>11</sup> Avista/100, Morris/7

1 A. The Company developed its projection of rate base in this proceeding based on  
2 an end-of-period December 31, 2014 calculation.<sup>12</sup> The rate base amount was  
3 forecasted based on actual plant in service on December 31, 2014, adjusted for  
4 capital additions forecast over calendar year 2015. The Company then adds  
5 forecast adjusted monthly average costs for new customer hookups through  
6 2016.

7 **Q. Please describe the 2015 capital additions proposed by the Company.**

8 A. The Company provided a list of 40 capital projects that it has forecast to be  
9 placed in service in calendar year 2015.<sup>13</sup> The list consists of both discrete  
10 capital projects, as well as blanket capital projects. Blanket capital projects are  
11 non-discrete, or routine, capital expenditures, such as technology and  
12 communications upgrades, replacement of aging infrastructure, vehicle and tool  
13 maintenance. Collectively these capital additions amount to \$45.6 million on an  
14 Oregon-allocated basis. (\$8.3 million of this amount is attributable to Project  
15 Compass, as discussed above.) System-wide, the capital additions total \$245.3  
16 million.

17 **Q. What documentation does the Company provide surrounding these**  
18 **capital projects?**

19 A. For most projects the Company included with its direct testimony a “Capital  
20 Program Business Case” form containing a high-level description, as well as  
21 approved budget amounts for the project.<sup>14</sup> Attached as Exhibit Staff/605,

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<sup>12</sup> Avista/600, Schuh/3-4

<sup>13</sup> Avista/600, Schuh/9-10

<sup>14</sup> Schuh Workpapers ET-1, pgs 1-73



1 Moore/9 is a sample of Capital Program Business Case forms for the projects  
2 Staff has reviewed in this proceeding. As can be noted, most of the forms  
3 contain little detail surrounding the specific project activities to be undertaken.  
4 Other than high-level statements that the project will be beneficial, the  
5 Company's forms do not contain project timelines or a calculation of expected  
6 customer benefit. The Company provided additional information for projects  
7 above \$500,000, in response to follow-up to Staff Data Request Nos. 190-192  
8 and 231-238.

9 **Q. In Staff's view, are capital program business case forms adequate**  
10 **documentation for inclusion of the underlying associated investment in**  
11 **the Company's revenue requirement?**

12 A. Generally, no. The Capital Program Business Case forms do not contain  
13 adequate information to determine whether a particular project is prudent and  
14 beneficial to rate-payers. The forms contain no calculations that would  
15 demonstrate that the projects will result in concrete economic benefits to  
16 ratepayers. This lack of detail indicates that the Company may not be  
17 performing a sufficient evaluation of these factors when budgeting new capital  
18 projects. In addition, the budget amounts approved in the Capital Program  
19 Business Case forms are often significantly lower than the capital amounts  
20 proposed in the Company's filing.

21 **Q. Please provide examples of what you found to be an insufficient form.**

22 A. A prime example is the form for project #5005 Technology Refresh to Sustain  
23 Business Process. The capital cost associated with this project in 2015 is

1 estimated at \$13.9 million in the business case form; the approved amount,  
2 which presumably tacks on O&M and other costs, is \$16.1 million.<sup>15</sup> But in the  
3 Company's filing, approximately \$21.4 million system-wide (\$1.9 million  
4 Oregon-allocated) is included for the project.<sup>16</sup>

5 Another example is the COF HVAC Improvement project #7101. The total  
6 project request for this multi-year project is for \$39.8 million. The budget  
7 timeline in the form spreads this total across 2012-2014. But then an additional  
8 \$5.7 million is approved for 2015 with no explanation. And yet in the filing, the  
9 Company doubles this amount and includes nearly \$11 million (\$955,000  
10 Oregon-allocated).<sup>17</sup> I discuss this project further below.

11 **Q. Was the additional supporting information supplied in response to Staff**  
12 **data requests sufficient to justify the capital expenditures?**

13 A. Generally, no. In some cases the information supplied might make the case for  
14 a reduced capital budget. An example is project #7101, the COF HVAC  
15 Improvement discussed above. Avista wants to add \$11 million system-wide  
16 (\$955,000 Oregon allocated) in 2015 for this multi-year HVAC system  
17 replacement project that appears to have begun in 1998. The plan was  
18 originally developed at an estimated cost of \$7.5 million. Attached is Exhibit  
19 Staff/603, Moore/1-11, which contains part of the Company's response to DR  
20 #190, in which Staff requested all project justification materials to demonstrate  
21 why the project is necessary for Oregon operations at this time. The response

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<sup>15</sup> Exhibit Staff/604, Moore/9: Project Capital Program Business Case for ER#5005, Technology Refresh

<sup>16</sup> Avista/600, Schuh/9

<sup>17</sup> Ibid.

1 included an executive update given in 2008, which shows the project costs  
2 increased from an initial \$7.5 million in 1998 to an updated estimate of \$12.2M  
3 in 2008. The scope of the project then increased to include additional HVAC  
4 systems, and other various upgrades at a projected cost of \$5.7 million, which  
5 put the projected cost at \$17.4 million. Between the years 2010-2014 alone,  
6 the Company had spent a total of \$25.5 million.<sup>18</sup> It is unknown what Avista  
7 spent on this project prior to that. For 2015, an additional \$11 million (\$0.96M  
8 Oregon allocated) in capital addition is projected, but there is no information  
9 that demonstrates what the additional amount is for and why it would be  
10 considered beneficial to rate payers. In fact the dramatic expansion of the  
11 program over the years to include multiple upgrades and “green additives” may  
12 indicate that the Company is simply seeking capital addition opportunities for  
13 increasing its rate base that are not necessary and related to providing service  
14 to customers. The information supplied by the Company in support of this  
15 HVAC project is vague, high-level, outdated, and not nearly sufficient to justify  
16 this level of capital spending.

17 **Q. Are there other projects for which the Company supplied additional**  
18 **information that Staff nevertheless is recommending disallowing for cost**  
19 **recovery in rates?**

20 A. Yes, this is the case for most projects in the filing. A different kind of example is  
21 the East Medford Reinforcement project #3203, for which the Company seeks  
22 \$5 million. The project is a 3.2-mile pipe installation to complete a 12” high-

---

<sup>18</sup> Exhibit Staff/602, Moore/1: Response to Staff DR #188

1 pressure loop across the east side of Medford, Oregon. The completion of the  
2 pipeline loop would increase capacity in the area. In the Company's response  
3 to DR 233, in confidential attachment B, the Company provides a slide  
4 presentation that gives an overview of capacity projects, in which the East  
5 Medford Reinforcement project is discussed. The presentation is about  
6 designing the gas distribution system to have the capacity to meet demand on  
7 "design day" temperature days, where extreme cold weather places higher-  
8 than-normal load on the system. Certain areas of the system have capacity  
9 deficiencies to meet demand at design day temperatures. East Medford is one  
10 of those areas.

11 However, the presentation also discusses how the Company has historically  
12 addressed these deficiencies by producing a "Cold Weather Action Plan" – or  
13 CWAP- in which personnel are deployed to manually bypass [regulator]  
14 stations and inject CNG into the system to keep the pressures up. The  
15 presentation notes that Avista has "not had to activate the CWAP in the last  
16 several years due to a combination of milder temperatures and a stronger  
17 system..." Nevertheless, the Company's "goal is to not have any cold weather  
18 action plans, but to have a system that is strong enough to support our design  
19 day loads, without manual intervention."<sup>19</sup>

20 **Q. What is Staff's reasoning for recommending a disallowance on this**  
21 **particular project?**

---

<sup>19</sup> CONFIDENTIAL Exhibit STAFF/605, Moore/3

1 A. Staff does not dispute that the East Medford pipeline project is necessary, but  
2 the Company has not presented compelling evidence to show that the project is  
3 so urgent that it must be completed this year. It does not appear nearly urgent  
4 enough in the context of a rate base increase of this magnitude. The  
5 Company's 2014 Integrated Resource Plan (IRP) identifies the East Medford  
6 reinforcement as one of its upcoming distribution projects scheduled for 2018.  
7 The IRP states: "Previous IRP and distribution planning analysis identified a  
8 near-term resource deficiency driven by forecasted local growth. Increased  
9 natural gas deliveries from the TransCanada Pipeline....will remedy this  
10 deficiency....This has been a multi-phase project spanning several years. As  
11 forecasted, needs have changed over time, and with no immediate resource  
12 need, completing the final phase of the project has been delayed."<sup>20</sup>

13 Staff supports the completion of this project, but the Company has not  
14 provided a compelling reason that it must be completed this year.

15 Regarding Avista's justification of capital distribution projects generally, it is not  
16 only in this filing where the Company's evidence is insufficient. Staff's  
17 comments to the 2014 IRP state: "...Staff finds it is missing a clear presentation  
18 of how Avista decides which distribution system projects to include in the IRP,  
19 and a clear description of the included projects, along with a justification for  
20 recommending or proceeding with the projects."<sup>21</sup>

<sup>20</sup> Exhibit STAFF/604, Moore/5-7: *"Avista Utilities 2014 Natural Gas IRP"* p. 129

<sup>21</sup> Exhibit STAFF/604, Moore/8: *OPUC ORDER NO.15-063, Appendix A, p. 10*

1 **Q. What is Staff's adjustment and how did you arrive at it?**

2 A. Staff recommends removing approximately \$30 million from the Company's  
3 capital additions. This adjustment is in addition to the specific adjustment for  
4 Project Compass recommended by Ms. Johnson, who recommends a \$1.3  
5 million reduction.

6 Staff arrives at this adjustment of \$30 million by setting a target for growth of  
7 net utility plant of 7.75 percent, which equates to a rate base addition of  
8 approximately \$16.4 million. This results in a \$31.3 million overall reduction in  
9 capital projects. From this amount, I subtract the \$1.3 million adjustment to  
10 Project Compass made by Ms. Johnson in Staff/300. This leaves a \$30 million  
11 adjustment to the overall capital budget.

Capital addition adjustment	
7.75%	Historical RB growth
\$210,751,974	2014 Net Utility Plant
\$47,658,000	UG 288 Avista Capital forecast
(\$16,333,278)	2014 net plant * 7.75%
<b>(\$31,324,722)</b>	Total Staff Adjustment
<b>(\$1,300,000)</b>	Project Compass Adjustment - J. Johnson
<b>(\$30,024,722)</b>	Net Staff Adjustment - M. Moore

12

13

14 Please refer to Exhibit Staff/606 Excel workpapers for the details of my  
15 recommended adjustment.

16 **Q. Does this conclude your testimony?**

17 A. Yes.

CASE: UG 288  
WITNESS: MITCHELL MOORE

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 601**

**Witness Qualification Statement**

**October 16, 2015**



### WITNESS QUALIFICATIONS STATEMENT

NAME: Mitchell Moore

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst  
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100  
Salem Oregon 97301-3612

EDUCATION: Bachelor of Arts, Journalism and Political Science  
University of Hawaii at Manoa (1992)

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program's Energy Rates, Finance and Audit division.

My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints.

Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UG 288  
WITNESS: MITCHELL MOORE

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 602**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

Avista Corp  
Actual Transfers to Plant: 2010-2014 (General Plant Capital Projects)  
Staff DR 188 Attachment C

System Balances

Sum of Current Activity Cost SUM Ervial	Jurisdiction	Asset Service	Year					Grand Total	OR Allocation %	OR Allocated Balance					
			2010	2011	2012	2013	2014			2010	2011	2012	2013	2014	
2277	AA	CD			1,067,211		12	485,690	1,552,913	8.702%	-	-	92,869	1	42,265
		GD						189,753	189,753	30.918%	-	-	-	-	58,668
5005	AA	CD	6,245,256	8,906,528	7,252,015	10,829,014	12,157,847	45,390,661	8.702%	543,462	775,046	631,070	942,341	1,057,976	
		GD					36,441	36,441	30.918%	-	-	-	-	11,267	
5006	AA	CD	2,263,886	5,567,590	5,878,977	5,473,024	4,459,561	23,643,038	8.702%	197,003	484,492	511,589	476,263	388,071	
		GD			336,971			336,971	30.918%	-	-	104,185	-	-	
5010	AA	CD	39,891	153,347	539,440		259,795	266,087	8.702%	3,471	13,344	46,942	22,607	23,155	
		GD						10,478	30.918%	-	-	-	-	3,240	
5014	AA	CD					2,002,533	869,234	2,871,767	8.702%	-	-	-	174,260	75,641
	OR	GD			32,487		25,496		57,983	100.000%	-	-	32,487	25,496	-
5106	AA	CD	108,225	62	7,465,012		3,344,494	11,483,620	22,401,412	8.702%	9,418	5	649,605	291,038	999,305
5138	AA	CD					10,390,158	138,886	10,529,044	8.702%	-	-	-	904,152	12,086
		GD						123,107	123,107	30.918%	-	-	-	-	38,062
5143	AA	CD					48,281	301,867	350,148	8.702%	-	-	-	4,201	26,268
5144	AA	CD						319,525	319,525	8.702%	-	-	-	-	27,805
		GD						262,027	262,027	30.918%	-	-	-	-	81,014
7000	AA	CD	15,093	33,690				37,057	85,840	8.702%	1,313	2,932	-	-	3,225
	OR	GD	176,304	480,871	109,246	530,175	0	1,296,596	1,296,596	100.000%	176,304	480,871	109,246	530,175	0
7001	AA	CD	2,183,983	2,876,313	3,017,087	659,195	2,238,406	10,974,984	8.702%	190,050	250,297	262,547	57,363	194,786	
	OR	CD					(483,555)	(483,555)	100.000%	-	-	-	-	(483,555)	
		GD	154,132		94,354	139,763	172,288	560,536	100.000%	154,132	-	94,354	139,763	172,288	
7003	AA	CD	434,858	488,437	549,006	788,838	92,159	2,353,298	8.702%	37,841	42,504	47,775	68,645	8,020	
7006	AA	CD	1,524,316	1,165,627	1,722,726	329,327	524,187	5,266,183	8.702%	132,646	101,433	149,912	28,658	45,615	
		GD	100,778	25,733	212,034	49,758	898,575	1,286,879	30.918%	31,159	7,956	65,557	15,384	277,821	
	OR	GD			34,048			34,048	100.000%	-	-	34,048	-	-	
7101	AA	CD	5,080,239	5,169,309	3,861,466	6,411,556	4,947,204	25,469,774	8.702%	442,082	449,833	336,025	557,934	430,506	
7126	AA	CD			54,062	10,111,250	982,481	11,147,792	8.702%	-	-	4,704	879,881	85,495	
7200	AA	CD		105,165	12,664		36,949	154,778	8.702%	-	9,151	1,102	-	3,215	
<b>Grand Total</b>			<b>18,326,961</b>	<b>24,972,673</b>	<b>32,238,806</b>	<b>51,392,669</b>	<b>40,549,874</b>	<b>167,480,983</b>		<b>1,918,883</b>	<b>2,617,865</b>	<b>3,174,015</b>	<b>5,118,162</b>	<b>3,582,237</b>	

Avista Corp  
Budgeted Transfers to Plant: 2010-2014 (Gas Distribution Capital Projects)  
Staff DR 189 Attachment C

Sum of Current Activity Cost SUN Year								OR Allocation % <sup>(C)</sup>					OR Allocated Balance						
Ercal	Asset Serv	Jurisdiction	2010	2011	2012	2013	2014	Grand Total	2010	2011	2012	2013	2014	2010	2011	2012	2013	2014	Total
1001	GD	AA	15,000,001	12,053,001	12,863,814	9,672,698	10,601,277	60,190,791	30.118%	29.425%	28.669%	32.935%	31.268%	4,517,700	3,546,596	3,687,927	3,185,703	3,314,807	18,252,733
1050	GD	AA	1,500,000	1,525,000	1,826,903	1,709,468	1,768,579	8,329,950	30.118%	29.425%	28.669%	32.935%	31.268%	451,770	448,731	523,755	563,013	552,999	2,540,269
1051	GD	AA	650,000	160,000	242,102	296,322	305,825	1,654,249	30.118%	29.425%	28.669%	32.935%	31.268%	195,767	47,080	69,408	97,594	95,625	505,474
1053	GD	AA	500,000	500,000	500,812	605,863	627,280	2,733,955	30.118%	29.425%	28.669%	32.935%	31.268%	150,590	147,125	143,578	199,541	196,138	836,972
3000	GD	AA	472,501	470,000	799,999	350,000	1,000,000	3,092,500	30.118%	29.425%	28.669%	32.935%	31.268%	142,308	138,298	229,352	115,273	312,680	937,910
3001	GD	AA	1,049,999	1,052,002	800,001	600,002	800,001	4,302,005	30.118%	29.425%	28.669%	32.935%	31.268%	316,239	309,552	229,352	197,611	250,144	1,302,898
3002	GD	AA	420,001	500,001	399,999	400,000	600,000	2,320,001	30.118%	29.425%	28.669%	32.935%	31.268%	126,496	147,125	114,676	131,740	187,608	707,645
3003	GD	AA	1,260,003	1,850,001	2,199,999	2,000,000	4,500,000	11,810,003	30.118%	29.425%	28.669%	32.935%	31.268%	379,488	544,363	630,718	658,700	1,407,060	3,620,328
3004	GD	AA	472,500	500,000	500,001	500,001	800,000	2,772,502	30.118%	29.425%	28.669%	32.935%	31.268%	142,308	147,125	143,345	164,675	250,144	847,597
3005	GD	AA	3,360,002	2,900,002	3,822,998	3,949,690	5,600,000	19,632,692	30.118%	29.425%	28.669%	32.935%	31.268%	1,011,965	853,326	1,096,015	1,300,830	1,751,008	6,013,145
3006	GD	AA	440,000	440,000	499,999	900,000	900,000	3,179,999	30.118%	29.425%	28.669%	32.935%	31.268%	132,519	129,470	143,345	296,415	281,412	983,161
3007	GD	AA			1,095,000	2,348,333	2,598,333	6,041,666	30.118%	29.425%	28.669%	32.935%	31.268%	-	-	313,926	773,423	812,447	1,899,796
3008	GD	AA			5,000,000	8,250,000	16,452,196	29,702,196	30.118%	29.425%	28.669%	32.935%	31.268%	-	-	1,433,450	2,717,138	5,144,273	9,294,860
3055	GD	AA				1,000,000	1,000,000	30.118%	29.425%	28.669%	32.935%	31.268%	-	-	-	-	-	312,680	312,680
3117	GD	AN	217,860	360,000	370,800	511,010	400,000	1,859,670	30.118%	29.425%	28.669%	32.935%	31.268%	65,615	105,930	106,305	168,301	125,072	571,223
3203	GD	OR	597,355		550,056	-		1,147,411	100%	100%	100%	100%	100%	597,355	-	550,056	-	-	1,147,411
7201	GD	AA		580,666	630,000	1,000,000	500,000	2,710,666	30.118%	29.425%	28.669%	32.935%	31.268%	-	170,861	180,615	329,350	156,340	837,166
		AN	429,000					429,000	0.000%	0.000%	0.000%	0.000%	0.000%	-	-	-	-	-	-
<b>Grand Total</b>			<b>26,369,222</b>	<b>22,890,673</b>	<b>32,102,483</b>	<b>33,093,387</b>	<b>48,453,491</b>	<b>162,909,256</b>						<b>8,230,120</b>	<b>6,735,581</b>	<b>9,595,821</b>	<b>10,899,307</b>	<b>15,150,438</b>	<b>50,611,266</b>

CASE: UG 288  
WITNESS: MITCHELL MOORE

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 603**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**



## Executive Update

April 23, 2008

DRAFT 4/18/08 Noon

## HVAC history and project costs

**Early 1990s:** critical equipment failure in central plant

**1994 – 1997:** Spent \$1.6M

**1998:** Multi-year project plan developed with cost estimate of \$7.5M

**1999:** Complete \$300K work

**1999 – 2000:** Tom Matthews' growth strategy focuses on subsidiaries

**2001 – 2005:** Financial on Fundamentals to rebuild the Utility, credit rating

**2006:** Spent \$130K on designing HVAC for G&P shop

- Updated cost estimate **\$12.2M from MW Engineering** (excl. tax, escalation, architect)

**2007:** \$1M for HVAC upgrades completed

- G&P, electric, gas meter shops.
- Request GMAX price for Design & Build from **McKinstry**

**2008:** \$5M approved for service building, cafeteria/auditorium, window wall



## Changes in scope

1. Additional HVAC Systems added due to age	\$ .822M
2. Lighting and Electrical System Upgrades	\$1.371M
3. Window Interior Shading System	\$ .529M
4. Additional Glazing of Buildings	\$ .219M
5. Fire Sprinkler Systems	\$ .517M
6. General Construction (Ceilings/Fireproofing)	\$2.242M
<b>TOTAL</b>	<b>\$5.70M</b>





## HVAC current budget outlook

	2008	2009	2010	2011	2012	Subtotal	2013	2014	Total
<b>Budget *</b> <b>in \$Millions</b>	\$4,990	\$4,159	\$3,327	\$2,733	\$3,000	\$18,209			
<b>McKinstry</b> <b>GMAX</b>	\$4,936	\$1,713	\$3,600	\$3,541	\$3,667	\$17,457	\$3,943	\$4,286	\$25,686

\* Budget represents Long Range Plan Placeholder Amount



## LEED strategy for Existing Building

- HVAC renovation & remodeling positions Avista for LEED Existing Building certification at completion
- Lighting & ceiling costs could be reduced
  - re-use existing systems
- Discuss future floor plan design
  - day lighting and views
- Implementing new floor plan design requires purchasing interior wall system and some furniture
- Fireproofing and fire sprinkler systems are life safety improvements – not LEED related



## Possible scenarios

### Scenario 1: Reduce scope of work

• Lighting and Electrical System Upgrades	\$1.371M
• Window Interior Shading System	\$ .529M
• Additional Glazing of Buildings	\$ .219M
• Fire Sprinkler Systems	\$ .517M
• General Construction (Ceilings/Fireproofing)	\$2.242M
<b>TOTAL</b>	<b>\$5.70M</b>

### Scenario 2: Compress work schedule to reduce escalation costs

- Savings TBD. Need to explore options with McKinstry

### Scenario 3:



# Questions?



Page 10

**CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER.**

## LEED estimates and green additives

	Code Bldg.	Certified	Silver	Gold	Platinum
<b>Best Estim.</b>	\$10.6M	\$11M	\$11.9M	\$13.5M	\$16.7M
<b>LEED Pts.</b>	0-26	26 - 32	33 - 38	39 - 51	52 - 69
<b>Green Additives</b>	Design/Build contractor No additives Boiler/Chiller 208 swales	Traditional HVAC Recycling program White roof Reduce water 20% Storm wtr. qual. ctrl. Reduce energy 14% Basic lighting sys.	HVAC heat pump Advcd. Mech. Sys. Adv. stormwater ctrl. Reduce water 30% Reduce irrigat. 50% Reduce energy 42%	All of Silver PLUS 35kW solar panels Rain garden Green roof canopy Shade trees/parking Reduce energy 42%	Green tech. demo. proj. 30% onsite generation Onsite waste treatment Gray water recycling Reduce energy 42%
<b>Future Expenses</b>	Avg energy bills Avg O&M Costs Avg Carbon Print	Avg energy bills Avg O&M Costs Avg Carbon Print	Low energy bills Low O&M Costs Low Carbon Print	Low energy Bills Lower O&M Costs Lower Carbon Print	Lowest energy bills Lowest O&M Costs Zero Carbon Print



## Ross Court reductions

<b>Land transfer fee removed</b> (Utility Accounting)	<b>\$600K</b>
<b>Green additives removed</b>	<b>\$433,200</b>
Green roof (entry canopy only)	\$12K
35kW PV Array	\$350K
Rain gardens	\$27K
Parking lot trees	\$11K
<b>Subtotal Alternatives</b>	<b>\$400K</b>
Sales Tax	\$33,200
<b>Total Alternatives</b>	<b>\$433,200</b>
<b>Well estimate removed</b>	<b>\$100K</b>
<b>Reduce estimating contingency</b>	<b>5%</b>
<b>Reduce general contractor markup</b> (improved market conditions)	<b>2%</b>



## Investing in: our facilities, our environment and our business



### Replace current HVAC system

50 years old  
Outdated  
Inefficient

### New HVAC system

Energy efficient  
Other energy renovations to building

### New Building

38,000 sq. ft. facility  
Relocate employees during renovation  
Accommodate future growth  
LEED certified building  
Legacy of Environmental Stewardship





CASE: UG 288  
WITNESS: MITCHELL MOORE

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 604**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**



# Positioned for performance: An overview of Q1 2015 and beyond

June 2015

# Steadily building long-term value

## Projecting earnings and dividend growth of 4% to 5%

### Avista Utilities

- 5% to 6% rate base growth through utility capital investments
  - Upgrading infrastructure
  - Grid modernization
- Customer and load growth (~1%)

### AEL&P

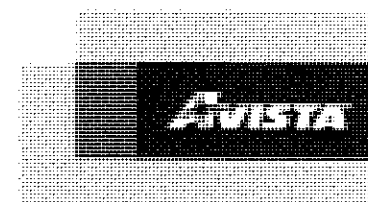
- Strong near-term rate base growth through investment in generation
- Customer and load growth (~1%)
- Evaluating LNG/LDC\* opportunities

### Strategic Investments

- Developing platforms for future growth
  - Targeting expanded natural gas services via LNG
  - Exploring data science and advanced analytics

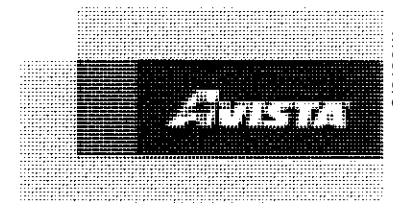
*Reliably building value for our customers,  
investors, communities and employees*

\*LNG: Liquefied natural gas  
LDC: Local distribution company



# Avista Utilities

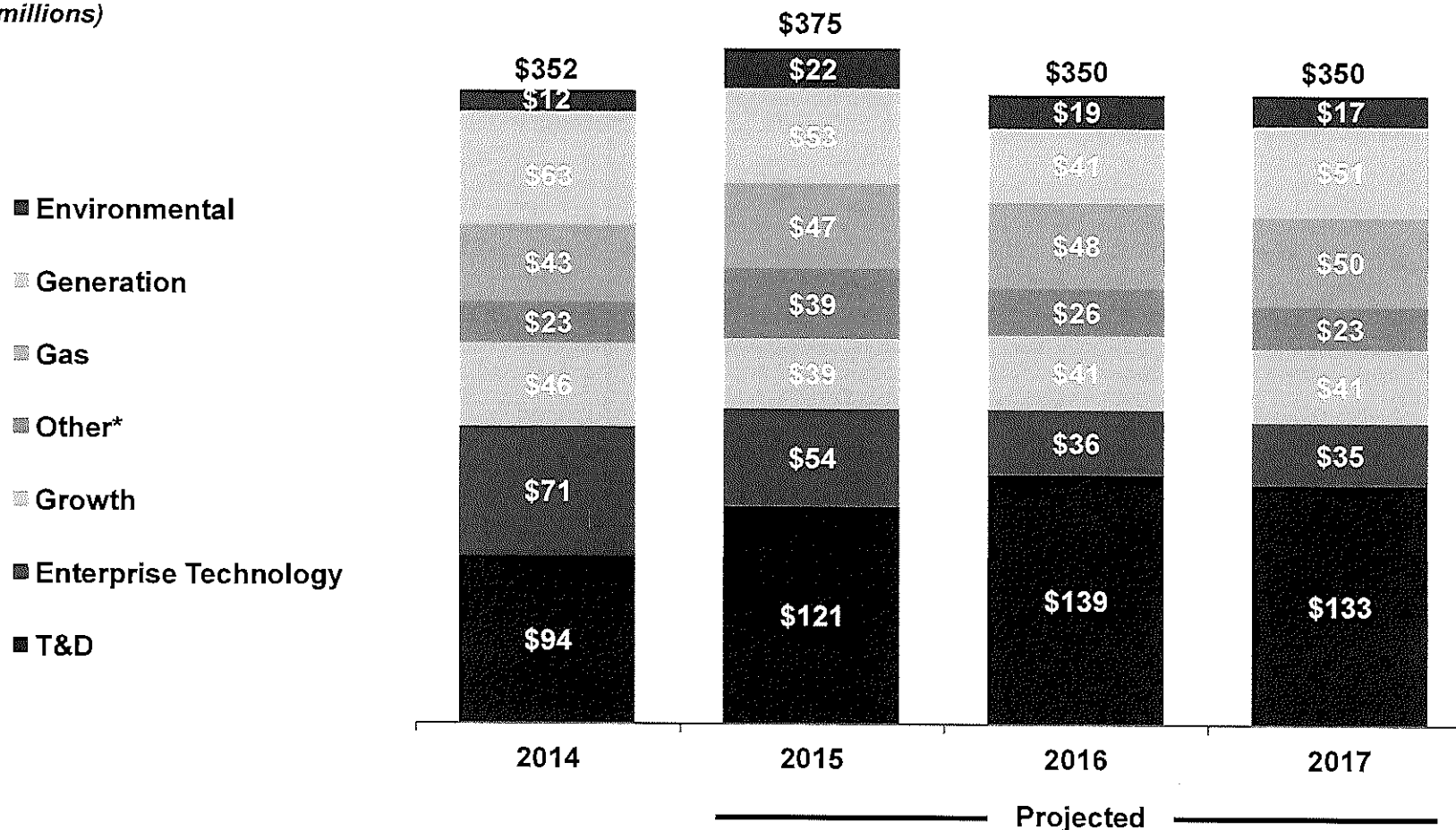
## Significant investments in utility infrastructure



# Significant investments to upgrade all systems

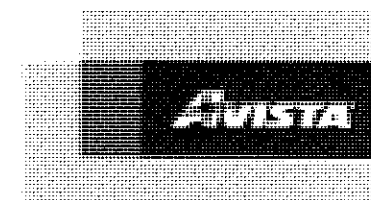
5% to 6% rate base growth

**Avista Utilities Capital Expenditures\*\***  
(\$ millions)



\* Other includes Facilities and Fleet

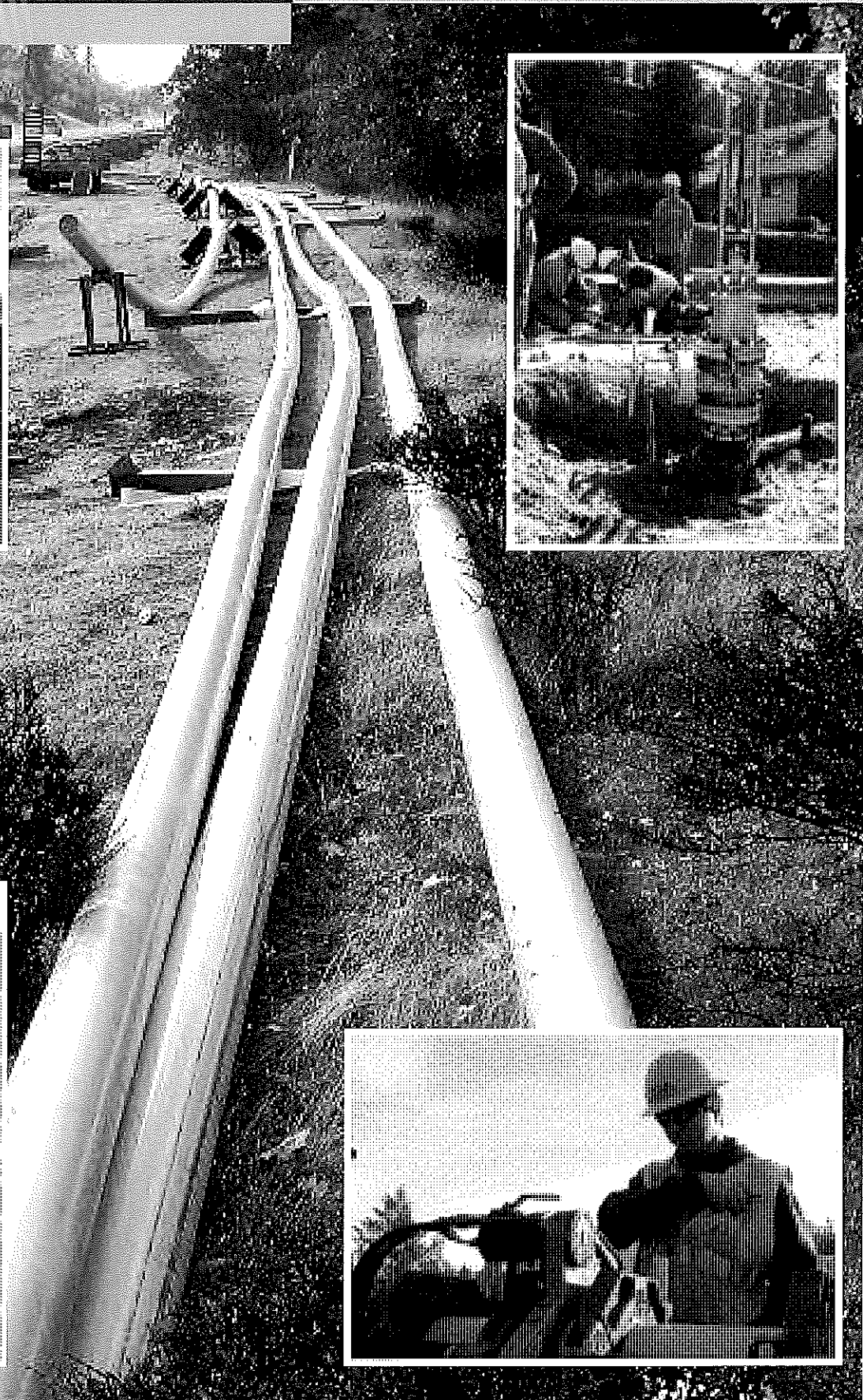
\*\* Excludes planned capital expenditures at AEL&P of \$15 million in 2015, 2016 and 2017





# 2014 Natural Gas Integrated Resource Plan

August 31, 2014



Compressors can be a cost effective option to resolving system constraints; however, regulatory and environmental approvals to install a station, along with engineering and construction time can be a significant deterrent. Adding compressor stations typically involves considerable capital expenditure. Based on Avista's detailed knowledge of the distribution system, there are no foreseeable plans to add compressors to the distribution network.

## Conservation Resources

Included in the evaluation of distribution system constraints is the consideration of targeted conservation resources to reduce or delay distribution system enhancements. The consumer is still the ultimate decision-maker regarding the purchase of a conservation measure. Because of this, Avista attempts to influence conservation through the DSM measures discussed in Chapter 3 – Demand-Side Resources, but does not depend on estimates of peak day demand reductions from conservation to eliminate near-term distribution system constraints. Over longer-term, targeted conservation programs provide a cumulative benefit that offsets potential constraint areas and may be an effective strategy.

## Planning Results

Table 7.1 summarizes the cost of major distribution system enhancements addressing growth-related system constraints, system integrity issues and the timing of these expenditures. These projects are preliminary estimates of timing and costs of major reinforcement solutions. The scope and needs of these projects generally evolves with new information requiring ongoing reassessment. Actual solutions may differ due to differences in actual growth patterns and/or construction conditions from the initial assessment.

The following discussion provides information about key near-term projects:

**East Medford Reinforcement:** Previous IRP and distribution planning analysis identified a near-term resource deficiency driven by forecasted local growth. Increased natural gas deliveries from the TransCanada Pipeline source at Phoenix Road Gate Station in southeast Medford will remedy this deficiency. To facilitate distribution receipt of the increased natural gas volumes, a new high-pressure (HP) line encircling Medford to the east and tying into an existing high-pressure line in White City will improve delivery capacity and provide reinforcement in the East Medford area.

This has been a multi-phase project spanning several years. As forecasted, needs have changed over time, and with no immediate resource need, completing the final phase of the project has been delayed. Other factors may drive completion of the project including reliability needs, flexibility of natural gas supply management and optimizing

Chapter 7: Distribution Planning

synergies of other construction projects to reduce project cost. Avista will continue to evaluate forecasts and assess the most appropriate timing for completion of this project.

**U.S. Highway 2 North Spokane Reinforcement:** This project will reinforce the area north of Spokane along U.S. Highway 2. This mixed-use area experiences low pressure during winter at unpredictable times given demand profiles of the diverse customer base. Completion of this reinforcement will improve pressures in the U.S. 2 North Kaiser area. Approximately 8,000 feet of HP steel gas main will be installed in a newly established easement along U.S. Highway 2.

**Chase Road Gate Station, Post Falls, Idaho:** This gate station will allow Avista to split the large load at the Rathdrum Gate Station. Approximately 18,000 feet of new HP line will connect the Chase Road Gate Station to the existing HP line. This gate station will give Avista the opportunity to feed the growing Post Falls and Coeur d’Alene areas from the north.

**Table 7.1 Distribution Planning Capital Projects**

		2015	2016	2017	2018
<b>Projects</b>	*East Medford Reinforcement	\$0	\$0	\$0	\$5,000,000
	Goldendale HP	\$3,500,000	\$0	\$0	\$0
	NSC Greene ST HP	\$0	\$0	\$0	\$1,500,000
	Rathdrum Prairie HP Gas Reinforcement	\$100,000	\$4,900,000	\$5,000,000	\$0
	*Reinforcement, Hwy 2 Kaiser	\$1,300,000	\$0	\$0	\$0
	Spokane St Bridge Gas	\$1,000,000	\$0	\$0	\$0

\*Details of project described in IRP

Table 7.2 shows city gate stations identified as over utilized or under capacity. Estimated cost, year and the plan to remediate the capacity concern are shown.



ORDER NO.

15 065

Docket No. LC 61  
February 10, 2015  
Page 10

**Staff recommends the Commission direct Avista, in future IRPs, to provide a discussion of Avista's hedging strategies as to their impact on customer rates, how hedge prices compare with prevailing spot market prices, and any action taken by Avista to protect its customers from unnecessary losses associated with its hedging strategies. In addition, Staff recommends the Commission direct Avista, in future IRPs, to provide a discussion of procurement plans and risk management that is of sufficient detail to allow Staff to do a thorough review of the purchasing, hedging and risk management plans/policies/strategies.**

### ***Distribution Planning***

Avista's IRP presents a discussion of distribution system planning. While the discussion is informative, Staff finds it is missing a clear presentation of how Avista decides which distribution system projects to include in the IRP, and a clear description of the included projects, along with a justification for recommending or proceeding with the projects.

#### *Parties' Positions*

##### CUB

CUB's January 26, 2015, reply comments express agreement with Staff's comments related to distribution planning.

##### *Avista's Position*

Avista states in its response comments that, in future IRPs, Avista will work to enhance the distribution planning discussion "to more clearly state the information" within the discussion, "and also to provide a more detailed description of the projects themselves."

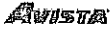
#### *Staff Position and Recommendation*

**Staff recommends the Commission direct Avista, in future IRPs, to include a clear presentation of how Avista decides which distribution system projects to include in the IRP, and a clear description of the included projects, along with a justification for recommending or proceeding with the projects.**

### ***Climate Change Regulation***

Staff, in its comments, expressed concern that all of the climate change regulatory implications, beyond simply the immediate regulatory effects of the Environmental Protection Agency's proposed rules under Section 111 (d) of the federal Clean Air Act, are not currently accounted for in the planning period.

Capital Program Business Case



Investment Name:	Technology Refresh to Sustain Business Proca	Assessments:	
Requested Amount	\$ 15,362,243	Financial:	Medium - >= 5% & <= 8% CIRR
Duration/Timeframe	10 Year Program	Strategic:	Life Cycle Programs
Dept., Area:	IS/IT	Operational:	Operations require execution to perform at current levels.
Owner:	Jacob Reid/Jim Corder	Business Risk:	ERM Reduction >5 and <= 10
Sponsor:	Jim Kensok	Program Risk:	High certainty around cost, schedule and resources
Category:	Program	Assessment Score:	89
Mandate/Reg. Reference:	N/A	Annual Cost Summary - Increase/(Decrease)	

<b>Recommend Program Description:</b> This program is in place to provide for technology refresh in alignment with the roadmaps for application and technology lifecycles. The continuation of technology refresh programs provides benefit to Avista by providing a stable and reliable application and computing platform to allow for the safe and reliable operation of our electric and gas infrastructures.	Performance	Capital Cost	O&M Cost	Other Costs	Business Risk Score
	This program provides for current technologies for the normal operation of the business	\$ 15,362,243			15

Alternatives:		Performance	Capital Cost	O&M Cost	Other Costs	Business Risk Score
Unfunded Program:	Not doing this program will result in four major impacts: 1) Reduction of 62 staff members with key institutional knowledge 2) Decrease in business process efficiency 3) Increase in O&M labor to support the technology 4) Increase technology outages impacting the operations of the business.	The performance of the computing technology at			\$ 1,895,751	20
Technology Refresh Programs	This program is in place to provide for technology refresh in alignment with the roadmaps for application and technology lifecycles. The continuation of technology refresh programs provides benefit to Avista by providing a stable and reliable application and computing platform to allow for the safe and reliable operation of our electric and gas infrastructures.	This program provides for current technologies for the normal	\$ 15,362,243			15
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations				0
Alternative 3 Name: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations				0

Program Cash Flows					Associated Eris (list all applicable):		
5 years of costs					5005		
	Capital Cost	O&M Cost	Other Costs	Approved			
	\$ 3,973,758	\$	\$	\$ 3,973,758			
2013	\$ 10,019,774	\$	\$	\$ 14,110,491			
2014	\$ 12,129,043	\$	\$	\$ 15,362,243			
2015	\$ 13,949,536	\$	\$	\$ 16,094,833			
2016	\$ 17,183,753	\$	\$	\$ 16,094,833			
2017	\$ 19,031,035	\$	\$	\$ 16,094,833			
2018	\$	\$	\$	\$ 18,094,833			
2019	\$	\$	\$	\$ 20,094,833			
Total	\$ 72,313,141	\$	\$	\$ 102,825,824			

**Mandate Excerpt (if applicable):**  
 provide brief citation of the law or regulation and a reference number if possible

**Additional Justifications:**  
 Technology refresh program costs increase year over year to two main reasons. The first is because of the continuous technological evolution which causes obsolescence. Manufacturers continue to upgrade and improve their systems to provide improved performance and function. This in turn requires companies to replace system on a periodic basis to maintain reliability and functionality. The second main reason is due to the addition of new hardware and software to support new business requirements and growth. New equipment purchased under Technology Expansion Program will have to be refreshed in 3-5 years adding to the refresh budget. For example, Infrastructure refresh costs the increase from year to year due to prior years spend in Technology Expansion, roughly \$800k in Distributed Systems and \$500k in Network Systems per year. Business Application Expansion is up between 2011 & 2012 because of the inclusion of some small to medium projects into the expansion program.

**Resources Requirements: (request forms and approvals attached)**

Internal Labor Availability:	<input type="checkbox"/> Low Probability	<input type="checkbox"/> Medium Probability	<input checked="" type="checkbox"/> High Probability	Enterprise Tech:	<input checked="" type="checkbox"/> YES - attach form	<input type="checkbox"/> NO or Not Required
Contract Labor:	<input checked="" type="checkbox"/> YES	<input type="checkbox"/> NO		Facilities:	<input checked="" type="checkbox"/> YES - attach form	<input type="checkbox"/> NO or Not Required
				Capital Tools:	<input type="checkbox"/> YES - attach form	<input checked="" type="checkbox"/> NO or Not Required
				Fleet:	<input type="checkbox"/> YES - attach form	<input checked="" type="checkbox"/> NO or Not Required

Check the appropriate box. The Internal and contract labor boxes should be checked to indicate if the resource owners have been contacted and to provide a general sense of how likely staff will be provided. (this does not require a firm commitment).

CASE: UG 288  
WITNESS: MITCHELL MOORE

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 605**

**Confidential Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**STAFF EXHIBIT 605**  
**IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE**  
**ORDER NO. 15-141 IN UG 288**

CASE: UG 288  
WITNESS: ERIK COLVILLE

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 700**

**Gas Storage in Rate Base, Underground Storage  
Operating Expenses, Other Gas Expense,  
Purchased Gas Expense, Integrated Resource  
Plan**

**Opening Testimony**

**October 16, 2015**

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Erik Colville. My business address is 201 High Street, SE Suite  
3 100, Salem, Oregon 97301-3612.

4 **Q. Please describe your educational background and work experience.**

5 A. My Witness Qualification Statement is found in Exhibit Staff/701.

6 **Q. What is the purpose of your testimony?**

7 A. I present Staff’s recommendations regarding the rate treatment of gas storage  
8 in rate base, “underground storage operating expense,”“other gas supply  
9 expense,” “purchased gas expense,” and the Integrated Resource Plan (IRP).

10 **Q. Did you prepare an exhibit for this docket?**

11 A. Yes. I prepared Exhibit Staff/701 Witness Qualification Statement, consisting of  
12 one page, Exhibit Staff/702 Data Request Responses, and Exhibit Staff/703  
13 Other Gas Supply Expense, consisting of two pages.

14 **Q. How is your testimony organized?**

15 A. My testimony is organized as follows:

16	Issue 1. Gas Storage In Rate Base.....	3
17	Issue 2. Underground Storage Operating Expense .....	7
18	Issue 3. Other Gas Expense.....	11
19	Issue 4. Purchased Gas Expense.....	14
20	Issue 5. Integrated Resource Plan (IRP) .....	15

21

22 **Q. Please summarize your recommendations regarding each of these**  
23 **issues.**

24 A. Issue 1. Gas Storage in Rate Base – As a result of my analysis of the issue, I  
25 have no proposed adjustment at this time. I recommend the Commission adopt

1 the amount of \$3,078,000 for Gas Storage in Rate Base, as requested by  
2 Avista.

3  
4 Issue 2. Underground Storage--I recommend the Commission adopt the  
5 amount of \$136,000 for "underground storage operating expense," as  
6 requested by Avista.

7  
8 Issue 3. Other Gas Expense – I propose to reduce Avista's requested "other  
9 gas expense" by \$80,000, from \$550,000 to \$470,000.

10  
11 Issue 4. Purchased Gas Expense – The actual cost of gas is reconciled with  
12 customers each year in the Purchased Gas Adjustment (Order No. 14-238 in  
13 Docket No. UM 1286). Therefore, I have no proposed adjustment for  
14 "purchased gas expense" in this rate case at this time.

15  
16 Issue 5. IRP - The IRP does not identify a need for new resources within the  
17 20-year planning period. There is no connection made in the presentation to  
18 the rate case.

**ISSUE 1. GAS STORAGE IN RATE BASE****Q. Please describe the gas storage costs at issue.**

A. Storage gas consists of two components, “cushion gas” and “working gas inventory.” Cushion gas is permanently retained in storage to maintain operational pressure and prevent water deterioration in an underground storage reservoir. “Working gas inventory” is the gas that flows in and out of the storage reservoir (or Liquid Natural Gas (LNG) tank) to serve customer loads.

**Q. Please summarize Avista’s and your proposed rate treatment of Avista’s gas storage costs.**

A. Avista includes \$3,078,000 for gas storage in its rate base. Avista/501 Smith/4-11, lines 247-250. This amount is the 2014 end-of-year balance for Avista’s working gas inventory. I support including the cost of working gas inventory in rate base. I do not recommend an adjustment to the amount included in rate base as proposed by Avista. I do propose the cost of working gas inventory in rate base to be based on the average of monthly working gas inventories for 2014, rather than the end-of-year amount.

**Q. Please summarize the Commission’s historical treatment of gas storage in rate base.**

A. Few orders<sup>1</sup> expressly address the appropriate regulatory treatment of working gas inventory costs, but all three gas utilities in Oregon currently include these

---

<sup>1</sup> See *Order No. 77-125 and Order No. 13-349*.



1 costs in rate base.<sup>2</sup> In 1977, the Commission expressly allowed Cascade to  
2 include its gas storage costs as an asset in rate base.<sup>3</sup>

3 **Q. Did Staff oppose inclusion of working gas inventory in rate base in NW**  
4 **Natural's last general rate case (Docket No. UG 221)?**

5 A. Yes. Staff recommended that NW Natural recover a return on its working gas  
6 inventory through the Purchased Gas Adjustment (PGA), which would allow  
7 the Commission to annually update the working gas inventory. Staff, NW  
8 Natural, and other parties entered into a stipulation in UG 221 under which the  
9 working gas inventory issue was moved to a separate docket, Docket No.  
10 UM 1651. In that docket, Staff, NW Natural and other parties stipulated to the  
11 inclusion of working gas inventory in NW Natural's rate base and the  
12 Commission adopted the Stipulation.<sup>4</sup>

13 **Q. Does Staff still believe it is preferable to allow a utility to recover a**  
14 **return on its working gas inventory through its PGA?**

15 A. No. Staff is persuaded that the benefit obtained by updating the level of  
16 working gas inventory each year does not warrant introducing a complicated  
17 adjustment into the PGA mechanism.

18 **Q. Please summarize your analysis of the amount that should be included**  
19 **in rate base for working gas inventory.**

20 A. Staff's analysis in Docket No. UM 1651 showed that year-to-year variations in  
21 average annual gas storage are caused by variations in weather from that

---

<sup>2</sup> See e.g., Order No. 13-349 (Commission adopting stipulation including NW Natural Gas Company's working gas inventory in rate base).

<sup>3</sup> Re Cascade Natural Gas Corporation, Order No. 77-125 (1977 WL 440903 at 3).

<sup>4</sup> Order No. 13-049.

1 forecasted and spot market gas prices falling below the average cost of gas in  
2 storage. Staff's analysis also showed that the amount NW Natural could  
3 include in rate base should be calculated using NW Natural's forecasted  
4 average working gas inventory balances for the November 2013-October 2014  
5 time period.

6 While it may be possible to recommend the amount of storage gas in rate base  
7 based upon historical data and forecasting models, historical treatment of the  
8 issue has been to use the most recent or forecasted 12-month average to  
9 calculate the amount to include in rate base. I therefore recommend that the  
10 amount of gas storage in rate base be based upon a recent 12-month average.

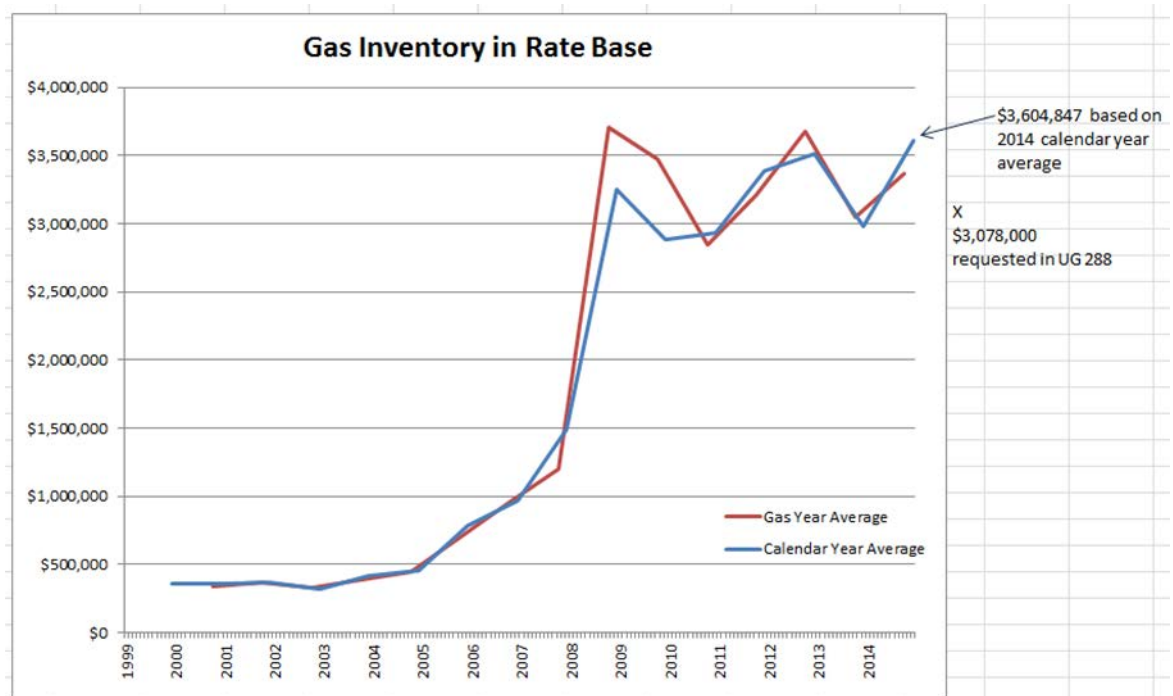
11 **Q. Did you issue data requests to Avista about the working gas inventory**  
12 **issue?**

13 A. Yes. Staff Data Requests (DR) Nos. DR 124 and 125 were issued to Avista  
14 requesting monthly storage inventory levels as well as the monthly storage  
15 guideline for each storage facility. Based upon Avista's responses to DR Nos.  
16 124 and 125, cushion gas is valued in this rate case at its cost when placed in  
17 the reservoir. Refer to Exhibit Staff/702 for DR responses.

18 **Q. Please explain how Avista's responses to your DRs affected your**  
19 **analysis.**

20 A. As a result of Avista's responses, my analysis primarily deals with working gas.  
21 Avista's response to DR Nos. 124 and 125 did not include a forecast of working  
22 gas in storage for 2015. In addition, Avista's rate case uses the 2014 Results of  
23 Operations (ROO) as its base year. For these two reasons, for the amount of

1 Gas Storage in Rate Base, I propose to use the 2014 calendar year average  
 2 instead of using the current forecast gas year (Nov 2014-Oct 2015) average.  
 3 Using data provided in Avista's response to DRs 124 and 125 to calculate the  
 4 annual averages, the historic calendar year and historic gas year averages are  
 5 depicted in the figure below. Based upon the 2014 calendar year average gas  
 6 storage, an amount up to \$3,604,847 could be justified.



7

8 **Q. Please describe your proposed adjustment to Gas Storage in Rate**  
 9 **Base.**

10 A. As a result of my analysis of the issue, I have no proposed adjustment at this  
 11 time. I propose to allow the amount of \$3,078,000 for Gas Storage in Rate  
 12 Base, as requested by Avista.

**ISSUE 2. UNDERGROUND STORAGE OPERATING EXPENSE****Q. What is “underground storage operating expense?”**

A. “Underground storage operating expense” is expense recorded in FERC Accounts 814, 824, and 837 and includes: the cost of labor and expenses incurred in the general supervision and direction of underground storage operations; the cost of labor, material used and expenses incurred in operating underground storage plant, and other underground storage operating expenses, not includible in any of the foregoing accounts, including research, development, and demonstration expenses; and the cost of labor, materials used and expenses incurred in the maintenance of equipment, the book cost of which is includible in Account 357, Other Equipment.<sup>5</sup>

**Q. Please summarize Avista’s proposal related to “underground storage operating expense.”**

A. Avista proposes to begin with the Total Underground Storage Operating Expense from its 2014 Results Of Operation (ROO), and to apply adjustments, which results in a Restated 2016 average of monthly averages (AMA) Test Period Total Underground Storage Operating Expense of \$136,000. Avista/501, Smith/4-11, line 45.

**Q. Please summarize the Commission’s historical treatment of “underground storage operating expense.”**

---

<sup>5</sup> See 18 C.F.R. FERC Accounts 814, 824, and 837.

1 A. I was not able to find a Commission order expressly addressing how to  
2 determine the proper amount of “underground storage operating expense” that  
3 should be included in revenue requirement.

4 **Q. What is your recommendation?**

5 A. Staff practice is a general preference for considering the previous three year’s  
6 expense results more heavily than a long-term trend, unless there is a reason  
7 not to do so. Thus, I conclude that using the adjusted ROO expense is not the  
8 optimum way to calculate the appropriate amount to include in revenue  
9 requirement. Accordingly, my recommendation is based on review of Avista’s  
10 actual “underground storage operating expense” for the previous three years.

11 **Q. Please summarize your analysis.**

12 A. No detail was provided initially for supervision and engineering, other  
13 expenses, or other equipment. Staff issued DR 123 seeking 10-year historical  
14 “underground storage operating expense” results, as well as a breakdown of  
15 “underground storage operating expense” into supervision and engineering,  
16 other expenses, and other equipment categories. The breakdown provided in  
17 response to DR 123 is shown in the following table and on the following figure.  
18 Refer to Exhibit Staff/702 for DR response.

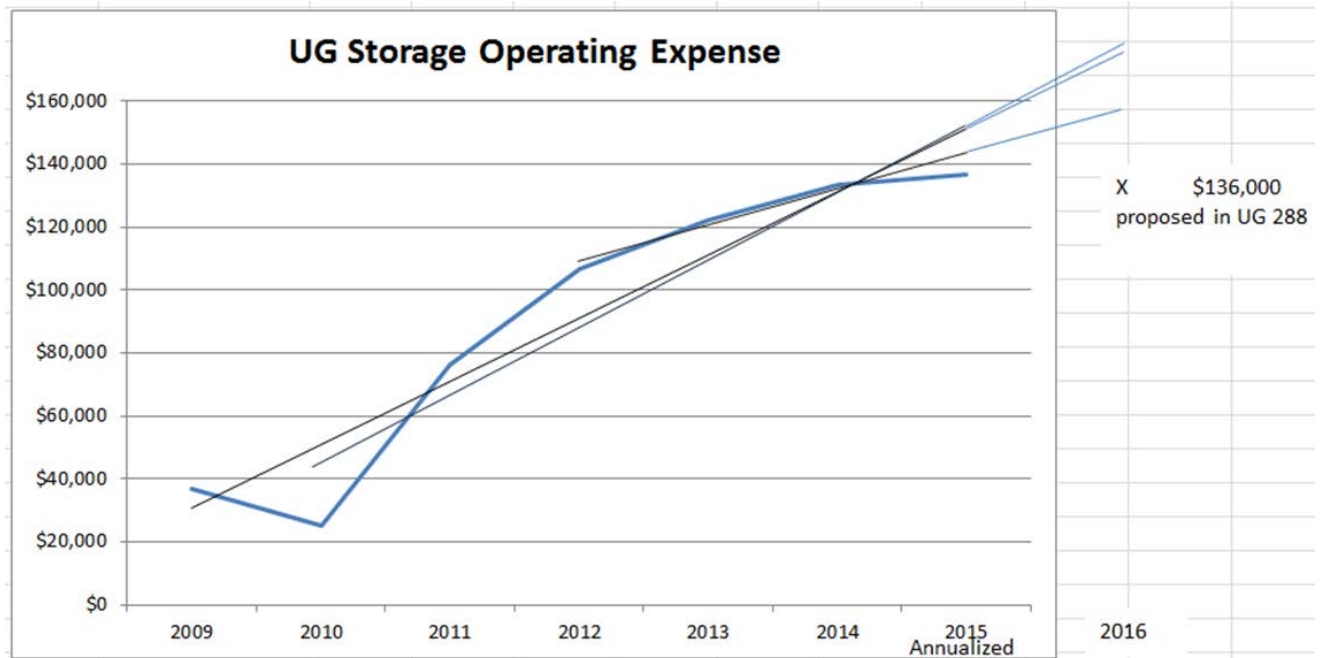
19 **Q. Please explain how to understand the following table and figure.**

20 A. The 2015 amount represents four months ended 4/30/15. Supervision and  
21 engineering was \$0 in each year, so that detail is omitted. In addition, there  
22 were no Oregon ratepayer expenses for storage prior to 2009, thus there is no  
23 detail prior to 2009.

1

		Annualized										
	OR Only	2009	2010	2011	2012	2013	2014	2015	Jan-15	Feb-15	Mar-15	Apr-15
824000	NAT GAS STORAGE - OTHER EXPENSES	19,152	12,048	39,772	57,988	67,117	69,813	74,035	7,022	7,165	4,751	5,741
837000	NAT GAS STORAGE - OTHER EQUIPMENT	17,674	13,041	36,225	48,707	54,844	63,795	62,794	3,776	6,020	5,142	5,993
	Total	\$36,826	\$25,089	\$75,997	\$106,695	\$121,961	\$133,608	\$136,829	10,798	13,185	9,893	11,733

2



3

**Q. Please continue with explaining your analysis.**

4

A. Based upon Avista’s responses to DRs 208 and 209, the dip in “underground storage operating expense” for 2010 reflects increasing Oregon’s share of Jackson Prairie operating and maintenance expenses from 3.08 percent to 9.65 percent, corresponding with the increase in capacity for Oregon customers. This increase in allocation percentage is the primary reason for the increase in expenses between 2010 and 2011. In addition, there is a timing lag associated with invoice processing and expense recognition because Avista is not the operating partner for Jackson Prairie. For example, \$46,000 of costs

10

11

1 incurred in 2010 were expensed in 2011. Refer to Exhibit Staff/702 for DR  
2 responses.

3 **Q. What conclusions do you draw from this information?**

4 A. All the trend lines through the historical “underground storage operating  
5 expense” data indicate justification for an amount greater than that requested  
6 by Avista. Given recent “underground storage operating expenses,” Avista’s  
7 proposed \$136,000 appears to have a reasonable basis.

8 **Q. Please summarize your proposed adjustment to “underground storage  
9 operating expense.”**

10 A I have no proposed adjustment at this time. I propose to allow \$136,000 for  
11 “underground storage operating expense,” as requested by Avista.

**ISSUE 3. OTHER GAS EXPENSE****Q. What is “other gas expense?”**

A. “Other gas expense” is expense recorded in FERC Account 813, and includes the cost of labor, materials used and expenses incurred in connection with gas supply functions, including, research and development expenses, not provided for in any other FERC account for gas expense.<sup>6</sup>

**Q. Please summarize Avista’s proposal related to other gas expense.**

A. Avista proposes to begin with the Total Other Gas Supply Expense from its 2014 ROO, to apply adjustments, which results in a Restated 2016 AMA Test Period Total Other Gas Supply Expense of \$550,000. Avista/501, Smith/4-11, line 37.

**Q. Please summarize Commission historical treatment of “other gas expense.”**

A. I was not able to find a Commission order expressly addressing how to determine the proper amount of “other gas expense” that should be included in revenue requirement.

**Q. What is your recommendation?**

A. As stated previously, Staff’s practice is to consider the previous three year’s expense results more heavily than a long term trend, unless there is a reason not to do so. Thus, I conclude that using the adjusted ROO expense is not the optimum way to calculate the appropriate amount to include in revenue

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<sup>6</sup> See 18 C.F.R. FERC Account 813.



1 requirement. Accordingly, my recommendation is based on review of Avista's  
2 actual "other gas expense" for the previous three years.

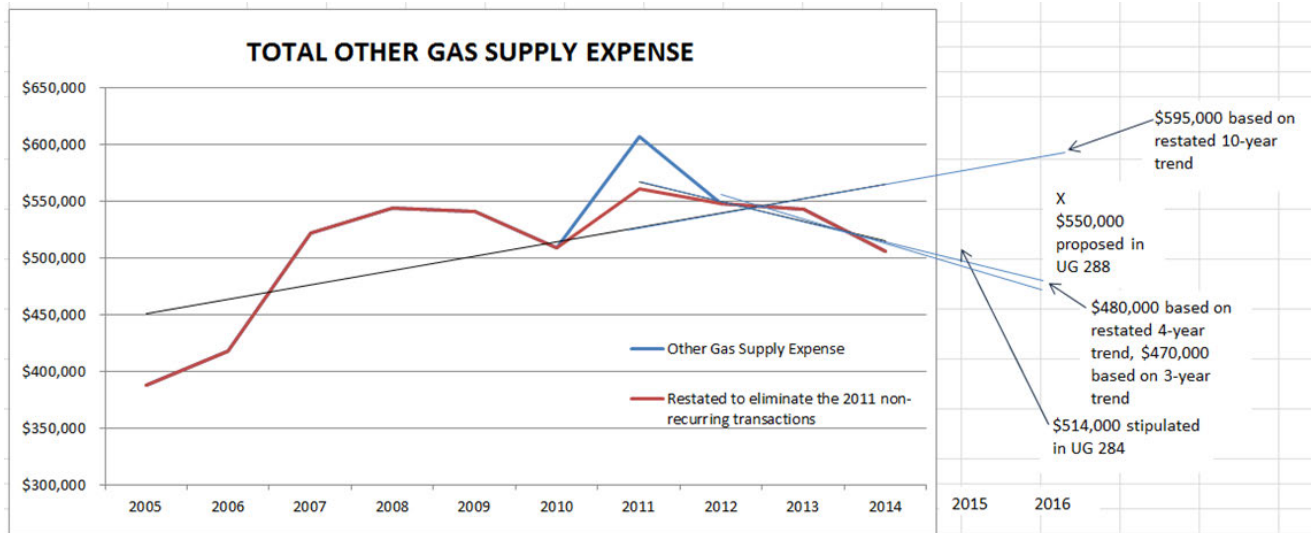
3 **Q. Please summarize your analysis.**

4 A. The "other gas expense" amount in this rate case, \$550,000, is consistent with  
5 that requested in the last rate case (Docket No. UG 284), \$574,000, just one  
6 year ago.

7 I issued DR 122 seeking 10-year historical "other gas expense" results, as well  
8 as a breakdown of the "other gas expense" into Other Gas Purchases,  
9 Purchased Gas Expenses, Natural Gas Storage Transactions, Gas Used for  
10 Products Extraction, Other Gas Expenses, and Gas Technology Institute  
11 Expense categories. Of these six expense subcategories, only Other Gas  
12 Expenses, and Gas Technology Institute (GTI) Expenses remain after the  
13 various rate case adjustments. Refer to Exhibit Staff/702 for DR response.

14 **Q. What was Avista's response to your DR 122?**

15 A. Avista's response to DR 122 is depicted in the figure below, and in Exhibit  
16 Staff/703. For the period of 2011 through 2014, there is a downward trend for  
17 the "other gas expense." Without a reason to discount the downward trend,  
18 Staff's analysis approach is to set the "other gas expense" for 2016 so that it  
19 lies on the 3-year trend line which begins in 2012. The resulting "other gas  
20 expense" I propose for 2016 is \$470,000, as depicted below, and in Exhibit  
21 Staff/703.



1

2

**Q. Please summarize your proposed adjustment to “other gas expense.”**

3

A. I propose to reduce Avista’s requested “other gas expense” by \$80,000, from

4

\$550,000 to \$470,000.

1

**ISSUE 4. PURCHASED GAS EXPENSE**

2

**Q. Please describe your proposed adjustment of “purchased gas**

3

**expense.”**

4

A. The actual cost of gas is reconciled with customers each year in the Purchased

5

Gas Adjustment (Order No. 14-238 in Docket No. UM 1286). Therefore, I have

6

no proposed adjustment for “purchased gas expense” in this rate case at this

7

time.

1

**ISSUE 5. IRP**

2

**Q. Does Avista make a proposal related to its IRP in this rate case?**

3

A. No.

4

**Q. Do you have an IRP related concern?**

5

A. No. Avista/400, Moorehouse/11-12 presents that Avista filed its 2014 IRP on

6

August 29, 2014 and that the IRP does not identify a need for new resources

7

within the 20-year planning period. There is no connection made in the

8

presentation to the rate case.

9

**Q. Does this conclude your testimony?**

10

A. Yes.

CASE: UG 288  
WITNESS: ERIK COLVILLE

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 701**

**Witness Qualifications Statement**

**October 16, 2015**

WITNESS QUALIFICATIONS STATEMENT

NAME: Erik E. Colville, P.E.

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst  
Energy Resources and Planning Division

ADDRESS: 201 High St. SE., Suite 100  
SALEM, OR. 97301

EDUCATION: Bachelor of Science in Agricultural Engineering  
Washington State University, Pullman, WA, 1979

Master of Business Administration  
City University, Seattle, WA, 1989

Licensed Professional Engineer since 1984, and licensed as such  
in Oregon since 1997

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon  
since June of 2010. I am a Senior Utility Analyst in the Energy  
Resources and Planning Division of the Utility Program. Current  
responsibilities include lead analyst for integrated resource planning  
and resource acquisition, analyst for rate case elements, and other  
regulated utility matters.

I have approximately 36 years of professional engineering  
experience, including approximately 23 years:

- Relating to air, water and soil environmental issues; and
- Evaluating, planning, permitting, designing, and supporting  
construction of energy facilities

CASE: UG 288  
WITNESS: ERIK COLVILLE

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 702**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	05/15/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 122	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

**REQUEST:**

Please provide, in a single electronic spreadsheet format with cell references and formulae intact, for each calendar year from 2005 through 2014, and to the extent as available monthly through 2015, the other gas supply expense results, as well as a breakdown of the other gas supply expense into other gas purchases, purchased gas expenses, natural gas storage transactions, gas used for products extraction, other gas expenses, and Gas Technology Institute categories. Separately identify any related labor expense for each calendar year from 2005 through 2014, and to the extent as available monthly through 2015. Provide results separately for total company and for Oregon. This request relates to Avista/501, Smith/4 at line 37, and Avista/502, Smith/1 at lines 30 through 37.

**RESPONSE:**

Please see Staff\_DR\_122 Attachment A for a breakdown of Other Gas Supply expenses included in this case. Per discussion with Staff, those accounts which are included in the Company's Purchase Gas Cost Adjustment (PGA) have been eliminated from the attachment (ie other gas purchases, purchased gas expenses, natural gas storage transactions, and gas used for products extraction.)



Other Gas Supply Expense  
 Calendar Years 2005-2014

Acct	Description	(a)										(b)
		12/31/2005	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014*	
813010	GTI	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 11,959	\$ 47,508	\$ 43,989	\$ 47,751	\$ 40,632	
	<b>GTI</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 11,959</b>	<b>\$ 47,508</b>	<b>\$ 43,989</b>	<b>\$ 47,751</b>	<b>\$ 40,632</b>	
813000	OTHER EXPENSE - Labor	\$ 387,728	\$ 186,588	\$ 191,991	\$ 239,623	\$ 252,767	\$ 254,295	\$ 268,009	\$ 237,604	\$ 225,823	\$ 229,743	
813000	OTHER EXPENSE - Non Labor	not avail	\$ 231,149	\$ 329,765	\$ 304,732	\$ 288,507	\$ 243,023	\$ 291,882	\$ 266,410	\$ 269,970	\$ 235,939	
	<b>OTHER EXPENSE</b>	<b>\$ 387,728</b>	<b>\$ 417,737</b>	<b>\$ 521,756</b>	<b>\$ 544,355</b>	<b>\$ 541,274</b>	<b>\$ 497,318</b>	<b>\$ 559,891</b>	<b>\$ 504,014</b>	<b>\$ 495,793</b>	<b>\$ 465,681</b>	
	<b>TOTAL</b>	<b>\$ 387,728</b>	<b>\$ 417,737</b>	<b>\$ 521,756</b>	<b>\$ 544,355</b>	<b>\$ 541,274</b>	<b>\$ 509,277</b>	<b>\$ 607,399</b>	<b>\$ 548,003</b>	<b>\$ 543,544</b>	<b>\$ 506,313</b>	

\* Total amount ties to 2014 Restated Historical AMA Base Test Year and excludes all PGA Accounts.

(a) 2011 included two non-recurring transactions.

1	Encana Gas Reserve Write Off	\$ 26,000	The Company elected not to move forward with the Encana Gas Reserve Deals and wrote off expenses accrued for this purpose.
2	Labor Back-fill	\$ 20,000	
	<b>Total</b>	<b>\$ 46,000</b>	

(b) Reduction in non-labor expense from 2013 to 2014 is due to the change in Labor Loading Rates from 63% (Dec. 2013) to 39% (Dec 2014). This is due to various actuarial assumptions for Pension and Medical regarding the discount rate and expected return on assets. Please see Staff\_DR\_059C Confidential Attachment A for year over year comparison.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	05/15/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 123	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

**REQUEST:**

Please provide, in a single electronic spreadsheet format with cell references and formulae intact, for each calendar year from 2005 through 2014, and to the extent as available monthly through 2015, the underground storage operating expense results, including a breakdown of the underground storage operating expense into supervision and engineering, other expenses, and other equipment categories. Separately identify any related labor expense for each calendar year from 2005 through 2014, and to the extent as available monthly through 2015. Provide results separately for total company and for Oregon. This request relates to Avista/501, Smith/4 at line 45, and Avista/502, Smith/1 at lines 41 through 45

**RESPONSE:**

Please see Staff\_DR\_123 Attachment A for yearly values for Jackson Prairie operating expenses for 2009-2013 yearly and monthly values for 2015. Puget Sound Energy is the operating partner for the facility and maintains individual expense account details. The Company records all expenses at a summary level into general ledger account 824000 Natural Gas Storage – Other Gas Supply and 837000 Natural Gas Storage – Other Equipment.

Oregon customers were assigned a portion of the Jackson Prairie facility effective November 1, 2008 with the first O & M charges being incurred January 2009. Prior to this time, Oregon customers' participation in the facility was contracted under Northwest Pipeline SGS-2 rate schedule and flowed through demand costs in the PGA. There are no labor expenses included in the provided values.

**STATE OF OREGON  
 JACKSON PRAIRIE  
 OPERATING EXPENSES**

	<b>OR Only</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>	<b>Jan-15</b>	<b>Feb-15</b>	<b>Mar-15</b>	<b>Apr-15</b>
824000	NAT GAS STORAGE - OTHER EXPENSES	19,152	12,048	39,772	57,988	67,117	69,813	7,022	7,165	4,751	5,741
837000	NAT GAS STORAGE - OTHER EQUIPMENT	17,674	13,041	36,225	48,707	54,844	63,795	3,776	6,020	5,142	5,993
Total		36,826	25,089	75,997	106,695	121,961	133,608	10,798	13,185	9,893	11,733

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	05/15/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 124	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

**REQUEST:**

Please provide, in a single electronic spreadsheet format with cell references and formulae intact, the monthly historical working gas inventory balances (excluding labor dollars) for each storage facility (in both volume and in dollars) and the monthly working gas storage guideline, or goal or target, for each storage facility (in the same volume units as used for the inventory). Provide the monthly data requested above from the first date each storage facility was placed in operation through 2013, and to the extent as available monthly through 2014. Please identify whether the values given above are for beginning or end of month. Separately identify any related labor expense for each calendar year from 2004 through 2013, and to the extent as available monthly through 2014. This request relates to Avista/601, Andrews/4 at line 242, and Avista/602, Andrews/5 at lines 236 through 240.

**RESPONSE:**

Please see Staff\_DR\_124 Attachment A for Storage detail for 09/1999-12/2006.  
Please see Staff\_DR\_124 Attachment B for Storage detail for 01/2007-12/2008.  
Please see Staff\_DR\_124 Attachment C for Storage detail for 01/2008-04/2015.

Data is provided in electronic format as requested. The accounting department maintains spreadsheets in individually grouped workbooks (for instance 09/1999-12/2006) for prior periods. Data is provided for end of month values in the format that is readily available. No labor dollars are included in working gas inventory. Avista injects gas yearly in accordance with operating procedures which require 35% of the facility be full by June 30, 80% by August 31, and 100% by September 30.

Oregon Jackson Prairie Inventory/Prepaid Gas									
Account 164100 GD OR			Contract 100403		GL Account changed to 164105 effective 7/01/2007				
Dekatherms									
	Injected Volumes	Withdrawal Volumes	Volume Adjustments	Volume Balance	Injected Value	Withdrawal Value	Cost Adjustments	Balance	WACOG
Balance				93,736				\$ 187,093.20	\$1.9960
Adjustment to Beginning Balance			(13,736)	80,000			\$ (27,417.06)	\$ 159,676.14	\$1.9960
Sep-99	-	-		80,000	\$ -	\$ -		\$ 159,676.14	\$1.9960
Oct-99	-	-		80,000	\$ -	\$ -		\$ 159,676.14	\$1.9960
Nov-99	-	-		80,000	\$ -	\$ -		\$ 159,676.14	\$1.9960
Dec-99	-	(20,000)		60,000	\$ -	\$ (39,920.00)		\$ 119,756.14	\$1.9960
Jan-00	-	(20,000)		40,000		\$ (39,920.00)		\$ 79,836.14	\$1.9960
Feb-00	-	(20,000)		20,000		\$ (39,920.00)		\$ 39,916.14	\$1.9960
Mar-00	-	(20,000)		-		\$ (39,916.14)		\$ -	
Apr-00	-	-		-		\$ -		\$ -	
May-00	20,000	-		20,000	\$ 56,550.74	\$ -		\$ 56,550.74	\$2.8275
Jun-00	20,000	-		40,000	\$ 71,035.31	\$ -		\$ 127,586.05	\$3.1897
Jul-00	20,000	-		60,000	\$ 79,608.41	\$ -		\$ 207,194.46	\$3.4532
Aug-00	20,000	-		80,000	\$ 65,802.05	\$ -		\$ 272,996.51	\$3.4125
Sep-00	-	-		80,000		\$ -		\$ 272,996.51	\$3.4125
Oct-00	-	-		80,000		\$ -		\$ 272,996.51	\$3.4125
Nov-00	-	-		80,000		\$ -		\$ 272,996.51	\$3.4125
Dec-00	-	(20,000)		60,000		\$ (68,250.00)		\$ 204,746.51	\$3.4124
Jan-01	-	(20,000)		40,000		\$ (68,248.00)		\$ 136,498.51	\$3.4125
Feb-01	-	(20,000)		20,000		\$ (68,250.00)		\$ 68,248.51	\$3.4124
Mar-01	-	(20,000)		-		\$ (68,248.51)		\$ -	#DIV/0!
Apr-01	-	-		-		\$ -		\$ -	#DIV/0!
May-01	20,000	-		20,000	\$ 97,763.11	\$ -		\$ 97,763.11	\$4.8882
Jun-01	20,000	-		40,000	\$ 73,056.63	\$ -		\$ 170,819.74	\$4.2705
Jul-01	20,000	-		60,000	\$ 55,327.99	\$ -		\$ 226,147.73	\$3.7691
Aug-01	20,000	-		80,000	\$ 49,998.37	\$ -		\$ 276,146.10	\$3.4518
Sep-01	-	-		80,000		\$ -		\$ 276,146.10	\$3.4518
Oct-01	-	-		80,000		\$ -		\$ 276,146.10	\$3.4518
Nov-01	-	-		80,000		\$ -		\$ 276,146.10	\$3.4518
Dec-01	-	(20,000)		60,000		\$ (69,036.00)		\$ 207,110.10	\$3.4518
Jan-02	-	(20,000)		40,000		\$ (69,036.00)		\$ 138,074.10	\$3.4519
Feb-02	-	(20,000)		20,000		\$ (69,038.00)		\$ 69,036.10	\$3.4518
Mar-02	-	(20,000)		-		\$ (69,036.10)		\$ -	#DIV/0!
Apr-02	-	-		-		\$ -		\$ -	#DIV/0!
May-02	20,000	-		20,000	\$ 57,233.59	\$ -		\$ 57,233.59	\$2.8617
Jun-02	20,000	-		40,000	\$ 49,801.34	\$ -		\$ 107,034.93	\$2.6759
Jul-02	20,000	-		60,000	\$ 39,920.57	\$ -		\$ 146,955.50	\$2.4493
Aug-02	20,000	-		80,000	\$ 36,571.96	\$ -		\$ 183,527.46	\$2.2941
Sep-02	-	-		80,000		\$ -		\$ 183,527.46	\$2.2941
Oct-02	-	-		80,000		\$ -		\$ 183,527.46	\$2.2941
Nov-02	-	-		80,000		\$ -		\$ 183,527.46	\$2.2941
Dec-02	-	(20,000)		60,000		\$ (45,882.00)		\$ 137,645.46	\$2.2941
Jan-03	-	(20,000)		40,000		\$ (45,882.00)		\$ 91,763.46	\$2.2941
Feb-03	-	(20,000)		20,000		\$ (45,882.00)		\$ 45,881.46	\$2.2941
Mar-03	-	(20,000)		-		\$ (45,881.46)		\$ -	#DIV/0!
Apr-03	-	-		-		#DIV/0!		\$ -	#DIV/0!
May-03	20,000	-		20,000	\$ 95,948.81	\$ -		\$ 95,948.81	\$4.7974
Jun-03	20,000	-		40,000	\$ 95,646.54	\$ -		\$ 191,595.35	\$4.7899
Jul-03	20,000	-		60,000	\$ 101,777.20	\$ -		\$ 293,372.55	\$4.8895
Aug-03	20,000	-		80,000	\$ 84,310.86	\$ -		\$ 377,683.41	\$4.7210
Sep-03	-	-		80,000	\$ 420.37	\$ -		\$ 378,103.78	\$4.7263
Oct-03	-	-		80,000		\$ -		\$ 378,103.78	\$4.7263
Nov-03	-	-		80,000		\$ -		\$ 378,103.78	\$4.7263
Dec-03	-	(20,000)		60,000		\$ (94,526.00)		\$ 283,577.78	\$4.7263
Jan-04	-	(20,000)		40,000		\$ (94,500.00)		\$ 189,077.78	\$4.7269
Feb-04	-	(20,000)		20,000		\$ (94,500.00)		\$ 94,577.78	\$4.7289
Mar-04	-	(20,000)		-		\$ (94,577.78)		\$ -	#DIV/0!
Apr-04	-	-		-		\$ -		\$ -	#DIV/0!
May-04	20,000	-		20,000	\$ 101,550.79	\$ -		\$ 101,550.79	\$5.0775
Jun-04	20,000	-		40,000	\$ 113,018.43	\$ -		\$ 214,569.22	\$5.3642
Jul-04	20,000	-		60,000	\$ 107,747.71	\$ -		\$ 322,316.93	\$5.3719
Aug-04	20,000	-		80,000	\$ 108,112.60	\$ -		\$ 430,429.53	\$5.3804
Sep-04	-	-		80,000		\$ -		\$ 430,429.53	\$5.3804
Oct-04	-	-		80,000		\$ -		\$ 430,429.53	\$5.3804
Nov-04	-	-		80,000		\$ -		\$ 430,429.53	\$5.3804
Dec-04	-	(20,000)		60,000		\$ (107,608.00)		\$ 322,821.53	\$5.3804

Oregon Jackson Prairie Inventory/Prepaid Gas									
Account 164100 GD OR			Contract 100403		GL Account changed to 164105 effective 7/01/2007				
Dekatherms									
	Injected Volumes	Withdrawal Volumes	Volume Adjustments	Volume Balance	Injected Value	Withdrawal Value	Cost Adjustments	Balance	WACOG
Jan-05	-	(20,000)		40,000		\$(107,608.00)		\$ 215,213.53	\$5.3803
Feb-05	-	(20,000)		20,000		\$(107,606.00)		\$ 107,607.53	\$5.3804
Mar-05	-	(20,000)		-		\$(107,607.53)		\$ -	#DIV/0!
Apr-05	-	-		-				\$ -	#DIV/0!
May-05	-	-		-				\$ -	#DIV/0!
Jun-05	42,295	-		42,295	\$ 238,768.46			\$ 238,768.46	\$5.6453
Jul-05	32,546	-		74,841	\$ 198,976.36		\$ 1,062.16	\$ 436,806.98	\$5.8365
Aug-05	4,000	-		78,841	\$ 25,737.81		\$ 0.02	\$ 462,544.81	\$5.8668
Sep-05	3,602	-		82,443	\$ 31,312.01		\$ (66.42)	\$ 493,790.40	\$5.9895
Oct-05	-	-		82,443		\$ -	\$ (21.53)	\$ 493,768.87	\$5.9892
Nov-05	-	-		82,443				\$ 493,768.87	\$5.9892
Dec-05	-	-	13,122	95,565			\$ 82,783.77	\$ 576,552.64	\$6.0331
Jan-06	-	(34,502)		61,063		\$(208,154.02)		\$ 368,398.62	\$6.0331
Feb-06	-	(41,018)		20,045		\$(247,465.70)		\$ 120,932.92	\$6.0331
Mar-06	-	(6,842)		13,203		\$(41,278.47)		\$ 79,654.45	\$6.0331
Apr-06	-	-		13,203		\$ -		\$ 79,654.45	\$6.0331
May-06	27,324	-		40,527	\$ 212,298.49	\$ -		\$ 291,952.94	\$7.2039
Jun-06	29,434	-		69,961	\$ 179,014.64	\$ -		\$ 470,967.58	\$6.7319
Jul-06	25,604	-		95,565	\$ 151,317.08	\$ -		\$ 622,284.66	\$6.5116
Aug-06	-	-		95,565	\$ -	\$ -		\$ 622,284.66	\$6.5116
Sep-06	-	-		95,565	\$ -	\$ -		\$ 622,284.66	\$6.5116
Oct-06	-	-		95,565	\$ -	\$ -		\$ 622,284.66	\$6.5116
Nov-06	-	-		95,565	\$ -	\$ -		\$ 622,284.66	\$6.5116
Dec-06	-	(7,962)		87,603	\$ -	\$(51,845.67)		\$ 570,438.99	\$6.5116

Oregon Plymouth Inventory/Prepaid Gas				Contract 100602					
Account 164200 GD OR									
Dekatherms									
	Injected Volumes	Withdrawal Volumes	Volume Adjustments	Volume Balance	Injected Value	Withdrawal Value	Cost Adjustments	Balance	WACOG
Balance				107,608				\$ 204,356.85	\$ 1.8991
Sep-99	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Oct-99	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Nov-99	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Dec-99	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jan-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Feb-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Mar-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Apr-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
May-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jun-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jul-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Aug-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Sep-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Oct-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Nov-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Dec-00	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jan-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Feb-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Mar-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Apr-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
May-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jun-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jul-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Aug-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Sep-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Oct-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Nov-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Dec-01	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jan-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Feb-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Mar-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Apr-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
May-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jun-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jul-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Aug-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Sep-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Oct-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Nov-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Dec-02	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jan-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Feb-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Mar-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Apr-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
May-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jun-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jul-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Aug-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Sep-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Oct-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Nov-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Dec-03	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jan-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Feb-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Mar-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Apr-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
May-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jun-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jul-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Aug-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Sep-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Oct-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Nov-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Dec-04	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Jan-05	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Feb-05	0	0		107,608	\$ -	\$ -		\$ 204,356.85	\$ 1.8991
Mar-05	64,792	0		172,400	\$ 341,356.65	\$ -		\$ 545,713.50	\$ 3.1654
Apr-05	-	0		172,400	\$ -	\$ -		\$ 545,713.50	\$ 3.1654
May-05	-	0		172,400	\$ -	\$ -		\$ 545,713.50	\$ 3.1654
Jun-05	-	0		172,400	\$ -	\$ -		\$ 545,713.50	\$ 3.1654
Jul-05	-	0		172,400	\$ -	\$ -		\$ 545,713.50	\$ 3.1654
Aug-05	-	0		172,400	\$ -	\$ -		\$ 545,713.50	\$ 3.1654

Oregon Plymouth Inventory/Prepaid Gas				Contract 100602					
Account 164200 GD OR									
Dekatherms									
	Injected	Withdrawal	Volume	Volume	Injected	Withdrawal	Cost		
Sep-05	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Oct-05	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Nov-05	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Dec-05	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Jan-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Feb-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Mar-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Apr-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
May-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Jun-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Jul-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Aug-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Sep-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Oct-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Nov-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654
Dec-06	-	0	172,400	\$	-	\$	-	\$ 545,713.50	\$ 3.1654



Oregon Jackson Prairie Inventory/Prepaid Gas					Storage Leased - Account for fuel as a reduction of injection (808200). Priced at daily injection price. AVA leases from JP/NWP for OR and gets charged for fuel only on injections from NWP					
Account 164105 GD OR			Contract 100403							
Dekatherms										
GL Account	808200 GD OR	808100 GD OR	808200 GD OR		808200 GD OR	808100 GD OR	808100 GD OR	808200 GD OR	164105 GD OR	
	Injected	Withdrawal	Injection	Volume	Injected	Withdrawal	Adjustments	Injection		Inventory
	Volumes	Volumes	Fuel	Balance	Value	Value		Fuel	Balance	WACOG
			Volumes					Value		
Balance Dec-06				87,603					\$ 570,438.99	\$ 6.51160
Jan-07	0	(50,368)	0	37,235	\$0.00	(\$327,978.25)		\$0.00	\$ 242,460.74	\$ 6.51164
Feb-07	0	(22,066)	0	15,169	\$0.00	(\$143,685.75)		\$0.00	\$ 98,774.99	\$ 6.51163
Mar-07	0	(8,350)	0	6,819	\$0.00	(\$54,372.15)		\$0.00	\$ 44,402.84	\$ 6.51164
Apr-07	0	(6,819)	0	-	\$0.00	(\$44,402.84)		\$0.00	\$ -	\$ 6.51164
May-07	15,198	0	(69)	15,129	\$89,348.40	\$0.00		(\$417.51)	\$ 88,930.89	\$ 5.87817
Jun-07	26,998	0	(120)	42,007	\$131,954.63	\$0.00		(\$653.60)	\$ 220,231.92	\$ 5.24274
Jul-07	27,957	0	(124)	69,840	\$132,265.05	\$0.00		(\$639.17)	\$ 351,857.80	\$ 5.03806
Aug-07	19,476	0	(93)	89,223	\$81,626.66	\$0.00		(\$461.20)	\$ 433,023.26	\$ 4.85327
Sep-07	6,366	0	(30)	95,559	\$18,931.54	\$0.00		(\$143.72)	\$ 451,811.08	\$ 4.72809
Oct-07	6	0	0	95,565	\$23.62	\$0.00		\$0.00	\$ 451,834.70	\$ 4.72804
Nov-07	0	(1,500)	0	94,065	\$0.00	(\$7,091.56)		\$0.00	\$ 444,743.14	\$ 4.72804
Dec-07	0	(15,779)	0	78,286	\$0.00	(\$7.13)		\$0.00	\$ 444,736.01	
YTD 2007 Activity	96,001	(104,882)	(436)		\$454,149.90	(\$577,537.68)		(\$2,315.20)		
Balance Dec-07				78,286					\$ 444,736.01	\$ 4.72804
Jan-08	0	(31,018)	0	47,268	\$0.00	\$ (221,251.25)		\$0.00	\$ 223,484.76	\$ 4.72804
Feb-08	0	(27,154)	0	20,114	\$0.00	\$ (128,385.06)		\$0.00	\$ 95,099.70	\$ 4.72804
Mar-08	0	(20,114)	0	-	\$0.00	\$ (95,099.70)		\$0.00	\$ -	\$ -
Apr-08	0	-	0	-	\$0.00	\$ -		\$0.00	\$ -	\$ -
May-08	30,080	-	(80)	30,000	\$279,464.26	\$ -		(\$743.26)	\$ 278,721.00	\$ 9.29070
Jun-08	26096	-	(64)	56,032	\$248,497.58	\$ -		(\$610.62)	\$ 526,607.96	\$ 9.39834
Jul-08	8032	-	(16)	64,048	\$77,276.88	\$ -		(\$153.95)	\$ 603,730.89	\$ 9.42623
Aug-08	22121	-	(55)	86,114	\$137,882.35	\$ -		(\$342.92)	\$ 741,270.32	\$ 8.60801
Sep-08	9477	-	(26)	95,565	\$47,560.29	\$ -		(\$130.70)	\$ 788,699.91	\$ 8.25302
Oct-08	0	-	0	95,565	\$1,935.00	\$ -		(\$5.87)	\$ 790,629.04	\$ 8.27321
Nov-08	0	-	0	95,565	\$0.00	\$ -		\$0.00	\$ 790,629.04	\$ 8.27321
Dec-08	0	(26,343)	0	69,222	\$0.00	\$ (217,941.16)		\$0.00	\$ 572,687.88	\$ 8.27321
YTD 2008 Activity	95,806	(104,629)	(241)		\$792,616.36	(\$662,677.17)		(\$1,987.32)		\$127,951.87

Staff/02  
Colville/10

Oregon JP Storage/Prepaid Gas				Storage Owned - Account for fuel as a withdrawal (808100). Price at WACOG. AVA gets a 1/3 charge from JP for fuel volumes burnt on both injections and withdrawals and assigns volumes to AN/OR for 100408 owned.							
Account 164100 GD OR			Contract 100408								
Dekatherms											
GL Account	808200 GD OR	808100 GD OR	808100 GD OR		808200 GD OR	808100 GD OR	808100 GD OR	808100 GD OR	164100 GD OR		
	Injected Volumes	Withdrawal Volumes	Injection Fuel Volumes	Volume Balance	Injected Value	Withdrawal Value	Adjustments	Injection Fuel Value	Balance	Inventory WACOG	
Balance Dec-06				0					\$0.00		
Jan-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00		
Feb-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00		
Mar-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00		
Apr-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00		
May-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00		
Jun-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00		
Jul-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00	\$ 4,22109	
Aug-07	55,163	(13,201)	0	41,962	\$230,845.65	(\$55,722.61)		\$0.00	\$175,123.04	\$4,17337	
Sep-07	38,931	(11,116)	(117)	69,660	\$113,351.86	(\$39,624.76)		(\$436.52)	\$248,413.62	\$3,56609	
Oct-07	0	(13,057)	(153)	56,450	\$0.00	(\$46,573.50)		\$545.58	\$202,385.70	\$3,58522	
Nov-07	0	(11,477)	0	44,973	\$0.00	(\$40,925.72)		(\$1,091.16)	\$160,368.82	\$3,56589	
Dec-07	0	(10,794)	0	34,179	\$0.00	(\$113,086.75)		\$0.00	\$47,282.07	\$1,38337	
YTD 2007 Activity	94,094	(59,645)	(270)		\$344,197.51	(\$295,933.34)		(\$982.10)			
Balance Dec-07				34,179					\$47,282.07		
Jan-08	-	(7,584)	-	26,595	\$0.00	\$ 47,552.83		\$0.00	\$94,834.90	\$3,56589	
Feb-08	-	(10,937)	-	15,658	\$0.00	(\$39,000.14)		\$0.00	\$55,834.76	\$3,56589	
Mar-08	-	(11,282)	-	4,376	\$0.00	(\$40,230.37)		\$0.00	\$15,604.39	\$3,56590	
Apr-08	11,000	(11,659)	-	3,717	\$105,784.00	(\$2,043.96)		\$0.00	\$29,344.43	\$7,89465	
May-08	65,874	(10,793)	(23)	58,775	\$ 613,862.85	(\$100,321.26)		\$ (195.66)	\$542,690.36	\$9,23335	
Jun-08	15,000	(9,577)	-	64,198	\$ 139,032.00	(\$8,293.55)		\$ (203.52)	\$593,225.29	\$9,24056	
Jul-08	46,500	(8,774)	(13)	101,911	\$ 415,978.50	(\$80,251.83)		\$ (121.36)	\$928,830.60	\$9,11413	
Aug-08	83,211	(11,741)	(148)	173,233	\$ 490,705.30	(\$91,988.39)		\$ (1,261.70)	\$1,326,285.81	\$7,65608	
Sep-08	55,000	(5,345)	(193)	222,695	\$ 270,447.00	(\$37,393.25)		\$ (1,380.57)	\$1,557,958.99	\$6,99593	
Oct-08	21,615	(12,091)	(262)	231,957	\$ 72,466.15	(\$80,798.17)		\$ (1,748.36)	\$1,547,878.61	\$6,67313	
Nov-08	-	(61)	-	231,896	\$ -	\$ -		\$ (407.06)	\$1,547,471.55	\$6,67313	
Dec-08	-	(48,063)	-	183,833	\$ -	(\$320,730.64)		\$ -	\$1,226,740.91	\$6,67313	
YTD 2008 Activity	298,200	(147,907)	(639)		\$2,108,275.80	(\$923,498.73)		(\$5,318.23)			

Staff/702  
Colville/11

Oregon Mist Storage/Prepaid Gas					Storage Leased - Account for fuel as a reduction of injection (808200). Priced at daily injection price. AVA leases from Mist for OR and gets charged for fuel only on injections from NWP					
Account 164110 GD OR										
Dekatherms										
GL Account	808200 GD OR	808100 GD OR	808200 GD OR		808200 GD OR	808100 GD OR	808100 GD OR	808200 GD OR	164110 GD OR	
	Injected Volumes	Withdrawal Volumes	Injection Fuel Volumes	Volume Balance	Injected Value	Withdrawal Value	Adjustments	Injection Fuel Value	Balance	Inventory WACOG
Balance Dec-06				0					\$0.00	
Jan-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00	
Feb-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00	
Mar-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00	
Apr-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00	
May-07	0	0	0	0	\$0.00	\$0.00		\$0.00	\$0.00	
Jun-07	105,312	0	(2,108)	103,204	\$513,728.12	\$0.00		(\$10,139.12)	\$503,589.00	\$ 4.87955
Jul-07	79,085	0	(1,580)	180,709	\$374,084.07	\$0.00		(\$7,700.15)	\$869,972.92	\$ 4.81422
Aug-07	64,882	0	(1,299)	244,292	\$270,484.97	\$0.00		(\$6,166.57)	\$1,134,291.32	\$ 4.64318
Sep-07	42,926	0	(855)	286,363	\$126,543.83	\$0.00		(\$3,854.41)	\$1,256,980.74	\$ 4.38947
Oct-07	13,910	0	(273)	300,000	\$69,007.44	\$0.00		\$0.00	\$1,325,988.18	\$ 4.41996
Nov-07	0	0	0	300,000	\$0.00	\$0.00		(\$1,355.08)	\$1,324,633.10	\$ 4.41544
Dec-07	0	0	0	300,000	\$0.00	\$0.00		\$0.00	\$1,324,633.10	\$ 4.41544
YTD 2007 Activity	306,115	0	(6,115)		\$1,353,848.43	\$0.00		(\$29,215.33)		
Balance Dec-07				300,000					\$1,324,633.10	\$ 4.41544
Jan-08	-	(155,000)	-	145,000	\$0.00	(\$684,393.60)		\$0.00	\$640,239.50	\$ 4.41544
Feb-08	-	(145,000)	-	-	\$0.00	(\$640,239.50)		\$0.00	\$0.00	\$ -
Mar-08	-	-	-	-	\$ -	\$ -		\$ -	\$0.00	\$ -
Apr-08	-	-	-	-	\$ -	\$ -		\$ -	\$0.00	\$ -
May-08	69,478	-	(1,384)	68,094	\$ 643,471.03	\$ -		\$ (12,817.97)	\$630,653.06	\$ 9.26151
Jun-08	150,204	-	(3,004)	215,294	\$ 1,396,460.21	\$ -		\$ (27,927.61)	\$1,999,185.66	\$ 9.28584
Jul-08	126,542	-	(2,542)	339,294	\$ 1,132,016.18	\$ -		\$ (22,740.18)	\$3,108,461.66	\$ 9.16156
Aug-08	100,149	-	(1,995)	437,448	\$ 640,230.85	\$ -		\$ (12,754.18)	\$3,735,938.33	\$ 8.54030
Sep-08	63,833	-	(1,281)	500,000	\$ 321,787.40	\$ -		\$ (6,456.46)	\$4,051,269.27	\$ 8.10254
Oct-08	-	-	-	500,000	\$ 2,962.49	\$ -		\$ (59.99)	\$4,054,171.77	\$ 8.10834
Nov-08	-	-	-	500,000	\$ -	\$ -		\$ -	\$4,054,171.77	\$ 8.10834
Dec-08	-	(88,300)	-	411,700	\$ -	(\$715,966.41)		\$ -	\$3,338,205.36	\$ 8.10834
YTD 2008 Activity	510,206	(388,300)	(10,206)		\$4,136,928.16	(\$2,040,599.51)		(\$82,756.39)		

Oregon Storage Inventory										
Account Totals										
Dekatherms										
2009-2015										
	Injected Volumes	Withdrawal Volumes	Injection Fuel Volumes	Volume Balance	Injected Value	Withdrawal Value	Injection Fuel Value	Balance	Inventory WACOG	Injection Prices
Balance Dec-08				664,755				\$ 5,137,633.64		
Jan-09	-	(228,997)	(145)	435,613	-	(1,671,952.58)	(662.65)	\$ 3,465,018.41	\$ 7.9544	\$ 4.5700
Feb-09	-	(284,997)	(314)	150,302	-	(2,317,303.43)	(1,152.38)	\$ 1,146,562.60	\$ 7.6284	\$ 3.6700
Mar-09	194,315	(150,304)	(2,877)	191,436	609,230.00	(1,146,563.10)	(9,020.18)	\$ 600,209.32	\$ 3.1357	\$ 3.1353
Apr-09	100,181	(30,032)	(665)	260,920	273,790.39	(93,599.24)	(1,953.63)	\$ 778,446.84	\$ 2.9835	\$ 2.7316
May-09	406,700	-	(3,667)	663,953	1,170,503.71	-	(10,610.52)	\$ 1,938,340.03	\$ 2.9194	\$ 2.8779
Jun-09	250,182	(118,158)	(3,821)	792,156	678,874.10	(337,521.56)	(10,437.82)	\$ 2,269,254.75	\$ 2.8647	\$ 2.7132
Jul-09	40,569	(273,952)	(5)	558,768	121,333.47	(786,373.09)	(13.85)	\$ 1,604,201.28	\$ 2.8710	\$ 2.9908
Aug-09	106,066	(46,066)	(1,231)	617,537	293,082.39	(134,318.30)	(3,352.85)	\$ 1,759,612.52	\$ 2.8494	\$ 2.7637
Sep-09	429,113	(186,204)	(2,638)	857,808	1,170,497.87	(503,348.04)	(7,328.82)	\$ 2,419,433.53	\$ 2.8205	\$ 2.7274
Oct-09	21,084	-	(411)	878,481	88,578.89	-	(1,145.23)	\$ 2,506,867.19	\$ 2.8536	\$ 4.2294
Nov-09	26,730	(47,272)	-	857,939	77,239.17	(136,699.19)	-	\$ 2,447,407.17	\$ 2.8527	\$ 2.8896
Dec-09	78,966	(309,740)	(276)	626,889	438,633.68	(887,845.13)	(798.11)	\$ 1,997,397.61	\$ 3.1862	\$ 5.5641
2009 Activity	1,653,906	(1,675,722)	(16,050)		4,921,764	(8,015,524)	(46,476)			
Balance Dec-09				626,889				\$ 1,997,397.64		
Jan-10	-	(161,283)	(657)	464,949	-	(530,223.89)	(2,689.96)	\$ 1,464,483.79	\$ 3.1498	\$ 4.0943
Feb-10	-	(316,019)	(145)	148,785	-	(1,041,852.32)	(593.64)	\$ 422,037.83	\$ 2.8366	\$ 4.0941
Mar-10	328	(148,785)	(328)	-	1,214.88	(421,873.91)	(1,379.28)	\$ (0.48)	\$ -	\$ -
Apr-10	153,523	-	(1,478)	152,045	570,329.39	-	(5,454.09)	\$ 564,874.82	\$ 3.7152	\$ 3.7152
May-10	304,300	-	(3,872)	452,473	1,147,836.56	-	(14,606.00)	\$ 1,698,105.38	\$ 3.7529	\$ 3.7721
Jun-10	200,850	-	(2,550)	650,773	823,299.11	-	(10,403.21)	\$ 2,511,001.28	\$ 3.8585	\$ 4.0993
Jul-10	142,120	(107,818)	(1,885)	683,190	531,967.70	(414,586.11)	(7,069.76)	\$ 2,621,313.11	\$ 3.8369	\$ 3.7430
Aug-10	140,096	(141,794)	(1,984)	679,508	455,552.08	(540,412.17)	(6,411.66)	\$ 2,530,041.36	\$ 3.7233	\$ 3.2520
Sep-10	201,488	(41,630)	(1,708)	837,658	669,649.86	(153,062.06)	(5,894.05)	\$ 3,040,935.11	\$ 3.6303	\$ 3.3234
Oct-10	20,768	-	(773)	857,653	69,962.09	-	(4,205.18)	\$ 3,106,692.02	\$ 3.6223	\$ 3.2887
Nov-10	6,000	(56,187)	-	807,466	24,553.38	(202,518.97)	-	\$ 2,928,726.43	\$ 3.6271	\$ 4.0922
Dec-10	97,515	(184,055)	(158)	720,768	387,244.45	(674,699.70)	(590.34)	\$ 2,640,680.84	\$ 3.6637	\$ 3.9715
2010 Activity	1,266,988	(1,157,571)	(15,538)		4,681,610	(3,979,229)	(59,097)			
Balance Dec-10				720,768				\$ 2,640,681.64		
Jan-11	-	(229,500)	(35)	491,233	-	(838,800.08)	-	\$ 1,801,881.56	\$ 3.6681	\$ -
Feb-11	-	(364,523)	(153)	126,557	-	(1,339,458.27)	-	\$ 462,423.29	\$ 3.6539	\$ -
Mar-11	-	(81,460)	(568)	44,529	-	(297,738.16)	-	\$ 164,685.13	\$ 3.6984	\$ -
Apr-11	-	-	-	44,529	-	-	-	\$ 164,685.13	\$ 3.6984	\$ -
May-11	209,513	-	-	254,042	827,751.25	-	-	\$ 992,436.38	\$ 3.9066	\$ 3.9508
Jun-11	96,107	-	(371)	349,778	407,830.99	-	(1,502.58)	\$ 1,398,764.79	\$ 3.9990	\$ 4.2443
Jul-11	158,856	(78,426)	(98)	430,110	647,010.95	(315,466.62)	(395.38)	\$ 1,729,913.74	\$ 4.0220	\$ 4.0730
Aug-11	330,781	-	(368)	760,523	1,266,830.00	-	(1,437.00)	\$ 2,995,306.74	\$ 3.9385	\$ 3.8297
Sep-11	159,665	-	(1,286)	918,902	602,657.00	-	(5,054.00)	\$ 3,592,909.74	\$ 3.9100	\$ 3.7732
Oct-11	-	-	(629)	918,273	-	-	(2,463.00)	\$ 3,590,446.74	\$ 3.9100	\$ 3.9570
Nov-11	-	(14,400)	-	903,873	-	(56,393.00)	-	\$ 3,534,053.74	\$ 3.9099	#DIV/0!
Dec-11	-	(223,851)	(37)	679,985	-	(876,643.00)	(145.00)	\$ 2,657,265.74	\$ 3.9078	\$ 3.9489
2011 Activity	954,922	(992,160)	(3,545)		3,752,080	(3,724,499)	(10,997)			
Balance Dec-11				686,383				\$ 2,677,417.88		
Jan-12	2,513	(205,811)	(570)	482,515	6,156.97	(802,456.01)	(2,187.67)	\$ 1,878,931.17	\$ 3.8940	\$ 2.0429

Oregon Storage Inventory										
Account Totals										
Dekatherms										
2009-2015										
	Injected Volumes	Withdrawal Volumes	Injection Fuel Volumes	Volume Balance	Injected Value	Withdrawal Value	Injection Fuel Value	Inventory Balance	WACOG	Injection Prices
Feb-12	5,884	(188,293)	(671)	299,435	14,310.88	(719,526.68)	(2,616.08)	\$ 1,171,099.29	\$ 3.9110	\$ 2.2434
Mar-12	193	(58,823)	(647)	240,158	548.93	(230,022.00)	(2,437.78)	\$ 939,188.44	\$ 3.9107	\$ 4.1605
Apr-12	154,720	-	(496)	394,382	275,399.06	245.97	(1,619.66)	\$ 1,213,213.81	\$ 3.0762	\$ 1.7752
May-12	162,186	(613)	(496)	555,459	322,968.86	(1,403.64)	(1,500.31)	\$ 1,533,278.72	\$ 2.7604	\$ 1.9882
Jun-12	362,203	(72,009)	(265)	845,388	751,898.50	(184,486.80)	(668.42)	\$ 2,100,022.00	\$ 2.4841	\$ 2.0756
Jul-12	6,083	(3,191)	(751)	847,529	15,544.40	(8,183.67)	(1,873.80)	\$ 2,105,508.93	\$ 2.4843	\$ 2.5639
Aug-12	249,591	(217,841)	(464)	878,815	587,182.00	(542,050.66)	(1,125.69)	\$ 2,149,514.58	\$ 2.4459	\$ 2.3524
Sep-12	139,130	(139,130)	(156)	878,659	342,379.80	(341,868.16)	(343.07)	\$ 2,149,683.15	\$ 2.4465	\$ 2.4612
Oct-12	11,075	(12,191)	-	877,543	36,860.63	(38,592.93)	-	\$ 2,147,950.85	\$ 2.4477	\$ 3.3283
Nov-12	4,505	(4,448)	-	877,600	15,618.89	(15,225.02)	-	\$ 2,148,344.72	\$ 2.4480	\$ 3.4670
Dec-12	1,918	(20,919)	-	858,599	6,471.32	(53,823.13)	-	\$ 2,100,992.91	\$ 2.4470	\$ 3.3740
2012 Activity	1,100,001	(923,269)	(4,516)		2,375,340	(2,937,393)	(14,372)			
Balance Dec-12				858,599				\$ 2,100,992.88		
Jan-13	8,703	(783,846)	(43)	83,413	28,064.87	(1,931,089.76)	(105.89)	\$ 197,862.10	\$ 2.3721	\$ 3.2285
Feb-13	4,645	(3,227)	(2,625)	82,206	15,546.23	(10,759.69)	(6,464.48)	\$ 196,184.16	\$ 2.3865	\$ 4.4959
Mar-13	-	(1,446)	-	80,760	-	(4,876.80)	-	\$ 191,307.36	\$ 2.3688	#DIV/0!
Apr-13	-	(77,565)	-	3,195	-	(183,898.93)	-	\$ 7,408.43	\$ 2.3188	#DIV/0!
May-13	225,222	(281)	(118)	228,018	820,616.74	(1,058.84)	(422.50)	\$ 826,543.83	\$ 3.6249	\$ 3.6436
Jun-13	199,268	(90,548)	(599)	336,139	665,148.59	(319,063.29)	(2,091.39)	\$ 1,170,537.74	\$ 3.4823	\$ 3.3375
Jul-13	138,233	(499)	(213)	401,657.49	401,657.49	(1,238.68)	(736.95)	\$ 1,570,219.60	\$ 3.3151	\$ 2.9048
Aug-13	272,105	(14)	(378)	745,373	707,698.53	(33.61)	(1,216.71)	\$ 2,276,667.81	\$ 3.0544	\$ 2.6000
Sep-13	142,235	(5,207)	(845)	881,556	281,606.87	(15,754.47)	(2,516.66)	\$ 2,540,003.55	\$ 2.8813	\$ 1.9739
Oct-13	74,693	(507)	(543)	955,199	217,587.03	(1,438.59)	(1,579.93)	\$ 2,754,572.06	\$ 2.8838	\$ 2.9131
Nov-13	46,282	(276,395)	(72)	725,014	184,447.99	(812,432.41)	(209.49)	\$ 2,126,378.15	\$ 2.9329	\$ 3.9870
Dec-13	55,764	(320,008)	(575)	460,195	259,319.61	(970,335.10)	(1,693.70)	\$ 1,413,668.96	\$ 3.0719	\$ 4.6681
2013 Activity	1,167,150	(1,559,543)	(6,011)		3,581,694	(4,251,980)	(17,038)			
Balance Dec-13				460,195				\$ 1,413,668.88		
Jan-14	2,719	(154,386)	(805)	307,723	11,837.19	(475,234.99)	(2,510.19)	\$ 947,760.89	\$ 3.0799	\$ 4.8730
Feb-14	855	(202,262)	(717)	105,599	5,351.86	(625,250.40)	(2,235.79)	\$ 325,626.56	\$ 3.0836	\$ 22.5802
Mar-14	-	(104,512)	(850)	237	-	(321,941.29)	(2,650.57)	\$ 1,034.70	\$ 4.3658	\$ 3.1183
Apr-14	-	(54)	(487)	(304)	-	(336.79)	(1,518.63)	\$ (820.72)	\$ 2.6997	\$ 3.1183
May-14	261,314	(1)	(48)	260,961	1,125,674.35	(6.32)	(168.28)	\$ 1,124,679.03	\$ 4.3098	\$ 4.3079
Jun-14	76,993	-	(311)	337,643	341,072.29	-	(1,262.12)	\$ 1,464,489.20	\$ 4.3374	\$ 4.4314
Jul-14	168,598	-	(130)	506,111	669,997.47	-	(682.36)	\$ 2,133,804.31	\$ 4.2161	\$ 3.9730
Aug-14	251,842	-	(249)	757,704	949,658.07	-	(984.36)	\$ 3,082,478.02	\$ 4.0682	\$ 3.7707
Sep-14	146,510	(10,044)	(805)	893,365	551,411.82	(40,363.02)	(3,224.82)	\$ 3,590,302.00	\$ 4.0189	\$ 3.7623
Oct-14	12,958	(184)	(356)	905,783	42,591.36	(701.19)	(1,430.63)	\$ 3,630,761.54	\$ 4.0084	\$ 3.2662
Nov-14	63,934	(130,758)	(49)	838,910	227,824.23	(519,926.53)	(195.34)	\$ 3,338,463.90	\$ 3.9795	\$ 3.5631
Dec-14	78,230	(124,120)	(392)	792,628	228,979.01	(485,781.43)	(1,547.72)	\$ 3,080,113.76	\$ 3.8860	\$ 2.9219
2014 Activity	1,063,953	(726,321)	(5,199)		4,154,398	(2,469,542)	(18,411)			

11/14

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	05/15/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 125	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

**REQUEST:**

Please provide, in the spreadsheet requested above, the historical cushion gas inventory balances for each storage facility (in both volume and in dollars), by month from the first date each storage facility was placed in operation through 2014, and to the extent as available monthly through 2015. For the dollar values provided, please provide an explanation as to how the dollar value was derived. Please identify whether the values given above are for beginning or end of month. Separately identify any related labor expense for each calendar year from 2005 through 2014, and to the extent as available monthly through 2015. Provide results separately for total company and for Oregon. This request relates to Avista/501, Smith/4 at line 246 through 252, and Avista/502, Smith/5 at lines 246 through 252.

**RESPONSE:**

Working gas capacity, as requested in Staff\_DR\_124 changes every month based on daily/monthly injections and withdrawals. Cushion gas, however, remains constant unless there is a major expansion completed. Oregon customers have participated in two expansions of the facility. Balances are summarized in the table below:

	Ending Balance 10/31/2008	Ending Balance 05/31/2011
Cushion Gas Dth	174,964	495,223
Cushion Gas \$	\$976,027	\$1,711,623

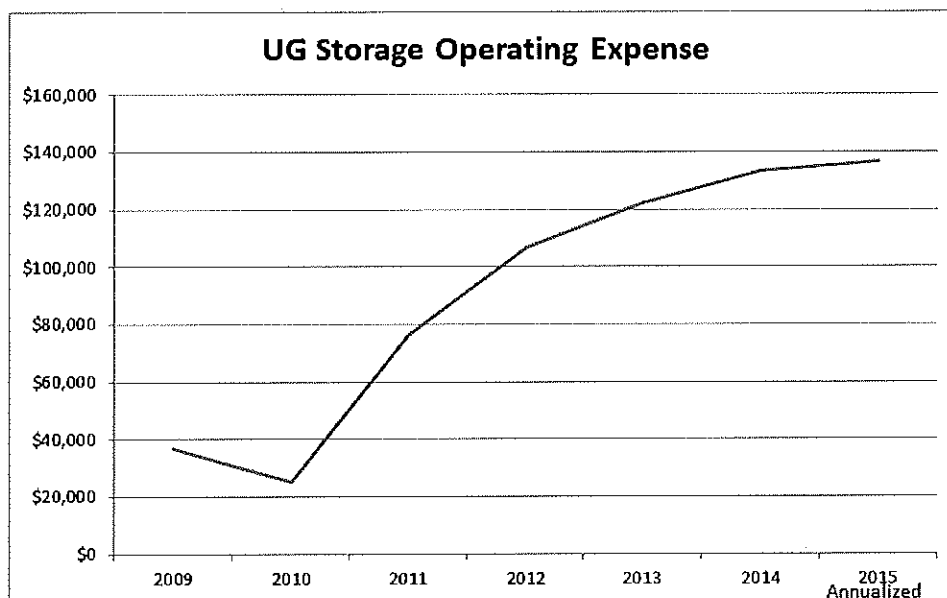
The cushion gas value is based on the cost of the cushion gas as it was being injected into the facility in accordance with GAAP. No labor dollars are included. The above balances include both recoverable FERC account 117.1 and non-recoverable 352.3.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/07/2015
CASE NO:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 208	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

**REQUEST:**

Related to Avista's response to Staff DR 123, please provide a description of the cause for 2010 underground storage operating expenses deviating from the 2009 and 2011 expenses. Refer to the figure below.



**RESPONSE:**

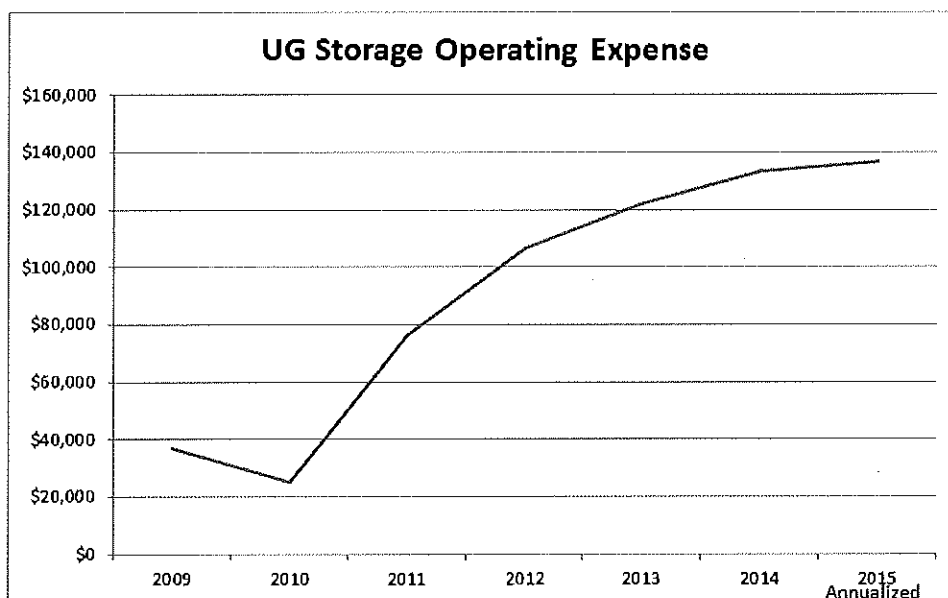
Beginning in May 2011, Oregon's share of Jackson Prairie operating and maintenance expenses increased from 3.08% to 9.65% corresponding with the increase in capacity for Oregon customers. This increase in allocation percentage is the primary reason for the increase in expenses between 2010 and 2011. Please see the Company's response to Staff\_DR\_209 for a table summarizing the allocation change. In addition, there is a timing lag associated with invoice processing and expense recognition because Avista is not the operating partner for Jackson Prairie. For example, \$46,000 of costs incurred in 2010 were expensed in 2011.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/07/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 209	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

**REQUEST:**

Related to Avista’s response to Staff DR 123, please provide a description of the cause for the more rapid increase in expenses before 2012 than after 2012. Refer to the figure below.



**RESPONSE:**

As noted in the Company’s response to Staff\_DR\_208, beginning in May 2011 Oregon’s share of Jackson Prairie operating and maintenance expenses increased from 3.08% to 9.65% corresponding with the increase in capacity for Oregon customers. This is the primary contributor for more rapid increase in expenses pre-2012 than post-2012.

The table below summarizes this change:



<b>Calculations for JP Costs Allocation</b>		
<b>Jackson Praire (JP) Allocation</b>		
	<b>Dth</b>	<b>Allocation</b>
<b>January 2009 - April 2011</b>		
Washington & Idaho (AN)	5,234.666	61.38%
Oregon	262.446	3.08%
Avista Energy Capacity release to Shell	3,030.901	35.54%
<b>Total Capacity</b>	<b>8,528.013</b>	<b>100.00%</b>
<b>May 2011 - Current</b>		
Washington & Idaho (AN)	7,704.676	90.35%
Oregon	823.337	9.65%
<b>Total Capacity</b>	<b>8,528.013</b>	<b>100.00%</b>

CASE: UG 288  
WITNESS: ERIK COLVILLE

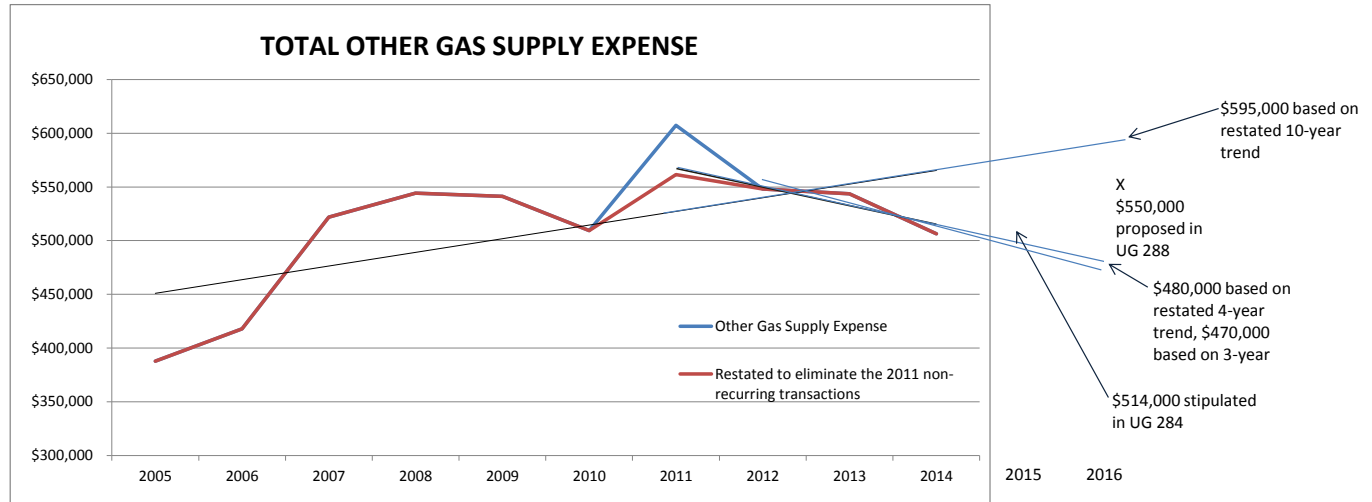
**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 703**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**





CASE: UG 288  
WITNESS: BRIAN BAHR

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 800**

**Medical Benefits, Wages & Salaries,  
Property Taxes, Pension Adjustment**

**Opening Testimony**

**October 16, 2015**

**CERTAIN INFORMATION CONTAINED IN  
STAFF EXHIBIT 800  
PAGES 7, 9-12, and 14  
ARE CONFIDENTIAL AND SUBJECT TO PROTECTIVE  
ORDER NO. 15-141 IN DOCKET NO. UG 288.**

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Brian Bahr. My business address is 201 High St. SE., Suite 100,  
3 Salem, Oregon 97301.

4 **Q. Please describe your educational background and work experience.**

5 A. My Witness Qualification Statement is found in Exhibit Staff/801.

6 **Q. What is the purpose of your testimony?**

7 A. The purpose of my testimony is to respond to specific issues in Avista  
8 Corporation’s (Avista or Company) request for general rate revision. Staff  
9 responds to the issues of medical benefits, wages and salaries, property taxes,  
10 and pensions and postretirement benefits.

11 **Q. Did you prepare an exhibit for this docket?**

12 A. Yes. I prepared Exhibit Staff/802, consisting of 35 pages, and Confidential  
13 Exhibit Staff/803, consisting of 14 pages. The exhibits contain analysis,  
14 responses to Staff data requests, and external references that support Staff’s  
15 recommendations.

16 **Q. How is your testimony organized?**

17 A. My testimony is organized as follows:

18	Summary of Recommendations.....	2
19	Issue 1, Pensions and Postretirement Benefits .....	3
20	Issue 2, Medical Benefits .....	14
21	Issue 3, Property Taxes .....	17
22	Issue 4, Wages, Salaries, and Incentives .....	20

1

**Summary of Recommendations**

2

**Q. Please provide a summary of Staff's recommendations.**

3

A. The following table illustrates the adjustments proposed by Staff.

4

**Table 1. Adjustments proposed by Staff**

	<u>Adjustment (000)</u>	<u>Expense or Rate Base</u>
FAS 87 Pension Cost	\$348	Expense
Postretirement Benefits	\$24	Expense
Prepaid Pension Asset (net of deferred taxes)	\$5,655	Rate Base
Debt Interest on Prepaid Pension Asset	\$63	Expense
Medical Benefits	\$175	Expense
Property Taxes	\$67	Expense
Wages & Salaries	\$62	Expense
Wages & Salaries	\$5	Rate Base
Incentives	\$288	Expense
Incentives	\$278	Rate Base
Payroll Taxes	\$17	Expense
Depreciation (for Cap adj)	\$0.2	Expense



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22**Issue 1, Pensions and Postretirement Benefits****Q. How are pension costs typically treated by the Commission?**

A. Though most expenses approved for inclusion in rates are based on cash costs during a company's test year, cash payments from a company to its pension fund can be volatile from year to year, depending on market and interest rates, as well as changing pension regulations. Because of the volatility of these cash payments, the Commission currently uses accrual pension costs as a proxy for cash payments. These accrual pension costs are calculated in accordance with applicable standardized accounting guidance and called a Company's Financial Accounting Standard (FAS) 87 expense.

The Commission recently conducted a general investigation into the recovery of pension costs in Docket No. UM 1633. In that docket, the Commission investigated whether FAS 87 expense should be continued for use in rate recovery of pension costs, whether a company's prepaid pension asset should be included in rate base, and whether there are more effective methods of pension cost recovery than those currently in practice in Oregon. Commission Order No. 15-226 reaffirmed the current pension cost recovery method for use in setting rates (ie. Forecasted FAS 87 expense used for ratemaking, net prepaid pension asset not allowed in rate base).

**Q. Please describe the Company's request regarding pension costs.**

A. The Company's proposed revenue requirement includes the test year pension expense of \$21 million on a total company basis, which is approximately

1           \$998,000 on an Oregon-allocated basis.<sup>1</sup> Also included is Postretirement  
2           Medical Benefit (FAS 106) expense of \$8.8 million (total company), which is  
3           \$418,000 on an Oregon-allocated basis.<sup>2</sup>

4           The Company also included in rate base its estimated prepaid pension  
5           asset, net of its related accumulated deferred taxes. The prepaid pension  
6           asset is defined as the difference between the Company's total cash payments  
7           into its pension fund and the cumulative accrual expense the Company has  
8           incurred, as calculated under FAS 87 and other relevant Generally Accepted  
9           Accounting Principles (GAAP). The Company included in the test year rate  
10          base the balance of the prepaid pension asset, net of the \$2.3 million of  
11          accumulated deferred taxes associated with it, of approximately \$5.7 million  
12          (Oregon allocated).<sup>3</sup> A similar asset/liability account exists for the Company's  
13          postretirement benefit account. In Avista's case, the Company has an accrued  
14          liability of \$1.3 million that reduces its working capital.<sup>4</sup>

15          **Q. How did Staff analyze the Company's requested pension costs?**

16          A. Staff reviewed the Company's responses to 15 Staff data requests related to  
17          pension costs as well as the testimony and supporting work papers included in  
18          the Company's filing. Staff also had various phone calls with the Company to  
19          discuss aspects of its pension costs. In analyzing the Company's requested  
20          pension costs, Staff distinguished between the three parts of the proposed

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<sup>1</sup> Confidential Exhibit Staff/803, Bahr/1. Company's confidential response to Staff Data Request No. 60.

<sup>2</sup> *Ibid.*

<sup>3</sup> Exhibit Staff/802, Bahr/1. Company Workpaper Smith 2.03.

<sup>4</sup> Exhibit Staff/802, Bahr/2-4. Company Workpaper Smith 2.08.

1 cost, the requested FAS 87 expense amount, the inclusion in rate base of both  
2 the prepaid pension asset and the related accumulated deferred taxes, and the  
3 postretirement medical benefits.

4 FAS 87 Expense

5 As described above, the Commission has historically relied on FAS 87  
6 expense as a reasonable representation of cash costs in any given year. The  
7 FAS 87 expense amount is calculated and determined by third-party actuaries.  
8 Though most of the calculation's inputs are based on actual costs and  
9 amounts, two of the inputs require a degree of subjective judgment; these are  
10 the expected long term market rate of return on pension assets (Expected  
11 Return on Assets or EROA) and the expected discount rate. Typically in  
12 reviewing pension costs as part of a general rate case, Staff analyzes these  
13 two inputs, reviews them for reasonableness, verifies the calculation, and  
14 potentially recommends an adjustment to the proposed cost based on  
15 recommended changes to the EROA or discount rate.

16 Staff carefully reviewed the recent reports prepared by the third party  
17 actuary that detail the calculations and inputs of the pension cost calculations.  
18 To compare the Company's EROA and discount rate used in the FAS 87  
19 expense calculation to those of other utility companies regulated in Oregon,  
20 Staff constructed the table on the following page using 2014 SEC 10k filings  
21 found online. As seen in the table on the following page, the Company's  
22 EROA was less than that of all five other companies' in both 2013 and 2014.

1 **Table 2. Expected Rate of Return on Assets used in FAS 87 Calculations**

Company	2013	2014
Avista <sup>5</sup>	6.6%	6.6%
Cascade <sup>6</sup>	7%	7%
Idaho Power <sup>7</sup>	7.75%	7.75%
NW Natural <sup>8</sup>	7.5%	7.5%
PacifiCorp <sup>9</sup>	7.5%	7.5%
PGE <sup>10</sup>	8.25%	7.5%
<b>AVERAGE</b>	<b>7.43%</b>	<b>7.31%</b>

2 The Company essentially relies on its third party actuary to determine its  
3 pension expense. However, the Company does have discretion in managing  
4 its pension asset investment mix.<sup>11</sup> According to the Company's response to a  
5 Staff Data Request:<sup>12</sup>

6 *Avista moved its Retirement Plan assets from a 31% fixed*  
7 *income allocation to 58% fixed income allocation during*  
8 *2014. While fixed income investments typically have lower*  
9 *expected returns than equity investments, their changes in*

<sup>5</sup> Avista's 2014 10k can be found online at:

[http://www.annualreports.com/Click/6241?\\_SID\\_=20150706190117-2fe6be35324430e88f3e9d1d6c83301a](http://www.annualreports.com/Click/6241?_SID_=20150706190117-2fe6be35324430e88f3e9d1d6c83301a). Page 89 is included as Exhibit Staff/802, Bahr/5.

<sup>6</sup> Cascade's 2014 10k can be found online at: <http://www.mdu.com/docs/default-source/Proxy-Materials/2014-annual-report-10-k-and-proxy.pdf>. Page 89 is included as Exhibit Staff/802, Bahr/6.

<sup>7</sup> Idaho Power's 2014 10k can be found online at: <http://www.idacorpinc.com/pdfs/annualreps/ar2014.pdf>. Page 110 is included as Exhibit Staff/802, Bahr/7.

<sup>8</sup> NW Natural's 2014 10k can be found online at: [https://www.nwnatural.com/Content/AnnualReport/2014/files/10K\\_2014.pdf](https://www.nwnatural.com/Content/AnnualReport/2014/files/10K_2014.pdf). Page 72 is included as Exhibit Staff/802, Bahr/8.

<sup>9</sup> PacifiCorp's 2014 10k can be found online at: <https://www.last10k.com/Search/LoadPDF?u=http://www.last10k.com/sec-filings/75594/000007559415000003/pacificorp123114form10-k.htm.pdf>. Page 79 is included as Exhibit Staff/802, Bahr/9.

<sup>10</sup> PGE's 2014 10k can be found online at: <http://files.shareholder.com/downloads/POR/401492826x0xS784977-15-5/784977/filing.pdf>. Page 102 of the report is included as Exhibit Staff/802, Bahr/10.

<sup>11</sup> Exhibit Staff/802, Bahr/11. Company's response to Staff Data Request No. 147.

<sup>12</sup> Exhibit Staff/802, Bahr/12-13. Company's supplemental response to Staff Data Request No. 204.

1            *value tend to correlate well to the nature of obligations in the*  
2            *pension plan, and the result is less volatility in funded levels*  
3            *of the Retirement Plan and less volatility in annual pension*  
4            *expense.*

5            Due to its change in asset mix, the Company's forecasted EROA used in its  
6            filed case decreased from the 6.6 percent used in 2014 to ■■■ percent.<sup>13</sup> The  
7            Company received an updated actuarial report subsequent to its initial filing  
8            that reduces the EROA even further from ■■■ percent to ■■■ percent.<sup>14</sup> Again,  
9            no other regulated utility in Oregon has an EROA below 7 percent at this time,  
10           and the average EROA in 2014 was 7.31 percent.

11           The Company provided additional information to support its asset  
12           allocation and low forecasted EROA. Excerpts of the Company's response to  
13           a Staff Data Request are included as follows:<sup>15</sup>

14           *At higher levels of funding, however, the objective shifts*  
15           *toward maintaining, not increasing the plans' funded status.*  
16           *The implementation of a "derisking strategy" whereby a*  
17           *portion of the overall portfolio is transferred from equity*  
18           *investments to fixed income investments, aids in the*  
19           *reduction of risk and volatility and strengthens the correlation*  
20           *between the Retirement Plan Obligations and the Retirement*  
21           *Plan assets. ... "Other companies may have significantly*

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<sup>13</sup> Confidential Exhibit Staff/803, Bahr/2-5. Company's confidential response to Staff Data Request No. 59.

<sup>14</sup> Exhibit Staff/802, Bahr/14-15. Company's response to Staff Data Request No. 143.

<sup>15</sup> Exhibit Staff/802, Bahr/16-17. Company's response to Staff Data Request No. 303.

1                    *different funded status for their pension obligations and*  
 2                    *significantly different investment philosophies and, hence,*  
 3                    *their expected return on assets would be derived from their*  
 4                    *situations.”*

5                    To evaluate whether higher funded statuses actually correlate with lower  
 6                    EROAs for the Oregon-regulated energy utilities, as the Company argues in  
 7                    support of its forecasted EROA, Staff put together the following table,  
 8                    comparing the funded status and EROA for the six regulated energy utilities  
 9                    operating in Oregon:<sup>16</sup>

10                   **Table 3. Funded Status and EROA of Oregon-Regulated Utilities**

2013			2014		
Company	% Funded	EROA	Company	% Funded	EROA
Avista	91.37%	6.60%	Avista	84.97%	6.60%
Cascade	83.13%	7.00%	Cascade	74.55%	7.00%
Idaho Power	78.42%	7.75%	Idaho Power	66.25%	7.75%
NW Natural	73.70%	7.50%	NW Natural	61.88%	7.50%
PacifiCorp	95.20%	7.50%	PacifiCorp	83.16%	7.50%
PGE	84.54%	8.25%	PGE	76.06%	7.50%

11                    A correlation coefficient of 1 would indicate that the data is perfectly  
 12                    positively correlated; or in other words, that a higher EROA would correlate  
 13                    perfectly with a higher funded percentage. A correlation coefficient of -1 would  
 14                    indicate a perfect negative correlation; or in other words, that a high funded  
 15                    percentage would perfectly correlate with a low EROA. A correlation  
 16                    coefficient of 0 would indicate no correlation between the two data sets  
 17                    whatsoever. The correlation coefficient of the two sets of data (% Funded and

<sup>16</sup> The information used for this table was retrieved from the same sources as those noted in Table 2 on page 6 of Staff's testimony. Calculations of the funded percentage are shown in Exhibit Staff/802, Bahr/18.

1 EROA) is -0.29. This indicates a negative correlation between the two data  
2 sets, although a relatively weak one. In other words, the data above mildly  
3 supports Avista's claim that higher funded percentages should correlate with  
4 lower expected rates of return on assets.

5 There are two additional important points to note. The first is that despite  
6 the derisking strategy implemented by Avista in 2014, its funded percentage  
7 still fell from over 91 percent to just under 85 percent over the course of the  
8 2014 calendar year. Even though the Company's funded percentage  
9 decreased significantly during 2014, the Company lowered its EROA even  
10 further in 2015 from 6.6 percent to ■■■ percent, which was then revised to ■■■  
11 percent. The second point of note is that PacifiCorp's 2013 funded percentage  
12 is the highest of all six utilities in either 2013 or 2014, and has the most similar  
13 funded percentage as Avista in both 2013 and 2014, and yet PacifiCorp  
14 maintains an EROA of 7.5 percent, well above Avista's.

15 Prepaid Pension Asset

16 With regard to the Company's request to include in rate base the prepaid  
17 pension asset, net of accumulated deferred taxes, Staff notes this request is  
18 similar to requests made in recent general rate cases of other utility companies  
19 such as Cascade, (Docket No. UG 287), NW Natural (Docket No. UG 221),  
20 PacifiCorp (Docket No. UE 263), Avista (Docket Nos. UG 246 and UG 284),  
21 and PGE (Docket Nos. UE 283 and UE 262). As these rate cases have been  
22 concurrent with Docket UM 1633, the Commission's general investigation into  
23 pension cost recovery, Staff recommended in each case that no change to cost

1 recovery methods was warranted until the conclusion of the general  
2 investigation.

3 Postretirement Medical Benefits

4 Medical benefits paid to retirees are generally treated akin to a Company's  
5 FAS 87 pension expense. Similar to how the accounting treatment for pension  
6 costs is prescribed by FAS 87, FAS 106 addresses the treatment of retirement  
7 benefit costs and defines the calculation of the cost using variable inputs such  
8 as EROA, discount rate, etc. In calculating its FAS 106 expense in its original  
9 filing, the Company used an EROA of ■■■ percent.<sup>17</sup> The Company's revised  
10 forecast, provided to Staff in response to Staff Data Request No. 149, uses an  
11 EROA of ■■■ percent.<sup>18</sup> From 2012 to 2014, the Company earned returns on  
12 its postretirement medical benefits asset of ■■■ percent, ■■■ percent, and  
13 ■■■ percent.<sup>19</sup> While past returns are not necessarily indicative of future  
14 results, Staff questions the Company's low forecasted return on its assets,  
15 especially considering that it's significantly lower than the Company's  
16 requested return in this rate case.

17 **Q. What adjustments does Staff propose to the company's proposed**  
18 **pension and postretirement medical benefit costs?**

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<sup>17</sup> Confidential Exhibit Staff/803, Bahr/2-5. Company's confidential response to Staff Data Request No. 59.

<sup>18</sup> Confidential Exhibit Staff/803, Bahr/6-7. Company's supplemental confidential response to Staff Data Request No. 149.

<sup>19</sup> Confidential Exhibit Staff/803, Bahr/2-5. Company's confidential response to Staff Data Request No. 59.



1 A. Staff proposes adjustments to the Company's proposed FAS 87 expense, the  
2 prepaid pension asset included by the Company in rate base, and the  
3 postretirement medical benefits expense.

4 FAS 87 Expense

5 Although Staff is well aware of a general market trend of declining  
6 EROAs,<sup>20</sup> Staff does not agree with an investment strategy that reduces the  
7 Company's expected return on assets to a rate approximately [REDACTED] full basis  
8 points below the average for the six regulated Oregon utilities, [REDACTED] basis points  
9 below the next closest utility EROA, and likely significantly below the  
10 Company's authorized return. Staff finds the EROA revision even more absurd  
11 considering the Company has earned returns on its pension asset of [REDACTED]  
12 percent, [REDACTED] percent, and [REDACTED] percent from 2012 through 2014.<sup>21</sup>

13 By allowing a FAS 87 expense calculated at that EROA, the Commission  
14 would essentially be allowing the Company to charge customers an amount at  
15 a return higher than 7 percent and invest the money in a fund expected to  
16 return only [REDACTED] percent. Though there are certain considerations, such as  
17 potential volatility of investments and the expected time horizon (short term  
18 versus long term), this arbitrage would not be fair to customers. By using the  
19 next lowest EROA for an Oregon-regulated utility, 7 percent rather than [REDACTED]  
20 percent (as filed) or [REDACTED] percent (updated), Staff's adjustment reduces the

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<sup>20</sup> The trend of declining EROAs for pension funds has been widely reported through various news outlets. Eg. <http://www.wsj.com/articles/SB10001424052702304026304579453740108053288> and <http://www.wsj.com/articles/taxpayers-more-pension-burdens-headed-your-way-1441388090>.

<sup>21</sup> Confidential Exhibit Staff/803, Bahr/2-5. Company's confidential response to Staff Data Request No. 59.

1 Company's proposed Oregon-allocated FAS 87 expense of [REDACTED] and to  
2 [REDACTED], a difference of \$348,000. Details and calculations of Staff's  
3 adjustment can be found at Confidential Exhibit Staff/803, Bahr/8-9.

4 Prepaid Pension Asset

5 With regard to the prepaid pension asset, per Order No. 15-226 in Docket  
6 No. UM 1633, Staff recommends removing it from rate base, net of the  
7 associated deferred taxes, as well as the associated debt interest and related  
8 flow-through cost items. The net rate base adjustment related to the prepaid  
9 pension asset and its associated deferred taxes is \$5.655 million. The flow-  
10 through adjustment related to debt interest is \$63,000. Details and calculations  
11 of Staff's adjustment can be found at Confidential Exhibit Staff/803, Bahr/8-9.

12 Postretirement Medical Benefits

13 Similar to FAS 87 expense, postretirement medical benefits should be  
14 adjusted to reflect a higher EROA than that proposed by the Company.  
15 Adjusting the EROA to 7 percent from its filed EROA of [REDACTED] percent and revised  
16 update of [REDACTED] percent results in an adjustment to the Company's expenses of  
17 \$450,000 on a system basis, and \$24,000 on an Oregon-allocated basis.  
18 Details and calculations of Staff's adjustment can be found at Confidential  
19 Exhibit Staff/803, Bahr/8-9.

20 **Q. Are there any other issues relating to pensions or postretirement**  
21 **benefits that Staff needs to address?**

22 A. Yes. Order No. 15-226 in Commission Docket No. UM 1633, the general  
23 investigation into the treatment of pension costs, affirms the Commission's

1 current policy of not including a utility's prepaid pension asset in rate base.  
2 The order, however, is silent as to the treatment of the prepaid asset or  
3 accrued liability associated with postretirement medical benefits costs.  
4 Because FAS 106 costs are generally treated similarly to FAS 87 costs, Staff  
5 recommends the Commission allow the Company to remove from its rate base  
6 the accrued liability associated with its postretirement medical benefits plan, in  
7 conjunction with the prepaid asset associated with the pension plan. For  
8 Avista, this results in an increase to rate base of \$1.3 million. However, Staff  
9 Gardner has already proposed an adjustment to the Company's working capital  
10 that includes this amount; therefore, Staff need not make an additional  
11 adjustment here. Further details of the adjustment to working capital can be  
12 found in Staff Gardner's testimony.

1

**Issue 2, Medical Benefits**

2

**Q. Please describe the Company's request regarding medical, dental, vision, and other benefits.**

3

4

A. The Company has requested approximately \$ [REDACTED] million in test year expenses relating to benefits on a system level, which is \$ [REDACTED] million on an Oregon-allocated basis.<sup>22</sup> This cost includes such forms of compensation as long-term disability benefits, employee wellness program, and the pension plan. The expense includes costs for both bargaining (union) and non-bargaining (non-union) employees. Benefit plan premiums are typically shared between the Company and the employees. The Company generally shares costs with employees at a ratio of 90/10 (i.e. employees pay 10 percent of premium costs and the Company pays 90 percent).

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**Q. Please describe the analysis performed by Staff.**

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A. As noted above, the Company's medical benefits include various categories of expenses. For Deferred Comp, Employee Assistance, HRA Benefit, Life/LT Disability/Other, Service Awards, and Tuition Aid, the Company escalated the 2014 base year costs by less than 1%. The test year total for these amounts is less than it was in 2011, 2012, and 2013. Staff does not propose an adjustment related to these expenses.

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For Health Insurance, Staff recommends employer/employee sharing of premium costs at 82/18, rather than that proposed by the Company of 90/10.

A survey in the 2014 Kaiser Family Foundation publication indicates that the

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<sup>22</sup> Confidential Exhibit Staff/803, Bahr/10-11. Company's confidential response to Staff Data Request No. 63.

1 average sharing ratio in the industry is 82/18 for single employees and 71/29  
2 for families. Staff typically relies on Kaiser Family Foundation research for  
3 industry health benefit trends and to date has yet to find a compelling reason to  
4 rely more heavily on other evidence. Regarding premium sharing, the survey  
5 states, "*Covered workers contribute on average 18% of the premium for single*  
6 *coverage and 29% of the premium for family coverage, the same percentages*  
7 *as 2013.*"<sup>23</sup>

8 Because the cost of health insurance increases by 15.54% from actual  
9 2014 to forecasted 2016, Staff used trend analysis of 2011 through 2014 to  
10 forecast the 2016 costs before making the premium sharing adjustment. Staff's  
11 adjustment comprises the difference between the Company's proposed test  
12 year amount versus Staff's trend forecast, and the difference between sharing  
13 the cost at a ratio of 82/18 versus 90/10.

14 Staff typically proposes no adjustment to sharing between the Company  
15 and its bargaining employees unless the sharing percentage is deemed  
16 unreasonable upon review. These rates are negotiated between the Company  
17 and the union, include a wide range of total compensation elements, and are  
18 difficult to adjust without upsetting the carefully negotiated compensation  
19 balance.

20 **Q. Does Staff propose any adjustments relating to medical benefits?**

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<sup>23</sup> The 2014 Kaiser Family Foundation Report executive summary can be found online at <http://files.kff.org/attachment/ehbs-2014-abstract-summary-of-findings>. The premium sharing information used by Staff is found on page one, included as Exhibit Staff/802, Bahr/19.

- 1 A. Yes. Staff's adjustment consists of two reductions to the Company's proposal.
- 2 The first adjustment is related to historical trends, and the second adjustment is
- 3 related to employer/employee sharing. Applying both of these adjustments
- 4 results in an adjustment to expense of \$175,000. Details and calculations of
- 5 Staff's adjustment can be found at Confidential Exhibit Staff/803, Bahr/12-14.

1

**Issue 3, Property Taxes**

2

**Q. Please describe the Company's request associated with property taxes.**

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A. The Company proposed approximately \$2.5 million of property taxes for inclusion in its test year expense.<sup>24</sup> This was based on an estimated property tax rate of 0.01341 applied to a tax base of approximately \$184.7 million. The Company forecasted the property tax rate by escalating the base year rate by 3 percent, as shown in the calculation below.

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**Table 4. Avista's Forecasted Test Year Property Taxes**

0.01303	2014 tax rate (per UG 288 Smith WP 2.04) <sup>25</sup>
0.03	escalation factor used by Company
0.01341	2015 forecasted tax rate (per UG 288 Smith WP 2.04)
\$184,700,000	2014 property value included in case (per UG 288 Smith WP 2.04)
\$2,477,471	amount included by Company in test year

10

**Q. How did Staff analyze the Company's requested property tax cost?**

11

A. The Company calculated its test year property tax expense by forecasting the expected property tax rate. The Company's forecast relied on an escalation factor of approximately 3 percent annually from the base year to the test year. Staff analyzed the historical property tax rate from 2007 through the test year, resulting in the following data shown in table and graph form:

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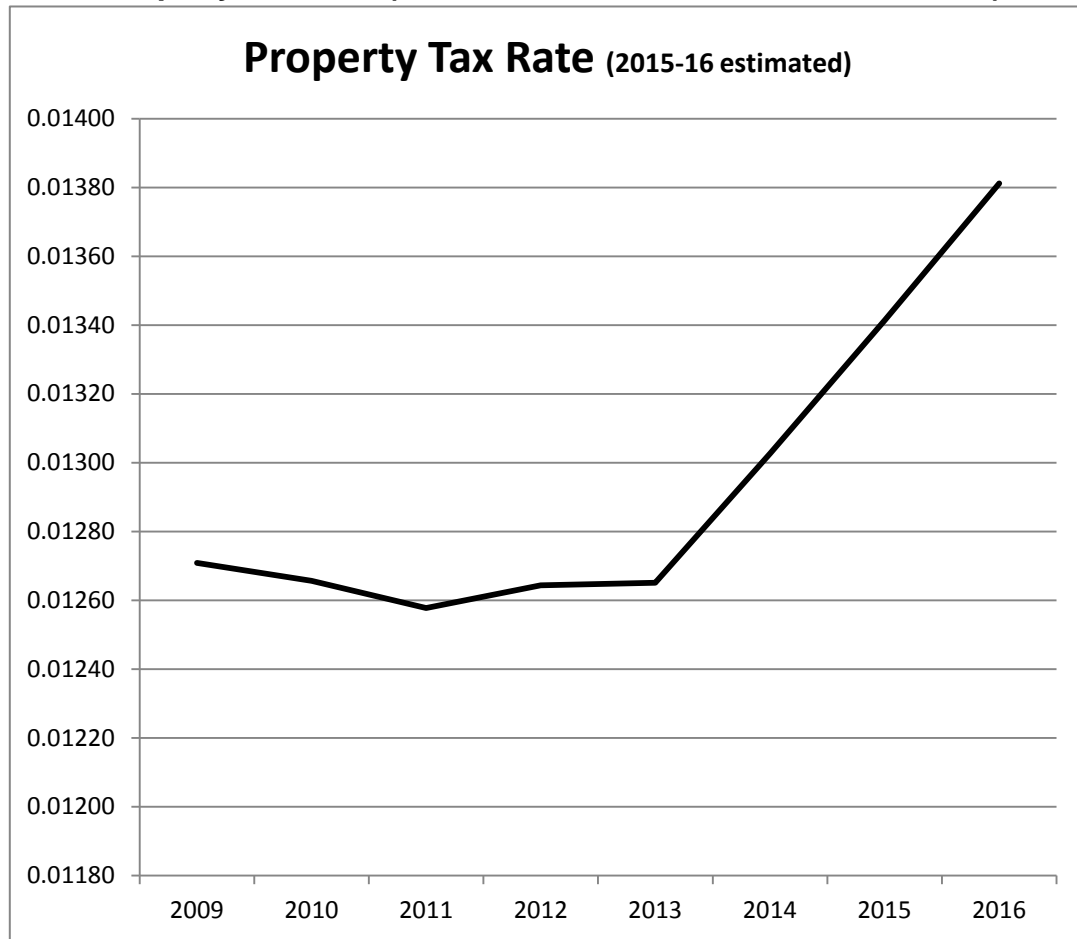
<sup>24</sup> Exhibit Staff/802, Bahr/20-22. Company Workpaper 2.04.

<sup>25</sup> *Ibid.*

1 **Table 5. Property Tax Rates 2007 through forecasted 2016**

Year	Property Tax Rate	Source
2009	0.01271	Tax Rate (per UG 201 Andrews WP F4 <sub>5</sub> ) <sup>26</sup>
2010	0.01266	Tax Rate (per UG 246 Andrews WP G-FPT-4) <sup>27</sup>
2011	0.01258	Tax Rate (per UG 246 Andrews WP G-FPT-4)
2012	0.01264	Tax Rate (per UG 246 Andrews WP G-FPT-4)
2013	0.01265	Tax Rate (per UG 288 Smith WP 2.04)
2014	0.01303	Tax Rate (per UG 288 Smith WP 2.04)
2015	0.01341	forecasted Tax Rate (per UG 288 Smith WP 2.04)
2016	0.01381	forecasted Tax Rate (per UG 288 Smith WP 2.04)

2 **Figure 1. Property Tax Rate (actual 2009-2014, forecasted 2015-2016)**



3

<sup>26</sup> Exhibit Staff/802, Bahr/23.  
<sup>27</sup> Exhibit Staff/802, Bahr/24.



1 **Q. Does Staff propose an adjustment related to property taxes?**

2 A. Yes. Based on the historical information, the Company's forecast for 2015 and  
 3 2016 appears excessively aggressive. Rather than using the Company's 3  
 4 percent escalation factor, Staff forecasted the test year property tax rate by  
 5 escalating the base year rate by the All-Urban CPI typically used by Staff,  
 6 which is 0.2 percent.<sup>28</sup> This results in an adjustment to expense of \$66,659, as  
 7 shown in the calculation below:

8 **Table 4. Property Tax Adjustment**

0.01303	2014 tax rate (per UG 288 Smith WP 2.04)
0.002	escalation factor used by Staff
0.01305	2015 forecasted tax rate (per Staff)
\$184,700,000	2014 property value included in case (per UG 288 Smith WP 2.04)
\$2,410,812	amount proposed by Staff
\$2,477,471	amount included by Company in test year
\$66,659	Staff Adjustment

<sup>28</sup> Exhibit Staff/802, Bahr/25. Also found on page 8 of the following site:  
<http://www.oregon.gov/DAS/OEA/docs/economic/appendixa.pdf>.

1 **Issue 4, Wages, Salaries, and Incentives**

2 **Q. Please describe the Company's request associated with Wages,**  
3 **Salaries, and Incentives.**

4 A. The Company proposes including in the test year approximately \$8 million in  
5 wages and salaries, \$0.4 million in overtime, and \$0.55 million in incentive  
6 compensation expense and \$0.56 million in capitalized incentive  
7 compensation. These amounts are found in the Company's workpapers 3.03  
8 and 2.12, and in its response to Staff Data Request No. 224.<sup>29</sup>

9 **Q. Please describe Staff's analysis regarding the Company's requested**  
10 **wages, salaries, and incentive costs.**

11 A. The Commission typically uses Staff's three-year wage and salary model to  
12 estimate expenses for non-union wages and salaries.<sup>30</sup> The increases in  
13 payroll from the historic base year should be tied to the rate of inflation using  
14 the All-Urban CPI.<sup>31</sup> Rather than using All-Urban CPI for union wages, the  
15 Commission in the past has ordered that union payroll increases be tied to  
16 negotiated wage increases as set forth in the union contract.<sup>32</sup> Staff applied  
17 this model to the information the Company provided in its filing and responses  
18 to Staff data requests

19 For incentives, Commission policy traditionally disallows 100 percent of  
20 officers' bonuses, which are typically based on earnings.<sup>33</sup> It is also

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<sup>29</sup> Exhibit Staff/802, Bahr/26-28.

<sup>30</sup> See e.g., Order No. 01-787.

<sup>31</sup> See Order 01-787 at 40; Order 99-697 at 43; Order 99-033 at 61; Order 95-322 at 10.

<sup>32</sup> See Order 99-697 at 43.

<sup>33</sup> See Order 99-033 at 62; Order 97-171 at 74-76.

1 Commission policy to disallow 75 percent of performance-based bonuses  
2 (because they are generally focused on increased earnings and, therefore,  
3 bring more benefit to shareholders) and disallow 50 percent of merit-based  
4 bonuses (because they equally benefit shareholders and ratepayers). Union  
5 bonuses are treated in the same manner as non-union bonuses.<sup>34</sup>

6 **Q. Does Staff propose an adjustment related to wages, salaries, and**  
7 **incentives?**

8 A. Yes. Based on Staff's three-year wage and salary model, Staff proposes an  
9 adjustment primarily to incorporate the difference in escalation factors used by  
10 the Company and Staff. This results in an adjustment to wages and salaries  
11 expense of \$62,000 and \$5,000 to capital. The adjustment to overtime for both  
12 expense and capital is not significant. Staff proposes an adjustment for  
13 incentives of \$288,000 in expenses and \$278,000 in capital. The flow-through  
14 effect of these adjustments is an additional adjustment to payroll taxes of  
15 \$17,000 and depreciation expense of \$200. Details and calculations of Staff's  
16 adjustment can be found at Exhibit Staff/802, Bahr/29-35.

17 **Q. Does Staff need to address any other issues relating to wages,**  
18 **salaries, and incentives?**

19 A. Yes. Depending on the projects on which they are working, Avista employees  
20 charge time to various accounts, which are either picked up with other O&M  
21 accounts and included in labor expenses in a general rate case or to certain  
22 accounts that are picked up by tariff riders, such as that for Demand Side

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<sup>34</sup> See Order 99-697 at 44-45; Order 99-033 at 62.

1 Management (DSM). These tariff riders, which include both fully loaded labor  
2 costs and non-labor costs, are addressed in proceedings separate from  
3 general rate cases.

4 As stated above, the labor costs included in the tariff riders are fully  
5 loaded, which means in addition to wage and salary costs, they also include  
6 things like medical benefits costs and incentive compensation. Staff has  
7 become aware that the adjustments recommended in rate cases for issues  
8 such as medical benefits or incentive compensation are not necessarily applied  
9 in other tariff filings. The opportunity exists, therefore, for a company to game  
10 the system by pushing more labor costs into tariff riders with unadjusted labor  
11 loadings from base rates. As this general rate case does not concern some of  
12 the tariff riders, Staff has no adjustment in this rate case, but recommends that  
13 the Commission direct the Company to apply adjustments made in rate cases  
14 to all of its tariff filings.

15 **Q. Does this conclude your testimony?**

16 A. Yes.

CASE: UG 288  
WITNESS: BRIAN BAHR

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 801**

**Witness Qualifications Statement**

**October 16, 2015**

**WITNESS QUALIFICATIONS STATEMENT**

NAME: Brian Bahr

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst  
Energy Rates, Finance & Audit Division

ADDRESS: 201 High Street SE., Suite 100  
Salem, OR. 97301

EDUCATION: Certificate of Public Management, Willamette University,  
Salem OR

Bachelor of Science, Accountancy, Brigham Young  
University, Provo UT

EXPERIENCE: Employed with the Oregon Public Utility Commission from  
March 2011 to present, currently serving as Senior Utility  
Analyst in the Rates, Finance, & Audit Section of the Energy  
Division.

Employed by Modern Seouf Plastics in Alexandria, Egypt as  
a Managerial Intern from January 2010 to June 2010.  
Assisted in variety of duties including supervision of  
production facilities and staff, market analysis, budget  
forecasting, sales, and office administration.

Employed by PricewaterhouseCoopers LLP in New York  
City as a Financial Assurance Associate from October 2007  
to November 2009. Performed audits of various financial  
institutions, including investment banks, hedge funds, and  
insurance companies.

Employed by TESRA, SA in Antofagasta, Chile as a Project  
Management Assistant from September 2005 to April 2006.  
Assisted in design process and implementation of rail road  
crossing and other civil engineering projects.

CASE: UG 288  
WITNESS: BRIAN BAHR

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 802**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

Statind:DL Company:( Name:AVA

		Ending Balance SUM														
		201312	201401	201402	201403	201404	201405	201406	201407	201408	201409	201410	201411	201412	AMA	
Ferc Acct	Ferc Acct I Service	Jurisdiction														
190150	ADFIT FAI CD	AA	(26,211,197)	(25,881,978)	(25,552,759)	(25,223,541)	(24,894,322)	(24,565,104)	(25,167,253)	(24,927,117)	(24,686,982)	(27,348,860)	(27,105,419)	(26,849,476)	(26,593,534)	(25,717,098)
		AN	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)
			<u>(26,980,497)</u>	<u>(26,651,278)</u>	<u>(26,322,059)</u>	<u>(25,992,841)</u>	<u>(25,663,622)</u>	<u>(25,334,404)</u>	<u>(25,936,553)</u>	<u>(25,696,417)</u>	<u>(25,456,282)</u>	<u>(28,118,160)</u>	<u>(27,874,719)</u>	<u>(27,618,776)</u>	<u>(27,362,834)</u>	<u>(26,486,398)</u>
228320	ACCUM PIZZ	ZZ	80,704,270	79,287,603	77,870,936	87,454,269	86,037,602	84,620,935	96,004,270	94,970,937	93,937,604	103,404,270	102,370,937	101,284,540	100,188,144	91,474,593

64,988,195  
8.702%  
**5,655,273**

Source: GL activity from Discoverer



Avista Corp  
Summary - Working Capital (Not Combined)  
For the Twelve Month Period Ended December 31, 2014 - Average of Monthly Averages Basis

4,739,320.90

Allocation Factors

Allocation Factor	Assigned Svc.Jur	Account	Account Description	Input Svc	Input Jur	Sum Averaged Amount	Less: Non-Operating	Operating ISWC	Gas-South	GD-OR	GD-OR
1	GD.OR	144030	ACC PRV UNCOLL NET OF ACTUAL-D	GD	OR	(3,772.37)					
1	GD.OR	144200	ACCUMULATED RETAIL WRITE-OFFS	GD	OR	11,242,439.79	\$543,923.25	\$10,698,516.54	100%	100%	10,698,516.54
1	GD.OR	144600	ACCUMULATED RETAIL REINSTATEME	GD	OR	(2,573,668.72)	(\$124,517.30)	(\$2,449,151.42)	100%	100%	(2,449,151.42)
1	GD.OR	144700	ACCUMULATED RETAIL RECOVERIES	GD	OR	(2,533,902.75)	(\$122,593.37)	(\$2,411,309.38)	100%	100%	(2,411,309.38)
1	GD.OR	165320	GAS IMBALANCE-AVISTA LDC	GD	OR	16,585.15	\$802.41	\$15,782.74	100%	100%	15,782.74
1	GD.OR	190200	ADFIT INJURY AND DAMAGE	GD	AS/OR	7,553.55	\$365.45	\$7,188.10	100%	100%	7,188.10
1	GD.OR	228200	ACCUM PROV FOR INJURY & DAMAGE	GD	AS/OR	(581,242.23)	(\$28,121.22)	(\$553,121.01)	100%	100%	(553,121.01)
1	GD.OR	228210	PAYMENT/REFUND INJURY & DAMAGE	GD	CA/OR	559,660.14	\$27,077.06	\$532,583.08	100%	100%	532,583.08
1	GD.OR	236250	MOTOR VEHICLE TAX-OREGON	ZZ	ZZ	0.00	\$0.00	\$0.00	100%	100%	0.00
1	GD.OR	236680	OR/CA TAXES ACCRUED BETC-OREGO	ZZ	ZZ	105,233.74	\$5,091.34	\$100,142.40	100%	100%	100,142.40
1	GD.OR	236690	OR REGULATORY BETC	ZZ	ZZ	34,911.00	\$1,689.04	\$33,221.96	100%	100%	33,221.96
1	GD.OR	242400	STATE COMMISSION FEE ACCRUED	GD	OR	139,024.89	\$6,726.20	\$132,298.69	100%	100%	132,298.69
1	GD.OR	242770	LOW INCOME ENERGY ASSIST	GD	OR	(50,901.88)	(\$2,462.70)	(\$48,439.18)	100%	100%	(48,439.18)
2	CD.AA	144200	ACCUMULATED RETAIL WRITE-OFFS	GD	CA	160,521.10	\$7,766.21	\$152,754.89	14.029%	100%	21,429.98
2	CD.AA	144600	ACCUMULATED RETAIL REINSTATEME	GD	CA	(80,198.40)	(\$3,880.10)	(\$76,318.30)	14.029%	100%	(10,706.69)
2	CD.AA	144700	ACCUMULATED RETAIL RECOVERIES	GD	CA	(61,131.61)	(\$2,957.62)	(\$58,173.99)	14.029%	100%	(8,161.23)
2	CD.AA	144990	ACC PROV FOR UNCOLLECTIBLES-RE	CD	AA	(45,300,686.02)	(\$2,191,703.66)	(\$43,108,982.36)	14.029%	100%	(6,047,759.14)
2	CD.AA	190810	ADFIT BAD DEBT RESERVE & WRITE	CD	AA	1,650,865.19	\$79,870.92	\$1,570,994.27	14.029%	100%	220,394.79
4	CD.AA	131100	CASH-US BANK	ZZ	ZZ	2,288,829.22	\$110,736.41	\$2,178,092.81	8.702%	100%	189,537.64
4	CD.AA	131110	CASH-WELLS FARGO	ZZ	ZZ	(2,656,306.30)	(\$128,515.41)	(\$2,527,790.89)	8.702%	100%	(219,968.36)
4	CD.AA	131120	CASH-PAYROLL	ZZ	ZZ	(320,102.75)	(\$15,486.97)	(\$304,615.78)	8.702%	100%	(26,507.67)
4	CD.AA	131140	CASH-WORKERS COMPENSATION	ZZ	ZZ	(29,742.96)	(\$1,439.00)	(\$28,303.96)	8.702%	100%	(2,463.01)
4	CD.AA	131170	CASH - AM&D (METALFX)	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	131400	CASH - CANADIAN ACCOUNT (USD)	ZZ	ZZ	22,268.78	\$1,077.39	\$21,191.39	8.702%	100%	1,844.07
4	CD.AA	134100	SPECIAL DEPOSITS-INTEREST RATE	ZZ	ZZ	9,166,666.67	\$443,494.76	\$8,723,171.91	8.702%	100%	759,090.42
4	CD.AA	134101	SPECIAL DEPOSITS-IR SWAP CONTRA	ZZ	ZZ	(8,980,833.33)	(\$434,503.91)	(\$8,546,329.42)	8.702%	100%	(743,701.59)
4	CD.AA	134120	OTHER SPECIAL DEPOSITS - NEWED	ZZ	ZZ	7,325,977.00	\$354,439.90	\$6,971,537.10	8.702%	100%	606,663.16
4	CD.AA	134122	OTHER SPECIAL DEPOSITS - MIZUH	ZZ	ZZ	3,420,320.55	\$165,479.37	\$3,254,841.18	8.702%	100%	283,236.28
4	CD.AA	135100	WORKING FUNDS-EMPLOYEE	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	135400	WORKING FUND-REAL ESTATE DEPT	ZZ	ZZ	10,000.00	\$483.81	\$9,516.19	8.702%	100%	828.10
4	CD.AA	135430	WORKING FUND-FLEET MANAGEMENT	ZZ	ZZ	5,000.00	\$241.91	\$4,758.09	8.702%	100%	414.05
4	CD.AA	136000	TEMPORARY CASH INVESTMENTS	ZZ	ZZ	7,665,254.42	\$370,854.56	\$7,294,399.86	8.702%	100%	634,758.68
4	CD.AA	136300	TEMP CASH INVEST-AFS SECURITIE	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	142100	CUST ACCT REC-RETAIL SERVICE	ZZ	ZZ	63,838,658.07	\$3,088,593.85	\$60,750,064.22	8.702%	100%	5,286,470.59
4	CD.AA	142350	CUST ACCT REC- NET PRESENTATIO	ZZ	ZZ	(4,159,145.26)	(\$201,224.63)	(\$3,957,920.63)	8.702%	100%	(344,418.25)
4	CD.AA	143020	GST	ZZ	ZZ	3,543,266.93	\$171,427.67	\$3,371,839.26	8.702%	100%	293,417.45
4	CD.AA	143025	HST	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	143050	OTHER ACCT REC-RETIREE DEDUCTI	ZZ	ZZ	(159,104.95)	(\$7,697.70)	(\$151,407.25)	8.702%	100%	(13,175.46)
4	CD.AA	143200	OTHER ACCT REC-OTHER MISC	ZZ	ZZ	69,235.77	\$3,349.71	\$65,886.06	8.702%	100%	5,733.40
4	CD.AA	143390	OTHER ACCT REC-WILMINGTON TRUS	ZZ	ZZ	4,595.66	\$222.34	\$4,373.32	8.702%	100%	380.57
4	CD.AA	143500	OTHER ACCT REC-MISCELLANEOUS	ZZ	ZZ	1,285,916.37	\$62,214.24	\$1,223,702.13	8.702%	100%	106,486.56
4	CD.AA	143510	CSS ACCOUNTS RECEIVABLES	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	143550	OTHER ACCT REC-DAMAGE CLAIMS	ZZ	ZZ	593,408.17	\$28,709.83	\$564,698.34	8.702%	100%	49,140.05
4	CD.AA	143900	OTHER ACCT REC-DEVELOPERS PROM	ZZ	ZZ	8,822.15	\$330.06	\$6,492.09	8.702%	100%	564.94
4	CD.AA	154100	PLANT MATERIALS & OPER SUPPLIE	ZZ	ZZ	24,717,855.76	\$1,195,880.67	\$23,521,975.09	8.702%	100%	2,046,882.27
4	CD.AA	154500	SUPPLY CHAIN RECEIVING INVENTO	ZZ	ZZ	4,322.61	\$209.13	\$4,113.48	8.702%	100%	357.95
4	CD.AA	154550	SUPPLY CHAIN AVERAGE COST VARI	ZZ	ZZ	(1,189.72)	(\$57.56)	(\$1,132.16)	8.702%	100%	(98.52)
4	CD.AA	154560	SUPPLY CHAIN INVOICE PRICE VAR	ZZ	ZZ	(245.06)	(\$11.86)	(\$233.20)	8.702%	100%	(20.29)
4	CD.AA	163000	STORES EXPENSE UNDISTRIBUTED	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	163200	STORES EXPENSE-SUPPLY CHAIN IN	ZZ	ZZ	4,549.66	\$220.12	\$4,329.54	8.702%	100%	376.76
4	CD.AA	165100	PREPAYMENTS-PREPAID INSURANCE	ZZ	ZZ	2,783,302.34	\$134,659.64	\$2,648,642.70	8.702%	100%	230,484.89
4	CD.AA	165110	PREPAYMENTS-MISC	ZZ	ZZ	10,739.67	\$519.60	\$10,220.07	8.702%	100%	889.35
4	CD.AA	165150	PREPAYMENTS-PREPAID LICENSE FE	ZZ	ZZ	4,465,176.91	\$216,030.82	\$4,249,146.09	8.702%	100%	369,760.69

**Avista Corp**  
**Summary - Working Capital (Not Combined)**  
For the Twelve Month Period Ended December 31, 2014 - Average of Monthly Averages Basis

4,739,320.90

Allocation Factors
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Allocation Factor	Assigned Svc.Jur	Account	Account Description	Input Svc	Input Jur	Sum Averaged Amount	Less: Non-Operating	Operating ISWC	Allocation Factors		
									Gas-South	GD-OR	GD-OR
4	CD.AA	165180	PREPAYMENTS-CUSTOMER BILLING S	ZZ	ZZ	50,180.04	\$2,427.77	\$47,752.27	8.702%	100%	4,155.40
4	CD.AA	165190	RESOURCE DEFERRED OPT EXPENSE	ZZ	ZZ	179,668.97	\$8,592.61	\$170,976.36	8.702%	100%	14,878.36
4	CD.AA	165191	RESOURCE DEFERRED OPT EXPENSE	ZZ	ZZ	(1,055,676.04)	(\$51,074.92)	(\$1,004,601.12)	8.702%	100%	(87,420.39)
4	CD.AA	165200	PREPAYMENTS-POSTAGE METERS	ZZ	ZZ	75,835.35	\$3,669.01	\$72,166.34	8.702%	100%	6,279.92
4	CD.AA	165550	PREPAYMENTS-WILMINGTON TRUST	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	171000	INTEREST & DIVIDENDS RECEIVABL	ZZ	ZZ	37,891.60	\$1,833.24	\$36,058.36	8.702%	100%	3,137.80
4	CD.AA	172500	RENTS RECEIVABLE-MISCELLANEOUS	ZZ	ZZ	248,283.48	\$12,012.26	\$236,271.22	8.702%	100%	20,560.32
4	CD.AA	172510	RENTS RECEIVABLE-ACCRUED	ZZ	ZZ	1,443,344.83	\$69,830.82	\$1,373,514.01	8.702%	100%	119,523.19
4	CD.AA	184260	PAYROLL BENEFITS CLEARING	ZZ	ZZ	11,155.21	\$539.70	\$10,615.51	8.702%	100%	923.76
4	CD.AA	184270	PAYROLL TAXES CLEARING	ZZ	ZZ	(342,114.31)	(\$16,551.92)	(\$325,562.39)	8.702%	100%	(28,330.44)
4	CD.AA	186180	PREPAID AIRPLANE LEASE EXPENSE	ZZ	ZZ	100,154.51	\$4,845.60	\$95,308.91	8.702%	100%	8,293.78
4	CD.AA	186205	PLANT ALLOC OF CLEARING JOURNA	ZZ	ZZ	2,378,271.49	\$115,063.74	\$2,263,207.75	8.702%	100%	196,944.34
4	CD.AA	186400	MISC DEFERRED DEBITS TREASURY	CD	AA	1,863.29	\$90.15	\$1,773.14	8.702%	100%	154.30
4	CD.AA	190150	ADFIT FAS87-UNFUNDED PENSION	CD/ZZ	AA/AN/ZZ	(26,486,398.12)	(\$1,281,444.96)	(\$25,204,953.16)	8.702%	100%	(2,193,335.02)
4	CD.AA	190830	ADFIT PAID TIME OFF	CD	AA	3,729,793.83	\$180,452.07	\$3,549,341.76	8.702%	100%	308,863.72
4	CD.AA	228210	PAYMENT/REFUND INJURY & DAMAGE	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	228300	ACCUM PROV FAS106 POST RET MED	ZZ	ZZ	(11,995,988.82)	(\$580,380.89)	(\$11,415,607.93)	8.702%	100%	(993,386.20)
4	CD.AA	228320	ACCUM PROV FAS87-ACCUM PEN COS	ZZ	ZZ	91,474,592.79	\$4,425,654.82	\$87,048,937.97	8.702%	100%	7,574,998.58
4	CD.AA	228330	HRA - RETIREE	ZZ	ZZ	(7,168,720.75)	(\$346,831.65)	(\$6,821,889.10)	8.702%	100%	(593,640.79)
4	CD.AA	228335	HRA - ACTIVE EMPLOYEES	ZZ	ZZ	(1,073,035.23)	(\$51,914.78)	(\$1,021,120.45)	8.702%	100%	(88,857.90)
4	CD.AA	228340	ACCUM PROV MED CLAIMS PAYABLE	ZZ	ZZ	(2,814,240.85)	(\$136,156.48)	(\$2,678,084.37)	8.702%	100%	(233,046.90)
4	CD.AA	232100	ACCTS PAY-GENERAL	ZZ	ZZ	(2,012,348.10)	(\$97,359.91)	(\$1,914,988.19)	8.702%	100%	(166,642.27)
4	CD.AA	232120	ACCTS PAY-PAYROLL OTHER	ZZ	ZZ	(328,157.05)	(\$15,876.65)	(\$312,280.40)	8.702%	100%	(27,174.64)
4	CD.AA	232135	ACCTS PAY-LDC GAS BROKER FEES	CD	AA	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	232160	ACCTS PAY-STAMPS	ZZ	ZZ	768.28	\$37.17	\$731.11	8.702%	100%	63.62
4	CD.AA	232200	ACCTS PAY-VOUCHERS	ZZ	ZZ	(12,147,242.81)	(\$587,698.75)	(\$11,559,544.06)	8.702%	100%	(1,005,911.52)
4	CD.AA	232300	ACCTS PAY-PAYROLL	ZZ	ZZ	(3,880,413.75)	(\$187,739.25)	(\$3,692,674.50)	8.702%	100%	(321,336.53)
4	CD.AA	232350	ACCTS PAY- NET PRESENTATION AC	ZZ	ZZ	4,159,145.26	\$201,224.63	\$3,957,920.63	8.702%	100%	344,418.25
4	CD.AA	232370	LIABILITY AWARD INCENTIVE ACCR	ZZ	ZZ	(999,279.69)	(\$48,346.40)	(\$950,933.29)	8.702%	100%	(82,750.22)
4	CD.AA	232380	ACCTS PAY-EMPLOYEE INCENTIVE P	ZZ	ZZ	(8,962,304.33)	(\$433,607.45)	(\$8,528,696.88)	8.702%	100%	(742,167.20)
4	CD.AA	232390	ACCTS PAY-SEVERANCE ACCRUAL	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	232400	ACCTS PAY-UNCLAIMED FUNDS	ZZ	ZZ	(91,205.88)	(\$4,412.65)	(\$86,793.23)	8.702%	100%	(7,552.75)
4	CD.AA	232650	ACCTS PAY-RESOURCE ACCOUNTING	ZZ	ZZ	(170,002.66)	(\$8,224.94)	(\$161,777.72)	8.702%	100%	(14,077.90)
4	CD.AA	232670	ACCTS PAY-RESOURCE TRANS FEE	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	232800	CUSTOMER REFUNDS PAYABLE-CSS	ZZ	ZZ	4,134.56	\$200.04	\$3,934.52	8.702%	100%	342.38
4	CD.AA	232820	CUSTOMER REFUNDS PAYABLE-CCB	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	236000	TAXES ACCRUED-FEDERAL	ZZ	ZZ	4,406,292.63	\$213,181.93	\$4,193,110.70	8.702%	100%	364,884.49
4	CD.AA	236050	TAXES ACCRUED - STATE	ZZ	ZZ	(5,014,551.11)	(\$242,610.23)	(\$4,771,940.88)	8.702%	100%	(415,254.30)
4	CD.AA	236100	TAXES OTHER THAN INC-WA/ID & O	ZZ	ZZ	(2,092.81)	(\$101.25)	(\$1,991.56)	8.702%	100%	(173.31)
4	CD.AA	236500	USE TAX ACCRUAL	ZZ	ZZ	(90,839.49)	(\$4,394.93)	(\$86,444.56)	8.702%	100%	(7,522.41)
4	CD.AA	237100	INTEREST ACCRUED - LT DEBT	ZZ	ZZ	(19,479,410.73)	(\$942,438.17)	(\$18,536,972.56)	8.702%	100%	(1,613,087.35)
4	CD.AA	237200	INTEREST ACCRUED - OTHER LIABI	ZZ	ZZ	(139,463.78)	(\$6,747.43)	(\$132,716.35)	8.702%	100%	(11,548.98)
4	CD.AA	237210	INTEREST ACCRUED - CUST DEPOSIT	ZZ	ZZ	(1,771.64)	(\$85.71)	(\$1,685.93)	8.702%	100%	(146.71)
4	CD.AA	241000	PAYROLL TAX PAYABLE	ZZ	ZZ	(316,892.69)	(\$15,331.66)	(\$301,561.03)	8.702%	100%	(26,241.84)
4	CD.AA	241200	SALES TAX PAYABLE	ZZ	ZZ	(10.57)	(\$0.51)	(\$10.06)	8.702%	100%	(0.88)
4	CD.AA	241300	DIRECTORS WA B&O TAXES PAYABLE	ZZ	ZZ	(9,295.80)	(\$449.74)	(\$8,846.06)	8.702%	100%	(769.78)
4	CD.AA	242050	MISC LIAB-MARGIN CALL DEPOSIT	ZZ	ZZ	(1,368,333.33)	(\$66,201.67)	(\$1,302,131.66)	8.702%	100%	(113,311.50)
4	CD.AA	242051	MISC LIAB-MARGIN CALL DEPOSIT CONTRA	ZZ	ZZ	0.00	\$0.00	\$0.00	8.702%	100%	0.00
4	CD.AA	242090	SETTLEMENT PAYABLE	ZZ	ZZ	(198,333.33)	(\$9,595.61)	(\$188,737.72)	8.702%	100%	(16,423.96)
4	CD.AA	242095	MISC LIAB-MIRABEAU ACCRUED REN	ZZ	ZZ	(34,913.89)	(\$1,689.18)	(\$33,224.71)	8.702%	100%	(2,891.21)
4	CD.AA	242200	MISC LIAB-AUDIT EXP ACC	ZZ	ZZ	260,648.64	\$12,610.51	\$248,038.13	8.702%	100%	21,584.28
4	CD.AA	242700	MISC LIAB-PAYROLL EQLZTN	ZZ	ZZ	(17,593,422.04)	(\$851,191.69)	(\$16,742,230.35)	8.702%	100%	(1,456,908.89)
4	CD.AA	242900	ACCTS PAYABLE INVENTORY ACCRUA	ZZ	ZZ	(138,748.68)	(\$6,712.83)	(\$132,035.85)	8.702%	100%	(11,489.76)

Avista Corp  
Summary - Working Capital (Not Combined)  
For the Twelve Month Period Ended December 31, 2014 - Average of Monthly Averages Basis

4,739,320.90

Allocation Factors

Allocation Factor	Assigned Svc.Jur	Account	Account Description	Input Svc	Input Jur	Sum Averaged Amount	Less: Non-Operating	Operating ISWC	Gas-South	GD-OR	GD-OR	
4	CD.AA	242910	ACCTS PAYABLE EXPENSE ACCRUAL-	ZZ	ZZ	(1,053,771.75)	(\$50,982.79)	(\$1,002,788.96)	8.702%	100%	(87,262.70)	
4	CD.AA	283150	FAS 106-CURRENT	CD/ZZ	AA/ZZ	3,797,347.73	\$183,720.42	\$3,613,627.31	8.702%	100%	314,457.85	
4	CD.AA	283152	FAS 106-CURRENT	CD	AA	330,279.81	\$15,979.35	\$314,300.46	8.702%	100%	27,350.43	
4	CD.AA	283153	FAS 106-CURRENT	CD	AA	294,146.41	\$14,231.17	\$279,915.24	8.702%	100%	24,358.22	
4	GD.AA	142510	CUST ACCT REC-UNBILLED REV GAS	ZZ	ZZ	17,263,637.79	\$835,236.32	\$16,428,401.47	30.918%	100%	5,079,333.17	
4	GD.AA	142600	CUST ACCT REC-RESALE GAS	ZZ	ZZ	13,507,560.03	\$653,512.59	\$12,854,047.44	30.918%	100%	3,974,214.39	
4	GD.AA	232130	ACCTS PAY-GAS SUPPLY TRANSACTI	ZZ	ZZ	(30,265,952.89)	(\$1,464,304.53)	(\$28,801,648.36)	30.918%	100%	(8,904,893.64)	
4	GD.AA	232135	ACCTS PAY-LDC GAS BROKER FEES	ZZ	ZZ	(30.85)	(\$1.49)	(\$29.36)	30.918%	100%	(9.08)	
4	GD.AA	232140	ACCTS PAY-GAS RESEARCH INSTITU	ZZ	ZZ	20,954.09	\$1,013.78	\$19,940.31	30.918%	100%	6,165.14	
4	GD.AA	232545	ACCTS PAY-JACKSON PRAIRIE STOR	ZZ	ZZ	(284,676.94)	(\$13,773.03)	(\$270,903.91)	30.918%	100%	(83,758.07)	
20	GD.OR	238100	TAXES OTHER THAN INC-WA/ID & O	GD	OR	(322,013.90)	(\$15,579.43)	(\$306,434.47)	100%	100%	(306,434.47)	
<b>Grand Total</b>						<b>\$97,957,808.89</b>	\$4,739,320.90	\$93,218,487.99			8,518,411.31	
											Less: Materials & Supplies	(2,047,121.41)
											Less: Pension, Net of ADFIT	(5,381,663.56)
											Working capital	<u>1,089,626.34</u>

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2014 and 2013 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
<b>Change in benefit obligation:</b>				
Benefit obligation as of beginning of year	\$ 527,004	\$ 584,619	\$ 108,249	\$ 132,541
Service cost	15,757	19,045	1,844	4,144
Interest cost	26,224	23,896	5,226	5,216
Actuarial (gain)/loss	97,128	(78,234)	18,714	(18,017)
Plan change	—	277	—	(10,788)
Transfer of accrued vacation	—	—	437	1,189
Benefits paid	(31,439)	(22,599)	(6,481)	(6,036)
Benefit obligation as of end of year	<u>\$ 634,674</u>	<u>\$ 527,004</u>	<u>\$ 127,969</u>	<u>\$ 108,249</u>
<b>Change in plan assets:</b>				
Fair value of plan assets as of beginning of year	\$ 481,502	\$ 406,061	\$ 29,732	\$ 25,288
Actual return on plan assets	55,974	52,502	1,580	4,444
Employer contributions	32,000	44,253	—	—
Benefits paid	(30,165)	(21,324)	—	—
Fair value of plan assets as of end of year	<u>\$ 539,311</u>	<u>\$ 481,502</u>	<u>\$ 31,312</u>	<u>\$ 29,732</u>
Funded status	<u>\$ (95,363)</u>	<u>\$ (45,502)</u>	<u>\$ (96,677)</u>	<u>\$ (78,517)</u>
Unrecognized net actuarial loss	175,596	107,043	82,421	56,885
Unrecognized prior service cost	256	278	(10,379)	(707)
Prepaid (accrued) benefit cost	80,489	61,819	(24,635)	(22,339)
Additional liability	(175,852)	(107,321)	(72,042)	(56,178)
Accrued benefit liability	<u>\$ (95,363)</u>	<u>\$ (45,502)</u>	<u>\$ (96,677)</u>	<u>\$ (78,517)</u>
Accumulated pension benefit obligation	<u>\$ 551,615</u>	<u>\$ 464,432</u>	—	—
Accumulated postretirement benefit obligation:				
For retirees			\$ 58,276	\$ 52,384
For fully eligible employees			\$ 31,843	\$ 24,320
For other participants			\$ 37,870	\$ 31,545
<b>Included in accumulated other comprehensive loss (income) (net of tax):</b>				
Unrecognized prior service cost	\$ 166	\$ 180	\$ (6,747)	\$ (7,472)
Unrecognized net actuarial loss	114,138	69,578	53,574	43,988
Total	114,304	69,758	46,827	36,516
Less regulatory asset	(106,484)	(64,925)	(46,759)	(37,116)
Accumulated other comprehensive loss (income) for unfunded benefit obligation for pensions and other postretirement benefit plans	<u>\$ 7,820</u>	<u>\$ 4,833</u>	<u>\$ 68</u>	<u>\$ (600)</u>
<b>Weighted-average assumptions as of December 31:</b>				
Discount rate for benefit obligation	4.21%	5.10%	4.16%	5.02%
Discount rate for annual expense	5.10%	4.15%	5.02%	4.15%
Expected long-term return on plan assets	6.60%	6.60%	6.40%	6.35%
Rate of compensation increase	4.87%	4.36%		
Medical cost trend pre-age 65—initial			7.00%	7.00%
Medical cost trend pre-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2021	2020
Medical cost trend post-age 65—initial			7.00%	7.50%
Medical cost trend post-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2022	2021

## Part II

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
(In thousands)						
Components of net periodic benefit cost (credit):						
Service cost	\$ 129	\$ 155	\$ 1,078	\$ 1,518	\$ 1,675	\$ 1,747
Interest cost	17,682	16,249	17,598	3,521	3,215	4,166
Expected return on assets	(21,218)	(19,917)	(23,536)	(4,617)	(4,343)	(4,890)
Amortization of prior service cost (credit)	71	71	(46)	(1,383)	(1,457)	(1,438)
Recognized net actuarial loss	4,859	7,173	7,070	649	1,814	2,134
Curtainment gain	—	—	(1,023)	—	—	—
Amortization of net transition obligation	—	—	—	—	—	2,128
Net periodic benefit cost (credit), including amount capitalized	1,533	3,731	1,141	(322)	904	3,847
Less amount capitalized	388	727	937	(21)	164	910
Net periodic benefit cost (credit)	1,145	3,004	204	(301)	740	2,937
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	77,238	(60,173)	19,982	15,114	(30,461)	1,863
Prior service credit	—	—	—	—	—	(11,418)
Amortization of actuarial loss	(4,868)	(7,173)	(7,070)	(649)	(1,814)	(2,134)
Amortization of prior service (cost) credit	(71)	(71)	1,069	1,393	1,457	1,438
Amortization of net transition obligation	—	—	—	—	—	(2,128)
Total recognized in accumulated other comprehensive (income) loss	72,298	(67,417)	13,981	15,858	(30,818)	(12,379)
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss	\$ 73,443	\$ (64,413)	\$ 14,185	\$ 15,557	\$ (30,078)	\$ (9,442)

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are \$7.1 million and \$71,000, respectively. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are \$1.8 million and \$1.4 million, respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Discount rate	3.70%	4.53%	3.74%	4.48%
Expected return on plan assets	7.00%	7.00%	6.00%	6.00%
Rate of compensation increase	N/A	N/A	3.00%	3.00%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Discount rate	4.53%	3.55%	4.43%	3.67%
Expected return on plan assets	7.00%	7.00%	6.00%	6.00%
Rate of compensation increase	N/A	N/A	3.00%	4.00%

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2014, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 65 percent to

In 2015, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost \$15 thousand from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2014, relating to the postretirement benefit plan. The entire amount represents \$15 thousand of amortization of prior service cost.

**Medicare Act:** The Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law in December 2003 and established a prescription drug benefit under Medicare Part D, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare's prescription drug coverage.

The following table summarizes the expected future benefit payments of the postretirement benefit plan and expected Medicare Part D subsidy receipts (in thousands of dollars):

	2015	2016	2017	2018	2019	2020-2024
Expected benefit payments	\$ 3,970	\$ 4,040	\$ 4,090	\$ 4,160	\$ 4,210	\$ 21,310
Expected Medicare Part D subsidy receipts	390	430	470	520	560	3,560

### Plan Assumptions

The following table sets forth the weighted-average assumptions used at the end of each year to determine benefit obligations for all Idaho Power-sponsored pension and postretirement benefits plans:

	Pension Plan		SMSP		Postretirement Benefits	
	2014	2013	2014	2013	2014	2013
Discount rate	4.25%	5.20%	4.20%	5.10%	4.20%	5.15%
Rate of compensation increase <sup>(1)</sup>	4.30%	4.38%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	6.4%	6.8%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2014	12/31/2013	12/31/2014	12/31/2013	12/31/2014	12/31/2013

<sup>(1)</sup> The 2014 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.55% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% for employees in their fortieth year of service and beyond.

The following table sets forth the weighted-average assumptions used to determine net periodic benefit cost for all Idaho Power-sponsored pension and postretirement benefit plans:

	Pension Plan			SMSP			Postretirement Benefits		
	2014	2013	2012	2014	2013	2012	2014	2013	2012
Discount rate	5.20%	4.20%	4.90%	5.10%	4.15%	5.10%	5.15%	4.20%	5.05%
Expected long-term rate of return on assets	7.75%	7.75%	7.75%	—	—	—	7.25%	7.25%	7.25%
Rate of compensation increase	4.30%	4.38%	4.35%	4.50%	4.50%	4.50%	—	—	—
Medical trend rate	—	—	—	—	—	—	6.4%	6.8%	6.5%
Dental trend rate	—	—	—	—	—	—	5.0%	5.0%	5.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.4 percent in 2014 and is assumed to decrease gradually to 5.1 percent by 2093. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2014 (in thousands of dollars):

	One-Percentage-Point	
	Increase	Decrease
Effect on total of cost components	\$ 325	\$ (241)
Effect on accumulated postretirement benefit obligation	3,426	(2,657)

Net periodic benefit costs are reduced by amounts capitalized to utility plant based on approximately 25% to 35% payroll overhead charge. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions. Net periodic pension cost less amounts charged to capital accounts and regulatory balancing accounts are expenses recognized in earnings.

The following table provides the assumptions used in measuring periodic benefit costs and benefit obligations for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	4.71%	3.84%	4.51%	4.45%	3.56%	4.33%
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	8.00%	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	3.85%	4.73%	3.85%	3.74%	4.45%	3.56%
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	7.50%	n/a	n/a	n/a

The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2014 was 8.00% for pre-65 and 11.75% for post-65 populations. These trend rates apply to both medical and prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 4.75% by 2022.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans; however, other postretirement benefit plans have a cap on the amount of costs reimbursable from the Company. A one percentage point change in assumed health care cost trend rates would have the following effects:

<i>In thousands</i>	1% Increase	1% Decrease
Effect on net periodic postretirement health care benefit cost	\$ 62	\$ (55)
Effect on the accumulated postretirement benefit obligation	1,260	(965)

The Company adopted a new set of mortality tables for its plans beginning with 2014. The tables were released in October 2014 by the Society of Actuaries' Retirement Plans Experience Committee and project a mortality improvement, thereby increasing benefit plan liabilities.

The following table provides information regarding employer contributions and benefit payments for the qualified pension plan, non-qualified pension plans, and other postretirement benefit plans for the years ended December 31, and estimated future contributions and payments:

<i>In thousands</i>	Pension Benefits	Other Benefits
Employer Contributions:		
2013	\$ 13,907	\$ 1,895
2014	12,077	1,871
2015 (estimated)	16,567	1,848
Benefit Payments:		
2012	18,195	1,971
2013	18,855	1,895
2014	19,932	1,871
Estimated Future Benefit Payments:		
2015	20,315	1,848
2016	20,993	1,918
2017	21,784	1,955
2018	22,799	2,007
2019	24,162	2,075
2020-2024	137,839	10,412

*Plan Assumptions*

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2014	2013	2012	2014	2013	2012
<b>Benefit obligations as of December 31:</b>						
Discount rate	4.00%	4.80%	4.05%	3.90%	4.90%	4.10%
Rate of compensation increase	2.75	3.00	3.00	N/A	N/A	N/A
<b>Net periodic benefit cost for the years ended December 31:</b>						
Discount rate	4.80%	4.05%	4.90%	4.90%	4.10%	4.95%
Expected return on plan assets	7.50	7.50	7.50	7.50	7.50	7.50
Rate of compensation increase	3.00	3.00	3.50	N/A	N/A	N/A

In establishing its assumption as to the expected return on plan assets, PacifiCorp utilizes the asset allocation and return assumptions for each asset class based on forward-looking views of the financial markets and historical performance.

	2014	2013
<b>Assumed healthcare cost trend rates as of December 31:</b>		
Healthcare cost trend rate assumed for next year	8.00%	8.00%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2025	2019

A one percentage-point change in assumed healthcare cost trend rates would have the following effects (in millions):

	Increase (Decrease)	
	One Percentage-Point Increase	One Percentage-Point Decrease
	Increase	Decrease
Increase (decrease) in:		
Total service and interest cost for the year ended December 31, 2014	\$ 3	\$ (2)
Other postretirement benefit obligation as of December 31, 2014	—	—

*Contributions and Benefit Payments*

Employer contributions to the pension and other postretirement benefit plans are expected to be \$4 million and \$- million, respectively, during 2015. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 ("ERISA") and the Pension Protection Act of 2006, as amended ("PPA"). PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the PPA. PacifiCorp's funding policy for its other postretirement benefit plan is to generally contribute an amount equal to the net periodic benefit cost, subject to tax deductibility limitations and other considerations.





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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES  
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, continued

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2014	2013	2014	2013	2014	2013
<b>Assumptions used:</b>						
Discount rate for benefit obligation	4.02%	4.84%	3.07% - 4.10%	3.46% - 4.96%	4.02%	4.84%
Discount rate for benefit cost	4.84%	4.24%	3.46% - 4.96%	2.77% - 4.13%	4.84%	4.24%
Weighted average rate of compensation increase for benefit obligation	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Weighted average rate of compensation increase for benefit cost	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Long-term rate of return on plan assets for benefit obligation	7.50%	7.50%	6.37%	6.46%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	7.50%	8.25%	6.46%	5.89%	N/A	N/A

\* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Regulatory assets due to the future recoverability from retail customers. Accordingly, as of the balance sheet date, such amounts are included in Regulatory assets.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan			Other Postretirement Benefits			Non-Qualified Benefit Plans		
	2014	2013	2012	2014	2013	2012	2014	2013	2012
Service cost	\$ 15	\$ 17	\$ 14	\$ 2	\$ 2	\$ 2	\$ —	\$ —	\$ —
Interest cost on benefit obligation	34	30	31	4	3	3	1	1	1
Expected return on plan assets	(39)	(40)	(41)	(2)	(1)	(1)	—	—	—
Amortization of prior service cost	—	—	—	1	1	1	—	—	—
Amortization of net actuarial loss	17	24	17	1	1	1	1	1	1
Net periodic benefit cost	\$ 27	\$ 31	\$ 21	\$ 6	\$ 6	\$ 6	\$ 2	\$ 2	\$ 2

PGE estimates that \$23 million will be amortized from AOCL into net periodic benefit cost in 2015, consisting of a net actuarial loss of \$20 million for pension benefits, \$1 million for non-qualified benefits and \$1 million for other postretirement benefits, and prior service cost of \$1 million for other postretirement benefits. Amounts related to the pension and other postretirement benefits are offset with the amortization of the corresponding regulatory asset.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	05/26/2015
CASE NO.:	UG 288	WITNESS:	Mark Thies
REQUESTER:	PUC Staff - Bahr	RESPONDER:	Rich Stevens
TYPE:	Data Request	DEPT:	Finance
REQUEST NO.:	Staff – 147	TELEPHONE:	(509) 495-2998
		EMAIL:	rich.stevens@avistacorp.com

**REQUEST:**

With regard to the Company's responses to Staff Data Requests Nos. 59 and 60, please provide a narrative description explaining the amount of discretion the Company has in determining the inputs (eg. expected rate of return on plan assets and discount rate) used in the calculation of pension expense.

**RESPONSE:**

The assumptions for the expected rate of return and the discount rate are prescribed by financial accounting standards, specifically Accounting Standards Codification 715. The Company's application of these accounting standards is reviewed by the independent auditors to determine compliance with generally accepted accounting principles applied on a consistent basis. These standards limit management's discretion.

The expected rate of return on plan assets is a forward-looking estimate of the returns that can be expected from the assets held by the benefit plan. Avista has used the same method consistently from year to year. The expected return on assets is affected by the asset allocation among investment types and by the expected returns for each type of investment. The Company determines how to allocate plan assets and then uses this allocation to weight components of the expected return on assets. The Company has a choice of the time horizon for expected returns. Avista's expected returns are based on a 10-year horizon of capital market assumptions. The Company obtains capital market assumptions of expected returns on various asset types or based on Avista's specific investment portfolio from three external parties who are investment advisors or actuaries and the Company has used inputs from the same sources annually. Market return outlook from each external party varies from year to year but such variations are not a product of management discretion.

According to ASC 715, the discount rate may be based on the rates implicit in current annuity rates or available rates on high-quality corporate bond yields. For Avista, the discount rate is based on high-quality corporate bond yields on the last day of the year for a set of bonds that have cash flows that closely match Avista's benefit obligations. The selected bonds are identified by a model developed by the Company's actuaries, which is a consistent practice from year to year. The Company validates the bond information selected in the discount rate bond model but the Company does not exercise selective discretion.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/11/2015
CASE NO:	UG 288	WITNESS:	Mark Thies
REQUESTER:	PUC Staff - Bahr	RESPONDER:	Rich Stevens
TYPE:	Data Request	DEPT:	Finance
REQUEST NO.:	Staff – 204 Supplemental	TELEPHONE:	(509) 495-4330
		EMAIL:	rich.stevens@avistacorp.com

**REQUEST:**

This request regards the Company's response to Staff Data Request No. 147. Using information found in utility companies' annual 10k reports found online, Staff compiled the following table:

Expected Rate of Return used in FAS 87 calculations

Company	2013	2014
Avista	6.6%	6.6%
Cascade	7%	7%
Idaho Power	7.75%	7.75%
NW Natural	7.5%	7.5%
PacifiCorp	7.5%	7.5%
PGE	8.25%	7.5%
AVERAGE	7.43%	7.31%

Given the information in the table above, please justify the Company's use of 6.6 percent for its expected return on assets input in the FAS 87 calculation.

**RESPONSE:**

The expected return on assets for Avista's Retirement Plan was determined based on a weighted calculation of the Avista Retirement Plan investment allocation and expected returns for each class of assets, consistent with ASC 715 (formerly FAS 87). Avista uses expected return inputs from independent investment advisors to determine expected return, not a peer comparison against expectations by other utilities. Each company should determine an appropriate expected return on its pension assets based on the investment profile of its own plan. Avista has not undertaken an analysis of pension plans at other utilities or their method of estimating expected returns.

**SUPPLEMENTAL RESPONSE:**

Avista's expected return on assets is driven in large part by the investment mix among assets in the Retirement Plan. In 2014, a liability-driven investment philosophy was implemented to strengthen the correlation between Retirement Plan obligations and Retirement Plan assets. The obligations for benefit payments represent a future liability, which is valued under GAAP based upon the end of year weighted average discount rate of a model bond portfolio that would provide cash flows equivalent to the benefit obligations. To match these obligations better, the

asset allocation was shifted into a higher fixed income level than that Retirement Plan held prior to 2014. Avista moved its Retirement Plan assets from a 31% fixed income allocation to 58% fixed income allocation during 2014. While fixed income investments typically have lower expected returns than equity investments, their changes in value tend to correlate well to the nature of obligations in the pension plan, and the result is less volatility in funded levels of the Retirement Plan and less volatility in annual pension expense. Other companies may have significantly different funded status for their pension obligations and significantly different investment philosophies and, hence, their expected return on assets would be derived from their situations. Return on assets should not be examined in isolation from other aspects of a pension plan to understand the impact on current and future costs of the benefit obligations.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	05/28/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith/Mark Thies
REQUESTER:	PUC Staff - Bahr	RESPONDER:	Rich Stevens
TYPE:	Data Request	DEPT:	Finance
REQUEST NO.:	Staff – 143	TELEPHONE:	(509) 495-4330
		EMAIL:	rich.stevens@avistacorp.com

**REQUEST:**

With regard to Avista/500, Smith/17, lines 1-4, please provide the revised pension forecast provided by Towers Watson as of May 2015.

**RESPONSE:**

Please see Staff\_DR\_143 Attachment A.

**Retirement Plan for Employees of Avista Corporation**  
**Actual 2014 and Estimated 2015-2019 Pension Expense**  
**Based on March 31, 2015 Assets and December 31, 2014 Assumptions**  
**2015-2019 Expected Return on Assets of 5.30%**

	2014	2015	2016	2017	2018	2019
Discount Rate	5.10%	4.21%	4.21%	4.21%	4.21%	4.21%
Expected Return on Assets	6.60%	5.30%	5.30%	5.30%	5.30%	5.30%
Expected Contributions*	32,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000
Expected Benefit Payments	30,200,000	26,500,000	27,600,000	28,600,000	29,800,000	31,300,000
1. Assets	481,500,000	540,600,000	557,900,000	571,200,000	584,100,000	596,600,000
2. Accumulated Benefit Obligation	441,900,000	526,600,000	542,000,000	557,600,000	574,600,000	591,300,000
3. Projected Benefit Obligation	501,100,000	604,800,000	623,600,000	642,300,000	660,800,000	679,000,000
4. ABO Funded Status (1. / 2.)	109.0%	102.7%	102.9%	102.4%	101.7%	100.9%
5. PBO Funded Status (1. / 3.)	96.1%	89.4%	89.5%	88.9%	88.4%	87.9%
1. Service Cost	15,700,000	19,900,000	20,100,000	20,100,000	20,200,000	20,100,000
2. Interest Cost	25,000,000	24,900,000	25,700,000	26,400,000	27,200,000	27,900,000
3. Expected Return on Assets Amortizations	(32,100,000)	(28,300,000)	(29,200,000)	(29,900,000)	(30,500,000)	(31,100,000)
4. - Net Transition Obligation	0	0	0	0	0	0
5. - Net Prior Service Cost	0	0	0	0	0	0
6. - Net Gain/Loss	3,800,000	8,100,000	7,100,000	6,700,000	5,900,000	5,500,000
7. Net Periodic Pension Expense	12,400,000	24,600,000	23,700,000	23,300,000	22,800,000	22,400,000

\* Contributions assumed deposited in equal installments on March 15, June 15, and September 15. Assuming annual contributions of \$12M for 2015-2019.

Note, all projected liabilities and results are based on 1/1/2014 data. New entrants are assumed to replace participants leaving active status. The plan is assumed to be closed to Non-union employees hired on or after 1/1/2014.

**Assumptions:**

- Mortality Assumption: Same as 12/31/2014 disclosure for 2015-2019.
- 2016-2019 Assets projected from 3/31/2015 asset value of \$548.6m provided by Avista.
- Expected Return on Assets: 5.30% for 2015-2019
- Average future working lifetime in 2014 is 13.0 years
- Discount Rate Assumption for 2015-2019: Discount rate from 12/31/2014 disclosure

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	10/01/2015
CASE NO:	UG 288	WITNESS:	Mark Thies
REQUESTER:	PUC Staff - Bahr	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 303	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

**REQUEST:**

Please provide any comparables or other support the Company has available demonstrating the reasonableness or comparability of the Company's Expected Return on Pension Assets used to calculated pension and post retirement expense

**RESPONSE:**

The Company's expected return on assets is driven in large part by the investment mix among assets in the Retirement Plan. At lower levels of funding, equity investments are typically weighted more heavily in the investment mix in order to capture the highest returns and increase the funding status. The probability of a higher return on assets, which could result in a higher funded status, is weighed against the potential risks associated with volatility over time. At higher levels of funding, however, the objective shifts toward maintaining, not increasing the plans' funded status. The implementation of a "derisking strategy" whereby a portion of the overall portfolio is transferred from equity investments to fixed income investments, aids in the reduction of risk and volatility and strengthens the correlation between the Retirement Plan Obligations and the Retirement Plan assets.

With a January 1, 2014 funding level of approximately 96%<sup>1</sup>, the Company implemented a derisking strategy and moved from a 31% fixed income allocation to a 58% fixed income allocation during 2014. This investment mix, together with lower market return expectations for various investment classes, results in an expected return on assets of approximately 5.3% for 2015. As noted in the Company's response to Staff\_DR\_204 Supplemental

"Other companies may have significantly different funded status for their pension obligations and significantly different investment philosophies and, hence, their expected return on assets would be derived from their situations."

By contrast, Idaho Power Pension Plan assets in comprised of approximately 67% funded with a 24% fixed asset investments and an expected return on assets of approximately 7.75% for 2014. Pacificorp is approximately 83% funded with 33-37% fixed income allocation and an expected return on assets of approximately 7.5%. This illustrates what the different funded status and

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<sup>1</sup> Excluding Executive Supplemental Executive Retirement Program (SERP).

investment philosophies of individual companies makes it difficult to compare expected return on assets between companies.

Idaho Power<sup>2</sup> and NW Natural<sup>3</sup> explain that expected returns are derived from historic returns of similar asset classes. Avista estimates returns for its plan primarily based on view of future expected returns while keeping awareness of historic returns. In light of continued low interest rates and reduced expectations for equity returns over the long run, Avista believes its' estimate of expected returns are reasonable.

A recent report published by Wilshire Consulting "2015 Report on Corporate Pension Funding Levels" dated April 2, 2015 lends credence to the point that an expected rate of return can vary from company to company based on individual asset allocation and further suggested that an expected return on assets of 7.3% in 2014 maybe too high:

"Although the median expected return on plan assets assumptions has fallen during the past thirteen years, from 9.5% in 2000 to 7.3% in 2014, many pension accounting critics believe that this assumption is still too high. Wilshire Consulting's long-term forecast for the return on corporate pension assets is approximately **5.3%**, based on the average asset allocation of corporate pension plans as noted in the companies' 10-Ks and or current capital market return and risk assumptions (summarized below). ***However, individual pension plan expected returns will vary considerable depending upon their unique asset allocation.***" emphasis added

The expected return on assets utilized by the Company is developed based on the asset allocation advice of the Company's independent pension investment advisors and expected future returns developed by three independent investment advisors.

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<sup>2</sup> IDACORP 10-K, page 70 "Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the yield on the Moody's AA Corporate Bond Index".

<sup>3</sup> NW Natural 10-K, Page 70 "In developing the expected long-term rate of return assumption, consideration was given to the historical performance of each asset class in which the plans' assets are invested and the target asset allocation of plan assets.



Year	Company	Benefit Obligation	Fair Value of Plan Assets	Amount Underfunded	% Funded
2013	nwn	362.4	267.1	95.3	74%
2014	nwn	451.2	279.2	172	62%
2013	avista	527	482	45	91%
2014	avista	635	539	96	85%
2013	cascade	403	335	68	83%
2014	cascade	475	354	121	75%
2013	IPC	695	545	150	78%
2014	IPC	845	560	285	66%
2013	Pac	1230	1171	59	95%
2014	Pac	1378	1146	232	83%
2013	PGE	705	596	109	85%
2014	PGE	777	591	186	76%

Year	Company	% Funded	EROA
2013	avista	91.37%	6.60%
2013	cascade	83.13%	7.00%
2013	Idaho Power	78.42%	7.75%
2013	NW Natural	73.70%	7.50%
2013	PacifiCorp	95.20%	7.50%
2013	PGE	84.54%	8.25%
2014	avista	84.97%	6.60%
2014	cascade	74.55%	7.00%
2014	Idaho Power	66.25%	7.75%
2014	NW Natural	61.88%	7.50%
2014	PacifiCorp	83.16%	7.50%
2014	PGE	76.06%	7.50%

Correlation Coefficient                      **-0.29**

# Employer Health Benefits

2014 Summary of Findings

Employer-sponsored insurance covers about 149 million nonelderly people.<sup>1</sup> To provide current information about employer-sponsored health benefits, the Kaiser Family Foundation (Kaiser) and the Health Research & Educational Trust (HRET) conduct an annual survey of private and nonfederal public employers with three or more workers. This is the sixteenth Kaiser/HRET survey and reflects employer-sponsored health benefits in 2014.

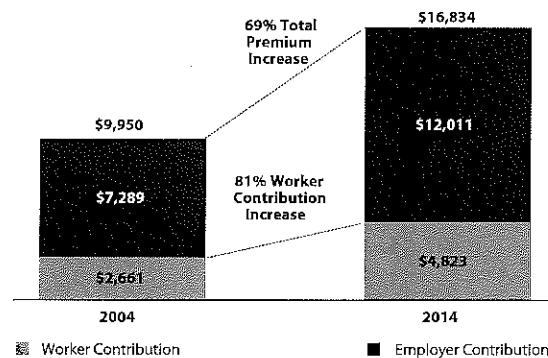
The key findings from the survey, conducted from January through May 2014, include a modest increase in the average premiums for family coverage (3%). Single coverage premiums are 2% higher than in 2013, but the difference is not statistically significant. Covered workers generally face similar premium contributions and cost-sharing requirements in 2014 as they did in 2013. The percentage of firms (55%) which offer health benefits to at least some of their employees and the percentage of workers covered at those firms (62%) are statistically unchanged from 2013. The percentage of covered workers enrolled in grandfathered health plans - those plans exempt from many provisions of the Affordable Care Act (ACA) - declined to 26% of covered workers from 36% in 2013. Perhaps in response to new provisions of the ACA, the average length of the waiting period decreased for those with a waiting period and the percentage with an out-of-pocket limit increased. Although employers continue to offer coverage to spouses, dependents and domestic partners, some employers are instituting incentives to influence workers' enrollment decisions, including nine percent of employers who attach restrictions for spouses' eligibility if they are offered coverage at another source, or nine percent of firms who provide additional compensation if employees do not enroll in health benefits.

## HEALTH INSURANCE PREMIUMS AND WORKER CONTRIBUTIONS

In 2014, the average annual premiums for employer-sponsored health insurance are \$6,025 for single coverage and \$16,834 for family coverage. The average family premium rose 3% over the 2013 average premium. Single coverage premiums rose 2% in 2014 but are not statistically different than the 2013 average premium. During the same period, workers' wages increased 2.3% and inflation increased 2%. Over the last ten years, the average

### EXHIBIT A

Average Annual Health Insurance Premiums and Worker Contributions for Family Coverage, 2004–2014



SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2004–2014.

premium for family coverage has increased 69% (Exhibit A). Premiums have increased less quickly over the last five years (2009 to 2014), than the preceding five year period (2004 to 2009) (26% vs. 34%).

Average premiums for high-deductible health plans with a savings option (HDHP/SOs) are lower than the overall average for all plan types for both single and family coverage (Exhibit B), at \$5,299 and \$15,401, respectively. There are important differences in premiums by firm size: the average premium for family coverage is lower for covered workers in small firms (3–199 workers) than for workers in larger firms (\$15,849 vs. \$17,265).

Premiums vary significantly around the averages for single and family coverage, resulting from differences in benefits, cost sharing, covered populations, and geographical location. Twenty percent of covered workers are in plans with an annual total premium for family coverage of at least \$20,201 (120% of the average family premium), and 20% of covered workers are in plans where the family premium is less than \$13,467 (80% of the average family premium). The distribution is similar around the average single

premium (Exhibit C).

Most often, employers require that workers make a contribution towards the cost of the premium. Covered workers contribute on average 18% of the premium for single coverage and 29% of the premium for family coverage, the same percentages as 2013. Workers in small firms (3–199 workers) contribute a lower average percentage for single coverage compared to workers in larger firms (16% vs. 19%), but they contribute a higher average percentage for family coverage (35% vs. 27%). Workers in firms with a higher percentage of lower-wage workers (at least 35% of workers earn \$23,000 or less) contribute higher percentages of the premium for single coverage (27% vs. 18%) and for family coverage (44% vs. 28%) than workers in firms with a smaller share of lower-wage workers.

As with total premiums, the share of the premium contributed by workers varies considerably among firms. For single coverage, 57% of covered workers are in plans that require them to make a contribution of less than or equal to a quarter of the total premium, 2% are in plans that require a contribution of more

**AVISTA UTILITIES**  
**Property Tax Adjustment**  
**2014 Test Year, 2016 Rate Year**

Gas

Oregon

Test Year Expense (Accrual per Results by State (Situs))	2,338,388 G-PFT-2	
Estimated 2016 Expense	<u>2,477,471 G-PFT-3</u>	
Total Adjustment	<table border="1"><tr><td>139,083</td></tr></table>	139,083
139,083		

Note: The purpose of the property tax adjustment is to look at future expense that will be paid. In this test year we looked at what will be paid in 2016.

Property tax estimates are developed by taking the last known value assessments from each state, and the average of the last known levy rates, adding 2014 plant additions, less depreciation, to the values, and then applying a small escalator to the levy rates to reflect their general increasing trend.

<u>Period</u>	<u>Currency</u>	<u>PTD</u>	<u>YTD</u>
201401	USD	176,647.23	176,647.23
201402	USD	176,647.23	353,294.46
201403	USD	176,647.23	529,941.69
201404	USD	176,647.23	706,588.92
201405	USD	176,647.23	883,236.15
201406	USD	176,647.22	1,059,883.37
201407	USD	185,646.00	1,245,529.37
201408	USD	185,646.00	1,431,175.37
201409	USD	230,208.00	1,661,383.37
201410	USD	230,208.00	1,891,591.37
201411	USD	230,208.00	2,121,799.37
201412	USD	216,588.50	2,338,387.87

G-PFT-1

408170.GD.OR

Prep by: \_\_\_\_\_

**REVISED as of 09/09/2014      REVISED 2013/2014 with Actual 2014 Assessments**

	in thousands		in thousands		in thousands		in thousands	
BOOK VALUE @ DEC	2012		2013		2014		2015	
YEAR ASSESSED	2013		2014		2015		2016	
YEAR TAX ACCRUED	2013		2014		2015		2016	
YEAR TAX PAYABLE ( Oregon & California)	2013-2014		2014-2015		2015-2016		2016-2017	
	2013 ACTUALS		2014 Estimate		2015 Estimate		2016 Estimate	
	13/14 Actual		14/15 Estimate		15/16 Estimate		16/17 Estimate	
<b>OREGON - GAS</b>								
HIST COST OREGON								
ESTIMATED STATE VALUE	168,937		184,700		184,700		184,700	
ADD : NET ADDITIONS TO PLANT					0		0	
LESS : DEPR EST					0		0	
TAXABLE PERCENTAGE	100.0000%		100.0000%		100.0000%		100.0000%	
STATE ALLOCATION %	100.0000%		100.0000%		100.0000%		100.0000%	
STATE VALUE	168,937		184,700		184,700		184,700	
Adjustments:								
	100.00%		100.00%		100.00%		100.00%	
GROSS ASSESSED VALUE	168,937		184,700		184,700		184,700	
RATIO	1.000		1.000		1.000		1.000	
ASSESSED VALUE	168,937		184,700		184,700		184,700	
TAX RATE	0.01265	3.0%	0.01303	2.0%	0.01341		0.01381	
TAX	2,137		2,406		2,477		2,551	

**Note:** Note: Property tax estimates are developed by taking the last known value assessments from each state, and the average of the last known levy rates, adding 2014 plant additions, less depreciation, to the values, and then applying a small escalator to the levy rates to reflect their general increasing trend.

in thousands

BOOK VALUE @ DEC	2008
YEAR ASSESSED	2009
YEAR TAX ACCRUED	2009
YEAR TAX PAYABLE ( oregon & california)	2009-2010
<b>OREGON - GAS</b>	<b>09/10 Actual</b>
HIST COST OREGON	
ESTIMATED STATE VALUE	129,100
ADD : NET ADDITIONS TO PLANT - <i>2009 ADDITIONS .</i>	
LESS : DEPR EST	
TAXABLE PERCENTAGE	
STATE ALLOCATION %	100.0000%
STATE VALUE	129,100
Adjustments:	631
	100.000%
GROSS ASSESSED VALUE	129,731
RATIO	99.995%
ASSESSED VALUE	129,725
TAX RATE	0.01270905
TAX	1,649

in thousands

2009
2010
2010
2010-2011
10/11 Estimate
130,100
0
0
100.0000%
100.0000%
130,100
100.00%
130,100
1.000
130,100
0.01309
1,703

3%

in thousands

2010
2011
2011
2011-2012
11/12 Estimate
130,100
30,506
-15,300
100.0000%
100.0000%
145,306
100.00%
145,306
1.000
145,306
0.01348
1,959

3%

F-45

Avista Corporation

**As of June 6, 2013**  
**2013 and 2014 Forecasts from January 2013**

OREGON - GAS	
HIST COST OREGON	
ESTIMATED STATE VALUE	142,400
ADD : NET ADDITIONS TO PLANT	
LESS : DEPR EST	
TAXABLE PERCENTAGE	100.0000%
STATE ALLOCATION %	100.0000%
STATE VALUE	142,400
Adjustments:	
	100.00%
GROSS ASSESSED VALUE	142,400
RATIO	1.000
ASSESSED VALUE	142,400
TAX RATE	0.012577
TAX	1,791

-0.63%

11/12 Actual	
ESTIMATED STATE VALUE	142,400
ASSESSED VALUE	142,400
TAX RATE	0.012577
TAX	1,791

0.53%

12/13 Actual	
Plant Balance as of 12/31/2011	
ESTIMATED STATE VALUE	160,600
ASSESSED VALUE	160,600
TAX RATE	0.01264
TAX	2,031

13/14 Estimate		14/15 Estimate	
Plant Balance as of 12/31/2012		Forecasted Plant Balance as of 12/31/2013 - Not used	
ESTIMATED STATE VALUE	160,600	ESTIMATED STATE VALUE	166,390
ADD : NET ADDITIONS TO PLANT	9,953	ADD : NET ADDITIONS TO PLANT	6,793
LESS : DEPR EST	-4,173	LESS : DEPR EST	-4,200
TAXABLE PERCENTAGE	100.0000%	TAXABLE PERCENTAGE	100.0000%
STATE ALLOCATION %	100.0000%	STATE ALLOCATION %	100.0000%
STATE VALUE	166,390	STATE VALUE	168,983
Adjustments:		Adjustments:	
	100.00%		100.00%
GROSS ASSESSED VALUE	166,390	GROSS ASSESSED VALUE	168,983
RATIO	1.000	RATIO	1.000
ASSESSED VALUE	166,390	ASSESSED VALUE	168,983
TAX RATE	0.01277	TAX RATE	0.01303
TAX	2,125	TAX	2,201

(Not used - see Capital Additions adjustments (2.06 & 2.07) for property tax on 2013 and 2014 additions.

14/15 Estimate	
ESTIMATED STATE VALUE	166,390
ASSESSED VALUE	166,390
TAX RATE	0.01303
TAX	2,167

**2,167** G-PFT-2

Property Tax on plant balance at 12/31/2012, to be expensed in 2014.

Note: Property tax estimates are developed by taking the last known value assessments from each state, and the average of the last known levy rates, adding 2012 plant additions, less depreciation, to the values, and then applying a small escalator to the levy rates to reflect their general increasing trend.

## Sept 2015 - Other Economic Indicators

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
GDP (Bil of 2009 \$), Chain Weight (in billions of \$)	15,020.6	15,369.2	15,710.3	16,085.6	16,447.2	16,950.2	17,408.8	17,846.9	18,295.6	18,761.3	19,225.5	19,665.9
% Ch	1.6	2.3	2.2	2.4	2.2	3.1	2.7	2.5	2.5	2.5	2.5	2.3
<b>Price and Wage Indicators</b>												
GDP Implicit Price Deflator, Chain Weight U.S., 2009=100	103.3	105.2	106.7	108.3	109.5	111.6	113.7	115.7	117.8	120.0	122.4	124.9
% Ch	2.1	1.8	1.5	1.5	1.1	1.9	1.8	1.8	1.8	1.9	2.0	2.1
Personal Consumption Deflator, Chain Weight U.S., 2009=100	104.1	106.1	107.3	108.8	109.1	110.7	112.7	115.0	117.2	119.2	121.5	124.1
% Ch	2.5	1.8	1.2	1.3	0.3	1.4	1.8	2.0	2.0	1.7	1.9	2.1
CPI, Urban Consumers, 1982-84=100												
Portland-Salem, OR-WA	224.6	229.8	235.5	240.4	241.2	245.6	250.9	256.6	262.1	267.3	273.1	279.4
% Ch	2.9	2.3	2.5	2.1	0.3	1.8	2.2	2.3	2.1	2.0	2.2	2.3
U.S.	224.9	229.6	233.0	236.7	237.1	241.4	246.9	253.2	259.3	264.4	270.4	277.4
% Ch	3.1	2.1	1.5	1.6	0.2	1.8	2.3	2.5	2.4	2.0	2.3	2.6
Oregon Average Wage Rate (Thous \$)	45.2	46.6	47.4	48.9	50.5	52.6	54.8	57.1	59.5	61.9	64.3	66.7
% Ch	3.2	3.2	1.8	3.1	3.2	4.2	4.2	4.2	4.2	4.1	3.9	3.7
U.S. Average Wage Wage Rate (Thous \$)	50.3	51.7	52.2	53.6	55.0	56.9	58.9	61.2	63.7	66.2	68.8	71.4
% Ch	2.8	2.7	1.0	2.6	2.6	3.4	3.7	3.8	4.0	3.9	3.9	3.9
<b>Housing Indicators</b>												
FHFA Oregon Housing Price Index 1980 Q1=100	347.9	346.9	372.2	406.0	441.6	478.6	499.3	517.3	535.6	554.8	574.3	594.2
% Ch	(6.9)	(0.3)	7.3	9.1	8.8	8.4	4.3	3.6	3.5	3.6	3.5	3.5
FHFA National Housing Price Index 1980 Q1=100	312.3	312.0	324.9	346.2	370.8	382.6	394.2	403.5	412.9	424.4	436.9	453.5
% Ch	(3.7)	(0.1)	4.1	6.6	7.1	3.2	3.0	2.4	2.3	2.8	3.0	3.8
Housing Starts Oregon (Thous)	8.0	10.9	14.2	15.6	14.9	17.9	20.8	22.6	23.1	23.7	24.1	24.0
% Ch	5.2	35.7	31.2	9.5	(4.1)	19.8	16.4	8.3	2.3	2.5	1.8	(0.2)
U.S. (Millions)	0.6	0.8	0.9	1.0	1.1	1.3	1.5	1.5	1.6	1.6	1.6	1.6
% Ch	4.5	28.1	18.4	7.8	10.3	19.3	10.4	4.3	3.4	2.5	(0.3)	0.1
<b>Other Indicators</b>												
Unemployment Rate (%) Oregon	9.4	8.8	7.8	7.0	5.7	5.8	5.4	5.6	5.6	5.5	5.4	5.5
Point Change	(1.1)	(0.7)	(1.0)	(0.8)	(1.3)	0.0	(0.3)	0.1	0.0	(0.2)	(0.0)	0.0
U.S.	8.9	8.1	7.4	6.2	5.4	5.1	5.0	5.1	5.1	5.0	5.0	5.0
Point Change	(0.7)	(0.9)	(0.7)	(1.2)	(0.7)	(0.3)	(0.1)	0.1	0.0	(0.0)	(0.0)	0.0
Industrial Production Index U.S, 2002 = 100	93.6	97.1	99.9	104.1	105.7	109.3	113.2	116.4	119.5	122.6	125.4	128.2
% Ch	3.3	3.8	2.9	4.2	1.5	3.4	3.5	2.8	2.7	2.6	2.3	2.2
Prime Rate (Percent)	3.3	3.3	3.3	3.3	3.3	4.2	5.7	6.5	6.5	6.5	6.5	6.5
% Ch	0.0	0.0	0.0	0.0	2.5	24.9	36.9	14.1	0.0	0.0	0.0	0.0
Population (Millions) Oregon	3.86	3.89	3.93	3.97	4.02	4.06	4.11	4.16	4.21	4.26	4.31	4.36
% Ch	0.6	0.7	0.9	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
U.S.	312.3	314.5	316.7	319.0	321.7	324.3	326.9	329.5	332.2	334.8	337.4	340.0
% Ch	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Timber Harvest (Mil Bd Ft) Oregon	3,649.0	3,749.0	4,199.0	4,126.0	4,479.7	4,735.9	4,708.8	4,683.1	4,681.9	4,662.5	4,643.3	4,650.5
% Ch	13.1	2.7	12.0	(1.7)	8.6	5.7	(0.6)	(0.5)	(0.0)	(0.4)	(0.4)	0.2



**AVISTA UTILITIES**  
**Calculation of PUC wage formula**

Explanation: Staff's proposal adjusts test period wages and salaries in accordance with guidelines followed in previous rate cases. Hence, staff allows wages and salaries to increase based on published CPI projections, and then allows the company to share 50/50 a 10% band around staff's calculated projection.

Line No.	Source		Excludes Overtime				Total
			Officers	Exempt	Non Exempt	Union	
1	Avista Data	Annualized Payroll-2013	\$296,984	\$3,206,598	\$1,091,376	\$2,611,743	7,206,701
2	Avista Data	Ave. # of Employees (FTE)-2013	1	30	18	31	80
3	(1)/(2)	Average Salary	\$296,984	\$106,887	\$60,632	\$84,250	\$90,084
4	CPI Index - See Below	Allowable % Increase	1.03812	1.03812	1.03812	1.08477	0.0
5	Avista Data	Ave. # of Employees (FTE)-2016	1	30	19	30	80
6	(3)*(4)*(5)	Projected Payroll	\$308,304	\$3,328,818	\$1,195,917	\$2,741,750	\$7,574,789
7	Avista Data	Annualized Payroll-2016	\$315,838	\$3,590,448	\$1,286,600	\$2,782,694	\$7,975,580
8	(6)-(7)	Total Difference	\$7,534	\$261,630	\$90,683	\$40,944	\$400,791
9	(6)*.10	10% Band - Allowable	\$30,830	\$332,882	\$119,592	\$274,175	\$757,479
10	[(8) or (9)] * .5	50% Sharing of Lesser of Difference or Band	\$3,767	\$130,815	\$45,341	\$20,472	\$200,395
11	(6)+/(10)	Staff Proposed Level	\$312,071	\$3,459,633	\$1,241,259	\$2,762,222	\$7,775,185
12	(11)-(7)	Net Payroll Adjustment	(\$3,767)	(\$130,815)	(\$45,341)	(\$20,472)	(\$200,395)
13	Avista Data	O&M Expense as % of Payroll Exp.	100.0%	77.5%	95.1%	87.8%	0.0%
14	(12)*(13)	O&M Expense Adjustment - Systemwide	(\$3,767)	(\$101,381)	(\$43,120)	(\$17,974)	\$0
15	SO	Oregon Allocation Factor	1	1	1	1	0
16	(14)*(15)	O&M Expense Adjustment	(\$3,767)	(\$101,381)	(\$43,120)	(\$17,974) (1)	(\$105,149)
17	Avista Data	Capitalized Labor % of Payroll Exp.	0.00%	22.50%	4.90%	12.20%	0.00%
18	(12)*(17)	Rate Base Adjustment - Systemwide	\$0	(\$29,433)		(1)	\$0
19	(18)*(15)	Rate Base Adjustment - Oregon	\$0	(\$29,433)	\$0	\$0	(\$29,433)

	Annual CPI	Union Increases - Actual
2013	1.5000	3.0000
2014	1.6000	3.0000
2015	0.6667	2.2500
	<u>1.03812</u>	<u>1.0848</u>

Officers	\$0
Exempt	(\$101,381)
Non Exempt	(\$43,120)
Admin	<u>(\$144,501)</u>

The Company used the method provided by Commission Staff to compute this adjustment. The method uses total Company data and allocates a portion to Oregon. Due to this, detailed data is not available for administrative vs. O&M. Therefore, the Company will allocate officers, exempt and non-exempt to administrative and union to O&M.

(1) The Company feels that all employee classes (officers, exempt, non-exempt, union) should be included in this calculation, whether it is an increase to expense or a decrease to expense, because it is the net that should also be considered. However, for purposes of this earnings test, the Company has removed any resulting increases to expense. It should be noted, the Company does not agree with removing this increase to expense and reserves the right to include all components in future rate case proceedings.

Prep by: \_\_\_\_\_ 1st Review: \_\_\_\_\_

**Avista Utilities**

Adjust 2014 Short Term Incentives  
Adjusts Incentives to 6-Year Average

	Non-Executive Adjust 6-Year Average	Executive Adjust 6-Year Average	Total Adjustment	
Results of Operations (System)	\$ 12,627,683	\$ 3,675,748	\$ 16,303,431	
O & M Percentage	59%	33%		
Total O & M s	\$ 7,440,231	\$ 1,223,657	\$ 8,663,888	
Projected O & M Payout	\$ 9,821,971	\$ 2,268,980	\$ 12,090,951	
O & M Percentage	60%	33%		
Total O & M s	\$ 5,893,183	\$ 748,763	\$ 6,641,946	
Projected Payout (System 6 Year Average)	102.16%	40.23%		
6 Year Average Amount	\$ 6,020,279	\$ 301,252	\$ 6,321,531	\$ OR Alloc 550,099.66
<b>Total Adjustment</b>	<b>(1,419,952)</b>	<b>(922,405)</b>	<b>(2,342,357)</b>	
<u>Allocated to Washington Electric</u>				
0.71547 Note 7				
0.67900 Note 4	\$ (689,819)	\$ (448,108)	\$ (1,137,927)	
<u>Allocated to Washington Gas</u>				
0.19751 Note 7				
0.70758 Note 4	\$ (198,444)	\$ (128,910)	\$ (327,354)	
<u>Allocated to Idaho Electric</u>				
0.71547 Note 7				
0.32100 Note 4	\$ (326,115)	\$ (211,845)	\$ (537,960)	
<u>Allocated to Idaho Gas</u>				
0.19751 Note 7				
0.29242 Note 4	\$ (82,011)	\$ (53,274)	\$ (135,285)	
<u>Allocated to Oregon</u>				
0.08702 Note 7	\$ (123,564)	\$ (80,268)	\$ (203,832)	

Source: G-ALL-12A  
Source: E-ALL-12A

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/20/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Bahr	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 224	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

**REQUEST:**

With regard to Workpaper Smith 2.12, what is the amount of capitalized incentive compensation included in the Company's proposed 2016 test year revenue requirement (system and Oregon allocated)?

**RESPONSE:**

The amount of Oregon capitalized incentive compensation included in the Company's proposed 2016 test year is approximately \$556,000. Staff\_DR\_224 Attachment A includes system level capital incentive.

Please note the calculation for the above estimate includes a calculation for 2013 and 2014 and is based on actual incentives capitalized and actual capital spend.

The calculation for 2015 and 2016 is based on an estimate of the actual amount capitalized in 2013 and 2014 compared to actual spend. This percentage was applied to pro-formed plant additions in the Company's Case.

Please see Staff\_DR\_224 Attachment A for the system detail as well as calculation support.

**Avista Utilities UG 288**  
**Test Year Ended 12/31/2016**  
**000's**

**S-X Wages and Salary**

Staff's adjustment is based on a series of adjustments in multiple accounts related to compensation. Wages & Salaries are adjusted using the Commission's 3-year wage and salary model. Overtime is adjusted using the same approach as is used in Staff's 3-year Wage and Salary Model. In this case, Staff does not propose an adjustment to the Company's FTE levels, which have remained relatively constant over the past 3 years. Finally, Payroll taxes and O&M depreciation expense are adjusted to reflect Staff's adjustments.

Description/ Account No.	OR-Allocated			
	Company Filing	Staff (O&M only)	O&M Adjustment	Capital Adjustment
Wages & Salaries	\$ 7,976	\$ 7,920	\$ (56)	\$ (4)
FTE Adjustment	\$ 7,781	\$ 7,781	\$ -	\$ -
Overtime	\$ 444	\$ 444	\$ (0)	\$ (0)
Bonus & Incentives	\$ 550	\$ 262	\$ (288)	\$ -
Bonus & Incentives	\$ 556	\$ 556	\$ -	\$ (278)
<b>Total OR - Allocated Adjustments</b>			<b>\$ (344)</b>	<b>\$ (282)</b>

	Oregon-Allocated		
Payroll Taxes	\$ 695	\$679	\$ (16)
Depreciation O&M Adjustment Associated with Capital Adjustment			\$ (0.2)

Avista Utilities UG 288							
Calculation of PUC 3-Year Wage Formula							
Actual 12/31/2013 to Proforma 12/31/2016							
Explanation: Staff's proposal adjusts Avista's test period base wages and salaries in accordance with guidelines followed in previous rate cases. Hence, Staff allows wages and salaries (excluding union wages) to increase based on published CPI projections, and then allows the Company to share 50/50 the lesser of the difference between the Company's & Staff's calculated projections, or a 10% band around Staff's calculated projection. Union wages are increased at the contracted amounts as the negotiations are considered to be conducted at "arms length."							
Line No.	Source		Officers	Exempt	Non Exempt	Union	Total
1	WP 3.03 Restate Labor - wp 1	Actual Base Payroll (2013)	\$296,984	\$3,206,598	\$1,091,376	\$2,611,743	\$7,206,701
2	WP 3.03 Restate Labor - wp 1	Ave. # of Employes (FTE) (2013)	1	30	18	31	80
3	(1)/(2)	Average Salary	\$296,984	\$106,897	\$60,632	\$84,250	
4	Actual/Forecast CPI Index*	Allowable % Increase	1.0364 <sup>1</sup>	1.0364 <sup>1</sup>	1.0364 <sup>1</sup>	1.0927 <sup>2</sup>	
5	WP 3.03 Restate Labor - wp 1	Ave. # of Employes (FTE) (2016)	1	30	19	30	80
6	(3)*(4)*(5)	Projected Payroll	\$307,781	\$3,323,179	\$1,193,891	\$2,761,861	\$7,586,712
7	WP 3.03 Restate Labor - wp 1	Test Period Payroll	\$315,838	\$3,590,448	\$1,286,600	\$2,782,694	\$7,975,580
8	(7)-(6)	Total Difference for Sharing	\$8,057	\$267,269	\$92,709	\$20,833	
9	(7)*.10	10% Band - Allowable	\$30,778	\$332,318	\$119,389	\$276,186	
10	((8) or (9)) *0.5	50% Sharing of Lesser of Difference or Band	\$4,028	\$133,635	\$46,354	\$10,417	
11	(6)+(10)	Staff Proposed Level	\$311,810	\$3,456,813	\$1,240,246	\$2,772,277	\$7,781,146
12	(11)-(7)	Net Payroll Adjustment	(\$4,028)	(\$133,635)	(\$46,354)	(\$10,417)	(\$194,434)
13	WP 3.03 Restate Labor - wp 1	O&M Expense as % of Payroll Exp	100.00%	77.50%	95.10%	87.80%	
14	(12)*(13)	O&M Expense Adjustment - Systemwide	(\$4,028)	(\$103,567)	(\$44,083)	(\$9,146)	(\$160,824)
15	WP 3.03 Restate Labor - wp 3)	Oregon Allocation Factor	1.0000	1.0000	1.0000	1.0000	1
16	(14)*(15)	O&M Expense Adjustment - Oregon	(\$4,028)	(\$103,567)	(\$44,083)	(\$9,146)	(\$160,824)
17	1 - (13)	Rate Base as % of Payroll Exp	0.00%	22.50%	4.90%	12.20%	0.00%
18	(12)*(17)	Rate Base Adjustment - Systemwide	\$0	(\$30,068)	(\$2,271)	(\$1,271)	(\$33,610)
19	(18)*(15)	Rate Base Adjustment - Oregon	\$0	(\$30,068)	(\$2,271)	(\$1,271)	(\$33,610)
<sup>1</sup> Source - OR Dept of Admin Svcs, Office of Economic Analysis Oregon Economic & Revenue Forecast Sept 2015, Volume XXXV, No. 3, page 47 Actual/Forecast All-Urban Consumer Price Index 2014: 1.6% 2015: 0.2% 2016: 1.8% 1.0364							
<sup>2</sup> Union Factor Source: Andrews WP 3.03 Restate Labor WP 1) Union Increase 2014: 3.00% 2015: 3.00% 2016: 3.00% 1.0927							

**Avista Utilities UG 288**  
**Wage & Salary Adjustment Based on Staff's FTE Adjustment**  
**Actual 12/31/2013 to Proforma 12/31/2016**

Explanation: Though the Company's system FTE increased from 1520 to 1548 from 2013-2014, the Company's Oregon-allocated FTE remained constant at 80. The Company proposes the 2014 FTE amount of 80. Staff finds the Oregon allocated FTE amount reasonable and proposes no adjustment.

Line No.	Source		Officers	Exempt	Non Exempt	Union	Total
1	WP 3.03 Restate Labor - wp 1	Test Period Base Wages & Salaries	\$315,838	\$3,590,448	\$1,286,600	\$2,782,694	\$7,975,580
2	PUC 3-year W&S Adj, line 16	Staff Adj to Test Period Payroll	(\$4,028)	(\$133,635)	(\$46,354)	(\$10,417)	(\$194,434)
3	(1)-(2)	Adjusted Payroll	\$311,810	\$3,456,813	\$1,240,246	\$2,772,277	\$7,781,146
4	WP 3.03 Restate Labor - wp 1	Ave. # of Employes (FTE) (2016)	1	30	19	30	80
5	(3)/(5)	Adjusted Average Salary	311,810	115,227	65,276	92,409	
6	See Explanation above	Staff Proposed FTE	1	30	19	30	80
7	(5)*(6)	Staff Proposed Proforma Payroll	\$311,810	\$3,456,813	\$1,240,246	\$2,772,277	\$7,781,146
8	(3)-(7)	<b>Net Payroll Adjustment</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>
9	PUC 3-year W&S Adj, line 13	O&M Expense as % of Payroll Expense	100.00%	77.50%	95.10%	87.80%	
10	(8)*(9)	O&M Expense Adjustment - Systemwide	\$0.00	\$0.00	\$0.00	\$0.00	
11	PUC 3-year W&S Adj, line 15	Oregon Allocation Factor	1	1	1	1	
12	(10)*(11)	<b>O&amp;M Adjustment - Oregon</b>	\$0.00	\$0.00	\$0.00	\$0.00	<b>\$0</b>
13	PUC 3-year W&S Adj, line 17	Capitalized Labor as % of Payroll Expense	0.00%	22.50%	4.90%	12.20%	
14	(8)*(13)	Rate Base Adjustment - Systemwide	\$0.00	\$0.00	\$0.00	\$0.00	
15	(14)*(11)	<b>Rate Base Adjustment - Oregon</b>	\$0.00	\$0.00	\$0.00	\$0.00	<b>\$0</b>

**Avista Utilities UG 288**  
**Calculation of PUC 3-Year Overtime Formula**  
**Actual 12/31/2013 to Proforma 12/31/2016**

Explanation: Staff's proposal adjusts Avista's test period overtime in accordance with guidelines followed in previous rate cases. Officers and Exempt FTE are not eligible for overtime so overtime is removed from the test period. Staff allows overtime to increase based on published CPI projections, and then allows the Company to share 50/50 the lesser of the difference between the Company's & Staff's calculated projections, or a 10% band around Staff's calculated projection.

Line No.	Source		Officers	Exempt	Non Exempt	Union	Total
1	WP 3.03 Restate Labor - wp 3)	Actual Overtime (2013)	\$0	\$179	\$49,746	\$394,636	\$444,561
2	WP 3.03 Restate Labor - wp 1	Average No. of FTE (2013)	1	30	19	30	80
3	(1)/(2)	Average Overtime per FTE	\$0	\$6	\$2,618	\$13,155	
4	PUC 3-year W&S Adj. line 4	Allowable % Increase	1.0364	1.0364	1.0364	1.0927	
5	S-2.2 FTE line 6	Staff Proposed Level FTE for Test Period	1	30	19	30	80
6	(3)*(4)*(5)	Projected Overtime	\$0	\$187	\$51,554	\$431,228	
7	WP 3.03 Restate Labor - wp 2)	Test Period Overtime	\$0 <sup>1</sup>	\$423 <sup>1</sup>	\$45,757 <sup>1</sup>	\$397,840 <sup>1</sup>	\$444,023
10	(7)-(6)	Total Difference	\$0	\$237	\$0	\$0	
11	(9)*.10	10% Band - Allowable	\$0	\$19	\$0	\$0	
12	[(10) or (11)] *.5	50% Sharing of Lesser of Difference or Band	\$0	\$9	\$0	\$0	
13	(6)+/(10)	Staff Proposed Level	\$0	\$196	\$45,757	\$397,840	\$443,793
14	(11)-(7)	Net Payroll Adjustment	\$0	(\$227)	\$0	\$0	(\$230)
15	WP 3.03 Restate Labor - wp 1	O&M Expense as % of Payroll Exp	100.00%	77.50%	95.10%	87.80%	
16	(12)*(13)	O&M Expense Adjustment - Systemwide	\$0	(\$176)	\$0	\$0	(\$176)
17	WP 3.03 Restate Labor - wp 2)	Oregon Allocation Factor	1	1	1	1	1
18	(14)*(15)	<b>O&amp;M Expense Adjustment - Oregon</b>	\$0	(\$176)	\$0	\$0	(\$176)
19	1 - (15)	Rate Base as % of Payroll Exp	0.000%	22.500%	4.900%	12.200%	
20	(14)*(19)	Rate Base Adjustment - Systemwide	\$0	(\$51)	\$0	\$0	(\$51)
21	(20)*(17)	<b>Rate Base Adjustment - Oregon</b>	\$0	(\$51)	\$0	\$0	(\$51)

<sup>1</sup> Per WP 3.03 2) 2014 YE OR Labor Detail - For 3YR CPI Analysis

	Officers	Exempt	Non-Exempt	Union
2014 OT Dollars	\$0	\$399	\$43,125	\$374,943
Increase - 2014		0.49%	0.49%	0.71%
Increase - 2015		3.00%	3.00%	3.00%
Increase - 2016		2.51%	2.51%	2.29%
2016 Test Year OT Dollars	\$0	\$423	\$45,757	\$397,840

**Avista Utilities UG 288  
Payroll Taxes  
Test Year Ended December 31, 2016**

	<u>OR-Alloc</u>
UG 288 Test Period Wages & Salaries and Overtime	\$ 8,419,603
UG 288 Payroll Tax as percentage of labor (per Staff Data Request No. 217)	8.25%
	\$ 694,617
Staff-Adjusted Wages & Salaries and Overtime	\$ 8,224,939
Payroll Taxes factor from above	8.25%
Staff Adjusted Payroll Taxes	\$ 678,557
Avista UG 288 Payroll Taxes	\$ 694,617
Staff Adjusted Payroll Taxes	\$ 678,557
<b>Adjustment</b>	<b>\$ (16,060)</b>



**Avista Utilities UG 288  
Depreciation  
Test Year Ended December 31, 2016**

	W&S		FTE		Overtime		Total	
	Co-wide	OR-Alloc	Co-wide	OR-Alloc	Co-wide	OR-Alloc	Co-wide	OR-Alloc
<b>O&amp;M</b>	(\$160,824)	(160,824)	\$0	\$0	(\$176)	(\$176)	(\$161,000)	(161,000)
<b>Rate Base</b>	(\$33,610)	(33,610)	\$0	\$0	(\$51)	(\$51)	(\$33,661)	(33,661)
							<b>(\$194,661)</b>	<b>(194,661)</b>

**O&M Depreciation associated with Capital Adjustments**

\$ (172)

<sup>1</sup> Test Year Gross Plant	\$ 368,415,000
<sup>2</sup> Annual Test Year Depreciation	<u>\$ 1,880,000</u>
% Avg. Depreciation to RB	0.5103%

<sup>1</sup>See Avista/502, Smith/4 at 219

<sup>2</sup>See Avista/502, Smith/3 at 131

**Avista Utilities UG 288  
Incentives  
Test Year Ending December 31, 2016**

Explanation: Bonuses and incentives for Officers are not allowed per Commission policy (Order No. 99-033 at 62; Order No. 97-171 at 74-76). Non-Officer bonuses are disallowed at 50 percent (Order No. 99-697 at 44-45; Order No. 99-033 at 62).

No.	Source		Officers	Exempt	Non Exempt	Union	Other*	Total
1	Note ****	Test Period O&M Incentives**	\$ 26,215	\$ 405,400	\$ 77,219	\$ 41,265	\$ -	\$ 550,100
2	See Explanation	Disallowance	100%	50%	50%	50%		
3	(1) * (2)	Staff Adjustment to Test Period Incentives	\$ 26,215	\$ 202,700	\$ 38,610	\$ 20,633		
4	(1) - (3)	Adjusted Incentives	\$ -	\$ 202,700	\$ 38,610	\$ 20,633	\$ -	
5	S-2.2 FTE	Average # of Employees (FTE)	1	30	19	30		
6	(4) / (5)	Adjusted Average Incentives	\$ -	\$ 6,757	\$ 2,032	\$ 688		
7	S-2.2 FTE	Staff Proposed FTE	1	30	19	30		
8	(6) * (7)	Staff Proposed Incentives	\$ -	\$ 202,700	\$ 38,610	\$ 20,633		\$ 261,942
9	(8) - (1)	<b>Net O&amp;M Incentive Adjustment</b>	<b>\$ (26,215)</b>	<b>\$ (202,700)</b>	<b>\$ (38,610)</b>	<b>\$ (20,633)</b>	<b>\$ -</b>	<b>\$ (288,157)</b>
10	Note ***	Test Period Capitalized Incentives		\$ 430,252	\$ 81,953	\$ 43,795		\$ 556,000
11	See Explanation	Disallowance	100%	50%	50%	50%		
12	(10) * (11)	Staff Adjustment to Test Period Incentives	\$ -	\$ 215,126	\$ 40,976	\$ 21,897		
13	(10) - (12)	Adjusted Incentives	\$ -	\$ 215,126	\$ 40,976	\$ 21,897		
	S-2.2 FTE	Average # of Employees (FTE)	1	30	19	30		
	(4) / (5)	Adjusted Average Incentives	\$ -	\$ 7,171	\$ 2,157	\$ 730		
14	S-2.2 FTE	Staff Proposed FTE	1	30	19	30		
15	(6) * (7)	Staff Proposed Incentives	\$ -	\$ 215,126	\$ 40,976	\$ 21,897		\$ 278,000
16	(8) - (1)	<b>Net Capital Incentive Adjustment</b>	<b>\$ -</b>	<b>\$ (215,126)</b>	<b>\$ (40,976)</b>	<b>\$ (21,897)</b>		<b>\$ (278,000)</b>

\* Other is usually comprised primarily of payroll taxes; however, per conversation with the Company, payroll taxes are included in WP 2.12 Incentive Adjustment

\*\* These amounts include O&M incentives only (per conversation with Company regarding DR 224 and WP 2.12 Incentive Adjustment)

\*\*\* Capitalized incentives obtained from DR 224 and allocated amongst labor groups by Staff using O&M amounts on line 1

	Capitalized TY OR incentives per DR 224	O&M % (see Note ****)	Capitalized OR TY Incentives
\$ 556,000			
Exempt		77.38%	\$ 430,252
Non-Exempt		14.74%	\$ 81,953
Union		7.88%	\$ 43,795

\*\*\*\* These amounts calculated by Staff as follows:

Executive	Non-executive			
\$ 301,252	\$ 6,020,279	from WP 2.12 Incentive Adjustment		
8.702%	8.702%	allocation % per WP 2.12 Incentive Adjustment		
\$ 26,215	\$ 523,885	TY incentives allocated to Oregon		
Employee Category	2015	per DR 218	% calc by Staff	Non-exec OR TY O&M incentives
Exempt	\$ 8,758,028		77.38%	\$ 405,400
Non-Exempt	\$ 1,668,196		14.74%	\$ 77,219
Union	\$ 891,467		7.88%	\$ 41,265
	\$ 11,317,691	Total Non-executive		

CASE: UG 288  
WITNESS: BRIAN BAHR

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 803**

**Confidential Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**STAFF EXHIBIT 803**

**IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE**

**ORDER NO. 15-141 IN UG 288**

CASE: UG 288  
WITNESS: MAX ST. BROWN

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 900**

**Other Revenue, Load Forecasting**

**Opening Testimony**

**October 16, 2015**

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Max St. Brown. I am a Utility Economist for the Public Utility  
3 Commission of Oregon (Commission or OPUC). My business address is 201  
4 High St. SE, Suite 100, Salem, Oregon 97301.

5 **Q. Please describe your educational background and work experience.**

6 A. My Witness Qualification Statement is found in Exhibit Staff/901.

7 **Q. Did you include any other exhibits for this testimony?**

8 A. Yes. Exhibit Staff/902 contains 16 pages, of which Staff prepared pages 14-  
9 15.

- 10 • Page 1: The Company's supplemental response to Staff DR 193  
11 providing a description of the Company's June 2015 forecasts.
- 12 • Page 2: Attachment A of the Company's response to Staff DR 187  
13 providing the composition of Other Revenue.
- 14 • Pages 3-13: Attachment A of the Company's response to Staff DR 194  
15 providing the Company's June 2015 load forecasting models.
- 16 • Pages 14-15: Staff's commercial and industrial load forecasting models.
- 17 • Pages 16-17: An example of using housing starts as a leading indicator  
18 in regression models.

19 **Q. What is the purpose of your testimony?**

20 A. Staff reviews of Avista's Other Revenue and Avista's commercial and industrial  
21 load forecasts.

22 **Q. How is your testimony organized?**

23 A. My testimony is organized as follows:

1	Issue 1, Other Revenue .....	5
2	Issue 2, Commercial and Industrial Load Forecasting .....	8

3

4

**Q. Has Avista made any adjustments to the load forecasting in its filed testimony?**

5

6

A. Yes, in June 2015 the Company produced a second round of forecasts using updated data. Staff refers to this as the Company's June 2015 forecasts (the Company's filed testimony uses forecasts from 2014). In many cases, the June 2015 forecasts were performed using model specifications different from those in the filed testimony, in order to better fit the updated data.

7

8

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11

**Q. Did the Company have adjustments to its filed testimony due to the June 2015 forecasts?**

12

13

A. Yes. In supplemental response to Staff DR 193, the Company stated, "The net effect of this adjustment is a revenue requirement increase of \$849,000 from the Company's original filing." This supplemental response is attached as Exhibit Staff/902, St. Brown/1.

14

15

16

17

**Q. Does Staff use the updated data?**

18

A. Yes, Staff uses the most recent data. The Company also used the most recent data in its June 2015 forecasts, but not in its filed testimony. The Company provided this data to Staff in response to Staff DR 193.

19

20

21

**Q. Please summarize your recommendations.**

22

A. Table 1 below provides a summary of Staff's adjustment related to Other Revenue.

23

24

25

Table 1			
Description	Company Filing – OR Allocated	Staff – OR Allocated	Adjustment
Other Revenue (000's of Dollars)	\$167 <sup>1</sup>	\$202	\$36

1

2

3

4

5

6

In regards to load forecasting, the testimony of Staff witness Bhattacharya in Exhibit Staff/1000 presents revenue requirement adjustments. For comparison purposes, Table 2 provides Staff's commercial and industrial load forecasts compared to the Company's June 2015 load forecasts.

Table 2			
Description	Company – June 2015 load forecasts (provided in response to Staff DR 193; differs from forecasts in filed testimony)	Staff – load forecasts	Adjustment
Sch. 420, Commercial and Industrial 2016 Normalized usage (in therms)	26,349,771 therms <sup>2</sup>	26,447,572 therms	97,801 therms
Large Sales Schs. 424, 440, & 444 2016 Normalized usage (in therms)	8,042,146 therms <sup>3</sup>	8,138,692 therms	96,546 therms
Transport Schs. 447 & 456 2016 Normalized usage (in therms)	44,926,584 therms <sup>4</sup>	45,073,772 therms	147,188 therms

7

<sup>1</sup> See: line 4 of Avista/501, Smith/1.

<sup>2</sup> See: Cells KA52:KA63 and KI52:KI63 in the "OR June 2015 Forecasts" tab of the file *Staff\_DR\_193 Attachment A - Gas Data and Forecasts June 2015.xlsx* submitted in response to Staff DR 193.

<sup>3</sup> See: id Cells KB52:KD63 and KJ52:KL63.

<sup>4</sup> *id*, Cells KE52:KE63 and KM52:KN63.



1 First, Staff recommends that Avista's test year Other Revenue be adjusted  
2 upwards by \$35,995. The driver of this result is the growth in miscellaneous  
3 service revenue from 2010-2014. Second, Staff recommends that Avista's  
4 commercial and industrial load forecasts be updated to address three issues  
5 identified by Staff: including a timber industry variable, avoiding subsetting the  
6 data, and including January 2004 through December 2004 data. Addressing  
7 these issues is relevant for both the Company's filed testimony and the  
8 Company's June 2015 forecasts. As described in the testimony of Staff witness  
9 Bhattacharya in Exhibit Staff/1000, Staff's resolution of these issues, and the  
10 issues in the residential load forecasts, results in Staff recommending that  
11 Avista's test year revenue be adjusted downwards by approximately \$867,796  
12 compared to the Company's filed testimony.

13

**ISSUE 1, OTHER REVENUE**

1  
2 **Q. Please summarize what Avista includes in revenue requirement for**  
3 **Other Revenue.**

4 A. The Company's test year adjusted total for Other Revenue is \$166,455. This is  
5 comprised of: sales for resale, miscellaneous service revenue, other gas  
6 revenue-gas property rent, other gas revenue – misc, and other gas revenue-  
7 DSM lost margin.<sup>5</sup> The value of other gas revenue – misc is zero for the test  
8 year.

9 **Q. How does the Company account for sales for resale?**

10 A. In response to Staff DR 169, the Company stated "Sales for Resale is a  
11 purchased gas cost related account, there is no net income impact associated  
12 with consolidating the gas costs."

13 **Q. How does the Company compute test year Other Revenue?**

14 A. The Company uses its 2014 value as its test year value because the 2014  
15 value in the Company's response to Staff DR 187 (attached as Staff/902, St.  
16 Brown/2) matches the 2016 value on line 4 of Avista/501, Smith/1. As  
17 described in Staff's previous answer, sales for resale revenue is subtracted  
18 from Other Revenue so as not to have a net income impact; additionally, "other  
19 gas revenue, DSM lost margin" is also subtracted from Other Revenue.

20 **Q. Excluding sales for resale and other gas revenue-DSM lost margin,**  
21 **what is the largest component of Other Revenue?**

---

<sup>5</sup> See: Company's response to Staff DR 187. This is attached as Staff/902, St. Brown/2.

1 A. The next largest element of Other Revenue is "Miscellaneous service revenue,"  
2 which in 2014 represented 99.5 percent of Other Revenue, excluding sales for  
3 resale and other gas revenue-DSM lost margin.

4 **Q. Please describe miscellaneous service revenue.**

5 A. Miscellaneous service revenues are revenues from the Miscellaneous Charges  
6 listed in Rule No. 20 in the Company's tariff. Examples include reconnect  
7 charges, late payment fees, and returned check bank charges. These charges  
8 correlate positively with the number of customers.

9 **Q. Does Staff forecast an increase in the number of customers between**  
10 **2014 and 2016?**

11 A. Yes, the testimony of Staff witness Bhattacharya forecasts a 1,488 increase in  
12 the monthly average number of customers between 2014 and 2016. The  
13 monthly average number of residential customers was 85,789 in 2014 and  
14 87,277 in 2016, as forecasted by Staff witness Bhattacharya in Exhibit  
15 Staff/1000. This is a 0.86 percent yearly increase in the average number of  
16 residential customers from 2014 to 2016.

17 **Q. What impact does this have on miscellaneous service revenue?**

18 A. Because, miscellaneous service charges correlate positively with the number  
19 of customers, Staff forecasts that miscellaneous service revenue increases  
20 from 2014 to 2016.

21 **Q. How did Staff forecast 2016 miscellaneous service revenue?**

22 A. Staff ran a regression with change in number of customers as the explanatory  
23 variable and with change in miscellaneous service revenues as the variable to

1 be explained. This regression indicated that in the data from 2010 to 2014, a  
2 one customer increase in the number of customers is associated with a \$24.19  
3 increase in the total miscellaneous service revenue. Notice this association  
4 cannot be interpreted as the average miscellaneous service charges per  
5 customer. This finding is applied to forecast miscellaneous service revenue in  
6 2016. As described above, Staff forecasts a 1,488 increase in the monthly  
7 average number of customers between 2014 and 2016. Multiplying this  
8 increase in customers by the \$24.19 impact per customer results in a \$35,995  
9 forecasted increase in miscellaneous service revenue.

10 **Q. Has Staff reviewed “other gas revenue-gas property rent”?**

11 A. Yes, Staff has reviewed the "Other Gas Revenue-Gas Property Rent" and has  
12 no adjustments.

13 **Q. What is Staff’s conclusion regarding test year Other Revenue?**

14 A. Staff forecasts Other Revenue at \$201,693; this is the sum of miscellaneous  
15 service revenue and “other gas revenue–gas property rent.” This is a \$35,995  
16 upwards adjustment to the Company’s filed value.

17

**ISSUE 2, COMMERCIAL AND INDUSTRIAL LOAD FORECASTING**

**Q. Please summarize the Company's load forecast for commercial and industrial customers.**

A. Table No. 1 at lines 4-10 of Avista/700, Forsyth/5 indicates that there are seven Schedules in Oregon. Schedules 420, 424, 440, 444, and 447 serve commercial customers. Schedules 420, 424, 440, 444, 447, and 456 serve industrial customers. Within each of these Schedule and customer type combinations, the Company prepares its forecasts by region in order to capture regional weather patterns. These regions are Medford, Roseburg, Klamath Falls, and La Grande. The two components of load are forecasted separately: use-per-customer and number of customers – where these components can be multiplied to obtain the load. Thus, there are four subgroupings for each forecast: Schedule, customer type, region, and load component.

Avista/700, Forsyth/4 at lines 14-16 describes that the Company forecasted each subgrouping using models that “range from linear regression models to simple smoothing (averaging) models, depending on ... the complexity of past customer growth.” DR 194 Attachment A indicates that in the Company's June 2015 forecasts the Company forecasted 64 commercial and industrial subgroupings and used regression models for 36 of these subgroupings.

**Q. What is the timing of the Company's forecasts?**

A. Company witness Forsyth provided forecasts using data up to 2014 in Exhibit Avista/700 of the Company's filed testimony. In data responses, the Company provided a second round of forecasts computed in June 2015 using data up to

1 April 2015. The Company provided its June 2015 forecasting models in  
2 response to Staff DR 194; these are attached as Staff/902, St. Brown/3-13.

3 The Company forecasts the test year January 2016 – December 2016. Thus,  
4 the June 2015 forecasts are for nine months to 20 months into the future.

5 **Q. Please summarize Staff's recommendations for the commercial and**  
6 **industrial load forecasts.**

7 A. Staff divides its recommendations based on the forecasting method used. For  
8 the simple smoothing (averaging) models, Staff recommends no change at this  
9 time. For the regression models, Staff makes three recommendations:

10 1. A variable related to the timber industry should be added to the use-per-  
11 customer regressions of timber industry customers.

12 2. Data time periods after 2004 should not be excluded from the regressions  
13 without a well-founded justification.

14 3. January 2004 – December 2004 data should not be excluded from the  
15 regressions because all data contains information and all information should be  
16 taken into account.

17 Staff applies adjustments based on these three recommendations to the  
18 Company's load forecasts, resulting in a 0.03 percent higher, than the  
19 Company's June 2015 forecasts, test year load for the commercial and  
20 industrial portion of the load forecasts. Staff's commercial and industrial load  
21 forecasts are below those found in the testimony of Company witness Forsyth  
22 in Exhibit Avista/700 of the Company's filed testimony, but are above the  
23 Company's June 2015 forecasts attached as Staff/902, St. Brown/3-13.

1 Staff's regression models are presented in Exhibit Staff/902, St. Brown/14-  
2 15. Staff used the output of these regression models to compute adjustments  
3 to Schedule 420, 424, 440, 444, 447, and 456 loads. Then these adjusted  
4 loads were plugged into the revenue model Excel spreadsheet provided by the  
5 Company in response to Staff's DR 300, which asked for a description of how  
6 Company witness "Forsyth's [Avista/700] models were incorporated in the  
7 revenue model." The results of the revenue model were plugged into the  
8 "Usage & Billings by Rate Schedule" portion of the workpaper supporting  
9 Avista/900 of Company witness Ehrbar. As described in the testimony of Staff  
10 witness Bhattacharya, Staff's addressing of the commercial and industrial load  
11 forecasting issues and the residential load forecasting issues results in Staff  
12 recommending that Avista's test year revenue be adjusted downwards by  
13 approximately \$867,796 from the Company's filed testimony.

14 **Q. What was the Company's approach in the simple smoothing**  
15 **(averaging) models?**

16 A. For the subgroupings that the Company identified as having non-complex past  
17 growth patterns, the Company primarily used a 12-month moving average  
18 model to forecast their future values. In this method, the May 2015 forecast is  
19 the average of the last 12 months' values. Likewise, the June 2015 forecast is  
20 the average of the last 11 months in data and the May 2015 forecast.

21 **Q. Does Staff find this approach reasonable?**

22 A. At this time, yes. Using simple smoothing (averaging) models is reasonable  
23 when explanatory data are not available. For example, the Company's

1 response to Staff DR 275 states, “much of the non-weather, non-seasonal  
2 volatility of the large customer cannot be modeled because it represents largely  
3 randomized operating events—for example, equipment failures and  
4 maintenance.”

5 **Q. What is Staff’s recommendation regarding the simple smoothing**  
6 **(averaging) models?**

7 A. At this time, Staff recommends no change and supports the simple smoothing  
8 (averaging) models for each of the subgroupings that the Company identified  
9 as having non-complex past growth patterns. However, Staff notes that it is  
10 important to regularly monitor trends that may affect the series being  
11 forecasted. To this end, Staff is supportive of the Company’s response to Staff  
12 DR 274 which states, “Avista, through its business managers and account  
13 executives, regularly communicate with its large commercial and industrial  
14 customers. ... we believe we know well in advance if a customer was going to  
15 materially increase or decrease its usage, or discontinue service.” Staff  
16 requests that this information be communicated with Staff as well for purposes  
17 of verifying the forecasting models.

18 **Q. What was the Company’s approach in the regression models?**

19 A. The Company uses “Autoregressive integrated moving average” (ARIMA)  
20 models. Explanatory variables used to predict future therm usage in the  
21 Company’s models include lagged (past) values of the usage itself and an  
22 industrial production index (IPBASE). The regression models also control for  
23 seasonality and outliers. Explanatory variables used to predict future



1 customers in the Company's commercial models include the number of  
2 residential customers. A defining characteristic of the ARIMA models is that  
3 they use past observations of the dependent variable itself as explanatory  
4 variables.

5 **Q. Staff's first recommendation is that a variable related to the timber**  
6 **industry should be added to the use-per-customer regressions of**  
7 **timber industry customers. How does Staff support this**  
8 **recommendation?**

9 A. The Company runs regressions for three special contract Schedule 447  
10 customers. All three of these customers are involved in the timber industry.  
11 Staff communicated with the Oregon Department of Forestry and learned that  
12 many of the wood products in Oregon are used in housing. Thus, Staff added  
13 lagged West housing starts valuation as an explanatory variable to the  
14 Schedule 447, Klamath Falls, use-per-customer regression. This variable  
15 improved the forecast accuracy of the model as measured by in-sample "mean  
16 absolute percentage error" (MAPE), a measure of forecast accuracy. Further,  
17 this variable is statistically significant at a lower p-value than the IPBASE  
18 variable that the Company included. Thus, Staff supports adding a variable  
19 related to the timber industry because it adds explanatory power to the  
20 Schedule 447, Klamath Falls use-per-customer regression.

21 **Q. How did Staff make adjustments based on Staff's first**  
22 **recommendation?**

1 A. As discussed in the previous answer, Staff added lagged West housing starts  
2 valuation to the regression. These data are available from the U.S. Census and  
3 they represent the one year lagged value of new housing starts in the West  
4 [U.S.]. Staff uses the lagged version of the variable because housing starts are  
5 often recognized as a leading indicator. A leading indicator is a variable that is  
6 measured in the current time period, but whose value often correlates with  
7 changes to a future time period. In Staff's usage, 2015 West housing starts  
8 valuation data is used as a predictor of 2016 natural gas therm usage in the  
9 timber industry. The theory is: increasing economic activity in the housing  
10 industry necessitates increased production of timber products. Exhibit  
11 Staff/902, St. Brown/16-17 presents an example of housing starts as a leading  
12 indicator.<sup>6</sup> Using the number of housing starts provides similar results, but  
13 since higher value homes tend to be larger and use more timber products, Staff  
14 decided that "valuation of homes" had the strongest theoretical basis for  
15 necessitating increased production of timber products.

16 **Q. What does Staff recommend for the Company's regression models?**

17 A. The Company should add lagged West housing starts valuation or a similar  
18 variable to its Schedule 447 use-per-customer regressions.

19 A similar variable is volume of timber harvested in Oregon. Staff found that  
20 data on volume of timber harvested from the Oregon Department of Forestry is  
21 positively correlated with Schedule 447 use-per-customer. Specifically, volume

---

<sup>6</sup> Roubini, Nouriel, "Housing Starts/Building Permits," NYU Stern School of Business. Accessed September 29, 2015 from: <http://pages.stern.nyu.edu/~nroubini/bci/housingstarts.htm>

1 of timber harvest has a stronger correlation than IPBASE with Schedule 447  
2 use-per-customer, as presented in the table below:

Correlation Coefficients for 2005-2014 data	
Oregon timber harvest and Schedule 447 therm usage:	IPBASE and Schedule 447 therm usage:
0.51	0.33

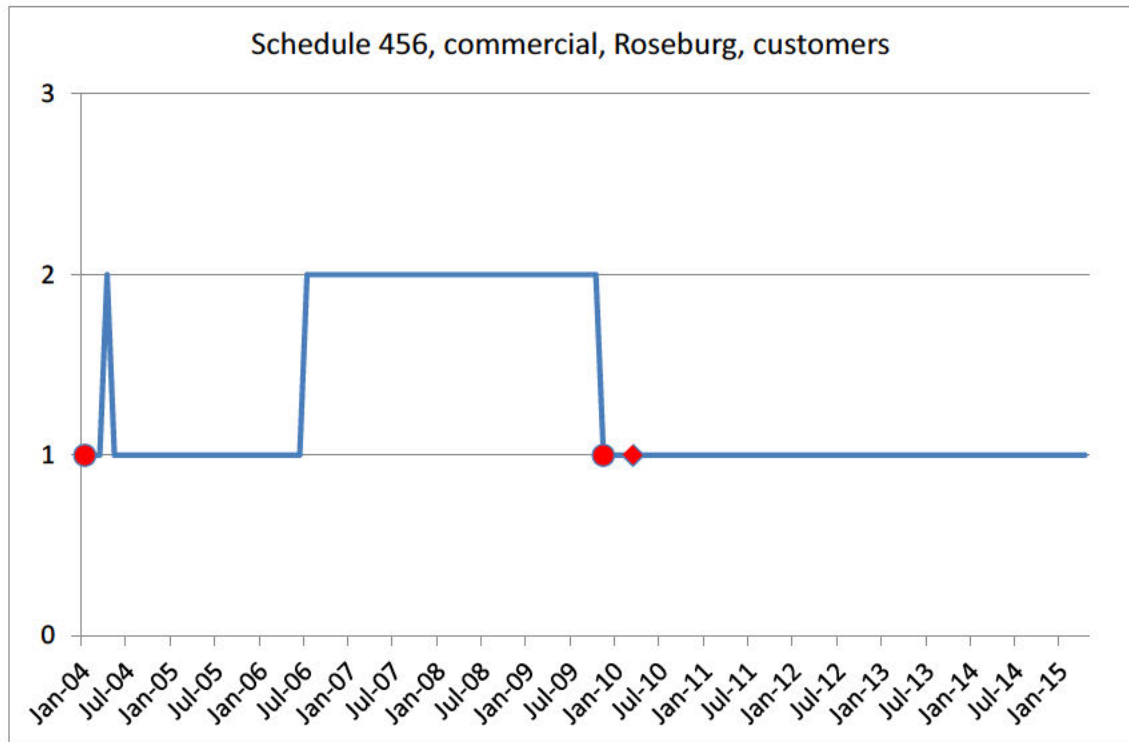
3  
4

5 The Company uses IPBASE in its regressions. The Company could obtain  
6 forecasts of timber harvests from a paid subscription.

7 **Q. Staff's second recommendation is that data time periods after 2004**  
8 **should not be excluded from the regressions without a well-founded**  
9 **justification. How does Staff support and make recommendations**  
10 **based on this recommendation?**

11 A. Staff adjusts the forecasting models of two subgroupings:

12 1. In regards to the Schedule 456, commercial, Roseburg, use-per-customer  
13 forecast, in response to Staff DR 194 the Company replied, "Model is restricted  
14 to March 2010 [onwards] because of a significant change in seasonality  
15 compared to earlier periods. This appears to reflect a downward-step in the  
16 number of customers in 2010." However, Staff determined that there were two  
17 customers in this subgrouping from July 2006 until October 2009 and then  
18 there was one customer from November 2009 onwards. This is shown in the  
19 graph below:

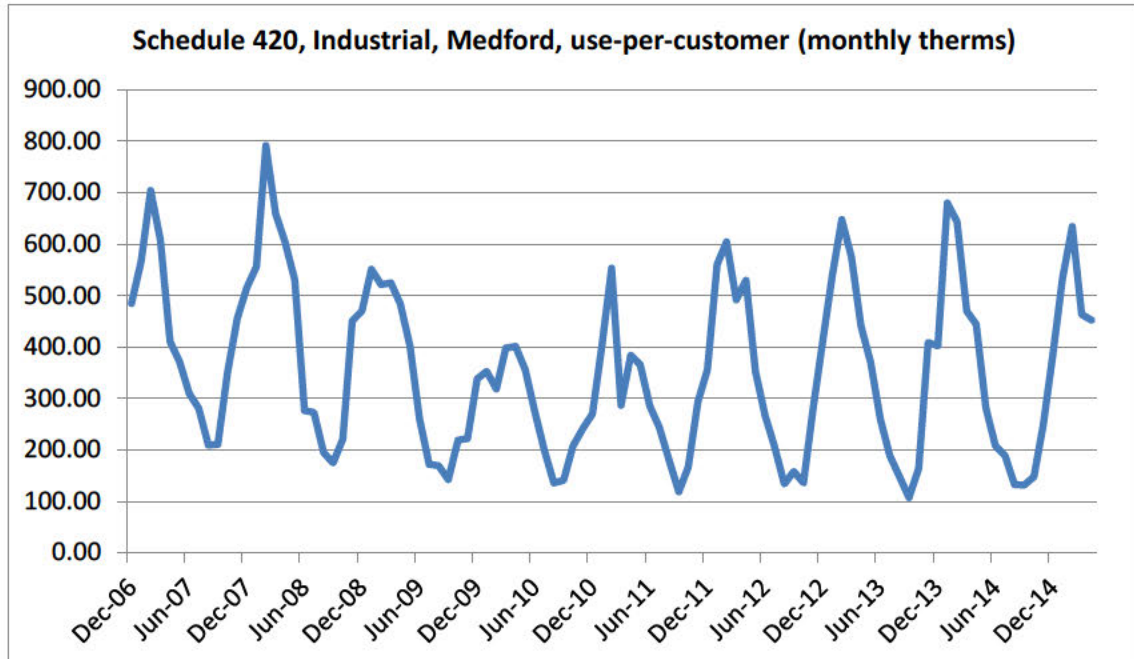


1  
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The figure demonstrates that the downward-step in the number of customers occurred in 2009, not 2010. In the figure, the diamond data point is where the Company began its dataset for the regression model of this use-per-customer subgrouping. Beginning the dataset at either circle is more appropriate. To be consistent with the Company’s current approach, Staff begins the regression at the second circle in the figure above by adding data from November 2009 through February 2010.

2. With regard to the Schedule 420, industrial, Medford, use-per-customer forecast, the Company’s response to Staff DR 194 states, “Model is restricted to 2008 [onwards] because schedule does not start until December 2006. In addition, seasonality changes significantly starting in 2008. Seasonality still

1 appears to be somewhat unstable.” Staff graphed the use-per-customer in  
2 order to view the seasonality of the series. This graph is below:



3  
4 From visually inspecting the graph above, Staff finds that seasonality is present  
5 from December 2006 onwards and thus does not support the Company’s sub-  
6 setting of the data. Staff reran the model using the dataset beginning  
7 December 2006.

8 **Q. What does Staff recommend for the Company’s regression models?**

9 A. Staff recommends that the Company include data from November 2009  
10 through February 2010 in its forecast of Schedule 456, commercial, Roseburg,  
11 use-per-customer and should include data from December 2006 through  
12 December 2007 in its forecast of Schedule 420, industrial, Medford, use-per-  
13 customer.

14 **Q. Staff’s third recommendation is that the January 2004 – December**  
15 **2004 data should not be excluded from the regressions because all**

1           **data contains information and all information should be taken into**  
2           **account. Has this issue been raised before?**

3           A. Yes, this issue was discussed in Avista's last rate case, UG 284. Lines 23-30  
4           of Joint Testimony Staff/102, Gardner and Muldoon/29 in the UG 284 rate case  
5           stated, "Based on the Company's response to Staff's Data Request 291 and  
6           conference calls, Staff understands that the explanation for selecting a subset  
7           of the sample is not based on any statistical tests, and thus is inconsistent with  
8           the standard econometric model building practices."

9           **Q. How did Staff make adjustments based on Staff's third**  
10           **recommendation?**

11          A. Staff reran the Company's regression models for each of the nine  
12          subgroupings using 2005 data not already facing an adjustment. Staff did not  
13          adjust the Schedule 420, commercial, Medford regressions which depend on  
14          the Schedule 410, residential regression, because that residential regression  
15          was not adjusted by Staff. Staff did not adjust the Schedule 444, industrial, La  
16          Grande, customer regression because the Company included ten dummy  
17          variables, indicating that there may be non-weather, non-seasonal volatility.

18          With that as a starting point, Staff made two adjustments:

19          1. Staff incorporated Staff/1000, Staff witness Bhattacharya's Schedule 410,  
20          residential, customer forecasts for the Roseburg, La Grande and Klamath Falls  
21          regions.

22          2. Staff reran the Company's regression models after adding back in the  
23          January 2004 to December 2004 data. Staff used the Company's own

1 regression model specifications, but included the January 2004 to December  
2 2004 data. This resulted in some load forecasts increasing and some load  
3 forecasts decreasing.

4 **Q. Did Staff try any approaches that did not become recommendations?**

5 A. Yes, Staff tried two theoretical approaches that did not fit the data well and thus  
6 did make not any recommendations related to these other approaches. First,  
7 Staff identified a theoretical relationship that population growth positively  
8 affects commercial customer growth. Thus Staff experimented with adding  
9 population as an explanatory variable in the commercial forecasts to replace  
10 the Company's residential customer variable. However, for this data set, using  
11 residential customers had more explanatory power, so Staff maintained the  
12 Company's approach in this respect. Second, Staff identified a theoretical  
13 relationship that economic activity positively affects commercial loads. Thus  
14 Staff experimented with adding Oregon total personal income from the Oregon  
15 Office of Economic Analysis. However this variable was not statistically  
16 significant in regressions, so Staff did not add this variable and maintained the  
17 Company's approach in this respect.

18 **Q. Does this conclude your testimony?**

19 A. Yes.

CASE: UG 288  
WITNESS: MAX ST. BROWN

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 901**

**Witness Qualifications Statement**

**October 16, 2015**



### WITNESS QUALIFICATIONS STATEMENT

NAME: Max St. Brown

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Economist  
Energy Rates, Finance & Audit Division

ADDRESS: 201 High Street SE. Suite 100  
Salem, OR. 97301

EDUCATION: Ph.D., Economics (2013)  
Washington State University

B.S., Economics (2009)  
Central Washington University

EXPERIENCE: I have been employed by the Public Utility Commission since July 2015, with my current position being a Utility Economist, in the Utility Program's Energy – Rates, Finance and Audit Division. My current responsibilities include analysis and technical support for rate, finance, and audit related proceedings, with an emphasis on forecasting and marginal cost studies.

Prior to working for the OPUC I served as an Assistant Professor of Economics at Eckerd College in St. Petersburg, FL from 2013 to 2015. I have taught courses including Econometrics, Labor Economics, and Intermediate Microeconomics. As a graduate student at Washington State University I taught six course sections, including Econ of Renewable Energy.

My published research in peer-reviewed academic journals includes a study of the U.S. renewable energy industry and includes international economic impact studies.

I served as a summer fellow at the American Institute for Economic Research during summers 2011 and 2012.

CASE: UG 288  
WITNESS: MAX ST. BROWN

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 902**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

## Exhibit 2

### SUPPLEMENTAL RESPONSE:

(a): In the Company's response to Staff-193, base data for the most recent customer and use per customer (UPC) forecasts were provided. The Company is supplementing the response to Staff-193 in order to reflect the revised billing determinants from this most recent forecast in adjustment number 2.01 (2016 Test Year Revenue Adjustment). The effect of this revised adjustment is to increase Oregon net operating income by \$3,608,000 (\$4,099,000 in original filing) and a reduction to revenue requirement of \$6,225,000 (\$7,074,000 in original filing). The net effect of this adjustment is a revenue requirement increase of \$849,000 from the Company's original filing. See the attachment labeled "Staff\_DR\_193 Supplemental Attachment A" for the workpapers supporting this revised adjustment.

During the analysis of the updated forecast data provided above, the Company discovered a formula error in its original filing which resulted in an incorrect assignment of usage to the individual rate blocks on Schedule 146. The resulting correction to the five usage blocks overstated revenue to Schedule 146 by \$119,000 in the Company's original filing. The Company has corrected the assignment of usage to the individual rate blocks in the attachment labeled "Staff\_DR\_193 Supplemental Attachment A" discussed above.

## Exhibit 2

	A	B	C	D	E	F	G	H	I
1	Avista Utilities								
2	Case No. UG 288								
3	Staff Data Request No. 187								
4									
5	Other Revenue Components 2010 through 2015								
6									
7	Part A. Actual Other Revenue by Category								
8									
9	FERC Account Description		2010	2011	2012	2013	2014	YTD 06.2015	
10									
11	483 Sales for Resale		60,527,185	76,479,320	67,211,233	90,624,357	115,399,902	39,737,199	
12	488 Miscellaneous Service Revenue		138,727	140,056	140,853	151,862	165,698	31,476	
13	493 Other Gas Revenue -Gas Property Re		1,697	757	1,257	757	757	387	
14	495 Other Gas Revenue - Misc		-	-	1,688	400	-	-	
15	495600 Other Gas Revenue - DSM Lost Margir		45,425	48,905	36,414	173,046	28,157	2,111	
16	<b>Actual Other Revenue</b>		<b>60,713,034</b>	<b>76,669,038</b>	<b>67,391,445</b>	<b>90,950,422</b>	<b>115,594,514</b>	<b>39,771,173</b>	
17									
18	Part B. Hypothetical GRC Adjustments to Other Revenue								
19			2010	2011	2012	2013	2014	YTD 06.2015	
20	Consolidate Sales for Resale with Gas Costs to Identify Net Gas Cost								
21	804 Purchased Gas Cost		116,944,219	137,348,913	119,814,355	138,793,793	161,753,493	59,222,060	
22	805 PGA Deferral & Amortization		(351,216)	(1,812,369)	(388,538)	(385,337)	(5,302,882)	2,106,059	
23	808 Nat Gas Storage Transactions		(658,386)	(20,098)	576,425	687,324	(1,666,445)	2,056,982	
24	811 Gas Used for Product Extraction		(316,247)	(483,360)	(484,856)	(416,865)	(471,284)	(88,455)	
25	483 Sales for Resale Revenue		(60,527,185)	(76,479,320)	(67,211,233)	(90,624,357)	(115,399,902)	(39,737,199)	
26	Net Gas Cost		55,091,185	58,553,766	52,306,153	48,054,558	38,912,980	23,559,447	
27									
28	Weather Adj Cost of Gas		658,529	(5,566,540)	(381,935)	(2,926,996)	5,218,230		
29	Normalized Cost of Gas		55,749,714	52,987,226	51,924,218	45,127,562	44,131,210	23,559,447	
30									
31	Eliminate DSM Lost Margin to Reset Base for Future Lost Margin Calculations								
32	495600 Other Gas Revenue - DSM Lost Margir		(45,425)	(48,905)	(36,414)	(173,046)	(28,157)	(2,111)	
33									
34	<b>Hypothetical Adjusted Other Revenue</b>		<b>140,424</b>	<b>140,813</b>	<b>143,798</b>	<b>153,019</b>	<b>166,455</b>	<b>31,863</b>	

## Exhibit 3

### 1. Medford, OR Forecasting Models

The forecasting models for the Medford region (Jackson County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, THM:

$$[7.51] THM/C_{t,y,MED410.r} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + \lambda RAP_{t,y-1,OR410} + \gamma_1 \ln T + \omega_{SD} D_{t,y} + \omega_{SC} D_{Jan 2006 \uparrow =1} + \omega_{OL} D_{Dec 2005 =1} + \omega_{OL} D_{May 2011 =1} + \omega_{OL} D_{Jun 2011 =1} + ARIMA \epsilon_{t,y} (11,0,0)(0,0,0)_{12}$$

[7.51] Model notes:

1. SC dummy controls for a step-down in UPC for January 2006  $\uparrow$ .
2. The variable  $\ln T$  reflects a general control for multiple factors lowering UPC, including the impact of RAP.
3. AHS is not included because its impact is unstable and not statistically significant.

$$[7.52] THM/C_{t,y,MED420.r} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \omega_{OL} D_{Dec 2009 =1} + \omega_{OL} D_{Jan 2010 =1} + \omega_{OL} D_{Feb 2010 =1} + \omega_{OL} D_{Jan 2011 =1} + ARIMA \epsilon_{t,y} (1,0,0)(0,0,0)_{12}$$

[7.52] Model notes:

1. This schedule represents less than 10 customers.
2. January 2012 also appears to be an outlier, but controlling for it causes a convergence failure; however, it not controlling for it does not have a large impact of the forecasts.

Residential Sector, Customers:

$$[7.53] C_{t,y,MED410.r} = \alpha_0 + \alpha_1 POP_{t,y,MED} + \omega_{SD} D_{t,y} + \omega_{SC} D_{Jan 2008 \uparrow =1} + \gamma_{RAMP} T_{Jan 2008} + \omega_{OL} D_{Feb 2015 =1} + ARIMA \epsilon_{t,y} (7,1,0)(0,0,0)_{12}$$

[7.53] Model notes:

1. SC dummy and ramping time trend control for a change in the time-path of customer growth starting in January 2008.

$$[7.54] C_{t,y,MED420.r} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

Commercial Sector, THM:

$$[7.55] THM/C_{t,y,MED420.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD} D_{t,y} + \omega_{SC} D_{Nov 2008 \uparrow =1} + \omega_{OL} D_{Jan 2005 =1} + \omega_{OL} D_{Dec 2005 =1} + \omega_{OL} D_{Dec 2006 =1} + \omega_{OL} D_{Mar 2010 =1} + \omega_{OL} D_{April 2010 =1} + ARIMA \epsilon_{t,y} (11,0,0)(0,0,0)_{12}$$

[7.55] Model notes:

1. SC dummy controls for a step-down in UPC for November 2008  $\uparrow$ .
2. Work is ongoing to determine if RAP can be integrated into the model.

$$[7.56] THM/C_{t,y,MED424.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Dec 2012 =1} + \omega_{OL} D_{Jan 2013 =1} + \epsilon_{t,y} \text{ for } t, y \text{ July} = 2010 \uparrow$$

[7.56] Model notes:

1. Model is restricted to July 2010  $\uparrow$  because of a significant change in UPC behavior compared to earlier periods.
2. Some non-stationarity at lag 3 in the ADF test; however this likely reflects the limited number of observations.

### Exhibit 3

$$[7.57] THM_{t,y,MED444.c} = \beta_0 + \omega_{SD}D_{t,y} + ARIMA\epsilon_{t,y}(1,0,0)(0,0,0)_{12}$$

$$[7.58] THM/C_{t,y,MED440.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \omega_{OL}D_{Sept\ 2008=1} + \omega_{OL}D_{Oct\ 2008=1} + \omega_{OL}D_{Nov\ 2008=1} + \omega_{OL}D_{Jan\ 2009=1} + \omega_{OL}D_{May\ 2009=1} + \omega_{OL}D_{Dec\ 2013=1} + ARIMA\epsilon_{t,y}(2,0,0)(0,0,0)_{12} \text{ for } t, y = April\ 2007 \uparrow$$

[7.58] Model notes:

1. Model is restricted to April 2009  $\uparrow$  because schedule does not start until February 2007.

$$[7.59] THM/C_{t,y,MED456.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \omega_{SD}D_{t,y} + \omega_{OL}D_{Sept\ 2009=1} + \omega_{OL}D_{Mar\ 2013=1} + \omega_{OL}D_{Dec\ 2013=1} + ARIMA\epsilon_{t,y}(12,0,0)(0,0,0)_{12}$$

[7.59] Model notes:

1. Transportation schedules are subject to structural change because of customers entering or exiting with enough loads to alter historical behavior.

#### Commercial Sector, Customers:

$$[7.60] C_{t,y,MED420.c} = \alpha_0 + \alpha_1 C_{t,y,MED410.r} + \omega_{SD}D_{t,y} + \omega_{OL}D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y}(12,1,0)(0,0,0)_{12}$$

[7.60] Model notes:

1.  $C_{t,y,MED410.r}$  are residential customers from residential schedule 410. They are being used as a forecast driver because of the historical positive correlation between residential and commercial customer growth. See Tables 5.1 and 5.2.

$$[7.61] C_{t,y,MED424.c} = C_{t,y-1} + 1 \text{ (add approximately one customer per year)}$$

[7.61] Model notes:

1. Due to the Compass software conversion, February 2015 is excluded from the historical data. The conversion resulted in a double counting of customers in February 2015. Therefore, including this month leads to a significant over-forecast of customers.

$$[7.62] C_{t,y,MED444.c} = 1 \text{ if } (THM/C_{t,y})_{MED,440.c} > 0$$

[7.62] Model notes:

1. There is typically only one customer served by this schedule. Therefore, the customer forecast is automatically set to one whenever the load forecast is greater than zero.

$$[7.63] C_{t,y,MED440.c} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

$$[7.64] C_{t,y,MED456.c} = C_{t-1} \text{ (Stable Customer Base; No Forecasting Model Required)}$$

#### Industrial Sector, THM:

$$[7.65] THM/C_{t,y,MED420.i} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + \delta_1 IP_{t,y} + \omega_{OL}D_{March\ 2011=1} + \omega_{SD}D_{t,y} + ARIMA\epsilon_{t,y}(1,0,0)(0,0,0)_{12} \text{ for } y = 2008 \uparrow$$

[7.65] Model notes:

1. Model is restricted to 2008  $\uparrow$  because schedule does not start until December 2006. In addition, seasonality changes significantly starting in 2008. Seasonality still appears to be somewhat unstable.  
2. Work is ongoing to determine if RAP can be integrated into the model.

## Exhibit 3

[7.66]

$$THM/C_{t,y,MED424.i} = \alpha_0 + \delta_1 IP_{t,y} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Aug\ 2012=1} + \omega_{OL} D_{Sept\ 2012=1} + ARIMA\epsilon_{t,y}(6,0,0)(0,0,0)_{12} \text{ for } y = 2010 \uparrow$$

[7.66] Model notes:

1. Model is restricted to 2010  $\uparrow$  because schedule does not start until January 2009. In addition, seasonality changes significantly starting in 2008. Seasonality still appears to be somewhat unstable.
2. There are typically only two customers in this schedule.

$$[7.67] THM/C_{t,y,MED440.i} = \alpha_0 + \omega_{SD} D_{t,y} + \omega_{SC} D_{May\ 2013\uparrow=1} + ARIMA\epsilon_{t,y}(0,0,0)(1,0,0)_{12} \text{ for } y = 2008 \uparrow$$

[7.67] Model notes:

1. Model is restricted to 2008  $\uparrow$  because seasonality changes significantly starting in this period. Seasonality still appears to be somewhat unstable. The change in seasonality reflects a very large step-down in customers in 2007—falling from around 22 to five.
2. SC dummy controls for a step-up in UPC starting in May 2013.
3. Some non-white noise issues at lag 40 and beyond; likely reflects short time-series and its erratic behavior.

$$[7.68] THM/C_{t,y,MED456.i} = \alpha_0 + \delta_1 IP_{t,y} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Jan\ 2008=1} + \omega_{OL} D_{Sept\ 2008=1} + ARIMA\epsilon_{t,y}(3,0,0)(0,0,0)_{12} \text{ for } y = 2007 \uparrow$$

[7.68] Model notes:

1. Model is restricted to 2007  $\uparrow$  because of a modest change seasonality compared to earlier periods.
2. Work is ongoing for statistical controls so that 2005-2006 can be added to the estimation period.
3. Transportation schedules are subject to structural change because of customers entering or exiting with enough loads to alter historical behavior.

Industrial Sector, Customers:

$$[7.69] C_{t,y,MED420.i} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

$$[7.70] C_{t,y,MED424.i} = C_{t-1} \text{ (Stable Customer Base; No Forecasting Model Required)}$$

$$[7.71] C_{t,y,MED440.i} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

$$[7.72] C_{t,y,MED456.i} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

## 2. Roseburg, OR Forecasting Models

The forecasting models for the Roseburg region (Douglas County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, THM:

$$[7.73] THM/C_{t,y,ROS410.r} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \gamma_1 \ln T + \lambda RAP_{t,y-1,OR410} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Dec\ 2006=1} + \omega_{OL} D_{Mar\ 2011=1} + \omega_{OL} D_{Dec\ 2011=1} + \omega_{OL} D_{Feb\ 2012=1} + ARIMA\epsilon_{t,y}(11,0,0)(0,0,0)_{12}$$

[7.73] Model notes:

1. The variable lnT reflects a general control for multiple factors lowering UPC, including the impact of RAP.
2. AHS is not included because its impact is unstable and not statistically significant.

### Exhibit 3

$$[7.74] THM/C_{t,y,ROS420.r} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD} D_{t,y} + \omega_{OL} D_{Jan\ 2013=1} + ARIMA\epsilon_{t,y} (1,0,0)(0,0,0)_{12} \text{ for } t, y = \text{March } 2010 \uparrow$$

[7.74] Model notes:

1. Model restricted to March 2010  $\uparrow$  because schedule does not start until October 2009.
2. This schedule appears to be dying out.

#### Residential Sector, Customers:

$$[7.75] C_{t,y,ROS410.r} = \varphi_0 + \omega_{SD} D_{t,y} + \omega_{SC} D_{Jan\ 2007\uparrow=1} + \gamma_{RAMP} T_{Jan\ 2007} + \omega_{OL} D_{Nov\ 2005=1} + \omega_{OL} D_{Dec\ 2005=1} + \omega_{OL} D_{Nov\ 2006=1} + \omega_{OL} D_{Mar\ 2007=1} + \omega_{OL} D_{Dec\ 2007=1} + \omega_{OL} D_{Feb\ 2008=1} + \omega_{OL} D_{Nov\ 2009=1} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y} (6,1,0)(0,0,0)_{12}$$

[7.75] Model notes:

1. SC dummy and ramping time trend control for a change in the time-path of customer growth starting in January 2007.

$$[7.76] C_{t,y,ROS420.r} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

[7.75] Model notes:

1. Schedule appears to have died; no customers are currently being reported.

#### Commercial Sector, THM:

$$[7.77] THM/C_{t,y,ROS420.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD} D_{t,y} + \omega_{OL} D_{Mar\ 2011=1} + ARIMA\epsilon_{t,y} (8,0,0)(0,0,0)_{12}$$

$$[7.78] THM/C_{t,y,ROS424.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Oct\ 2007=1} + \omega_{OL} D_{July\ 2009=1} + \omega_{OL} D_{Mar\ 2011=1} + \omega_{OL} D_{Feb\ 2013=1} + ARIMA\epsilon_{t,y} (9,0,0)(0,0,0)_{12}$$

$$[7.79] THM/C_{t,y,ROS440.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD} D_{t,y} + \omega_{SC} D_{Dec\ 2010\uparrow=1} + \omega_{OL} D_{Oct\ 2009=1} + \omega_{OL} D_{Nov\ 2009=1} + \omega_{OL} D_{Nov\ 2010=1} + \omega_{OL} D_{May\ 2013=1} + \omega_{OL} D_{June\ 2013=1} + \omega_{OL} D_{Oct\ 2013=1} + \omega_{OL} D_{Jan\ 2015=1} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y} (1,0,0)(0,0,0)_{12} \text{ for } t, y = \text{April } 2007 \uparrow$$

[7.79] Model notes:

1. Model is restricted to April 2007  $\uparrow$  because schedule does not start until February 2007.
2. SC dummy controls for step-up in UPC starting in December 2010.

$$[7.80] THM/C_{t,y,ROS456.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \omega_{OL} D_{July\ 2014=1} + ARIMA\epsilon_{t,y} (1,0,0)(0,0,0)_{12} \text{ for } t, y = \text{March } 2010 \uparrow$$

[7.80] Model notes:

1. Model is restricted to March 2010  $\uparrow$  because of a significant change in seasonality compared to earlier periods. This appears to reflect a downward-step in the number of customers in 2010.



### Exhibit 3

#### Commercial Sector, Customers:

$$[7.81] C_{t,y,ROS420.c} = \varphi_0 + \omega_{SD}D_{t,y} + \gamma_1 T + \omega_{OL}D_{Jan\ 2008=1} + \omega_{OL}D_{Mar\ 2009=1} + \omega_{OL}D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y}(6,1,0)(0,0,0)_{12}$$

[7.81] Model notes:

1. Model does not use schedule 410 customers as driver. This reflects the lack of correlation between residential 410 and commercial 420 customer growth.
2. The lack of correlation noted in Point 1 could reflect Roseburg's position between larger cities that offer a range of commercial activities. Competition from these cities may be inhibiting commercial growth in Roseburg.

$$[7.82] C_{t,y,ROS424.c} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

$$[7.83] C_{t,y,ROS440.c} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

$$[7.84] C_{t,y,ROS456.c} = C_{t-1} \text{ (Stable Customer Base; No Forecasting Model Required)}$$

#### Industrial Sector, THM:

$$[7.85] THM/C_{t,y,ROS420.i} = \varphi_0 + \delta_1 IP_{t,y} + \omega_{SD}D_{t,y} + ARIMA\epsilon_{t,y}(3,1,0)(0,0,0)_{12} \text{ for } y = 2010 \uparrow$$

[7.85] Model notes:

1. Model is restricted to 2010  $\uparrow$  since the schedule does not start until September 2009.

$$[7.86] THM/C_{t,y,ROS424.i} = \varphi_0 + \delta_1 IP_{t,y} + \omega_{SD}D_{t,y} + \omega_{OL}D_{Aug\ 2007=1} + ARIMA\epsilon_{t,y}(5,0,0)(0,0,0)_{12} \text{ for } y = 2007 \uparrow$$

[7.86] Model notes:

1. Model is restricted to 2007  $\uparrow$  because of a significant change in seasonality in earlier periods.
2. Schedule has died. No customers or load reported in 2015

$$[7.87] THM/C_{t,y,ROS440.i} = \varphi_0 + \delta_1 IP_{t,y} + \omega_{SD}D_{t,y} + \omega_{OL}D_{Feb\ 2012=1} + \omega_{OL}D_{Aug\ 2012=1} + \omega_{OL}D_{Jan\ 2014=1} + ARIMA\epsilon_{t,y}(4,0,0)(0,0,0)_{12} \text{ for } y = 2008 \uparrow$$

[7.87] Model notes:

1. Model is restricted to 2008  $\uparrow$  because of a significant step-down in UPC compared to earlier periods. This step-down reflects a large step-down in the number of customers from around 13 to 3 to 5.

$$[7.88] THM_{t,y,ROS447m.i} = \varphi_0 + \delta_1 IP_{t,y} + \omega_{SD}D_{t,y} + \omega_{OL}D_{Dec\ 2008=1} + ARIMA\epsilon_{t,y}(4,1,0)(0,0,0)_{12} \text{ for } t, y = \text{July } 2008 \uparrow$$

[7.88] Model notes:

1. Model is restricted to July 2008  $\uparrow$  because from September 2005 to November 2007 load fell to zero. Starting in July 2008, load returned to more normal operating levels.
2. This is a special contract customer. In Oregon, special contract customers have a different regulatory status during rate case proceedings.

### Exhibit 3

$$[7.89] THM_{t,y,ROS447r.i} = \varphi_0 + \delta_1 IP_{t,y} + \omega_{OL} D_{Apr\ 2010=1} + \omega_{OL} D_{Feb\ 2013=1} + ARIMA\epsilon_{t,y}(8,1,0)(0,0,0)_{12}$$

[7.89] Model notes:

1. This is a special contract customer. In Oregon, special contract customers have a different regulatory status during rate case proceedings.

$$[7.90] THM/C_{t,y,ROS456.i} = \varphi_0 + \delta_1 IP_{t,y} + \omega_{SD} D_{t,y} + \omega_{OL} D_{July\ 2013=1} + ARIMA\epsilon_{t,y}(7,1,0)(1,0,0)_{12} \text{ for } y = 2008 \uparrow$$

[7.90] Model notes:

1. Model is restricted to 2008  $\uparrow$  significant step-down in UPC compared to earlier periods. This likely reflects an increasing step-function of customers until 2010. Between 2005 and 2014 the number of customers increased from 1 to 8.

#### Industrial Sector, Customers:

$$[7.91] C_{t,y,ROS420.i} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

[7.91] Model notes:

1. Due to the Compass software conversion, February 2015 is excluded from the historical data. The conversion resulted in a double counting of customers in February 2015. Therefore, including this month leads to a significant over-forecast of customers.

$$[7.92] C_{t,y,ROS424.i} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

[7.91] Model notes:

1. Schedule appears to have died. No customers are currently being reported.

$$[7.93] C_{t,y,ROS440.i} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

$$[7.94] C_{t,y,ROS456.i} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

### 3. Klamath Falls, OR Forecasting Models

The forecasting models for the Klamath Falls region (Klamath County) are given below for the residential, commercial, and industrial sectors:

#### Residential Sector, THM:

$$[7.95] THM/C_{t,y,KLM410.r} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + \lambda RAP_{t,y-1,OR410} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Apr\ 2007=1} + \omega_{OL} D_{Dec\ 2008=1} + \omega_{OL} D_{Nov\ 2009=1} + \omega_{OL} D_{Feb\ 2011=1} + ARIMA\epsilon_{t,y}(10,0,0)(0,0,0)_{12}$$

[7.95] Model notes:

1. AHS is not included because its impact is unstable and not statistically significant.

### Exhibit 3

[7.96]  $THM/C_{t,y,KLM420.r} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD} D_{t,y} + \epsilon_{t,y}$  for  $t,y =$   
July 2011  $\uparrow$

[7.96] Model notes:

1. Potential non-white noise error and non-stationarity due to a short time-series used to estimate the model.
2. Model restricted to July 2011  $\uparrow$  because of a significant change in behavior compared to earlier periods.
3. Schedule has died; no longer showing load or customers.

Residential Sector, Customers:

[7.97]  $C_{t,y,KLM410.r} = \beta_0 + \omega_{SD} D_{t,y} + \omega_{SC} D_{Jan\ 2007\uparrow=1} + \gamma_{RAMP} T_{Jan\ 2007} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y} (6,1,0)(0,0,0)_{12}$

[7.97] Model notes:

1. SC dummy and ramping time trend control for a change in the time-path of customer growth starting in January 2007.

[7.98]  $C_{t,y,KLM420.r} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$

[7.98] Model notes:

1. Schedule appears to be dying out.

Commercial Sector, THM:

[7.99]  $THM/C_{t,y,KLM420.c} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD} D_{t,y} + \omega_{SC} D_{Aug\ 2012\uparrow=1} + \omega_{OL} D_{Aug\ 2012=1} + ARIMA\epsilon_{t,y} (1,0,0)(2,0,0)_{12}$  for  $y = 2008 \uparrow$

[7.99] Model notes:

1. Model is restricted to 2008  $\uparrow$  because of significant problems fitting a model to the entire series.
2. SC dummy controls for a step-down in base-load UPC starting in August 2012.
3. Work is ongoing for statistical controls so that 2005-2007 can be added to the estimation period.

[7.100]  $THM/C_{t,y,KLM424.c} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + ARIMA\epsilon_{t,y} (1,0,0)(0,0,0)_{12}$  for  $y = 2009 \uparrow$

[7.100] Model notes:

1. Model is restricted to 2009  $\uparrow$  because of a significant step-up in UPC and change in seasonality compared to earlier periods.
2. Work is ongoing for statistical controls so that 2005-2008 can be added to the estimation period.

[7.101]

$THM/C_{t,y,KLM440.c} = \frac{1}{N} \sum_{j=1}^N (THM/C_{t-j})$  for  $t,y = Feb\ 2008 \uparrow$  for  $N =$   
total available months of data since February 2007

[7.101] Model notes:

1. Model is restricted to February 2007  $\uparrow$  because schedule does not start until February 2007.
2. No identifiable trend or seasonality in this schedule.

### Exhibit 3

Commercial Sector, Customers:

$$[7.102] C_{t,y,KLM420.c} = \beta_0 + \beta_1 C_{t,y,KLM410.r} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Dec\ 2005=1} + ARIMA\epsilon_{t,y} (12,1,0)(0,0,0)_{12}$$

[7.102] Model notes:

1.  $C_{t,y,KLM410.r}$  are residential customers from residential schedule 410. They are being used as a forecast driver because of the historical positive correlation between residential and commercial customer growth. See Tables 5.1 and 5.2.

$$[7.103] C_{t,y,KLM424.c} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

$$[7.104] C_{t,y,KLM440.c} = \frac{1}{N} \sum_{j=1}^N C_{t-j} \text{ for } N = \text{total available months of data history since 2007}$$

Industrial Sector, THM:

$$[7.105] THM/C_{t,y,KLM420.i} = \beta_0 + \delta_1 IP_{t,y} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Jan\ 2010-Feb\ 2010=1} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y} (3,0,0)(0,0,0)_{12} \text{ for } t, y = \text{June 2008 } \uparrow$$

[7.105] Model notes:

1. Model is restricted to June 2008  $\uparrow$  because schedule does not start until December 2006.

$$[7.106] THM/C_{t,y,KLM424.i} = \beta_0 + \omega_{SD} D_{t,y} + ARIMA\epsilon_{t,y} (2,0,0)(0,0,0)_{12} \text{ for } t, y = \text{August 2009 } \uparrow$$

[7.106] Model notes:

1. Model is restricted to August 2009  $\uparrow$  because schedule does not start until April 2009, and April and May 2009 are extreme outliers.

$$[7.107] THM_{t,y,KLM440.i} = \beta_0 + \omega_{SD} D_{t,y} + \omega_{OL} D_{Sep\ 2008=1} + \omega_{OL} D_{Sep\ 2009=1} + \omega_{OL} D_{Oct\ 2010=1} + \omega_{OL} D_{Sept\ 2012=1} + \omega_{OL} D_{Sept\ 2013=1} + \omega_{OL} D_{Oct\ 2013=1} + \epsilon_{t,y} \text{ for } y = 2008 \uparrow$$

[7.107] Model notes:

1. Model is restricted to 2008  $\uparrow$  because of a significant change in seasonality compared to earlier periods.

[7.108]

$$THM_{t,y,KLM447w.i} = \beta_0 + \delta_1 IP_{t,y} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Feb\ 2008=1} + \omega_{OL} D_{Jul\ 2012=1} + ARIMA\epsilon_{t,y} (1,0,0)(0,0,0)_{12} \text{ for } y = 2008 \uparrow$$

[7.108] Model notes:

1. Model is restricted to 2008  $\uparrow$  because of a significant step-down in load compared to earlier periods.
2. This is a special contract customer. In Oregon, special contract customers have a different regulatory status during rate case proceedings.

[7.109]

$$THM/C_{t,y,KLM456.i} = \varphi_0 + \delta_1 IP_{t,y} + \omega_{SD} D_{t,y} + \omega_{SC} D_{Nov\ 2013\uparrow=1} + \omega_{OL} D_{Feb\ 2008=1} + \omega_{OL} D_{May\ 2012=1} + \omega_{OL} D_{Dec\ 2014=1} + ARIMA\epsilon_{t,y} (4,1,0)(0,0,0)_{12} \text{ for } y = 2008 \uparrow$$

[7.109] Model notes:

1. Model is restricted to 2008  $\uparrow$  because of a significant change in seasonality compared to earlier periods.
2. SC dummy controls for sudden step-up in UPC starting in November 2013.

## Exhibit 3

Industrial Sector, Customers:

$$[7.110] C_{t,y,KLM420.i} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

$$[7.111] C_{t,y,KLM424.i} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

$$[7.112] C_{t,y,KLM440.i} = 1 \text{ if } THM_{KLM,440.i} > 0$$

$$[7.113] C_{t,y,KLM456.i} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

### 4. La Grande, OR Forecasting Models

The forecasting models for the La Grande region (Union County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, THM:

[7.114]

$$THM/C_{t,y,LaG410.r} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD} D_{t,y} + \omega_{SC} D_{Jan\ 2009 \uparrow = 1} + \omega_{OL} D_{Feb\ 2007 = 1} + \omega_{OL} D_{May\ 2011 = 1} + \omega_{OL} D_{Jun\ 2011 = 1} + \omega_{OL} D_{Mar\ 2014 = 1} + ARIMA\epsilon_{t,y} (12,0,0)(0,0,0)_{12}$$

[7.114] Model notes:

1. RAP does not appear in the model because the coefficient's sign is unstable and statistically insignificant.
2. The variable lnT reflects a general control for multiple factors lowering UPC, including the impact of RAP.
3. SC dummy controls for a step-down in UPC.
4. AHS is not included because its impact is unstable and not statistically significant.

$$[7.115] THM/C_{t,y,LaG420.r} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD} D_{t,y} + \omega_{OL} D_{Feb\ 2012 = 1} + ARIMA\epsilon_{t,y} (1,0,0)(0,0,0)_{12} \text{ for } t, y = \text{June } 2010 \uparrow$$

[7.115] Model notes:

1. The short time-series used to estimate the model reflects a significant change in behavior in 2010 that cannot be fully controlled for.
2. This schedule in appears to be losing customers and load.

Residential Sector, Customers:

$$[7.116] C_{t,y,LaG410.r} = \theta_0 + \omega_{SD} D_{t,y} + \gamma_{RAMP} T_{Jan\ 2008} + \omega_{OL} D_{Dec\ 2009 = 1} + \omega_{OL} D_{Jul\ 2006 = 1} + \omega_{OL} D_{Feb\ 2015 = 1} + ARIMA\epsilon_{t,y} (9,1,0)(1,0,0)_{12} \text{ for } y = 2007 \uparrow$$

[7.116] Model notes:

1. Model is restricted to 2007  $\uparrow$  because of significant decline in customer growth following the Great Recession. Including pre-2007 periods produces forecasted growth rates that are too high compared to the post- recession growth trend.
2. Ramping time trend controls for a change in the time-path of customer growth starting in January 2008.
3. Work is ongoing for statistical controls so that 2005-2006 can be added to the estimation period.

## Exhibit 3

$$[7.117] C_{t,y,LaG420.r} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

[7.117] Model notes:

1. This schedule had died; reported customers have fallen to zero.

### Commercial Sector, THM:

$$[7.118] THM/C_{t,y,LaG420.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \omega_{SC} D_{Aug\ 2012 \uparrow =1} + \omega_{SD} D_{t,y} + ARIMA \epsilon_{t,y} (3,0,0)(0,0,0)_{12} \text{ for } y = 2008 \uparrow$$

[7.118] Model notes:

1. Model is restricted to 2007  $\uparrow$  because of a significant change in seasonality compared to earlier periods.
2. Work is ongoing for statistical controls so that 2005-2006 can be added to the estimation period.
3. SC dummy controls for a significant step-down in base-load for August 2012  $\uparrow$ .

$$[7.119] THM/C_{t,y,LaG424.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD} D_{t,y} + \omega_{OL} D_{Jan\ 2011 =1} + ARIMA \epsilon_{t,y} (2,0,0)(0,0,0)_{12} \text{ for } t, y = \text{June } 2010 \uparrow$$

[7.119] Model notes:

1. Model is restricted to June 2010  $\uparrow$  because of a significant change in seasonality compared to earlier periods.

$$[7.120] THM/C_{t,y,LaG444.c} = \frac{1}{N} \sum_{j=1}^N (THM/C_{t,y-j}) \text{ for } y = 2011 \uparrow$$

[7.120] Model notes:

1. Model is restricted to 2011  $\uparrow$  because the schedule does not start until 2011.

$$[7.121] THM/C_{t,y,LaG440.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \omega_{SD} D_{t,y} + \omega_{SC} D_{Sept\ 2013 \uparrow =1} + \omega_{OL} D_{July\ 2014 =1} + \omega_{OL} D_{Aug\ 2014 =1} + \omega_{OL} D_{Oct\ 2014 =1} + \omega_{OL} D_{Sept\ 2013 =1} + ARIMA \epsilon_{t,y} (3,0,0)(0,0,0)_{12} \text{ for } t, y = \text{Sept } 2009 \uparrow$$

[7.121] Model notes:

1. Model is restricted to September 2009  $\uparrow$  because of a significant change in seasonality compared to earlier periods. There is a sharp change in seasonality in June/July 2014. It's not clear if this change is permanent.
2. SC dummy controls for a step-up in UCP starting in September 2013.

$$[7.122] THM/C_{t,y,LaG456.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD} D_{t,y} + \omega_{OL} D_{Mar\ 2009 =1} + \omega_{OL} D_{May\ 2013 =1} + ARIMA \epsilon_{t,y} (1,0,0)(0,0,0)_{12}$$

[7.122] Model notes:

1. Base load forecast months are often negative; these are set to zero in the forecast spreadsheet.

### Commercial Sector, Customers:

$$[7.123] C_{t,y,LaG420.c} = \theta_0 + \theta_1 C_{t,y,LaG410.r} + \omega_{OL} D_{Dec\ 2008 =1} + \omega_{OL} D_{Mar\ 2011 =1} + ARIMA \epsilon_{t,y} (1,1,0)(0,0,0)_{12} \text{ for } y = 2008 \uparrow$$

[7.123] Model notes:

1.  $C_{t,y,LaG410.r}$  are residential customers from residential schedule 410. They are being used as a forecast driver because of the historical positive correlation between residential and commercial customer growth. See Tables 5.1 and 5.2.
2. Model is restricted to 2008  $\uparrow$  because of significant change in seasonality compared to earlier periods.

### Exhibit 3

$$[7.124] C_{t,y,LaG424.c} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

$$[7.125] C_{t,y,LaG444.c} = 1 \text{ if } (THM/C_{t,y})_{LaG,444.c} > 0$$

$$[7.126] C_{t,y,LaG440.c} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

$$[7.127] C_{t,y,LaG456.c} = C_{t-1} \text{ (Stable Customer Base; No Forecasting Model Required)}$$

Industrial Sector, THM:

$$[7.128] THM/C_{t,y,LaG440.i} = \theta_0 + \omega_{SD} D_{t,y} + \omega_{OL} D_{Sept\ 2008=1} + \omega_{OL} D_{Oct\ 2008=1} + \omega_{OL} D_{Jan\ 2010=1} + \omega_{OL} D_{Sept\ 2012=1} + \omega_{OL} D_{Feb\ 2013=1} + \omega_{OL} D_{Nov\ 2013=1} + \omega_{OL} D_{Sept\ 2014=1} + ARIMA\epsilon_{t,y} (12,1,0)(0,0,0)_{12}$$

$$[7.129] THM/C_{t,y,LaG444.i} = \theta_0 + \omega_{SD} D_{t,y} + \omega_{OL} D_{Oct\ 2007=1} + \omega_{OL} D_{Sept\ 2008=1} + \omega_{OL} D_{Nov\ 2010=1} + \omega_{OL} D_{Jan\ 2011=1} + \omega_{OL} D_{July\ 2012=1} + \omega_{OL} D_{Sept\ 2012=1} + \omega_{OL} D_{April\ 2013=1} + \omega_{OL} D_{July\ 2014=1} + ARIMA\epsilon_{t,y} (5,0,0)(0,0,0)_{12}$$

$$[7.130] THM/C_{t,y,LaG456.i} = \theta_0 + \omega_{SD} D_{t,y} + \omega_{OL} D_{Oct\ 2008=1} + \omega_{OL} D_{Dec\ 2014=1} + \omega_{OL} D_{Mar\ 2015=1} + ARIMA\epsilon_{t,y} (5,1,0)(0,0,0)_{12} \text{ for } t, y = \text{July } 2008 \uparrow$$

[7.130] Model notes:

1. Model is restricted to July 2008  $\uparrow$  because significant step-down in UPC and seasonality compared to earlier periods.

Industrial Sector, Customers:

$$[7.131] C_{t,y,LaG440.i} = \theta_0 + \omega_{SD} D_{t,y} + \omega_{OL} D_{Dec\ 2007=1} + \omega_{OL} D_{Sept\ 2008=1} + \omega_{OL} D_{Jan\ 2010=1} + \omega_{OL} D_{Aug\ 2011=1} + \epsilon_{t,y}$$

$$[7.132] C_{t,y,LaG444.i} = \theta_0 + \omega_{SD} D_{t,y} + \omega_{OL} D_{t,y} + ARIMA\epsilon_{t,y} (9,0,0)(0,0,0)_{12}$$

( $\omega_{OL} D_{t,y} = \text{Aug } 2007, \text{Sept } 2008, \text{Jan } 2010, \text{Aug } 2011, \text{Aug } 2012, \text{Nov } 2012, \text{Dec } 2012, \text{Jan } 2013, \text{Feb } 2013, \text{Jan } 2014 \text{ outliers for } )$

$$[7.133] C_{t,y,LaG456.i} = \frac{1}{12} \sum_{j=1}^{12} C_{t-j}$$

## Exhibit 4

$$[7.57] THM_{t,y,MED444.c} = \beta_0 + \omega_{SD}D_{t,y} + ARIMA\epsilon_{t,y}(1,0,0)(0,0,0)_{12} \text{ for } y = \text{January } 2004 \uparrow$$

$$[7.59] THM/C_{t,y,MED456.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \omega_{SD}D_{t,y} + \omega_{OL}D_{Sept\ 2009=1} + \omega_{OL}D_{Mar\ 2013=1} + \omega_{OL}D_{Dec\ 2013=1} + ARIMA\epsilon_{t,y}(12,0,0)(0,0,0)_{12} \text{ for } y = \text{January } 2004 \uparrow$$

$$[7.65] THM/C_{t,y,MED420.i} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + \delta_1 IP_{t,y} + \omega_{OL}D_{March\ 2011=1} + \omega_{SD}D_{t,y} + ARIMA\epsilon_{t,y}(1,0,0)(0,0,0)_{12} \text{ for } y = \text{December } 2006 \uparrow$$

$$[7.77] THM/C_{t,y,ROS420.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD}D_{t,y} + \omega_{OL}D_{Mar\ 2011=1} + ARIMA\epsilon_{t,y}(8,0,0)(0,0,0)_{12} \text{ for } y = \text{January } 2004 \uparrow$$

$$[7.78] THM/C_{t,y,ROS424.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \omega_{SD}D_{t,y} + \omega_{OL}D_{Oct\ 2007=1} + \omega_{OL}D_{Mar\ 2011=1} + \omega_{OL}D_{Feb\ 2013=1} + ARIMA\epsilon_{t,y}(9,0,0)(0,0,0)_{12} \text{ for } y = \text{January } 2004 \uparrow$$

[7.78] Model notes:

1. Omitted  $\omega_{OL}D_{July\ 2009=1}$  in order to avoid "Parameter estimation failed" error message in SAS statistical software.

$$[7.80] THM/C_{t,y,ROS456.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \omega_{OL}D_{July\ 2014=1} + ARIMA\epsilon_{t,y}(1,0,0)(0,0,0)_{12} \text{ for } y = \text{November } 2009 \uparrow$$

$$[7.81] C_{t,y,ROS420.c} = \varphi_0 + \omega_{SD}D_{t,y} + \gamma_1 T + \omega_{OL}D_{Jan\ 2008=1} + \omega_{OL}D_{Mar\ 2009=1} + \omega_{OL}D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y}(6,1,0)(0,0,0)_{12} \text{ for } y = \text{January } 2004 \uparrow$$

[7.81] Model notes:

1. Model uses Staff's Schedule 410, residential, Roseburg, customer forecast output.

$$[7.102] C_{t,y,KLM420.c} = \beta_0 + \beta_1 C_{t,y,KLM410.r} + \omega_{SD}D_{t,y} + \omega_{OL}D_{Dec\ 2005=1} + ARIMA\epsilon_{t,y}(12,1,0)(0,0,0)_{12} \text{ for } y = \text{January } 2004 \uparrow$$

[7.108]

$$THM_{t,y,KLM447w.i} = \beta_0 + \delta_1 IP_{t,y} + \delta_2 HS_{t,y} + \omega_{SD}D_{t,y} + \omega_{OL}D_{Feb\ 2008=1} + \omega_{OL}D_{Jul\ 2012=1} + ARIMA\epsilon_{t,y}(1,0,0)(0,0,0)_{12} \text{ for } y = \text{2008 } \uparrow$$

[7.108] Model notes:

1. HS is lagged West Housing Starts valuation.

$$[7.122] THM/C_{t,y,LaG456.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SD}D_{t,y} + \omega_{OL}D_{Mar\ 2009=1} + \omega_{OL}D_{May\ 2013=1} + ARIMA\epsilon_{t,y}(1,0,0)(0,0,0)_{12} \text{ for } y = \text{January } 2004 \uparrow$$



## Exhibit 4

$$[7.128] THM/C_{t,y,LaG440,i} = \theta_0 + \omega_{SD}D_{t,y} + \omega_{OL}D_{Sept\ 2008=1} + \omega_{OL}D_{Oct\ 2008=1} + \omega_{OL}D_{Jan\ 2010=1} + \omega_{OL}D_{Sept\ 2012=1} + \omega_{OL}D_{Feb\ 2013=1} + \omega_{OL}D_{Nov\ 2013=1} + \omega_{OL}D_{Sept\ 2014=1} + ARIMA\epsilon_{t,y}(12,1,0)(0,0,0)_{12} \text{ for } y = \text{January } 2004 \uparrow$$

$$[7.129] THM/C_{t,y,LaG444,i} = \theta_0 + \omega_{SD}D_{t,y} + \omega_{OL}D_{Oct\ 2007=1} + \omega_{OL}D_{Sept\ 2008=1} + \omega_{OL}D_{Nov\ 2010=1} + \omega_{OL}D_{Jan\ 2011=1} + \omega_{OL}D_{July\ 2012=1} + \omega_{OL}D_{Sept\ 2012=1} + \omega_{OL}D_{April\ 2013=1} + \omega_{OL}D_{July\ 2014=1} + ARIMA\epsilon_{t,y}(5,0,0)(0,0,0)_{12} \text{ for } y = \text{January } 2004 \uparrow$$

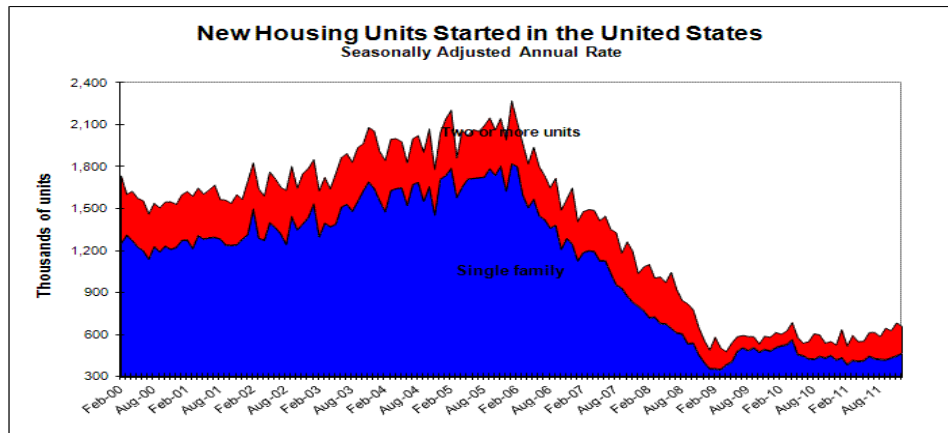
$$[7.131] C_{t,y,LaG440,i} = \theta_0 + \omega_{SD}D_{t,y} + \omega_{OL}D_{Dec\ 2007=1} + \omega_{OL}D_{Sept\ 2008=1} + \omega_{OL}D_{Jan\ 2010=1} + \omega_{OL}D_{Aug\ 2011=1} + \epsilon_{t,y} \text{ for } y = \text{January } 2004 \uparrow$$

## Exhibit 5

### Housing Starts/Building Permits

**Importance:** \*\*\*

**Definition:** The housing industry accounts for about 27% of investment spending and 5% of the overall economy. Housing starts is important because it is a leading indicator. Sustained declines in housing starts slow the economy and can push it into a recession. Likewise, increases in housing activity triggers economic growth.



### Related Indicators:

**Source:** Bureau of the Census of the U.S. Department of Commerce

**Frequency:** Monthly

**Availability:** Two to three weeks following the reported month

**Direction:**

**Timing:**

**Volatility:** Moderate

### Likely Impact on Financial Markets:

**Interest Rates:** Larger-than expected monthly increase or increasing trend is considered inflationary, causing bond prices to drop and yields and interest rates to rise.

**Stock Prices:** ⬇️

**Exchange Rates:** ....

## Exhibit 5

### Ability to affect markets:

### Analysis of the Indicator:

Housing data tracks the four major regions of the U. S.: Northeast, Midwest, South, and West.

Building permit data is released at the same time as housing starts. Permit activity provides insight into housing and overall economic activity in upcoming months. It is so important that it is included in the index of leading economic indicators.

Housing activity is directly impacted by mortgage rates. Higher interest rates increase housing costs and reduce the number of qualified borrowers, thus, a decline in home sales and drop-off in starts. Conversely, lower interest rates increases housing affordability and spurs homes sales and housing starts.

Housing data can have a significant impact on the bond market. A stronger-than-expected report is viewed negatively, suggesting strong growth and possible inflationary side-effects. A weak report has the opposite effect on the market.

### WEB Links

A Graph of the latest Housing Starts data from [The Economic Statistics Briefing Room of the White House](#).

The latest [Housing Starts report](#) from BLS.

CASE: UG 288  
WITNESS: SUPARNA BHATTACHARYA

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1000**

**Load Forecasting, Decoupling,  
Public Purpose Charge**

**Opening Testimony**

**October 16, 2015**

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Suparna Bhattacharya. My business address is 201 High Street,  
3 SE Suite 100, Salem, Oregon 97301-3612.

4 **Q. Please describe your educational background and work experience.**

5 A. My Witness Qualification Statement is found in Exhibit Staff/1001.

6 **Q. What is the purpose of your testimony?**

7 A. This testimony presents Staff’s analysis and recommendations regarding  
8 Avista Corporation’s (Avista or Company) residential sales forecast, revenue  
9 adjustments, decoupling mechanism, and the public purpose charge.

10 **Q. Did you prepare exhibits for this docket?**

11 A. Yes. I prepared the following exhibits for this docket:

- 12 Exhibit Staff/1001 Witness Qualification
- 13 Exhibit Staff/1002 Avista’s responses to Data Requests (DRs)

14 **Q. How is your testimony organized?**

15 A. My testimony is organized as follows:

17	Issue 1, -----Residential Load Forecast.....	4
18	Issue 2, -----Decoupling and Public Purpose Charge.....	10

19  
20 **Q. What are the main conclusions from your analysis?**

21 A. The main conclusions are summarized below:

- 22 1. Residential Load Forecast: In this proceeding, Staff has reviewed the  
23 Company’s June 2015 forecasting models that were provided by the  
24 Company in response to Staff Data Request 193 (Exhibit 1002). Staff notes  
25 that the Company’s forecasts provided in these data requests were not  
26 incorporated in the Company’s filed revenue model. Staff is proposing model

1 specifications for customer and use-per-customer forecasts that best fit the  
2 data and capture the key factors driving the forecasts. Based on Staff's  
3 econometric models, Avista's test year sales for residential customers served  
4 under Schedule 410 will increase by 0.12% compared to the Company's  
5 residential forecasts submitted through data requests.

6 Since the filed revenue model is not updated based on the Company's  
7 June 2015 forecasts, Staff is recommending test year revenue adjustments  
8 relative to the Company's revenue proposed in the revenue model. Based on  
9 Staff's analysis, test year revenue decreases by approximately \$867,796.  
10 Staff witness St. Brown in his testimony (Staff/900) has reviewed forecasts for  
11 non-residential customers and revenue adjustments for these groups are  
12 based on his analysis.

13  
14 2. Decoupling Mechanism: After reviewing the Company's proposed decoupling  
15 mechanism and existing public purpose funds, Staff proposes that the  
16 Commission:

- 17 a. approve the Company's request to establish decoupling in its Oregon  
18 service territories effective 2016;
- 19 b. establish an opportunity to review the proposed mechanism by  
20 September, 2019 to allow Staff and other parties to recommend any  
21 changes;
- 22 c. implement the Company's proposed decoupling mechanism with some  
23 modifications. Two deferral accounts to explicitly account for weather

1 and conservation should be created. This would allow the Commission  
2 and stakeholders to analyze the decoupling adjustment associated  
3 with weather and understand the factors causing the changes in the  
4 decoupling rates;

5 d. establish a new tariff, Schedule 475, effective 2017, to administer rate  
6 adjustments associated with the new decoupling mechanism;

7 e. establish a separate public purpose tariff to collect costs for  
8 administering and delivering energy efficiency programs. In 2016,  
9 Avista will still be offering conservation programs and a single program  
10 will be offered by the ETO. The monies collected through this tariff  
11 would go to Avista in 2016. In 2017, the monies collected through this  
12 tariff should be transferred to the Energy Trust of Oregon (ETO). The  
13 tariff should be revised to match the ETO's administrative costs and  
14 expenses needed to offer conservation programs to Avista's customers  
15 in 2017;

16 f. allow the Company to retain collection for funding low income  
17 household programs, delivered by Community Action Agencies: Avista  
18 Oregon Low Income Energy Efficiency Program (AOLIEE) and the Low  
19 Income Rate Assistance Program (LIRAP). Effective 2017, a separate  
20 tariff to administer AOLIEE program should be established. The  
21 Company should continue Schedule 493 tariff for collecting expenses  
22 related to LIRAP.





- 1 a. thoroughly analyzed the Company’s methodology and models used to
- 2 forecast UPC and number of customers;
- 3 b. verified the available data used for the analysis;
- 4 c. reviewed the Company’s response to Staff’s 15 DRs;
- 5 d. developed alternate ARIMA models to evaluate and compare model
- 6 performances; and
- 7 e. discussed forecasting issues with the Company

8 **Q. Please explain your Table 1 shown below.**

9 A. Table 1 provides a high-level summary of Staff’s test year residential load  
10 forecast analysis for the four service territories.

11 **Table 1. Staff’s Proposed Changes to Residential Load Forecast**

	<u>Medford</u>	<u>Roseburg</u>	<u>Klamath Falls</u>	<u>La Grande</u>
<b><u>Models</u></b>				
Customer	AVA model	Staff model	Staff model	Staff model
UPC	Staff model	AVA model	AVA model	AVA model
<b><u>Effects</u></b>				
Customer	NA	0.58% increase	0.078% increase	0.004% decrease
UPC	0.037% increase	NA	NA	NA
Load	0.038% increase	0.56% increase	0.074% increase	0.039% increase

12  
13  
14  
15  
16  
17  
18  
19 Staff has estimated different time series ARIMA models. The model that best  
20 fits the data and explains the factors driving the Company’s test year sales and  
21 customers is selected. The key factors include population and economic  
22 growth, weather conditions and the price of natural gas. “AVA model” indicates

1 that Staff accepts the Company's latest forecasting model<sup>5</sup>, while "Staff model"  
2 indicates that alternative models are proposed by Staff. The final load  
3 adjustments with Staff's higher customer or UPC forecasts are expressed in  
4 percentages. For example, in Medford, 0.038% increase in load means that  
5 Staff's adjustments result in approximately 0.038% higher load than that  
6 proposed by the Company in this filing.

7 For each region, Staff now presents a detailed discussion of the steps  
8 involved to reach the conclusions presented in Table 1.

### 9 **1. Medford**

10 Customer Forecast: Staff agrees with the Company's proposed customer  
11 forecast model. Following discussions with Staff in its last rate case (UG 284),  
12 the Company integrated population as an explanatory variable to identify the  
13 effect of population on customer count. The current version of the Schedule  
14 410 customer forecast model reflects this change.<sup>6</sup> In the last rate case, an  
15 adjustment for population growth was made after a baseline customer forecast  
16 was generated. Staff appreciates that the Company has adopted Staff's  
17 suggestion and verifies that the population coefficient in the integrated model is  
18 positive and significant, as expected. This change in methodology corrects the  
19 omitted variable bias and also simplifies the procedure as the regression  
20 coefficient attached to population directly captures the relationship between  
21 population and customers. Staff also reviewed the intervention variables  
22 added as explanatory variables by running the Company's model in SAS. Staff

---

<sup>5</sup> Staff/1002, Avista Response to Staff Data Request 193

<sup>6</sup> Staff/1002, Avista Response to Staff Data Request 282

1 notes that these variables effectively control for outliers and pre- and post-  
2 recession effects of the estimation time period January, 2005 through April,  
3 2015 (these issues were also raised by Staff in the last rate case). The error  
4 correction terms (AR term) produce the minimum Akaike Info Criterion (AIC)  
5 and Schwarz Criterion (SBC) values.<sup>7</sup>

6 UPC Forecast: Staff proposes an alternative UPC model that better captures  
7 the error assumptions and generates lower AIC and SBC values. The  
8 Company's current UPC model (that includes HDDs, natural gas price,  
9 seasonal dummies, intervention, and trend as explanatory variables) performs  
10 better with Staff's proposed adjustment ARIMA (8,0,0)(0,0,0)<sub>12</sub>. ARIMA order  
11 selection process is an important procedure for time series models and should  
12 provide minimum AIC and SBC values. Staff generated this term using order  
13 selection test and analyzing autocorrelation and partial autocorrelation  
14 functions. AR (8) generates lower criterion values (AIC = 262, SBC = 347)  
15 than AR (11), as proposed by the Company (AIC = 264, SBC = 357). Staff has  
16 used the Company's HDDs and price data for this analysis. Staff reviewed the  
17 Company's 20-year moving average for defining normal weather over the  
18 forecast period and accepts the methodology.<sup>8</sup>

19 Load Forecast: Based on Staff's adjustments, the residential load for the  
20 Medford region is predicted to be approximately 0.038% higher than the  
21 Company's forecast.

---

<sup>7</sup> Lower AIC and SBC values indicate better model performance.

<sup>8</sup> Staff/1002, Avista Response to Staff Data Request 243

**2. Roseburg, Klamath Falls and La Grande**

Customer Forecast: For customer forecast models, Staff is proposing to include population as an independent variable. Staff developed alternate integrated models with population as the key regression variable (along with seasonal dummies and intervention variables) to predict customers for the Roseburg, Klamath Falls and La Grande regions. Similar to the Medford customer model, Staff's proposed customer models for these three regions correct the omitted variable bias and the effect of population on customers is not captured by either seasonal or intervention variables. Staff has used the Global Insight county-based population data provided by the Company.<sup>9</sup> The regression coefficients representing the population variable are significant and show a positive association with the response variable- customer counts.

Staff's customer forecasts increases by 0.58% and 0.078% for Roseburg and Klamath Falls, and decreases by 0.004% for La Grande, relative to the Company's forecast.

In response to Staff's data request, the Company explains that since population and customer growth in these areas are relatively low, a simple time series models are developed that do not use population as an independent variable.<sup>10</sup> Staff asserts that the coefficients of the variables in the Company's current residential customer count models are capturing the effects of the key economic driver- population that is missing in the model.

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<sup>9</sup> Staff/1002, Avista Response to Staff Data Request 197 Supplemental

<sup>10</sup> Staff/1002, Avista Response to Staff Data Request 244

1 Staff also identifies that for these three regions, the Company has not used  
2 the updated customer data series for forecasting purpose. The actual  
3 estimation period is from January, 2005 through April 2015; however, the  
4 Company's customer models exclude April from the analysis.<sup>11</sup> Staff's  
5 alternate models take into account this data error.

6 UPC Forecast: Staff has reviewed UPC models for these three regions<sup>12</sup> and  
7 agrees to the Company's models and forecast results. Identification of error  
8 correction terms, as well as selection of intervention variables and outliers,  
9 were appropriately done and the proposed model specifications produced  
10 minimum AIC and SBC values.

11 Load Forecast: With Staff's customer count adjustments, the load is  
12 approximately 0.56% higher for Roseburg, 0.074% higher for Klamath Falls,  
13 and 0.039% higher for La Grande. All these percentage increases are higher  
14 as compared to the Company's proposed test year load prediction for these  
15 regions.

16 **Q. Please provide Staff's revenue adjustments.**

17 A. Staff incorporated the inputs (customers and total therms) generated from  
18 Staff's models into the Company's filed revenue requirement model to  
19 calculate the increase/decrease in revenue for all schedules for the test year  
20 2016.<sup>13</sup> Test year revenue decreases by approximately \$\$867,796.

21

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<sup>11</sup> Staff/1002, Avista Response to Staff Data Request 301

<sup>12</sup> Staff/1002, Avista Response to Staff Data Requests 279, 280, and 281

<sup>13</sup> Staff/1002, Avista Response to Staff Data Requests 300

**ISSUE 2, DECOUPLING AND PUBLIC PURPOSE CHARGE****Q. Please summarize the Company's proposed decoupling mechanism.**

A. In this general rate case, the Company is proposing a revenue-per-customer decoupling mechanism that would compare the actual non-weather normalized revenue to the expected revenue determined on a per-customer basis. This mechanism would allow the Company to recover the Commission-approved fixed costs through volumetric energy rates if gas usage per customer declines between general rate cases. Thus, the disincentive to promote conservation practices would be removed. Customers will benefit as over-collected revenues would be credited if a winter is colder than normal and gas usage is higher than the forecast.<sup>14</sup>

The proposed decoupling mechanism would be applicable to two Rate Groups: Group 1 representing residential Schedule 410 customers and Group 2 representing non-residential customers served under Schedules 420, 424, 440 and 444 respectively.<sup>15</sup>

The high-level overview of the proposed deferral calculation is illustrated below:<sup>16</sup>

Approved Monthly Base Revenue Per Customer	x	Actual number of customers in a month	=	Allowed Monthly Base Revenue
Allowed Monthly Base Revenue	-	Actual Monthly Base Revenue	=	Decoupling Deferral Revenue

<sup>14</sup> AVISTA/900, Ehrbar/12-16

<sup>15</sup> AVISTA/900, Ehrbar/16

<sup>16</sup> AVISTA/900, Ehrbar/20

1 The deferral calculations apply for both residential and non-residential Rate  
2 Groups. The proposed mechanism does not incorporate weather  
3 normalization adjustments and thus, the actual monthly base revenue will be  
4 primarily calculated based on actual non-weather normalized volumes.

5 A new tariff Schedule 475 has been proposed that would describe this  
6 mechanism and identify temporary annual rate adjustments for each Rate  
7 Group based on decoupling deferred revenues and estimated therm sales.<sup>17</sup>

8 **Q. Please describe Staff's proposal regarding the Company's decoupling**  
9 **mechanism.**

10 A. Staff has reviewed the Company's proposed decoupling mechanism, data  
11 responses to Staff's eight data requests and the Commission-approved  
12 decoupling practices adopted by Cascade and Northwest Natural. Following  
13 are Staff's proposals:

14 Implementation of decoupling: Staff recommends the Commission allow the  
15 Company's request to establish a decoupling mechanism in its Oregon service  
16 areas, effective 2016. A review of the decoupling mechanism, however, should  
17 be required by the end of September 2019, to allow Staff and interested parties  
18 to recommend changes, if any.

19 Deferral accounts: The Company's proposed mechanism would create a  
20 deferral account that would defer the difference between allowed revenue and  
21 actual (not weather normalized) revenue. Staff proposes that two deferral  
22 accounts should be maintained to better understand the consumer's bill

---

<sup>17</sup> AVISTA/900, Ehrbar/23

1 variability due to weather variances and conservation or other economic  
2 shocks. The weather deferral account should record the difference between  
3 weather-normalized actual revenue and the actual revenue, while the  
4 conservation deferral account should track the difference between allowed and  
5 weather-normalized actual revenue. Adding up these two accounts will give  
6 the deferred revenue (allowed revenue – actual revenue), as proposed by the  
7 Company.

8 Staff believes that separately tracking these components will be informative  
9 and allow the Commission and stakeholders to analyze the decoupling  
10 adjustment associated with weather and understand the factors causing the  
11 changes in the decoupling rates.

12 Public purpose charge: Staff notes that the Company currently collects two  
13 types of public purpose funds in Oregon. The first is related to DSM/Energy  
14 Efficiency. The Company provides DSM services directly and does not utilize  
15 the ETO for administering DSM. This funding occurs through a tariff rate,  
16 Schedule 478, adjusted on an annual basis. Avista also collects monies  
17 through Schedule 478 for funding Avista Oregon Low Income Energy Efficiency  
18 Program (AOLIEE), delivered by Community Action Agencies.

19 The second public purpose fund is the Low Income Rate Assistance Program  
20 (LIRAP) that provides assistance to qualified low income households. The  
21 program and rates are administered through Schedule 493.

22 Staff proposes that the Company establish public purpose funds and transfer  
23 these funds to the ETO for delivering conservation programs to the Oregon



1 customers. In 2016, Avista will still be offering conservation programs and a  
2 single program will be offered by the ETO. A separate public purpose tariff  
3 should be introduced in 2016 and funds collected through this tariff should go  
4 to the Company for administering and delivering conservation programs. In  
5 2017, the ETO takes over, and funds collected through this tariff should be  
6 transferred to the ETO. The tariff should be revised to match the ETO's  
7 administrative costs and expenses needed to offer conservation programs to  
8 Avista customers in 2017.

9 The Company should continue collecting public purpose surcharge for  
10 funding Low Income Rate Assistance Program (LIRAP) and Avista Oregon Low  
11 Income Energy Efficiency Program (AOLIEE). A separate tariff, effective 2017  
12 should be implemented for the AOLIEE program. Schedule 493 currently  
13 administering the rates associated with LIRAP should continue.

14 **Q. Does this conclude your testimony?**

15 A. Yes, it does.

16

CASE: UG 288  
WITNESS: SUPARNA BHATTACHARYA

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1001**

**Witness Qualifications Statement**

**October 16, 2015**

**WITNESS QUALIFICATIONS STATEMENT**

NAME: Suparna Bhattacharya

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist  
Energy Rates, Finance & Audit Division

ADDRESS: 201 High Street SE., Suite 100  
Salem, OR. 97301

EDUCATION: Ph.D. Agricultural Economics  
University of Nebraska, Lincoln  
Specialization: Industrial Organization,  
Environmental & Natural Resource Economics,  
Production and Development Economics

M.S. Agricultural Economics  
University of Nebraska, Lincoln  
Specialization: Statistics, Econometrics

B.A. Economics  
Sambalpur University, India  
Specialization: Mathematical Economics

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since April, 2014, with my current position being a Senior Economist, in the Utility Program's Energy - Rates, Finance and Audit Division. My current responsibilities include reviewing sales forecast, long run marginal generation and transmission costs, revenue requirements, tariff verification, decoupling, and energy efficiency. I have provided testimony in UE 283, UE 294, UG 284, and UG 287, filed comments in LC 61, LC 59, and prepared public meeting memos for UG 281, UG 301 and UG 295.

CASE: UG 288  
WITNESS: SUPARNA BHATTACHARYA

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1002**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	07/15/2015
CASE NO.:	UG 288	WITNESS:	Patrick Ehrbar
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Patrick Ehrbar
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 181	TELEPHONE:	(509) 495-8620
		EMAIL:	pat.ehrbar@avistacorp.com

**REQUEST:**

Avista/900-Ehrbar/Page 21, lines 8-10 state that two of the items that ultimately impact the Company's fixed cost recovery relate to weather and participation in the Company's energy efficiency programs.

- a. Please explain how the proposed decoupling mechanism (Avista/900, Ehrbar/Page 16, lines 8-9) that compares the actual, non-weather adjusted revenues to the allowed revenue on a per-customer basis, captures the risk associated with weather variations and reduces the Company's disincentive to promote energy efficiency?
- b. Avista/902 Ehrbar shows the new tariff schedule 475 that outlines the steps to calculate monthly decoupling deferral. Please explain how this monthly deferral account would track both weather and conservation variations without a weather normalization adjustment?

**RESPONSE:**

- a. The Company recovers a substantial portion of its fixed costs in its variable energy rates. The goal of the Company's proposed decoupling mechanism is simply to ensure that the Company has the opportunity to recover its fixed costs, on a per customer basis. Without decoupling, if a winter is colder than normal, thereby increasing overall customer usage, customers would provide a higher level of fixed cost recovery than if weather was normal, and the Company would rebate the higher level of cost recovered. Likewise the Company would under-recover its fixed costs if weather was warmer than normal and customer usage was lower. With decoupling, variations in usage due to weather, as well variations due to other factors that affect customers usage (i.e., energy efficiency) would not impact the Company's recovery of its fixed costs.
- b. The Company's proposed mechanism tracks the difference between the allowed decoupled revenue and actual decoupled revenue. Because the Company is interested in recovering its fixed costs approved by the Commission in a general rate case, on a per customer basis, a separate weather normalization adjustment is not required. Conducting a weather normalization adjustment would modify the "actual" decoupled revenue, which could lead to over- or under-recovery of fixed costs. This is explained further in the Company's response to Staff-182.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	07/15/2015
CASE NO.:	UG 288	WITNESS:	Patrick Ehrbar
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Patrick Ehrbar
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 182	TELEPHONE:	(509) 495-8620
		EMAIL:	pat.ehrbar@avistacorp.com

**REQUEST:**

Lines 14-16 of Avista/900 Ehrbar/Page 14 says "If weather were to be normalized as part of the mechanism, the mechanism would not provide the same level of fixed cost recovery as determined in the last general rate case". Please explain and if possible provide an illustrative example for the above statement using the time period 2010 through 2014, inclusive.

**RESPONSE:**

The Company's proposed mechanism tracks the difference between the actual decoupled revenue received from customers and the allowed decoupled revenue. This ensures that the Company receives recovery of the fixed costs that are embedded in customer's volumetric rates. For example, if the Company had a colder than normal winter, Avista may over-recover its fixed costs. Under the proposed mechanism, the amount of revenue received in excess of what is allowed would be deferred and returned to customers. If the Company normalized weather in this example, the effect would be to increase the "actual decoupled revenue", and therefore the difference between actual and allowed would be less (and could actually go from a rebate to a surcharge, as discussed below). The Company would retain the difference between the actual revenue and the weather normalized, and customers would only receive or be surcharged the difference between weather normalized revenue and allowed.

Provided as Staff\_DR\_182 Attachment A is an illustrative example of how normalizing weather would impact the "decoupled revenue." For this example, the Company used actual usage (Lines 1-7), and weather normalized usage (lines 9-15) for 2010 through 2014. The Company also used the actual billings for 2010-2014 as shown on lines 17-23. Lines 25-29 show the proposed volumetric rates in this case.<sup>1</sup> To determine the "Decoupled Revenue" for each year as shown on lines 30 and 31, the Company applied the proposed "Annual Decoupled Revenue Per Customer" to the actual number of customers for each year.<sup>2</sup> The resulting calculation is the illustrative allowed revenue per customer. Lines 33 and 34 show the illustrative "Actual Volumetric Base Rate Revenue from Rates" which is calculated by multiplying the proposed volumetric base rates by the annual actual customer usage. Under the Company's proposed Decoupling Mechanism, the Actual Volumetric Base Rate Revenue is compared to the Allowed Decoupled Revenue, with the difference/deferral shown in lines 36 and 37. Attachment A also

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<sup>1</sup> The Company has not conducted an actual year-by-year study, so for this illustrative example it is using the proposed rates and per customer values proposed in this case.

<sup>2</sup> id.

shows the “Weather Normalized Volumetric Base Rate Revenue from Rates” (lines 39 and 40), and resulting difference between that, and the Allowed Decoupled Revenue, shown on lines 42 and 43.

What the results show based on comparing the level of fixed cost recovery using actual volumetric revenue (as proposed by the Company) on line 45 and using weather normalized revenue, as shown on line 46, is that in some years the Company would over recover its fixed costs (2011, 2012, and 2013) and in other years under recover its fixed costs (2010 and 2014).

As it relates to my previous example where there is a year with colder than normal weather, in looking at 2011 in the illustrative example, line 38 shows that under the Company’s proposed mechanism, it would have rebated \$3.2 million to customers because it received more revenue (\$46.9 million – line 35) than what was allowed (\$43.7 million – line 32). If, however, customer usage was weather normalized, the adjusted actual revenue would have been \$42.7 million (line 41), and the Company would have recorded a deferral surcharge of approximately \$1.1 million (line 44) when customers already provided \$3.2 million more than expected. The result by using weather normalized usage is a net over recovery of \$4.3 million (line 47).

In summary, the Company does not believe that customer usage should be weather normalized as it essentially defeats the purpose of the mechanism, that is, the recovery of the fixed costs that are embedded in customer’s volumetric rates. Further, including the effects of weather in the mechanism is consistent with the Company’s earnings test which does not normalize weather.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	07/15/2015
CASE NO.:	UG 288	WITNESS:	Patrick Ehrbar
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Patrick Ehrbar
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 183	TELEPHONE:	(509) 495-8620
		EMAIL:	pat.ehrbar@avistacorp.com

**REQUEST:**

Avista/ 904-Ehrbar/Page 3 of 4, lines 4 and 8 show weather-normalized therm delivery volumes for residential and non-residential customers. Please define: a) normal Heating Degree Days; and b) normal Cooling Degree Days; and provide cites for the source of each definition.

**RESPONSE:**

Included on p. 3 of Exhibit 904 are the monthly volumes for 2016 from the Company’s natural gas load forecast. As discussed in detail by Company witness Dr. Forsyth, the Company assumes average or normal weather in the forecast period. As stated by Dr. Forsyth, starting in 2013, the Company moved to a 20-year moving average for the definition of normal weather.

Prior to 2013, NOAA's standard 30-year average was used. This means, each year the definition of normal weather is updated by moving the 20-year average ahead one year.

For heating and cooling degree days, the Company uses the NOAA standard calculation where you either subtract from 65 degrees (heating) or subtract 65 degrees from (cooling) the average daily temperature.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	07/15/2015
CASE NO.:	UG 288	WITNESS:	Patrick Ehrbar
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Patrick Ehrbar
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 184	TELEPHONE:	(509) 495-8620
		EMAIL:	pat.ehrbar@avistacorp.com

**REQUEST:**

Please refer to Avista/900, Ehrbar/Page 23. Please explain how did the Company determined 3% rate increase limitation test?

**RESPONSE:**

The Company has a 3% rate increase limitation test in its Washington electric and natural gas decoupling mechanisms. Avista used the same 3% test in its proposed mechanism for Oregon in an effort to align the mechanisms.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	07/07/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Bhattacharya	RESPONDER:	Ryan Finesilver
TYPE:	Data Request	DEPT:	State and Federal Regulation
REQUEST NO.:	Staff – 185	TELEPHONE:	(509) 495-4873
		EMAIL:	ryan.finesilver@avistacorp.com

**REQUEST:**

Please provide the excel spreadsheet showing amount of monies collected annually by the Company for funding Energy Trust of Oregon (ETO) administered conservation programs by rate schedules from 2010 through 2015.



**RESPONSE:**

The Company provides DSM services directly and does not utilize the Energy Trust of Oregon for administering DSM. Please see Staff\_DR\_185 Attachment A for annual collections related to the DSM program.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	07/07/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Bhattacharya	RESPONDER:	Ryan Finesilver
TYPE:	Data Request	DEPT:	State and Federal Regulation
REQUEST NO.:	Staff – 186	TELEPHONE:	(509) 495-4873
		EMAIL:	ryan.finesilver@avistacorp.com

**REQUEST:**

Please provide the excel spreadsheet showing annual expenses by rate schedules, incurred by ETO to deliver conservation programs, for each year from 2010 through 2014, inclusive.

**RESPONSE:**

The Company provides DSM services directly and does not utilize the Energy Trust of Oregon for administering DSM. Please see Staff\_DR\_186 Attachment A for annual expenses related to the DSM program.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/27/2015
CASE NO:	UG 288	WITNESS:	Grant D. Forsyth/Patrick Ehrbar
REQUESTER:	PUC Staff - Bhattacharya and St. Brown	RESPONDER:	Grant D. Forsyth/Joe Miller
TYPE:	Data Request	DEPT:	Financial Planning & Analysis State and Federal Regulation
REQUEST NO.:	Staff – 193 Supplemental	TELEPHONE:	(509) 495-2765/(509)495-4546
		EMAIL:	grant.forsyth@avistacorp.com joe.miller@avistacorp.com

**SUPPLEMENTAL RESPONSE:**

(a): In the Company's response to Staff-193, base data for the most recent customer and use per customer (UPC) forecasts were provided. The Company is supplementing the response to Staff-193 in order to reflect the revised billing determinants from this most recent forecast in adjustment number 2.01 (2016 Test Year Revenue Adjustment). The effect of this revised adjustment is to increase Oregon net operating income by \$3,608,000 (\$4,099,000 in original filing) and a reduction to revenue requirement of \$6,225,000 (\$7,074,000 in original filing). The net effect of this adjustment is a revenue requirement increase of \$849,000 from the Company's original filing. See the attachment labeled "Staff\_DR\_193 Supplemental Attachment A" for the workpapers supporting this revised adjustment.

During the analysis of the updated forecast data provided above, the Company discovered a formula error in its original filing which resulted in an incorrect assignment of usage to the individual rate blocks on Schedule 146. The resulting correction to the five usage blocks overstated revenue to Schedule 146 by \$119,000 in the Company's original filing. The Company has corrected the assignment of usage to the individual rate blocks in the attachment labeled "Staff\_DR\_193 Supplemental Attachment A" discussed above.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/28/2015
CASE NO.:	UG 288	WITNESS:	Grant D. Forsyth
REQUESTER:	PUC Staff - Bhattacharya	RESPONDER:	Grant D. Forsyth
TYPE:	Data Request	DEPT:	Financial Planning & Analysis
REQUEST NO.:	Staff – 282	TELEPHONE:	(509) 495-2765
		EMAIL:	grant.forsyth@avistacorp.com

**REQUEST:**

Please refer to Staff DR 193 Attachment B - June 2015 OR Gas Model Runs that shows the model specifications and parameter estimates of the forecasting models. For the Medford region, excel file SAS Parameters.xlsx file in the folder OR MED Sch 410r Cus shows the model specification for Medford customer forecast. The regression model includes AR terms, seasonal dummies, intervention variables and population variable JACKMSAPOP (significant and positive).

- a. Please explain why the above model specification is different from the mathematical equation of the Medford residential customer forecasting model given in line 22 of Avista/701, Forsyth/3. Specifically explain why population variable is not included, as well as AR terms and intervention variables are different.
- b. The population variable, JACKMSAPOP, is positive and significant. Please explain why and how the Medford baseline customer forecast model is further adjusted to match the population growth (Avista/700, Forsyth/5).

**RESPONSE:**

(a): Following discussions with staff in the last rate case, population was integrated in as a regression variable. In prior versions of the forecast, an adjustment for population growth was made after a base-line forecast had been generated. In other words, population was not an explicit regression variable. At the time Avista/701, Forsyth/3 was written, the new version of the model had not been completed, so the discussion focused on the procedure used in the June 2014 forecast.

(b): In the procedure for the June 2015 forecast, there are no further adjustments. The earlier procedure used in the June 2014 forecast made the simplifying assumption that Medford 410 residential customer growth would follow population growth. The new procedure allows the regression coefficient attached to JACKMSAPOP to determine the relationship between population and customers. The change in methodology did not create a large change in the forecast between the June 2014 and June 2015 forecasts.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/12/2015
CASE NO.:	UG 288	WITNESS:	Grant D. Forsyth
REQUESTER:	PUC Staff - Bhattacharya	RESPONDER:	Grant D. Forsyth
TYPE:	Data Request	DEPT:	Financial Planning & Analysis
REQUEST NO.:	Staff – 244	TELEPHONE:	(509) 495-2765
		EMAIL:	grant.forsyth@avistacorp.com

**REQUEST:**

Avista/700, Forsyth/8 states that an integrated customer forecast model with population as an explicit explanatory variable will better capture the relationship between residential customer growth and population growth.

- a. Please explain clearly all the steps involved to develop the integrated model specification;
- b. Explain all statistical tests performed that shows that the integrated model with population as an independent variable better captures the relationship between customer count and population;
- c. Please provide the excel spreadsheet (with cell formulae intact) showing the customer forecasts generated from the integrated model;
- d. Line 8 of Avista/700, Forsyth/8 mentions about the population data for the integrated customer forecast model. Please explain in detail how the monthly population data series is created for the historical and forecast period by interpolating annual historical population estimates. Provide the monthly population data used for the integrated model in an excel format with cell formulae intact; and
- e. Please provide the information requested in parts (a), (b), (c), and (d) for Medford, Roseburg, Klamath and La Grande regions.

**RESPONSE:**

**(a):** The integrated model applies to the Medford region only. The Roseburg, Klamath, and La Grande regions rely on time-series models that do not use population as a regression variable. Since population and customer growth in these three areas is relatively low, relatively simple time-series models are effective for capturing their customer growth.

In the case of the Medford region, the first step was to obtain annual population estimates from the U.S. Census (as pulled from the BEA's county data base). The second step was to transform the annual population series to a monthly series by interpolation. The third step was to use the interpolated series in the regression model.

**(b):** The statistical tests for the new Medford schedule 410 model can be found as part of the Company's response to Staff\_DR\_193 Attachment B (see "OR MED Sch 410r Cus"). Tests

for error white noise and stationary were all within acceptable limits, and the adjusted  $R^2$  of the model is 0.997. The addition of both the population variable and a “ramping” time trend provided enough statistical controls to extend the model’s estimation period back to 2005, a period which fully includes Medford’s housing bubble period. The model, as provided in Staff\_DR\_194 (Exhibit A), is:

$$C_{t,y,MED410,r} = \alpha_0 + \alpha_1 POP_{t,y,MED} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Dec\ 2005=1} + \omega_{SC} D_{Jan\ 2008=1} + \gamma_{RAMP} T_{Jan\ 2008} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y} (7,1,0)(0,0,0)_{12}$$

Model notes:

1. SC dummy and ramping time trend control for a change in the time-path of customer growth starting in January 2008.

The estimation period for the model used in the previous rate case extended back to 2007. Without population directly in the model, using the 2005-2006 period in the estimation period generated customer forecasts that were too high given the Medford region’s slow post-recession recovery.

Referring again to the Company’s response to Staff\_DR\_193 Attachment A-Gas Data and Forecasts June 2015 shows the change in Medford’s residential 410 customer forecast between the June 2014 forecast, which uses the previous methodology for population, and the June 2015 forecast, which uses the interpolated population series. For 2016 through 2020, there was an upward revision of about 0.1%. These values can be found under the tab “OR June 2015 Forecasts” starting in cell B-156.

(c): The all customer forecasts were submitted under the Company’s response to Staff\_DR\_193 Attachment A-Gas Data and Forecasts June 2015; in this file, the Medford customer forecast can be found under the tab “OR June 2015 Forecasts” starting in cell B-44.

(d): Several issues arise when using population as an explanatory variable. First, U.S. Census county population estimates are generated on an annual basis but the customer data is monthly. Second, U.S. Census population estimates occur mid-year. The first issue can be solved by interpolation using the standard population growth model. The second issue can be solved by making sure the interpolated population values are applied recognize the timing of the estimates. Mathematically, the monthly interpolation between years is done treating the annual Census estimates (CPOP) as measuring population in June. Since the standard population model assumes continuous compounding, the June to June growth rate is calculated as:

$$[1] r_y = \ln \left( \frac{CPOP_{June,y}}{CPOP_{June,y-1}} \right)$$

The growth rate in [1] is converted to a monthly rate,  $m_y = r_y/12$ . The rate  $m_y$  is then applied as follows between the historical CPOP estimates:

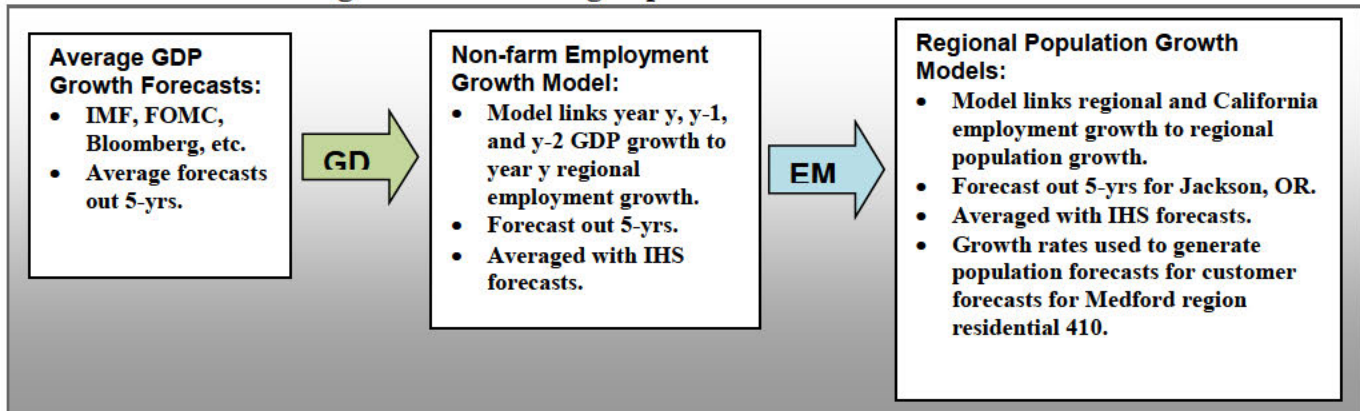
$$[2] POP_t = POP_{t-1} (e^{m_y}) \text{ for month } t \text{ between June } y - 1 \text{ and June } y$$

Using the above method produces an interpolated monthly series for Jackson County (the Medford MSA) where the June population estimates in the historical interpolated monthly series are the same as the official mid-year Census estimates used to calculate  $r_y$ . The monthly data used for the forecast has already been provided as part of the Company's response to Staff\_DR\_193 Attachment A-Gas Data and Forecasts June 2015; the Jackson County population values can be found under the tab "OR SAS Forecasting Data" starting in

cell E-2 under the column heading "JACKMSAPOP". The same interpolated series can be found in Staff\_DR\_244 Attachment A-Jackson County Population Interpolation-June 2015 Forecast. The forecasted population values are derived using the population forecasts described next.

Figure 1 describes the forecasting process for population growth:

**Figure 1: Forecasting Population Growth**



The forecasting models for regional employment growth are

$$[3] \text{GEMP}_{y,JACK} = \phi_0 + \phi_1 \text{GGDP}_{y,US} + \phi_2 \text{GGDP}_{y-1,US} + \phi_3 \text{GGDP}_{y-2,US} + \omega_{SC} D_{HB,2004-2005=1} + \text{ARIMA}\epsilon_{t,y} (1,0,0)(0,0,0)_{12}$$

JACK is for Jackson County, OR (Medford MSA).  $\text{GEMP}_y$  is Jackson County employment growth in year  $y$ ;  $\text{GGDP}_{y,US}$  is U.S. real GDP growth in year  $y$ ; and  $D_{HB}$  is a dummy for the housing bubble specific to the Medford region. The average GDP forecasts are used in the estimated model to generate five-year employment growth forecasts. The employment forecasts are then averaged with IHS's forecasts (GIHSEMP) for the same county so that:

$$[4] F_{\text{Avg}}(\text{GEMP}_{y,JACK}) = \frac{F(\text{GEMP}_{y,JACK}) + F(\text{GIHSEMP}_{y,JACK})}{2}$$

Averaging reduces the systematic errors of a single-source forecast. Therefore, the average forecast generated by [4] is used to generate the population growth forecasts, which are described next.

The forecasting models for regional population growth are:

$$[5] \text{GPOP}_{y,JACK} = \psi_0 + \psi_1 \text{GEMP}_{y-1,JACK} + \psi_2 \text{GEMP}_{y-2,CA} + \omega_{OL} D_{1991=1} + \omega_{SC} D_{HB,2004-2006=1} + \epsilon_{t,y}$$

GPOP<sub>y,JACK</sub> is Jackson County population growth calculated from U.S. Census mid-year estimates; D<sub>1991=1</sub> is a dummy variables for recession impacts; GEMP<sub>y-1,US</sub> and GEMP<sub>y-2,U.S.</sub> are U.S. employment growth in year y-1 and y-2; and CA is California Employment growth in year y-1. Because of its close proximity to CA, CA employment growth is better predictor of Jackson, OR employment growth than U.S. growth. The employment forecasts from [4] are used in [5] to generate population growth forecasts. These forecasts are combined with IHS's forecasts (GIHSPop) for Jackson, OR in the form of a simple average:

$$[6] F_{Avg}(\text{GPOP}_{y,JACK}) = \frac{F(\text{GPOP}_{y,JACK}) + F(\text{GIHSPop}_{y,JACK})}{2}$$

The average forecast generated by [6] is converted to a monthly growth rate and used to forecast population for use in the Medford residential 410 customer forecast. The monthly forecasted growth rate is calculated as  $[1 + F_{Avg}(\text{GPOP}_{y,JACK})]^{\frac{1}{12}} - 1$  on a June to June basis, starting from the most recent mid-year Census estimate. The annual rates generated by [6] can be found in Staff\_DR\_244 Attachment B-Regional Indicator Data Base2-June 2015 Forecast by going to the tab "Population Forecast" and starting in cell X-35. This tab has links to the tab "Employment Forecast" which shows the forecasts generated by equation [3], starting in cell W-40. Due to the electronic nature of Attachment B it is being provided in electronic form only.

In order to maximize the available customer data, several months of forecasted population data may be used in regression estimation of the forecasting model. This issue occurs because of differences between the timing of the forecast and the release of the newest population estimates. For example, the 2015 population estimates will not be released until mid-2016; therefore, for the most recent Medford residential 410 customer forecast, forecasted population values for July 2014 through April 2015 were used to estimate the regression equation shown in 244 (b).

(e): See response to (a).

**AVISTA CORP.**  
**RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/24/2015
CASE NO.:	UG 288	WITNESS:	Grant D. Forsyth
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Grant D. Forsyth
TYPE:	Data Request	DEPT:	Financial Planning & Analysis
REQUEST NO.:	Staff – 279	TELEPHONE:	(509) 495-2765
		EMAIL:	grant.forsyth@avistacorp.com

**REQUEST:**

Please refer to Staff DR 193 Attachment B - June 2015 OR Gas Model Runs that shows the model specifications and parameter estimates of the forecasting models. Please explain the following for the Roseburg region:

- a. The historical residential customer count and residential use-per-customer data is available from January, 2004 through April, 2015. What statistical tests are performed for selecting the sub-sample from January, 2005 through April, 2015 for forecasting residential customer counts and residential use-per-customer?
- b. Please explain and provide any statistical tests performed for selecting intervention variables- Point: Mar2007, Point: Dec2007, Point: Feb2008, Point: Nov2009, Ramp: Jan2007, Step: Jan2007, Point: Feb2015, Point: Dec2005, Point: Nov2005, and Point: Nov2006 for the residential customer forecast model;
- c. Please explain and provide any statistical tests performed for selecting intervention variables- Point: Feb2012, Point: Mar2011, Point: Dec2006, and Point: Dec2011 for the residential use-per-customer forecast model;
- d. Please explain the parameter coefficients of the two variables ROSHDD and ROSQHDD as shown in SAS parameters.xlsx, included in the file OR ROS Sch 410r UPC; and
- e. Please explain why the company has included the squared weather variables represented as ROSHDD2 and ROSQHDD2, as shown in SAS parameters.xlsx, included in the file OR ROS Sch 410r UPC.

**RESPONSE:**

**(a):** The decision to leave out 2004 was not based on a statistical test. It was left out of the estimation period to provide the option of using 2004 as a lagged dependent variable in the customer regressions. The same applies for the use per customer regressions. This issue was discussed with Staff at the August 17<sup>th</sup> meeting at the OPUC's offices in Salem, OR.

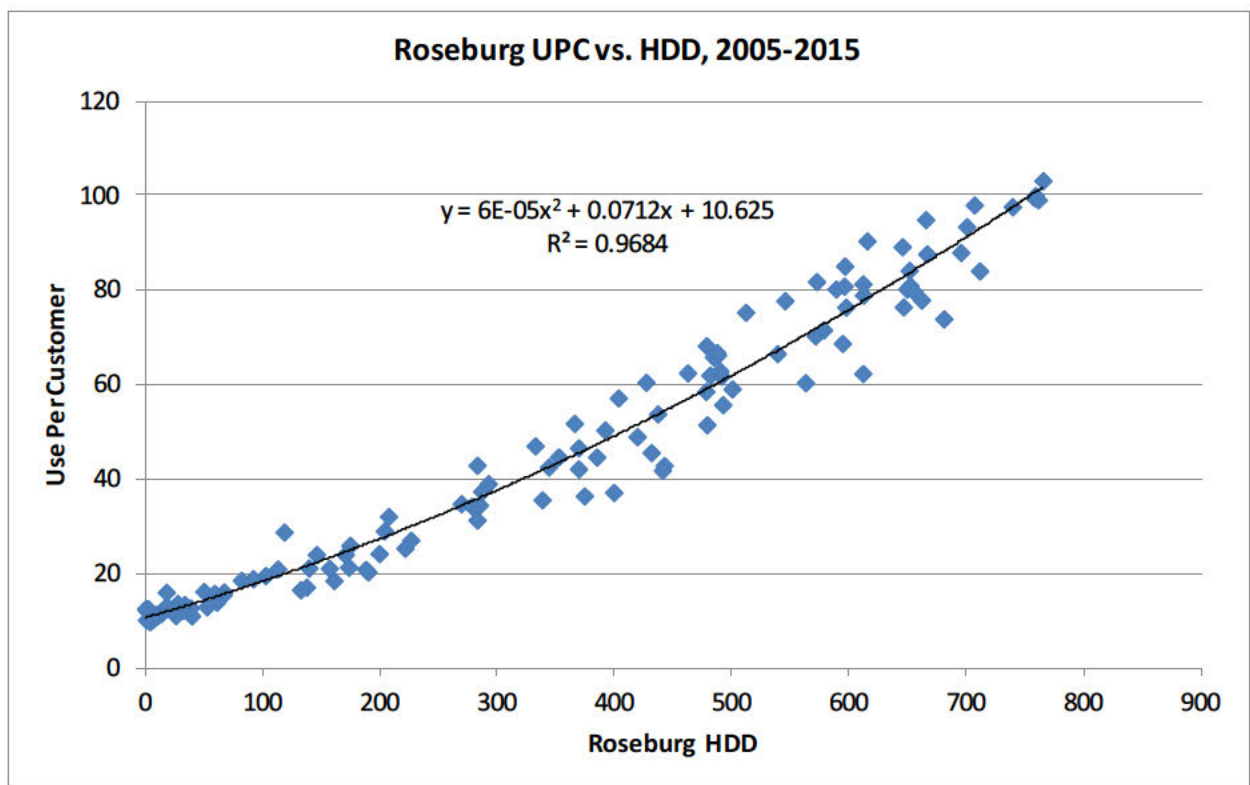


**(b)-(c):** The initial identification of potential outliers is done by examining the standardized residuals from the regression model. Next, a dummy is applied to the outlier to determine if applying the dummy alters regression coefficients (1) significantly alters the in-sample RMSE; (2) improves the outcome of white-noise tests; and (3) alters the type of needed error

correction. A significant change in any of these is a sign of influence. In addition to these tests, the error terms of the regression are often imported into SAS/JMP to determine to what extent potential outliers are impacting the assumption of error term normality. This is done by analyzing the normality assumption with and without the potential outliers. The normality test is done using the Shapiro-Wilk test. None of these tests were retained in this forecast. Repeated forecast runs suggest that, as a general rule of thumb, standardized outliers above 2.5 will likely have significant influence. This issue was discussed with Staff at the August 17<sup>th</sup> meeting at the OPUC's offices in Salem, OR.

The ramping variable is used to adjust for a sharp, structural decline in customer growth created by the collapse of the housing bubbling. That is, there was a sharp decline in the trend in customer growth starting in 2008. Excluding the ramping variable created customer forecasts that were higher than what could be supported with permitting and similar measures of regional economic activity. Including the ramping variable also improved error term behavior and the overall fit of the regression model.

**(d)-(e):** The weather variables ROSHDD, ROSHDD2, ROSQHDD, and ROSQHDD2 are included because of the non-linear relationship between use per customer and HDD. The graph below shows this relationship for Roseburg schedule 410 residential use per customer and HDD:



Note that the regression line bends up in a non-linear fashion in a way that would not be captured by a linear function incorporating only ROSHDD. The addition of the variables ROSQHDD and ROSQHDD2 control for the steep, non-linear run-up in use-per-customer in December to January/February and the steep run-down in load January/February to March. Approximately 60% of a calendar year's load will occur over these four months. Note that in January and February, the regression coefficients on ROSHDD and ROSQHDD are additive; the same holds for ROSHDD2 and ROSQHDD2.

By way of interpretation, the regression coefficients on ROSHDD, ROSHDD2, ROSQHDD, and ROSQHDD2 can be used to test the sensitivity of use-per-customer to changes in temperature. In addition, they can also be used to weather normalize usage using the difference between the current definition of normal weather HDD and to actual weather HDD over a given year. These issues were discussed with staff at the August 17<sup>th</sup> meeting at the OPUC's offices in Salem, OR.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/24/2015
CASE NO.:	UG 288	WITNESS:	Grant D. Forsyth
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Grant D. Forsyth
TYPE:	Data Request	DEPT:	Financial Planning & Analysis
REQUEST NO.:	Staff – 280	TELEPHONE:	(509) 495-2765
		EMAIL:	grant.forsyth@avistacorp.com

**REQUEST:**

Please refer to Staff DR 193 Attachment B - June 2015 OR Gas Model Runs that shows the model specifications and parameter estimates of the forecasting models. Please explain the following for the Klamath Falls region:

- a. The historical residential customer count and residential use-per-customer data is available from January, 2004 through April, 2015. What statistical tests are performed for selecting the sub-sample from January, 2005 through April, 2015 for forecasting residential customer counts and residential use-per-customer?
- b. Please explain and provide any statistical tests performed for selecting intervention variables- Ramp: Jan2007, Point: Feb2015, Step: Jan2007 for the residential customer forecast model;
- c. Please explain and provide any statistical tests performed for selecting intervention variables- Point: Feb2011, Point: Dec2008, Point: Nov2009, and Point: Apr2007 for the residential use-per-customer forecast model;

- d. Please explain the parameter coefficients of the two variables KLMHDD and KLMQHDD as shown in SAS parameters.xlsx, included in the file OR KLM Sch 410r UPC; and
- e. Please explain why the company has included the squared weather variables represented as KLMHDD2 and KLMQHDD2, as shown in SAS parameters.xlsx, included in the file OR KLM Sch 410r UPC.

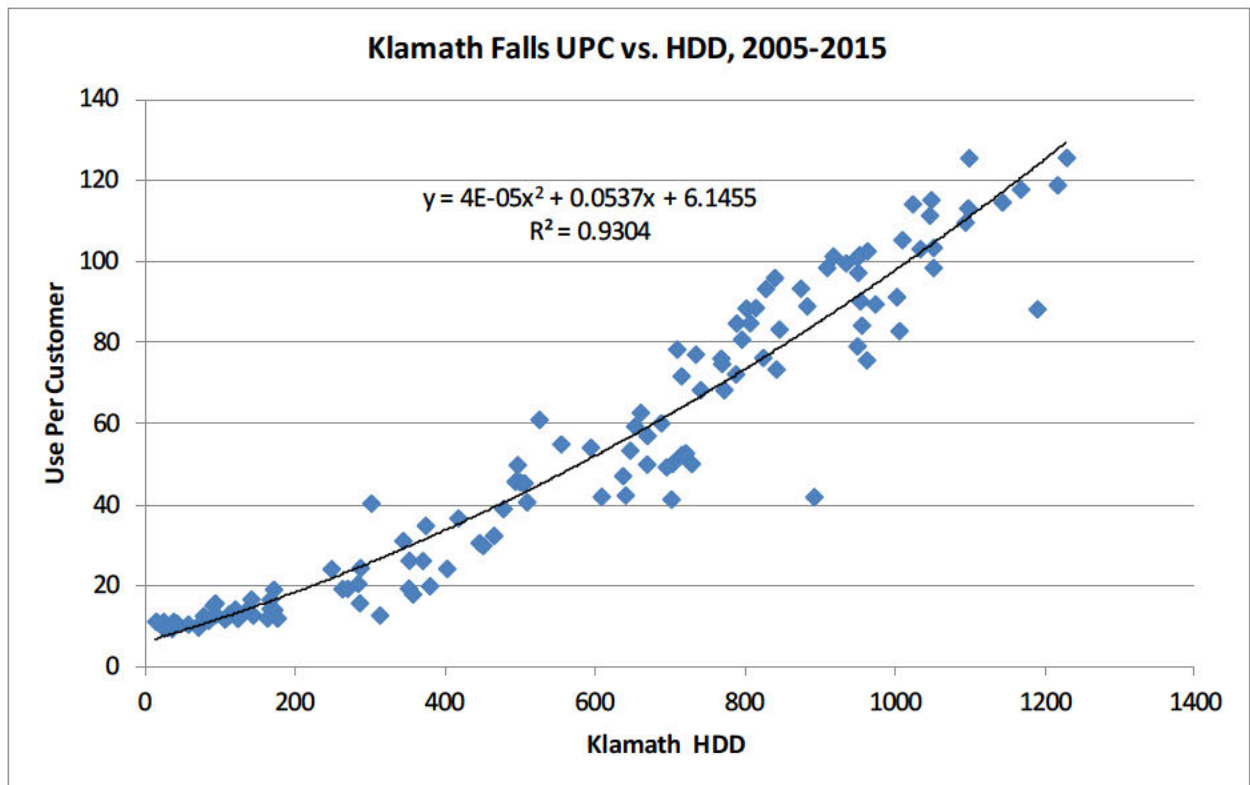
**RESPONSE:**

**(a):** The decision to leave out 2004 was not based on a statistical test. It was left out of the estimation period to provide the option of using 2004 as a lagged dependent variable in the customer regressions. The same applies for the use per customer regressions. This issue was discussed with Staff at the August 17<sup>th</sup> meeting at the OPUC's offices in Salem, OR.

**(b)-(c):** The initial identification of potential outliers is done by examining the standardized residuals from the regression model. Next, a dummy is applied to the outlier to determine if applying the dummy alters regression coefficients (1) significantly alters the in-sample RMSE; (2) improves the outcome of white-noise tests; and (3) alters the type of needed error correction. A significant change in any of these is a sign of influence. In addition to these tests, the error terms of the regression are often imported into SAS/JMP to determine to what extent potential outliers are impacting the assumption of error term normality. This is done by analyzing the normality assumption with and without the potential outliers. The normality test is done using the Shapiro-Wilk test. None of these tests were retained in this forecast. Repeated forecast runs suggest that, as general rule of thumb, standardized outliers above 2.5 will likely have significant influence. This issue was discussed with Staff at the August 17<sup>th</sup> meeting at the OPUC's offices in Salem, OR.

The ramping variable is used to adjust for a sharp, structural decline in customer growth created by the collapse of the housing bubbling. That is, there was a sharp decline in the trend in customer growth starting in 2008. Excluding the ramping variable created customer forecasts that were higher than what could be supported with permitting and similar measures of regional economic activity. Including the ramping variable also improved error term behavior and the overall fit of the regression model.

**(d)-(e):** The weather variables KLMHDD, KLMHDD2, KLMQHDD, and KLMQHDD2 are included because of the non-linear relationship between use per customer and HDD. The graph below shows this relationship for Klamath schedule 410 residential use per customer and HDD:



Note that the regression line bends up in a non-linear fashion in a way that would not be captured by a linear function incorporating only KLMHDD. The addition of the variables KLMQHDD and KLMQHDD2 control for the steep, non-linear run-up in use-per-customer in December to January/February and the steep run-down in load January/February to March. Approximately 60% of a calendar year's load will occur over these four months. Note that in January and February, the regression coefficients on KLMHDD and KLMQHDD are additive; the same holds for KLMHDD2 and KLMQHDD2.

By way of interpretation, the regression coefficients on KLMHDD, KLMHDD2, KLMQHDD, and KLMQHDD2 can be used to test the sensitivity of use-per-customer to changes in temperature. In addition, they can also be used to weather normalize usage using the difference between the current definition of normal weather HDD and to actual weather HDD over a given year. These issues were discussed with staff at the August 17<sup>th</sup> meeting at the OPUC's offices in Salem, OR.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION: Oregon  
CASE NO.: UG 288  
REQUESTER: PUC Staff – Bhattacharya  
TYPE: Data Request  
REQUEST NO.: Staff – 281

DATE PREPARED: 08/24/2015  
WITNESS: Grant D. Forsyth  
RESPONDER: Grant D. Forsyth  
DEPT: Financial Planning & Analysis  
TELEPHONE: (509) 495-2765  
EMAIL: grant.forsyth@avistacorp.com

**REQUEST:**

Please refer to Staff DR 193 Attachment B - June 2015 OR Gas Model Runs that shows the model specifications and parameter estimates of the forecasting models. Please explain the following for the LaGrande region:

- a. The historical residential customer count and residential use-per-customer data is available from January, 2004 through April, 2015. What statistical tests are performed for selecting the sub-sample from January, 2005 through April, 2015 for forecasting residential customer counts and residential use-per-customer?
- b. Please explain and provide any statistical tests performed for selecting intervention variables- Ramp: Jan2008, Point: Feb2015, Point: Jul2006, and Point: Dec2009 for the residential customer forecast model;
- c. Please explain and provide any statistical tests performed for selecting intervention variables- Point: Mar2014, Point: Jun2011, Point: May2011, Point: Feb2007, and Step: Jan2009 for the residential use-per-customer forecast model;
- d. Please explain the parameter coefficients of the two variables LAGHDD and LAGQHDD as shown in SAS parameters.xlsx, included in the file OR LaG Sch 410r UPC; and
- e. Please explain why the company has included the squared weather variables represented as LaGHDD2 and LaGQHDD2, as shown in SAS parameters.xlsx, included in the file OR LaG Sch 410r UPC.

**RESPONSE:**

**(a):** The decision to leave out 2004 was not based on a statistical test. It was left out of the estimation period to provide the option of using 2004 as a lagged dependent variable in the customer regressions. The same applies for the use per customer regressions. This issue was discussed with Staff at the August 17<sup>th</sup> meeting at the OPUC's offices in Salem, OR.

**(b)-(c):** The initial identification of potential outliers is done by examining the standardized residuals from the regression model. Next, a dummy is applied to the outlier to determine if

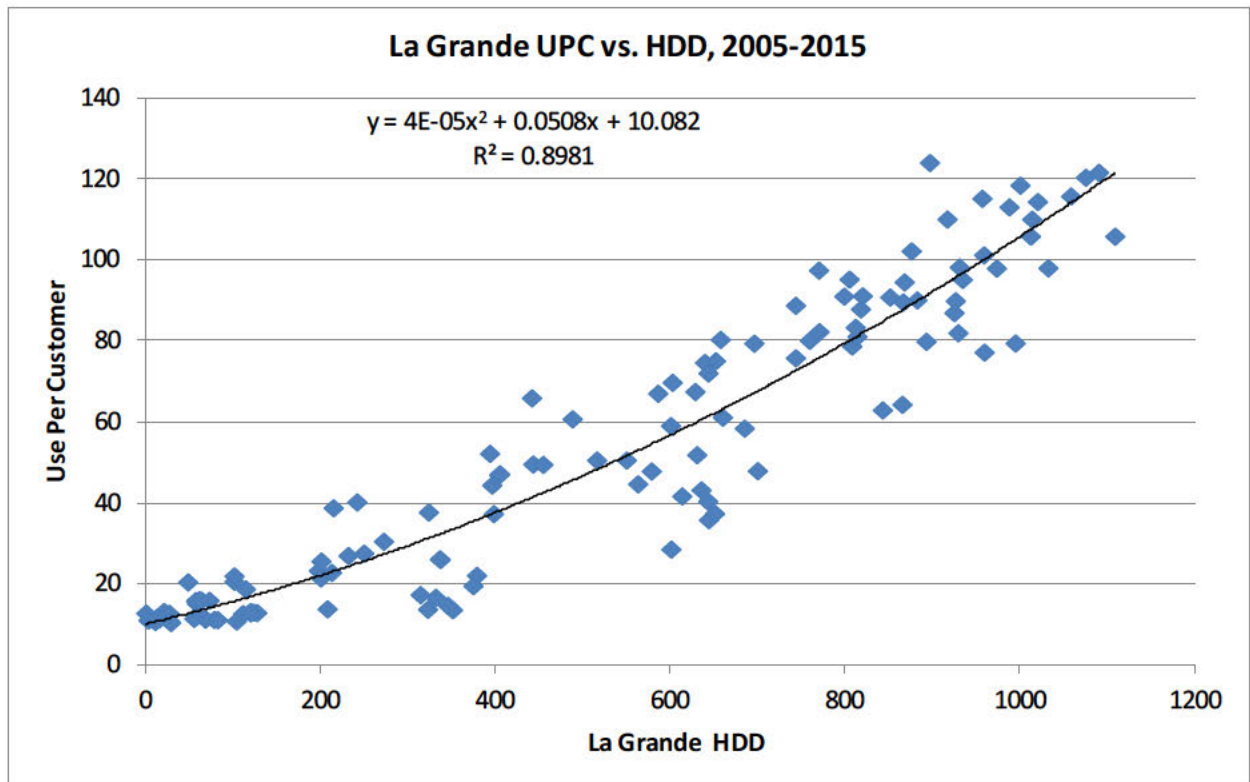


applying the dummy alters regression coefficients (1) significantly alters the in-sample RMSE; (2) improves the outcome of white-noise tests; and (3) alters the type of needed error correction. A significant change in any of these is a sign of influence. In addition to these

tests, the error terms of the regression are often imported into SAS/JMP to determine to what extent potential outliers are impacting the assumption of error term normality. This is done by analyzing the normality assumption with and without the potential outliers. The normality test is done using the Shapiro-Wilk test. None of these tests were retained in this forecast. Repeated forecast runs suggest that, as a general rule of thumb, standardized outliers above 2.5 will likely have significant influence. This issue was discussed with Staff at the August 17<sup>th</sup> meeting at the OPUC's offices in Salem, OR.

The ramping variable is used to adjust for a sharp, structural decline in customer growth created by the collapse of the housing bubbling. That is, there was a sharp decline in the trend in customer growth starting in 2008. Excluding the ramping variable created customer forecasts that were higher than what could be supported with permitting and similar measures of regional economic activity. Including the ramping variable also improved error term behavior and the overall fit of the regression model.

**281 (d)-(e):** The weather variables LaGHDD, LaGHDD2, LaGQHDD, and LaGQHDD2 are included because of the non-linear relationship between use per customer and HDD. The graph below shows this relationship for La Grande schedule 410 residential use per customer and HDD:



Note that the regression line bends up in a non-linear fashion in a way that would not be captured by a linear function incorporating only LaGHDD. The addition of the variables LaGQHDD and LaGQHDD2 control for the steep, non-linear run-up in use-per-customer in December to January/February and the steep run-down in load January/February to March. Approximately 60% of a calendar year's load will occur over these four months. Note that in January and February, the regression coefficients on LaGHDD and LaGQHDD are additive; the same holds for LaGHDD2 and LaGQHDD2.

By way of interpretation, the regression coefficients on LaGHDD, LaGHDD2, LaGQHDD, and LaGQHDD2 can be used to test the sensitivity of use-per-customer to changes in temperature. In addition, they can also be used to weather normalize usage using the difference between the current definition of normal weather HDD and to actual weather HDD over a given year. These issues were discussed with staff at the August 17<sup>th</sup> meeting at the OPUC's offices in Salem, OR.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	09/24/2015
CASE NO.:	UG 288	WITNESS:	Grant D. Forsyth
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Jeremiah Webster
TYPE:	Data Request	DEPT:	Budget & Forecast
REQUEST NO.:	Staff – 300	TELEPHONE:	(509) 495-2764
		EMAIL:	jeremiah.webster@avistacorp.com

**REQUEST:**

In response to OPUC DR 243 supplemental in the last rate case UG 284, the Company provided an Excel worksheet (attachment A) showing in detail how load forecasts from SENDOUT as well as forecasts from Grant Forsyth's models were incorporated in the revenue model. Please provide the revised version of this Excel file (with cell formulae intact), applicable for the current rate case UG 288.

**RESPONSE:**

Please see Staff\_DR\_300 Attachment A.

**AVISTA CORP.**  
**RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION: Oregon                      DATE PREPARED: 09/25/2015  
CASE NO: UG 288                              WITNESS: Grant D. Forsyth  
REQUESTER: PUC Staff - St. Brown      RESPONDER: Grant D. Forsyth  
TYPE: Data Request                          DEPT: Financial Planning &  
Analysis  
REQUEST NO.: Staff – 301                      TELEPHONE: (509) 495-2765  
EMAIL: grant.forsyth@avistacorp.com

**REQUEST:**

Please refer to Staff\_DR\_193 Attachment B - June 2015 OR Gas Model Runs. Please explain why Schedule 410 customer forecast models for Roseburg, LaGrande, and Klamath Falls do not consider April, 2015 actuals for forecasting test year customers.

**RESPONSE:**

The gas forecast covers three jurisdictions: Washington, Idaho, and Oregon. Due to the time required to finalize the gas forecast, the forecasting process must start well before the June deadline. Therefore, the forecasts for schedules with a relatively small number of customers are run earlier compared to the schedules with relatively large numbers of customers (e.g., schedule 410). As a result, the estimation and forecast period across schedules will differ by a month.

**AVISTA CORP.**  
**RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION: Oregon                      DATE PREPARED: 07/29/2015  
CASE NO: UG 288                              WITNESS: Grant D. Forsyth  
REQUESTER: PUC Staff – Bhattacharya      RESPONDER: Grant D. Forsyth  
and St. Brown                                  DEPT: Financial Planning & Analysis  
TYPE: Data Request                          TELEPHONE: (509) 495-2765  
REQUEST NO.: Staff – 193                      EMAIL: grant.forsyth@avistacorp.com

**REQUEST:**

Please provide a complete data and code documentation of the input/output files used to generate the final dataset for the monthly load forecast described in Avista/700, so that results can be replicated.

- a) Source of data;



- b) Input/output files for intermediate files and explain what variables are used to merge them into final data; and
- c) Input/output files of programs, analysis done in the program and any other comments that are necessary for someone else to run the program.

**RESPONSE:**

(a): The base data for the most recent customer and use per customer (UPC) forecasts can be found in Staff\_DR\_193 Attachment A - Gas Data and Forecasts June 2015. The tabs, “WA, ID, OR Residential”; “WA, ID, OR Commercial”; “WA, ID, OR Industrial”; and “WA, ID, OR Sch. 146, 456” contains the monthly billed data for our Oregon, Washington, and Idaho service territories. The tab “Code Book” is a partial description of the schedule titles contained in these four tabs. The customer, use per customer (UPC), and load forecasts for Oregon can be found under the tab “OR June 2015 Forecasts”.

(b): Data collated for the SAS/ETS forecasting software. This tab contains schedule customer counts, use per customer values, and all regression variables related to weather, population, price, and U.S. Industrial production.

(c): The forecast regressions for each schedule were estimated using the SAS/ETS forecasting system, which does require the user to write code. It is an interactive system based user defined characteristics. For each schedule regression, four Excel output files were retained: SAS Forecast; SAS Parameters; SAS Fit Tests; and SAS Error Tests. Since most schedules require a customer and UPC there are typically eight output files per schedule. In some cases, a regression model is not used to forecast either customers or UPC; in these cases, there is only one set of four output files. The content of each of these four output files are as follows:

<b>Output File</b>	<b>Output File Contents</b>
SAS Forecast	The base data used to generate the forecast; the forecasts; and error terms.
SAS Parameters	The estimated parameters in the model, including tests of parameter significance.
SAS Fit Tests	A selection of standard fit tests generated by SAS
SAS Error Tests	Autocorrelation functions, tests for white noise, and the Augmented Dickey-Fuller (ADF) stationarity test.

All output files can be found in the file folder “Staff\_DR\_193 Attachment B - June 2015 OR Gas Model Runs”. This file contains subfolders for each schedule requiring a SAS regression. For example, the subfolder “OR MED Sch 410r Cus” contains the output files for Medford’s schedule 410 residential customers; likewise, “OR MED Sch 410r UPC” contains the output files for Medford’s schedule 410 residential UPC. The same basic labeling is used for the other regions and the related schedules. To emphasize again, not all schedule forecasts need a regression (e.g., some are based on simple moving averages), which means some schedules may only have an output folder for customers or UPC.

Due to the size of the Attachments they are being provided in electronic form only.

**AVISTA CORP.**  
**RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/12/2015
CASE NO.:	UG 288	WITNESS:	Grant D. Forsyth
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Grant D. Forsyth
TYPE:	Data Request	DEPT:	Financial Planning & Analysis
REQUEST NO.:	Staff – 243	TELEPHONE:	(509) 495-2765
		EMAIL:	grant.forsyth@avistacorp.com

**REQUEST:**

Avista/700, Forsyth/11-12 report that the Company used 20-year moving average for defining normal weather over the forecast period.

- a. Please explain in detail the methodology used for calculating the normal weather for the test year period;
- b. For illustrative purpose, please explain how you derived January 2016 normal heating degree days (HDDs) and normal cooling degree days (CDDs) for the Medford region. Provide all associated worksheets (with cell formulae intact) in support of your explanation; and
- c. Lines 7-8 of Avista/700, Forsyth/12 state that 10- and 15- year moving averages showed considerably more year-to-year volatility than the 20-year average. Please explain all the necessary steps performed to identify the yearly fluctuations with 10, 15, and 20 year moving averages

**RESPONSE:**

**(a)-(b):** Please refer to Staff\_DR\_243 Attachment A - HDD and CDD Weather Data. By way of example, open the Excel file and go to tab “Medford, OR HDD Data” and go to cell S-99. This shows the 20-year moving average value for January for the 1995-2014 period using Avista’s billing adjusted HDD. This is the current 20-year period that defines normal weather. The remaining months are calculated in a similar fashion. The same calculation is done for the other city regions under the tabs, “Roseburg, OR HDD Data”; “Klamath Falls, OR HDD Data”; and “La Grande, OR HDD Data.” Due to the electronic nature of the attachment it is being provided in electronic form only.

**(c):** Please refer to Staff\_DR\_243 Attachment A - HDD and CDD Weather Data. By way of example, go to the tab “Medford Moving Average Analysis” and go to cell D-32. This cell shows the 30-year moving average of HDD for the period of 1948-1977. Under the current moving average methodology, this would have been (theoretically) the period defining normal weather for a load forecast starting in 1978. This approach is repeated for moving average periods of 25, 20, 15, 10, and 5 years. For each of these moving average periods, the standard deviation of the moving average is calculated and plotted against the period of the moving average in the graph “Relationship Between Moving Average Period

and Moving Average Standard Deviation.” Note that, depending on the region, the standard deviation of the moving average tends to escalate rapidly when the moving average falls below 15 to 20 years. This can be seen by the behavior of the dotted trend line. This is also the case for the three other city regions.

CASE: UG 288  
WITNESS: JORGE ORDONEZ

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1100**

Cost Allocations

**Opening Testimony**

**October 16, 2015**

**CERTAIN INFORMATION CONTAINED IN  
STAFF EXHIBIT 1100  
PAGES 4 , 5, 8 AND 9  
ARE CONFIDENTIAL AND SUBJECT TO PROTECTIVE  
ORDER NO. 15-141 IN DOCKET NO. UG 288.**

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Jorge Ordonez. I am employed by the Public Utility Commission of  
3 Oregon (OPUC) as a Senior Economist in the Energy Resources and Planning  
4 Division. My business address is 201 High St. SE Suite 100, Salem, Oregon  
5 97301-3612.

6 **Q. Please describe your educational background and work experience.**

7 A. My Witness Qualification Statement is found in Exhibit Staff/1101.

8 **Q. What is the purpose of your testimony?**

9 A. The purpose of my testimony is to describe Staff's review of Avista  
10 Corporation's (Avista or Company) cost allocations.

11 In conducting the aforementioned review, Staff referred to the Company's  
12 initial filing and approximately 14 initial and follow-up data requests (DRs).

13 **Q. Did you prepare exhibits for this docket other than your witness  
14 qualification statement?**

15 A. Yes. I prepared Exhibit Staff/1102, consisting of 43 pages (non-confidential  
16 responses including attachments to Staff DR 133, 239, 240, 283, 286, 287 and  
17 certain portions of Avista's 10-k reports filed with the Securities and Exchange  
18 Commission) and Confidential Exhibit Staff/1103, consisting of 1 page (page 5  
19 of confidential Attachment A to the Company's response to Staff DR 286).

20 **SUMMARY RECOMMENDATION**

21 **Q. What is Staff's recommendation or conclusion?**

22 A. Staff concludes that, with one exception, Avista's cost allocations are  
23 reasonable. The one exception concerns the test year salary amounts

1 assigned to utility operations (Utility Operations) by certain executives of the  
2 Company. With regard to this exception, Staff recommends a reduction of  
3 these executives' salaries assigned to Utility Operations by \$104,000 on a  
4 system wide basis, which represent approximately \$9,000 on an Oregon-  
5 allocated basis. Staff reserves its right to address additional issues that the  
6 intervening parties may raise about cost allocations in their respective opening  
7 testimonies.

8 **Q. How is your testimony organized?**

9 A. My testimony is organized as follows:

1. Description of Staff's Analysis; and
2. Conclusion.

10 **1. DESCRIPTION OF STAFF'S ANALYSIS**

11 **Q. Please explain how the Company allocates costs.**

12 A. The Company allocates common revenues, expenses, and rate base between  
13 its services (i.e. electric and gas) and its jurisdictions (i.e. Washington, Oregon,  
14 and Idaho).

15 **Q. Are there any allocation factors used by the Company to allocate**  
16 **costs?**

17 A. Yes. In the Company's work papers,<sup>1</sup> the Company illustrated the following  
18 allocation factors:  
19

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<sup>1</sup> See the Company's work paper MS Excel file "2) 2015-Allocation Factors-4 (E&G), 7,8,9-2014 Data," worksheet "NewMemo".

**Table 1**  
**(in %)**

Service	Description	Electric	Gas	Gas - Oregon
CD	No. of Customers	52.892	33.079	14.029
CD	Net Direct Plant	78.637	14.060	7.303
CD	Four Factor	71.547	19.751	8.702
GD	No. of Customers		70.219	29.781
GD	Four Factor		69.082	30.918

“CD” and “AA” stand for “common to all divisions” and “common to gas divisions” respectively, as described in the Company response to Staff DR 133, included to this testimony as Exhibit Staff/1102, Ordonez/1-3.

**Q. Did Staff review the correctness of the above percentage values?**

A. Yes. Staff reviewed the estimation of the above percentage values and determined they are correct.

**Q. You described the allocation factors used to allocate common costs. Are there any costs that are directly assigned to utility and non-utility operations?**

A. Yes. As described in Attachment A of the Company’s response to Staff DR 133, included as Exhibit Staff/1102, Ordonez/4-31, the Company directly assigns certain costs to Utility Operations and non-utility operations (Non-Utility Operations or unregulated subsidiaries). Staff’s analysis focused on the level of costs that are directly assigned to Non-Utility Operations by its highest paid executives and officers<sup>2</sup>.

<sup>2</sup> Staff understands that the definition of the Company of “officers” and “executives” might be different, however for the purpose of this testimony Staff refers to both terms as “executives”.





Averages by year	■	■	■	■	■	■
Averages by Operations		■			■	

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**Q. Did Staff contrast the percentage information provided in Table 3 with an amount that represents the share of the Company’s Non-Utility Operation from the Company as a whole?**

A. Yes. Staff reviewed the magnitude of Non-Utility Operations’ plant (Property, Plant and Equipment) and revenues (Operating Revenue) relative to the Company as a whole. By the Company as a whole, Staff means the combined Non-Utility Operations and Utility Operations. From the Company’s 2014 and 2013 10-k reports filed with the Securities and Exchange Commission, included as Exhibit Staff/1102, Ordonez/33-36, Staff built the Tables 4 and 5 shown below:

Table 4  
Financial Information for Non-Utility Operations, Utility Operations, and Total Corporation  
(\$)

#	Type of Financial Information	Non-Utility Operations			Utility Operations		
		2012	2013	2014	2012	2013	2014
1	Property, Plant and Equipment	52,828	51,997	221,155	4,197,742	4,450,787	4,750,468
2	Operating Revenue	38,953	39,549	39,219	1,352,385	1,402,195	1,433,343

Table 5  
Financial Information for Non-Utility Operations, Utility Operations, and Total Corporation  
(%)

#	Type of Financial Information	Non-Utility Operations			Utility Operations		
		2012	2013	2014	2012	2013	2014
1	Property, Plant and Equipment	1%	1%	4%	99%	99%	96%
2	Operating Revenue	3%	3%	3%	97%	97%	97%
	Averages by year	2%	2%	4%	98%	98%	96%
	Averages by Operations	3%			97%		

1

**2 Q. Please continue explaining Staff's analysis**

3 A. As shown in Table 5, the Company's Non-Utility Operations represent  
4 approximately three percent relative to the Company as a whole for the most  
5 recent three calendar year period (2012-2014).

6 As shown by Table 3, with exception of one executive, all of the executives'  
7 compensation assigned to Non-Utility Operations exceeds the three percent  
8 figure with the exception of one executive.

**9 Q. Why does this one executive you identified not directly assign more  
10 costs to the Non-Utility Operations of the Company?**

11 A. In Staff DR 287, Staff requested the Company to provide the title, duties and  
12 responsibilities of this executive. The body of the Company's response to Staff  
13 DR 287 is included in this testimony as Exhibit Staff/1102, Ordonez/37.

14 In Avista's response to this data request, the Company represented that the  
15 title of this executive is President of Avista Utilities.<sup>3</sup> Additionally, the Company  
16 provided the job description of this executive in confidential Attachment A to  
17 the Company's response to Staff DR 286, included as Confidential Exhibit  
18 Staff/1103, Ordonez/1. From the information provided by the Company and  
19 after reviewing the title and job description of this executive, Staff determines  
20 that due to this executive's title and duties and responsibilities, which are  
21 mostly related to the Company's Utility Operations, it is reasonable for this  
22 executive to directly assign a greater level of costs to Utility Operations.

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<sup>3</sup> The Company identified the title of this executive in its non-confidential response to Staff DR 287, I.

1 **Q. Did Staff corroborate its assessment that the highest paid executives'**  
2 **levels of costs assigned to Non-Utility Operations are reasonable?**

3 A. Yes. Staff corroborated its conclusion in two ways.

4 **Q. Please explain the first verification method Staff used.**

5 A. In the Company's response to part "a" of Staff DR 240, included as Exhibit  
6 Staff/1102, Ordonez/38-40, the Company represented that "the Company does  
7 maintain a timekeeping system within which each individual employee enters  
8 his/her time by day, by project (includes FERC accounts) for a two week  
9 period....This information is then reviewed and approved bi-weekly by the  
10 individual's supervisor to [ensure] accuracy in project selection. The  
11 timekeeping system gathers this information, summarizes it into monthly  
12 amounts, and feeds it to the general ledger in order to query for reporting  
13 purposes... Finally, the Company's third-party independent auditor Deloitte and  
14 Touche annually audits the timekeeping system from timekeeping entry to  
15 general ledger and reporting to actual payroll."<sup>4</sup>

16 Per the Company's response, Staff concluded that the Company has  
17 appropriate timekeeping controls.

18 **Q. Please explain Staff's second verification method**

19 A. Staff reviewed the involvement of these executives in Non-Utility Operations  
20 thorough the Board of Directors meetings and the respective meetings' minutes  
21 from 2012 through 2014. This was provided by the Company after Staff  
22 followed-up on Staff DR 286 (the body of the Company's initial response is

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<sup>4</sup> See the Company's response to part "a" of the Company's response to Staff DR 240 at Exhibit Staff/1102, Ordonez/35, included with this testimony.

1 included as Exhibit Staff/1102, Ordonez/41-43.) Staff found that these five  
 2 executive were present in almost all the Board of Directors meetings. Staff also  
 3 built Table 6 and 7 below.

4 **Q. Please explain your Tables 6 and 7.**

5 A. Table 6 provides the number of issues covered in the Board of Directors  
 6 meetings by year broken down into Non-Utility and Utility related issues. Table  
 7 7 expresses the same information in percentage values. From Table 7, the  
 8 number of Non-Utility Operations' issues covered in the Board of Directors  
 9 meetings represent approximately [REDACTED] percent relative to the total number of  
 10 issues covered for the most recent three calendar year period (2012-2014).  
 11 This percentage is close to the approximately [REDACTED] percent of the five  
 12 executives compensation assigned to Non-Utility operations in the most recent  
 13 three calendar year period (2012-2014).

14 Table 6  
 15 Number of Issues Covered in Board of Directors Meetings

	Non-Utility Operations Related Issues			Utility Operations Related Issues		
	2012	2013	2014	2012	2013	2014
By Year	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
By Operations	[REDACTED]			[REDACTED]		

16 Table 7  
 17 Number of Issues Covered in Board of Directors Meetings  
 18 (%)  
 19

	Non-Utility Operations Related Issues			Utility Operations Related Issues		
	2012	2013	2014	2012	2013	2014
By Year	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
By Operations	[REDACTED]			[REDACTED]		



1 **Q. In your summary recommendation you identified one “exception”**  
 2 **associated with the test year salary amounts assigned to Utility**  
 3 **Operations. Please elaborate on that issue.**

4 A. Yes. As shown by Table 8 below, the amounts of total compensation  
 5 represented by the percentage assigned to Utility Operations in the past three  
 6 years (i.e., 2012 through 2014) in aggregate differ with the *pro forma* (test year)  
 7 percentages proposed by the Company.

8 Table 8  
 9 Assignment of Cost to Utility Operations  
 10 (%)

#	Executive	Utility Operations	
		Historical <sup>5</sup> Average 2012-2014	Company- proposed Test Year <sup>6</sup>
1	██████████	██	██
2	██████████	██	██
3	██████████	██	██
4	██████████	██	██
5	██████████	██	██
Average		██	██

11  
 12 Applying the historical percentages to the salary compensation of these  
 13 executives for the test year salaries presented in workpaper workbook "2) 2015  
 14 OR Executive Officer Pro-Forma Labor.xlsx," worksheet "Pro-Forma Labor  
 15 Total," column "Z" instead of the Company-proposed test year information  
 16 results in a reduction of these executives' salaries assigned to Utility

<sup>5</sup> Source: Table 3 of this testimony.

<sup>6</sup> Source: workpaper workbook "2) 2015 OR Executive Officer Pro-Forma Labor.xlsx," worksheet "Pro-Forma Labor Total," column "K".

1 Operations of approximately \$104,000 on a system wide basis, which  
2 represents approximately \$9,000<sup>7</sup> on an Oregon-allocated basis.<sup>8</sup>

## 3 **2. CONCLUSION**

### 4 **Q. What is Staff's conclusion?**

5 A. Based upon the Company's filing including workpapers, initial and follow-up  
6 DRs, and Staff analysis, Staff concludes that, with one exception, Avista's cost  
7 allocations are reasonable. The one exception concerns the test year salary  
8 amounts assigned to Utility Operations by certain executives of the Company.  
9 With regard to this exception, Staff recommends a reduction of these  
10 executives' salaries assigned to Utility Operations by \$104,000 on a system  
11 wide basis, which represent approximately \$9,000 on an Oregon-allocated  
12 basis.

### 13 **Q. Would you like to address any other matters?**

14 A. Staff anticipates that other parties to this docket may raise issues related to  
15 cost allocations. Staff reserves the opportunity to address these issues and  
16 any additional issues or adjustments presented by an intervening party.

### 17 **Q. Does this conclude your testimony?**

18 A. Yes.

---

<sup>7</sup> The allocation factor used by Staff to express the system-wide figure into an Oregon-allocated figure is the four factor allocation factor of 8.702 percent for common costs presented in Table 3 of this testimony.

<sup>8</sup> For details of Staff's adjustment, please see confidential workpaper workbook "CONFIDENTIAL workpapers," worksheet "adjustment".

CASE: UG 288  
WITNESS: JORGE ORDONEZ

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1101**

**Witness Qualifications Statement**

**October 16, 2015**



**WITNESS QUALIFICATIONS STATEMENT**

NAME Jorge D. Ordonez

EMPLOYER Public Utility Commission of Oregon

TITLE Senior Economist  
Energy Resources and Planning Division

ADDRESS 201 High Street SE., Suite 100  
Salem OR 97301

EDUCATION AND TRAINING Utility Management Certificate  
Willamette University, Oregon, 2008

Certificate in Management of Hydropower Development  
Swedish International Development Cooperation Agency, Sweden,  
2006 & South Africa, 2007

Fulbright Scholar, MBA, concentration in finance  
Willamette University, Oregon, 2005

Certificate in Project Appraisal and Management  
Maastricht School of Management, Netherlands, 2002

BS, Mechanical Engineering, thermal power efficiency  
Electrical & Mechanical Engineering School  
San Antonio Abad University, Peru, 1998

EXPERIENCE I received a Bachelors of Science degree in Mechanical Engineering from San Antonio Abad University in Cusco, Peru in 1998. Subsequently, as a Fulbright Scholar, I received an MBA with an emphasis in finance from Willamette University in 2005. From 1999 to 2008, I worked for a Peruvian power generation company and was promoted many times, working as an Engineer, Resource Scheduler, Manager of Economic Planning and Vice-President of Generation, Commercial and Trading. Since January 2009, I have been employed by the Public Utility Commission of Oregon as a Senior Financial Economist, evaluating utilities' issuance of securities, cost of capital, mergers and acquisitions, cost of service studies, marginal cost studies, rate spread and rate design, integrated resource plans, purchased natural gas costs, and power costs.

CASE: UG 288  
WITNESS: JORGE ORDONEZ

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1102**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

- c. For each account under the Column “A” of worksheet "AF-01" in workpaper MS Excel file "1) 2014 Allocation Factor Adj," please provide a detailed explanation of the rationale by which the such allocation factor under Column “X” was used;<sup>1</sup>
- d. Regarding MS Excel rows “13” and “14” (both named “Taxes Other Than Inc – Storage”), where the Company used a 19.10 percent updated allocation factor, please:
  - i. Explain why the 19.10 percent number is not shown in the table above;
  - ii. Provide a detailed explanation of how the 19.10 percent number was calculated; please provide the Company’s workpapers in electronic spreadsheet formulae with cell references and formulae intact;
  - iii. Should the acronym “WA” under column “Ser” for rows “13” and “14” mean the Washington Jurisdiction, please provide a comprehensive explanation of why the Oregon Jurisdiction might being allocated costs related to the Washington Jurisdiction; and
  - iv. Provide a detailed explanation of the rationale by which the 19.10 percent figure was used and why not any of the other allocation factors referred in the above table was used (i.e., 14.029 percent 7.303 percent, 8.702 percent, 29.781 percent, 30.918 percent).

If the information requested in the above questions, including any component or subcomponent, was derived or obtained from other sources, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format indicating the specific page, section, etc. of the relevant source document.

## **RESPONSE:**

a) The Company converted to the Oracle Financial System on January 1, 2005. With the implementation of the Oracle Financial System, the two-digit alpha codes for service and jurisdiction were adopted. The two-digit alpha codes are described in the Company’s response Staff\_DR\_132. The allocation methodology did not change with the implementation of the Oracle Financial System, but only the account code labeling was changed. Prior to converting financial systems, the Company used a single-digit utility code to identify operating divisions. The Company used the following utility codes (with the new alpha codes identified in parenthesis):

---

<sup>1</sup> For example, regarding row “5,” (Depreciation Expense) of the MS Excel file "1) 2014 Allocation Factor Adj," worksheet "AF-01," where the Company used an updated allocation factor of 30.918 percent, please provide a comprehensive explanation of the rationale by which the 30.918 percent figure was used and why not any of the other allocation factor referred in the above table (i.e., 14.029 percent 7.303 percent, 8.702 percent, and 29.781 percent) was used.

Another example, regarding row “6,” (Depreciation Expense) of the MS Excel file "1) 2014 Allocation Factor Adj," worksheet "AF-01," where the Company used an updated allocation factor of 100 percent, please provide a comprehensive explanation of the rationale by which the 100 percent figure was used and why not any of the other allocation factor referred in the above table (i.e., 14.029 percent 7.303 percent, 8.702 percent, and 29.781 percent) was used.

Please perform the same analysis for each account under Column “A” of worksheet "AF-01" in workpaper MS Excel file "1) 2014 Allocation Factor Adj," as requested in part “c” of this data request.

- 0 –Electric division (ED ID, ED WA, ED AN)
- 1 – WA/ID Gas division (GD ID, GD WA, GD AN)
- 2 –OR Gas division (GD OR)
- 7 – Common to all divisions (CD AA)
- 8 – Common to only Gas divisions (GD AA)
- 9 – Common to WA/ID Electric and Gas divisions (CD ID, CD WA, CD AN)

When the Company converted financial systems in 2005, many Avista employees and Staff at the state utility Commissions were comfortable with the old utility codes, so the memo was updated to include the “new” service and jurisdiction codes with the “old” utility codes. The Company converted systems over 10 years ago, however, the utility codes are still used to refer to the allocation factors, so the information has not been removed from the memo.

b & c) Please see Staff\_DR\_133-Attachment A. This is an excerpt from testimony provided by Company witness Liz Andrews in Avista’s 2014 Washington GRC (Docket Nos. UE-140188 and UD-140189). It describes all of the allocation methodology used by the Company for both electric and natural gas.

d) The Jackson Prairie Natural Gas Storage Facility is located in Washington. The Company pays property taxes on the facility to Washington State. A portion of the facility is allocated for the benefit of Oregon customers. The Company uses the net book value of the property to allocate the property tax costs between Oregon and Washington/Idaho (AN) customers. Please see Staff\_DR\_133-Attachment B for the computation of the factor used in "1) 2014 Allocation Factor Adj”.

The service and jurisdiction are assigned to property taxes (expense FERC Accounts 408150, 408170, 408180, and 408190 and the liability FERC Account 236100) differently than the rest of the FERC accounts at Avista. For FERC accounts that are not property taxes, the jurisdiction assigned represents the jurisdiction that will be allocated the expense. For property taxes, the jurisdiction assigned represents the state where the tax is incurred and not where the tax will be expensed. In other words, the jurisdiction for property tax FERC accounts represents that taxes paid on the property that is located in that state. The Company allocates the property tax expense to the jurisdictions using specific FERC subaccounts. Because the tax on the Jackson Prairie Natural Gas Storage Facility is paid to Washington, it is assigned GD.WA. But, as described above, it is appropriate to allocate a portion of those costs to Oregon.

1           The Company has completed such audits for the periods 2010 through 2012, with  
2 each of these reports provided to all parties.<sup>48</sup> The Company provided a copy of its last  
3 report, the 2012 Accounting Practices Audit, to all parties on May 20, 2013. The cost of  
4 the 2012 audit was approximately \$49,000 in internal labor and benefit costs. The 2013  
5 Accounting Practices Audit report is scheduled to be complete in May 2014, at which  
6 time the report and the costs will be provided to all parties.

7           **Tracking of Aldyl-A Natural Gas Pipeline Replacement Program Projects**

8           **Q.     Order No. 9, approving the Settlement Stipulation in Docket Nos. UE-**  
9 **120436 and UG-120437, required Avista to begin tracking separately, on January 1,**  
10 **2013, all projects associated with its Aldyl-A natural gas pipeline replacement**  
11 **program. Has the Company fulfilled these requirements?**

12           A.     Yes. Beginning January 1, 2013 the Company began tracking through  
13 separate projects its Aldyl-A natural gas pipeline replacement program projects and will  
14 make this information available upon request to the Commission.

15           **Cost Assignment & Allocation Methodologies**

16           **Q.     Order No. 9, approving the Settlement Stipulation in Docket Nos. UE-**  
17 **120436 and UG-120437, required Avista to provide additional information**  
18 **regarding its cost<sup>49</sup> assignment and allocation methodologies in its next general rate**

---

<sup>48</sup> The Company provided its 2010 Accounting Practices Audit report and costs within its 2011 GRC filing in Docket Nos. UE-110876 and UG-110877. (See Exhibits Nos. \_\_\_(EMA-1T) and \_\_\_(EMA-5).) The Company provided its 2011 Accounting Practices Audit report and costs within its 2012 GRC filing in Docket Nos. UE-120436 and UG-120437. (See Exhibits Nos. \_\_\_(EMA-1T) and \_\_\_(EMA-4).)

<sup>49</sup> The Company records revenues, expenses and net plant investment in common accounts that must be allocated to services and jurisdictions. The same allocation process and methodologies are used for all of these accounts. The Company will refer to these revenues, expenses and net plant investment as “costs” throughout this document.

1 **case. Has the Company fulfilled these requirements?**

2 A. Yes. In Paragraph 17 of the Multiparty Settlement Stipulation in Dockets  
3 UE-120436 and UG-120437, the settling parties agreed that Avista, in its next general rate  
4 case, would provide justification for the service and jurisdictional cost allocation  
5 methodologies that it employs. The Company met with several members of the WUTC  
6 Staff on December 2, 2013, to provide an overview of Avista's operations and accounting  
7 practices, including an overview of its allocation processes and methodologies. The  
8 allocation presentation used by the Company at this meeting is provided as Exhibit No.  
9 \_\_\_\_ (EMA-7). The testimony that follows describes Avista's cost allocation procedures  
10 and why we believe the method used by Avista produces a reasonable allocation of costs.

11 **Q. Would you please describe the utility services provided by the**  
12 **Company and identify the jurisdictions within which the utility services are**  
13 **provided?**

14 A. Yes. The Company provides electric service in two retail jurisdictions<sup>50</sup>:  
15 Washington (WA) and Idaho (ID), and natural gas service in three retail jurisdictions:  
16 Washington, Idaho and Oregon (OR).

17 Retail natural gas service provided in eastern Washington and northern Idaho is  
18 accounted for separately as the WA/ID natural gas service, or as the North natural gas  
19 service. Natural gas service in central and southwest Oregon and is accounted for  
20 separately as our Oregon jurisdiction, or the South natural gas service.

21 **Q. How does the Company assign costs by service and jurisdiction?**

---

<sup>50</sup> Avista serves approximately 25 retail electric customers in Montana.

1           A.       Whenever possible, the Company directly assigns its revenues, operating  
2 costs and net plant investment to services and jurisdictions. For costs not directly  
3 assigned, the Company uses an allocation process using allocation factors that are derived  
4 from directly assigned costs which are updated annually. The costs that are not directly  
5 assigned are referred to as “common” costs.

6           For example, Avista’s main headquarters in Spokane supports all services and  
7 jurisdictions, therefore the operating costs, depreciation expense and net book value of the  
8 building is allocated to all services and jurisdictions using allocation factors.

9           **Q.       Please explain how the Company accounts for these “common” costs**  
10 **that must be allocated.**

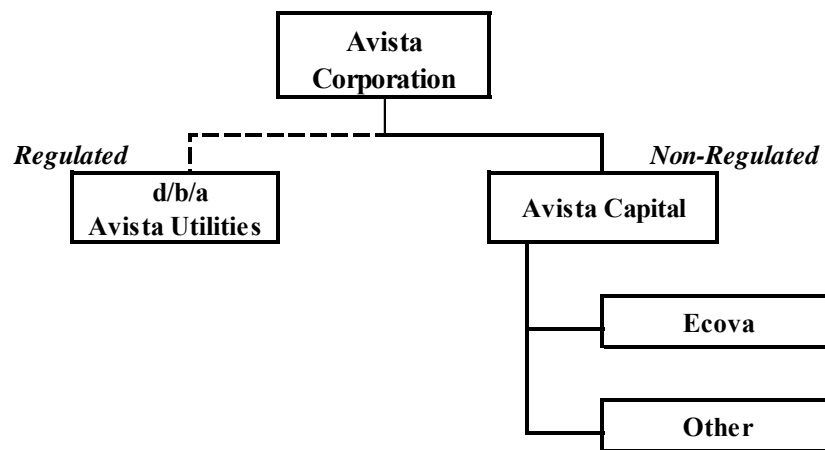
11          A.       The Company uses service codes (electric, natural gas and common) and  
12 jurisdiction codes (state and common) on all accounting transactions to indicate where  
13 costs should be recorded (either directly assigned or where a common cost should be  
14 allocated). Both service codes and jurisdiction codes consist of two-digit alpha codes,  
15 described further below. The assignments and allocations are used for internal, financial  
16 and regulatory reporting and for ratemaking purposes.

17          **Q.       Are costs also allocated to non-utility operations or subsidiary**  
18 **companies of Avista Corp.?**

19          A.       Instead of being allocated, certain costs are directly assigned to non-utility  
20 operations or subsidiaries. Avista Utilities is the regulated operating division of Avista  
21 Corp. A current organization chart for Avista Corp. is provided in Illustration No. 3  
22 below.

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**Illustration No. 3**



Certain officers and general office employees of Avista spend time on corporate service support, such as accounting, federal income tax filing, planning, or incur costs for supplies, postage, legal, graphic services, etc. for subsidiaries. Their time and costs are directly charged to suspense accounts and then billed to the subsidiary or directly charged to non-utility FERC accounts. Therefore, there is no need to allocate costs to subsidiaries or non-utility accounts as part of the allocation procedures described below, because they are all directly assigned.

An example of the Company’s process for recording subsidiary-related costs is provided in Table No. 2 below.



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**Table No. 2**

<b>Detail of Directors' Fees</b>																																															
<b>For Twelve Months Ended June 30, 2013</b>																																															
<b>(\$000's)</b>																																															
Total Directors' Fees		\$1,531																																													
Less: Subsidiary Directors' Fees Charged to FERC 417/186		<u>44</u>																																													
Avista Corp. Directors' Fees		1,488																																													
Less: 10% Charged to Non-utility (FERC 417)		<u>148</u>																																													
Utility Directors' Fees - System		<u>\$1,340</u>																																													
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Idaho Natural Gas	29.397%	<u>76</u>																																													
Total	<u>100.000%</u>	<u>\$ 260</u>																																													

Table No. 2 shows that a total of \$1.53 million of directors' fees was paid during the twelve months ended June 30, 2013. Of this amount, \$44,000 was direct charged to either a subsidiary receivable or to a non-utility FERC account related to Ecova's Board of Director fees. In addition, of the \$1.53 million of Avista Corp. Board of Director Fees, \$148,000 was directly charged to a non-utility FERC account related to subsidiary

1 operations.<sup>51</sup> The remaining \$1.34 million that was charged to the utility is allocated by  
2 service and jurisdiction.

3 **Q. Do you believe the allocation methodology used today by the**  
4 **Company is appropriate for allocating common costs?**

5 A. Yes, I do. When the Company designed the allocation methodology that is  
6 being used today, the specific objectives identified were as follows:

- 7 a) The method must be acceptable to all regulators to prevent any stranded  
8 costs or investment,
- 9
- 10 b) The number of cost allocation methods should be minimized,
- 11
- 12 c) The method needs to be simple,
- 13
- 14 d) The method needs to have a sound, rational basis,
- 15
- 16 e) Allocations under the method should be automated, and
- 17
- 18 f) The method needs to produce reasonable results.

19 These objectives are still relevant today. The Company believes the methodology  
20 continues to meet these over-all objectives.

21 The over-all goal the Company was trying to accomplish as it designed its  
allocation methodology was to produce a reasonable method to allocate common costs  
and common plant by service and jurisdiction. The method ultimately proposed by Avista  
and approved by the state Commissions (Washington, Idaho, and Oregon) produced a  
reasonable allocation of common costs.

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<sup>51</sup> The Company regularly surveys each member of its Avista Corp Board of Directors to determine how much of each member's time while serving on the Board is devoted to activities not directly related to the operations of the Utility itself, so that costs may be appropriately assigned to utility and non-utility operations. Current Board of Directors survey results show a 90% assignment to utility, and 10% to non-utility.

1           **Q. Please explain when the Company began using the current**  
2 **methodology.**

3           A. The current method used for electric generation and transmission expenses  
4 and net plant investment was reviewed and supported by the Washington and Idaho  
5 Commission staffs in 1984. This methodology uses the production/transmission ratio for  
6 electric expense FERC Accounts 500 through 573, which is described further below.

7           The current method for all other expenses (expense FERC Accounts 580 through  
8 935) and net plant investment (i.e. excluding electric generation and transmission  
9 expenses and net plant investment), was developed and presented to the Commission  
10 staffs of Washington, Idaho and Oregon utility commissions for approval in 1993. The  
11 Company obtained approval letters from each jurisdiction and implemented the new  
12 utility codes and allocation methodology in 1994. This allocation methodology and the  
13 actual allocation of common costs using the factors computed using that methodology,  
14 have been provided in each general rate case filed by the Company in each of its  
15 jurisdictions since the method was implemented.

16           **Q. When did the Company begin using the current service and**  
17 **jurisdiction codes?**

18           A. The Company converted to the Oracle Financial System on January 1,  
19 2005. With the implementation of the Oracle Financial System, the two-digit alpha codes  
20 for service and jurisdiction were adopted. The allocation methodology did not change  
21 with the implementation of the Oracle Financial System, but only the account code  
22 labeling was changed.

1           **Q.     Would you please identify the service codes that are used?**

2           A.     Yes. The Company uses the following service codes:

3                     ED – Electric Direct

4                     GD – Gas Direct

5                     CD – Common Direct

6                     ZZ – No Service (Used for balance sheet accounts (FERC Accounts 100-

7                             399) that are not assigned to a service (i.e. cash, accounts payable, etc.)

8                             and non-utility accounts)

9  
10           **Q.     Would you please identify the jurisdiction codes that are used?**

11           A.     Yes. The Company uses the following jurisdiction codes:

12                     AA – Allocated All

13                     AN – Allocated North

14                     ID – Idaho

15                     MT – Montana

16                     OR – Oregon

17                     WA – Washington

18                     ZZ – No Jurisdiction (Used for balance sheet accounts (FERC Accounts

19                             100-399) that are not assigned to a jurisdiction (i.e. cash, accounts

20                             payable, etc.) and non-utility accounts)

21

22           **Q.     Would you please summarize the assignment and utility**  
23 **code/allocation method currently in use for costs?**

24           A.     Yes. To begin with, revenues, operating costs and plant are directly  
25 assigned to services and jurisdictions whenever possible.

26                     As explained earlier, for those costs not directly assigned, the costs are allocated  
27 using a variety of allocation factors. The Company annually computes the allocation  
28 factors using actual direct costs and other data points (i.e. customer counts, customer  
29 usage, etc.). Updating the factors with current data on an annual basis is appropriate so  
30 that growth in each jurisdiction is factored into the current year allocation. When the

1 factors are updated annually, the factors are reviewed to identify any unusual trends or  
2 unexpected shifts in costs.

3 **Q. Would you describe the various types of allocation factors used by the**  
4 **Company?**

5 A. Yes. The Company uses primarily three different types of allocation  
6 factors, including:

7 a) Allocation factors that are used to allocate common costs and are  
8 comprised of an equal weighting of four factors, and are therefore called  
9 “4-factors”. The four factors are (1) direct O&M and A&G costs,  
10 excluding labor and resource costs, (2) direct O&M and A&G labor, (3)  
11 number of customers, and (4) net direct plant.

12 b) Allocation factors that use one data point (i.e. customer count or directly  
13 assigned distribution costs, etc.)

14 c) Allocation factors specific to electric costs or natural gas costs. These  
15 factors are the Production/Transmission (P/T) ratio for electric service and  
16 the System Contract Demand ratio for natural gas service, which are  
17 described below.

18 **Allocation Factors**

19 **Allocation of Electric Production and Transmission Costs and Plant**

20 **Q. Would you please summarize the P/T ratio computation that is**  
21 **currently used to allocate electric generation and transmission costs and plant**  
22 **between Washington and Idaho?**

1           A.     Yes. The Company annually computes an allocation factor, called the P/T  
2 ratio (production/transmission ratio) using the previous year's actual usage amounts for  
3 retail customer demand and energy consumption. The kilowatt demand figures are the  
4 coincident contributions of each jurisdiction to the Company's monthly system peak  
5 loads. The kilowatt-hour energy consumption represents the actual sales figures. Both  
6 demand and energy use ratios are weighted equally in arriving at the allocation factor.  
7 This is Factor 1 for electric service.

8           **Allocation of Natural Gas Underground Storage Costs and Plant**

9           **Q.     Would you please summarize the System Contract Demand ratio**  
10 **computation that is currently used to allocate natural gas underground storage costs**  
11 **and plant?**

12           A.     Yes. The Company annually computes the System Contract Demand  
13 allocation factor (also known as the five-day peak factor) using the actual therm  
14 throughput during the five consecutive days in the year with the highest throughput. The  
15 actual throughput for Washington and Idaho for this five-day period is averaged over  
16 three years, to determine the allocation of costs between Washington and Idaho. The  
17 Company directly assigns the O&M costs (FERC Account Nos. 824 and 837) of its share  
18 of the Jackson Prairie storage facility to Oregon and Natural Gas North Service, using the  
19 proportionate share of capacity assigned to each. Therefore, no further allocation of these  
20 costs to Oregon is required. This is Factor 1 for natural gas service.

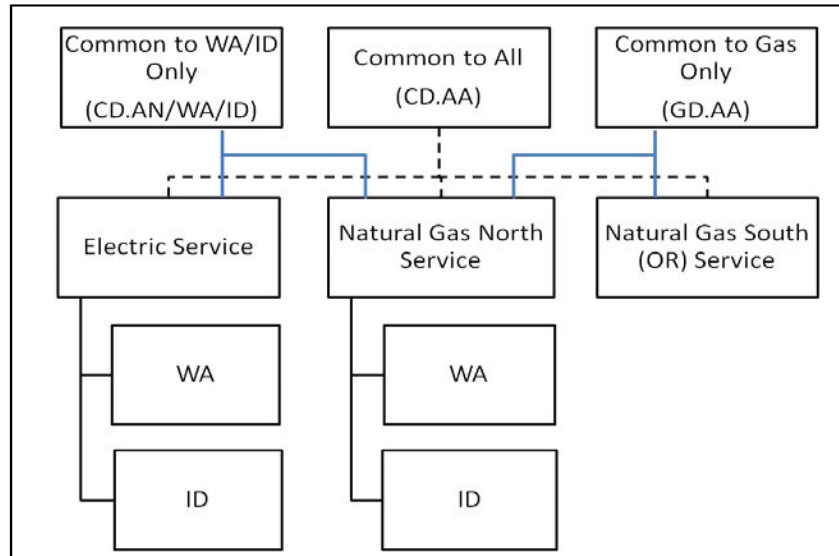
21

1 **Allocation of Common Costs**

2 **Q. Would you describe the allocation process used by the Company to**  
3 **allocate common costs?**

4 A. Yes. Illustration No. 4 below depicts the allocation of common costs.

5 **Illustration No. 4**



6  
7  
8  
9  
10  
11  
12  
13  
14 The allocation of common costs is a two-step process. The first step is to allocate  
15 the common costs to one of the three services: Electric, Natural Gas North or Natural Gas  
16 South.

17 Three different 4-factors are used to allocate the common costs to the three  
18 services. These 4-factors are used to allocate all common costs recorded in all FERC  
19 Accounts, except FERC Accounts 901-905 (Customer Accounts Expense), FERC  
20 Accounts 906-910 (Customer Service and Information Expense), and FERC Accounts  
21 911-917 (Sales Expenses). These costs in FERC Accounts 901 through 917 are heavily

1 influenced by the number of customers, and therefore, it is more appropriate to allocate  
2 these common costs using the number of customers.

3 The three 4-factors that are used to allocated common costs to services follows:

4 • Factor 7 (CD.AA) – Factor used to allocate common costs to all services,  
5 including Electric, Natural Gas North and Natural Gas South. The 4-factor  
6 is developed using the following data:

7 (1) Direct O&M and A&G costs, excluding labor and resource costs,  
8 that are assigned to electric service, natural gas North service and  
9 natural gas South service.

10 (2) Direct O&M and A&G labor that are assigned to electric service,  
11 natural gas North service and natural gas South service.

12 (3) Number of customers for electric service, natural gas North service  
13 and natural gas South service.

14 (4) Net direct plant that is assigned to electric service, natural gas  
15 North service and natural gas South service.

16  
17 • Factor 8 (GD.AA) – Factor used to allocate common natural gas costs to  
18 natural gas services, including Natural Gas North and Natural Gas South.

19 The 4-factor is developed using the following data:

20 (1) Direct O&M and A&G costs, excluding labor and resource costs,  
21 that are assigned to natural gas North service and natural gas South  
22 service.

23 (2) Direct O&M and A&G labor that are assigned to natural gas North  
24 service and natural gas South service.

25 (3) Number of customers for natural gas North service and natural gas  
26 South service.

27 (4) Net direct plant that is assigned to natural gas North service and  
28 natural gas South service.

29  
30 • Factor 9 (CD.AN) – Factor used to allocate costs common in Washington  
31 and Idaho to Electric service and Natural Gas North service. The 4-factor  
32 is developed using the following data:



- 1 (1) Direct O&M and A&G costs, excluding labor and resource costs,
- 2 that are assigned to electric service and natural gas North service.
- 3 (2) Direct O&M and A&G labor that are assigned to electric service
- 4 and natural gas North service.
- 5 (3) Number of customers for electric service and natural gas North
- 6 service.
- 7 (4) Net direct plant that is assigned to electric service and natural gas
- 8 North service.
- 9

10 These factors at June 30, 2013, used in this filing, are shown in Table No. 3  
11 below:

**Table No. 3**

Factor	Service Code	Jurisdiction Code	Allocation Percentages		
			Electric	Natural Gas North	Natural Gas South
Factor 7	CD	AA	72.346%	19.401%	8.253%
Factor 8	GD	AA	0.000%	70.320%	29.680%
Factor 9	CD	AN/WA/ID	79.221%	20.779%	0.000%
Customer Ratio of Factor 7	CD	AA	52.888%	33.009%	14.103%
Customer Ratio of Factor 8	GD	AA	0.000%	70.065%	29.935%
Customer Ratio of Factor 9	CD	AN/WA/ID	61.572%	38.428%	0.000%

18 The second step is to allocate the common operating costs for Electric and Natural  
19 Gas North to the appropriate jurisdiction (Washington or Idaho).

20 These costs are allocated using the jurisdictional allocation factors, including:

- 21 • P/T ratio (Electric Factor 1), which was described above.
- 22 • System Contract Demand ratio (Natural Gas Factor 1), which was
- 23 described above.
- 24 • Factor 2 (Number of Customers) – For both electric service and natural gas
- 25 North service, Washington and Idaho’s proportional share of total electric
- 26 customers and total natural gas North customers are used to assign certain
- 27 costs, as described below.

- 1           • Factor 3 (Directly-Assigned Distribution Costs) - For both electric and  
2           natural gas North service, Washington and Idaho’s proportional share of  
3           total actual directly assigned distribution O&M expenses are used to assign  
4           certain costs, as described below.
- 5           • Factor 4 (Electric Common Costs) - Factor used to allocate common  
6           electric service costs to Washington and Idaho. The 4-factor is developed  
7           using the following data:
- 8                     (1) Direct O&M and A&G costs, excluding labor and resource costs,  
9                     that are assigned to Washington and Idaho electric service.  
10                    (2) Direct O&M and A&G labor that are assigned to Washington and  
11                    Idaho electric.  
12                    (3) Number of customers for Washington and Idaho electric.  
13                    (4) Net direct plant that is assigned to Washington and Idaho electric  
14                    service.
- 15
- 16           • Factor 4 (Natural Gas Common Costs) - Factor used to allocate common  
17           natural gas North service costs to Washington and Idaho. The 4-factor is  
18           developed using the following data:
- 19                    (1) Direct O&M and A&G costs, excluding labor and resource costs,  
20                    that are assigned to Washington and Idaho natural gas North service.  
21                    (2) Direct O&M and A&G labor that are assigned to Washington and  
22                    Idaho natural gas North service.  
23                    (3) Number of customers for Washington and Idaho natural gas North  
24                    service.  
25                    (4) Net direct plant that is assigned to Washington and Idaho natural  
26                    gas North service.
- 27
- 28           • Factor 10 (Natural Gas Actual Annual Throughput) – For natural gas  
29           North service, Washington and Idaho’s proportional share of total actual  
30           annual therm throughput are used to assign certain costs, as described  
31           below.

1  
2           These factors at June 30, 2013, used in this filing for both electric and natural gas  
3 operations, are shown in Table No. 4 below:

**Table No. 4**

<b>Factors</b>	<b>Service Code</b>	<b>Jurisdiction Code</b>	<b>Allocation Percentages</b>	
			<b>Washington</b>	<b>Idaho</b>
<b>Electric:</b>				
PT Ratio (Electric Factor 1)	ED	AN	65.010%	34.990%
Customer Ratio (Factor 2)	ED	AN	65.618%	34.382%
Direct Distribution Costs (Factor 3)	ED	AN	66.932%	33.068%
Common Factor (Electric Factor 4)	ED	AN	67.000%	33.000%
<b>Natural Gas:</b>				
System Contract Demand Ratio (Nat. Gas Factor 1)	GD	AN	69.990%	30.010%
Customer Ratio (Factor 2)	GD	AN	66.411%	33.589%
Direct Distribution Costs (Factor 3)	GD	AN	70.462%	29.538%
Common Factor (Nat. Gas Factor 4)	GD	AN	70.603%	29.397%
Actual Annual Throughput Ratio (Factor 10)	GD	AN	69.163%	30.837%

12           These allocation factors are applied in a jurisdictional allocation model outside of  
13 the general ledger system. This model produces the monthly Results of Operations  
14 reports. Washington’s Results of Operations reports as of June 30, 2013 have been  
15 provided with my workpapers at Section 1.00 for both electric and natural gas.  
16 Additional workpapers supporting the allocations described above are provided as  
17 Andrews Workpapers (Part 3), both in hard copy and electronic formats.

18 **Allocation Methodology**

19           **Q.     Would you describe for electric service for each income statement and**  
20 **rate base FERC account the allocation method that is used by the Company and a**  
21 **brief explanation of how the use of that factor produces a reasonable allocation of**  
22 **costs?**

1           A.     Yes. For electric operations, Table No. 5 below summarizes the various  
2 factors that are used for each FERC account.

**Table No. 5:**

Line Description Income Statement	FERC Accounts	Allocation Method to Electric/Natural Gas	Allocation Method to State
1) Sales to Customers	440-446, 448, 499	Direct Assignment	Direct Assignment
2) Other Sales, including Sales for Resale, Rent, etc.	447, 451-456	Direct Assignment	PT Ratio (Electric Factor 1)
3) Generation O&M - Steam Power	500-514	Direct Assignment	PT Ratio (Electric Factor 1)
4) Generation O&M - Hydro	535-545	Direct Assignment	PT Ratio (Electric Factor 1)
5) Generation O&M - Other Generation	546-554	Direct Assignment	PT Ratio (Electric Factor 1)
6) Other Power Supply (i.e. Purchased Power)	555-557	Direct Assignment	Direct Assignment or PT Ratio (Electric Factor 1)
7) Transmission O&M	560-573	Direct Assignment	PT Ratio (Electric Factor 1)
8) Distribution O&M	580-598	Direct Assignment	Direct Assignment or Factor 3 (Directly-Assigned Distribution Costs)
9) A&G - Customer Accounts Expenses	901-905	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
10) A&G - Customer Service and Info Expenses	908-910	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
11) A&G - Sales Expenses	912-916	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
12) A&G - Other Expenses	920-927, 930-935	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
13) A&G - Regulatory Expenses	928	Factors 7, 8 & 9 (Common Factor)	PT Ratio (Electric Factor 1)
14) Depreciation and Amortization - Generation	403-404	Direct Assignment	PT Ratio (Electric Factor 1)
15) Depreciation and Amortization - Transmission	403-404	Direct Assignment	PT Ratio (Electric Factor 1)
16) Depreciation and Amortization - Distribution	403-404	Direct Assignment	Direct Assignment
17) Depreciation and Amortization - General	403-404	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
18) Regulatory Amortizations	407	Direct Assignment	Direct Assignment or PT Ratio (Electric Factor 1)
<b>Rate Base</b>			
19) Intangible Plant and A/D	101, 108-111	Direct Assignment and Factors 7, 8 & 9 (Common Factor)	PT Ratio (Electric Factor 1) or Factor 4 (Common Factor)
20) Generation Plant and A/D	101, 108-111	Direct Assignment	PT Ratio (Electric Factor 1)
21) Transmission Plant and A/D	101, 108-111	Direct Assignment	PT Ratio (Electric Factor 1)
22) Distribution Plant and A/D	101, 108-111	Direct Assignment	Direct Assignment
23) General Plant and A/D	101, 108-111	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
24) Regulatory Deferred Assets and Liabilities	182, 186	Direct Assignment	Direct Assignment
25) Working Capital	ISWC	Investor Supplied Allocation	Investor Supplied Allocation

19           Lines 1 through 7 – Customer revenues, generation O&M costs, power supply  
20 costs and transmission O&M costs are directly assigned to electric service in the general  
21 ledger. Revenues are primarily directly assigned to the states. The costs are either  
22 directly assigned to Washington and Idaho or are allocated to Washington and Idaho

1 electric service using the P/T ratio. As discussed above, the P/T ratio is an equal  
2 weighting of actual usage amounts for retail customer demand and energy consumption.  
3 Since the P/T ratio is derived from actual sales data in each state, the use of the P/T ratio  
4 to allocate these costs produces a matching of costs with the revenues.

5 Line 8 – Distribution costs are directly assigned in the general ledger to electric  
6 service. The majority of costs are also directly assigned to Washington and Idaho. For  
7 those costs not directly assigned, the Company allocates the common distribution costs  
8 using the ratio of directly assigned distribution costs incurred in each state in comparison  
9 to the total.

10 Lines 9 through 11 – Customer count is one component of the 4-factors. Rather  
11 than using the over-all 4-factors (Factors 7, 8 and 9) to allocate the common costs to  
12 electric service for common portions of FERC Accounts 901-905 (Customer Accounts  
13 Expense), FERC Accounts 906-910 (Customer Service and Information Expense), and  
14 FERC Accounts 911-917 (Sales Expenses), the Company uses the customer component  
15 ratio of the 4-factors. These costs in these FERC accounts are heavily influenced by the  
16 number of customers, and therefore, the ratio based on customers is more appropriate to  
17 allocate the costs to electric and natural gas service than the over-all 4-factor. Using the  
18 same reasoning, the Company uses Factor 2 (Customer Ratio) to allocate the common  
19 electric costs to Washington and Idaho.

20 Line 12 - FERC Accounts 920-927 and 930-935 (Administrative and General)  
21 include various A&G costs, including salaries, office supplies and expenses, outside  
22 services, maintenance of common general plant, etc. The over-all 4-factor allocators

1 (Factors 7, 8 and 9) are used to allocate the common costs to electric service and the over-  
2 all 4-factor allocator (Factor 4) is used to allocate the common electric costs to  
3 Washington and Idaho. These costs are not influenced by any one factor, so the use of the  
4 over-all 4-factor that is equally weighted with customers, direct labor, other non-labor  
5 O&M and A&G direct costs and net direct plant, produces a reasonable allocation of  
6 common costs.

7 Line 13 – FERC Accounts 928 (Regulatory Commission expenses) include state  
8 and FERC fees that are based on revenues, in addition to other A&G expenses of the  
9 State and Federal Regulation department. The Company directly assigns the fees to  
10 electric service. For the state commission fees, the Company directly assigns the fees  
11 paid to each state to the appropriate state. For the FERC fees, the Company uses the P/T  
12 ratio to allocate the fees to Washington and Idaho. Since these fees are based on  
13 revenues, the use of the P/T ratio to allocate the fees produces the best matching of costs  
14 with revenues in each state. For the other common A&G expenses of the State and  
15 Federal Regulation department, the over-all 4-factors are used to allocate to electric  
16 service (Factors 7, 8 and 9).

17 Lines 14 through 15 – Depreciation and amortization expense of generation and  
18 transmission property are allocated using the same methodology as the generation and  
19 transmission O&M costs, described above for lines 1 through 7.

20 Line 16 – Depreciation and amortization expense of electric distribution property  
21 are all directly assigned.

1           Line 17 – Depreciation and amortization expense of general plant are allocated  
2 using the same methodology as the Administrative and General costs, described above for  
3 line 12.

4           Line 18 – FERC Accounts 407 (Regulatory Amortizations) are primarily directly  
5 assigned to the state where the deferral of costs originated. However, for electric service,  
6 there are deferrals that were approved in both Washington and Idaho related to the Coeur  
7 d’ Alene Tribe Settlement (CDA Settlement) in 2008 that were recorded as a common  
8 electric deferral that is allocated to Washington and Idaho using the P/T ratio. The CDA  
9 Settlement relates to the use of the land for Avista’s hydro generating facilities.  
10 Therefore, the P/T ratio is appropriate to allocate these costs.

11           Line 19 – Intangible plant accounts and associated accumulated depreciation  
12 (A/D) accounts include two groups of plant: 1) general intangible plant, like software, and  
13 2) the CDA Settlement costs that were recorded as plant in 2008. The CDA Settlement  
14 costs are all directly assigned to electric service. General intangible plant and A/D is  
15 allocated to electric using the 4-factors (Factors 7, 8 and 9). The CDA Settlement costs  
16 are allocated to Washington and Idaho using the P/T ratio, using the same reasoning as  
17 describe in Line 18 above. General intangible plant and A/D is allocated to Washington  
18 and Idaho using the 4-factors (Factor 4). The amount of intangible plant, like software, is  
19 not directly influenced by just one factor, like customers; therefore the over-all 4-factors  
20 are used as a reasonable basis to allocate the rate base.

21           Lines 20-21 – Generation and transmission plant and associated A/D are directly  
22 assigned to electric service. Consistent with generation and transmission O&M costs and

1 depreciation expenses, the rate base is allocated to Washington and Idaho using the P/T  
2 ratio.

3 Line 22 - Distribution plant and associated A/D are directly assigned to electric  
4 service and to each state.

5 Line 23 – General plant includes structures and improvements, office furniture,  
6 power operated equipment and transportation vehicles, etc. General plant and A/D is  
7 allocated to electric using the 4-factors (Factors 7, 8 and 9). General plant and A/D is  
8 allocated to Washington and Idaho using the 4-factors (Factors 4). The amount of general  
9 plant is not directly influenced by just one factor, like customers; therefore the over-all 4-  
10 factors are used as a reasonable basis to allocate the rate base.

11 Line 24 – Regulatory deferred assets and liabilities are all directly assigned to  
12 electric service and to each state that approved the deferral.

13 Line 25 – Working capital is computed using the investor supplied working  
14 capital (ISWC) method. Each balance sheet account is categorized. The remaining  
15 accounts (primarily non-earning short-term assets and liabilities) are allocated to service  
16 and states by the types of activity in each account. A variety of the allocation factors are  
17 used depending on the types of activity.

18 **Q. Would you describe for natural gas service for each income statement**  
19 **and rate base FERC account the allocation method that is used by the Company and**  
20 **a brief explanation of how the use of that factor produces a reasonable allocation of**  
21 **costs?**



1           A.     For natural gas North operations, Table No. 6 below summarizes the  
2 various factors that are used for each FERC account.

**Table No. 6**

<b>Line Description</b>	<b>FERC Accounts</b>	<b>Allocation Method to Electric/Natural Gas</b>	<b>Allocation Method to State</b>
<b>Income Statement</b>			
1) Sales to Customers	480-484, 499	Direct Assignment	Direct Assignment
2) Other Sales, including Sales for Resale, Rent, etc.	483, 488-495	Direct Assignment	Direct Assignment or Factor 4 (Common Factor)
3) Production Expenses	804-813	Direct Assignment	Direct Assignment or Actual Annual Throughput Ratio (Nat. Gas Factor 10)
4) Underground Storage	814-837	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)
5) Distribution O&M	870-894	Direct Assignment	Direct Assignment or Factor 3 (Directly-Assigned Distribution Costs)
6) A&G - Customer Accounts Expenses	901-905	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
7) A&G - Customer Service and Info Expenses	908-910	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
8) A&G - Sales Expenses	912-916	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
9) A&G - Other Expenses	920-927, 930-935	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
10) A&G - Regulatory Expenses	928	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
11) Depreciation and Amortization - U/G Storage	403-404	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)
12) Depreciation and Amortization - Distribution	403-404	Direct Assignment	Direct Assignment
13) Depreciation and Amortization - General	403-404	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
14) Regulatory Amortizations	407	Direct Assignment	Direct Assignment
<b>Rate Base</b>			
15) Intangible Plant and A/D	101, 108-111	Direct Assignment and Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
16) U/G Storage Plant and A/D	101, 108-111	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)
17) Distribution Plant and A/D	101, 108-111	Direct Assignment	Direct Assignment
18) General Plant and A/D	101, 108-111	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
19) Regulatory Deferred Assets and Liabilities	182, 186	Direct Assignment	Direct Assignment
20) Working Capital	ISWC	Investor Supplied Allocation	Investor Supplied Allocation
21) Gas Inventory	117, 164	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)

19           Lines 1 through 2 – Customer revenues and other revenues are directly assigned to  
20 natural gas service in the general ledger. Revenues are primarily directly assigned to the  
21 states. There are other revenues that are allocated to Washington and Idaho natural gas  
22 service using the over-all 4-factor allocator (Factor 4). These other revenues are not

1 influenced by any one factor, so the use of the over-all 4-factor that is equally weighted  
2 with customers, direct labor, other non-labor O&M and A&G direct costs and net direct  
3 plant, produces a reasonable allocation of common revenues.

4 Line 3 – Production expenses, including natural gas purchases are directly  
5 assigned to natural gas service in the general ledger. The majority of these costs are  
6 directly assigned to Washington and Idaho using the actual sales data for each month. A  
7 small amount of the costs are allocated using the prior year’s actual annual throughput  
8 (Factor 10). Since all of these costs are allocated using actual sales data in each state, the  
9 use of these ratios to allocate these costs produces a matching of costs with the revenues.

10 Line 4 – Underground storage costs are directly assigned in the general ledger to  
11 natural gas service. The costs are allocated to Washington and Idaho using the System  
12 Contract Demand ratio. As described above, this ratio is the average of the highest 5  
13 consecutive days of throughput for a 3-year period.

14 Line 5 - Distribution costs are directly assigned in the general ledger to natural gas  
15 service. The majority of costs are also directly assigned to Washington and Idaho. For  
16 those costs not directly assigned, the Company allocates the common distribution costs  
17 using the ratio of directly assigned distribution costs incurred in each state in comparison  
18 to the total.

19 Lines 6 through 8 - Customer count is one component of the 4-factors. Rather  
20 than using the over-all 4-factors (Factors 7, 8 and 9) to allocate the common costs to  
21 natural gas service for common portions of FERC Accounts 901-905 (Customer Accounts  
22 Expense), FERC Accounts 906-910 (Customer Service and Information Expense), and

1 FERC Accounts 911-917 (Sales Expenses), the Company uses the customer component  
2 ratio of the 4-factors. These costs in these FERC accounts are heavily influenced by the  
3 number of customers, and therefore, the ratio based on customers is more appropriate to  
4 allocate the costs to electric and natural gas service than the over-all 4-factor. Using the  
5 same reasoning, the Company uses Factor 2 (Customer Ratio) to allocate the common  
6 natural gas costs to Washington and Idaho.

7 Line 9 - FERC Accounts 920-927 and 930-935 (Administrative and General)  
8 include various A&G costs, including salaries, office supplies and expenses, outside  
9 services, maintenance of common general plant, etc. The over-all 4-factor allocators  
10 (Factors 7, 8 and 9) are used to allocate the common costs to natural gas service and the  
11 over-all 4-factor allocator (Factor 4) is used to allocate the common natural gas costs to  
12 Washington and Idaho. These costs are not influenced by any one factor, so the use of the  
13 over-all 4-factor that is equally weighted with customers, direct labor, other non-labor  
14 O&M and A&G direct costs and net direct plant, produces a reasonable allocation of  
15 common costs.

16 Line 10 – FERC Accounts 928 (Regulatory Commission expenses) include state  
17 fees that are based on revenues, in addition to other A&G expenses of the State and  
18 Federal Regulation department. The Company directly assigns the fees to natural gas  
19 service. For the state commission fees, the Company directly assigns the fees paid to each  
20 state to the appropriate state. For the other common A&G expenses of the State and  
21 Federal Regulation department, the over-all 4-factors are used to allocate to natural gas  
22 service (Factors 7, 8 and 9).

1           Line 11 – Depreciation and amortization expense of underground storage property  
2 are allocated using the same methodology as the underground storage costs, described  
3 above for line 4.

4           Line 12 – Depreciation and amortization expense of natural gas distribution  
5 property are all directly assigned.

6           Line 13 – Depreciation and amortization expense of general plant are allocated  
7 using the same methodology as the Administrative and General costs, described above for  
8 line 9.

9           Line 14 – FERC Accounts 407 (Regulatory Amortizations) are primarily directly  
10 assigned to the state where the deferral of costs originated.

11           Line 15 – Intangible plant accounts and associated accumulated depreciation  
12 (A/D) accounts includes general intangible plant, like software. General intangible plant  
13 and A/D is allocated to natural gas service using the 4-factors (Factors 7, 8 and 9).  
14 General intangible plant and A/D is allocated to Washington and Idaho using the 4-factors  
15 (Factors 4). The amount of intangible plant, like software, is not directly influenced by  
16 just one factor, like customers; therefore the over-all 4-factors are used as a reasonable  
17 basis to allocate the rate base.

18           Line 16 – Underground storage plant and associated A/D are directly assigned to  
19 natural gas service. Consistent with underground storage costs and depreciation  
20 expenses, the rate base is allocated to Washington and Idaho using the System Contract  
21 Demand ratio.

1 Line 17 - Distribution plant and associated A/D are directly assigned to natural gas  
2 service and to each state.

3 Line 18 - General plant includes structures and improvements, office furniture,  
4 power operated equipment and transportation vehicles, etc. General plant and A/D is  
5 allocated to natural gas using the 4-factors (Factors 7, 8 and 9). General plant and A/D is  
6 allocated to Washington and Idaho using the 4-factors (Factors 4). The amount of general  
7 plant is not directly influenced by just one factor, like customers; therefore the over-all 4-  
8 factors are used as a reasonable basis to allocate the rate base.

9 Line 19 – Regulatory deferred assets and liabilities are all directly assigned to  
10 natural gas and each state that approved the deferral.

11 Line 20 – Working capital is computed using the investor supplied working  
12 capital (ISWC) method. Each balance sheet account is categorized. The remaining  
13 accounts (primarily non-earning short-term assets and liabilities) are allocated to service  
14 and states by the types of activity in each account. A variety of the allocation factors are  
15 used depending on the types of activity.

16 Line 21 – Natural gas inventory is directly assigned to natural gas service in the  
17 general ledger. The costs are allocated to Washington and Idaho using the System  
18 Contract Demand ratio. This method is consistent with the method used to allocate  
19 underground storage costs, as described in Line 4 above.

20 **Summary**

21 **Q. What portion of Washington’s costs are allocated in the test period?**

1           A.     A summary of the costs for the test period (twelve months ended June 30,  
2     2013) is provided in Table No. 7 below.

**Table No. 7**

<b>Operating Costs</b>						
<b>For the Twelve Months Ended June 30, 2013</b>						
(\$000's)						
	WA Electric			WA Natural Gas		
	<u>Direct</u>	<u>Allocated</u>	<u>Total</u>	<u>Direct</u>	<u>Allocated</u>	<u>Total</u>
Power Supply/Generation & Transmission/Production/Underground Storage	\$ 11,347	\$ 395,045	\$ 406,392	\$ 136,095	\$ 2,045	\$ 138,140
O&M Distribution	15,401	5,734	21,135	7,898	2,758	10,656
Depreciation and Amortization	23,092	12,007	35,099	7,649	3,228	10,877
Administrative and General	20,336	50,347	70,683	8,588	16,265	24,853
Taxes other than Income Taxes	39,617	-	39,617	12,532	-	12,532
Total Other Costs	98,446	68,088	166,534	36,667	22,251	58,918
<b>Total</b>	<b>\$ 109,793</b>	<b>\$ 463,133</b>	<b>\$ 572,926</b>	<b>\$ 172,762</b>	<b>\$ 24,296</b>	<b>\$ 197,058</b>

13           Excluding the allocated power supply, generation and transmission costs that are  
14     allocated using the P/T ratio, the Company has allocated \$68,088,000 of costs to  
15     Washington electric service. This represents approximately 14% of total electric costs  
16     (\$68,088/\$572,926) that have been allocated to Washington electric service. Excluding  
17     the costs that are allocated using the P/T ratio, this represents approximately 41% of non-  
18     generation, transmission and power supply costs are allocated for electric service in  
19     Washington (\$68,088/\$166,534).

20           Excluding the allocated production and underground storage costs, the Company  
21     has allocated \$22,251,000 of costs to Washington natural gas service. This represents  
22     approximately 11% of total natural gas costs (\$22,251/\$197,058) that have been allocated

1 to Washington natural gas service. Excluding production and underground storage costs,  
2 this represents approximately 38% of non-production costs and underground storage costs  
3 are allocated for natural gas service in Washington (\$22,251/\$58,918).

4 **Q. What portion of Washington’s plant costs are allocated in the test**  
5 **period?**

6 A. A summary of plant costs for the test period (June 30, 2013 AMA basis) is  
7 provided in Table No. 8 below.

**Table No. 8**

Plant Costs						
Average of Monthly Averages at June 30, 2013						
(\$000's)						
	WA Electric			WA Natual Gas		
	<u>Direct</u>	<u>Allocated</u>	<u>Total</u>	<u>Direct</u>	<u>Allocated</u>	<u>Total</u>
Generation & Transmission/Underground Storage	\$ -	\$ 1,108,341	\$ 1,108,341	\$ -	\$ 24,503	\$ 24,503
Distribution	768,726	-	768,726	300,048	1,792	301,840
Intangible	2,762	52,535	55,296	965	7,282	8,247
General Plant	46,573	118,765	165,338	13,945	24,818	38,764
Total Other	<u>818,061</u>	<u>171,300</u>	<u>989,360</u>	<u>314,958</u>	<u>33,892</u>	<u>348,851</u>
Total	<u>\$ 818,061</u>	<u>\$ 1,279,641</u>	<u>\$ 2,097,701</u>	<u>\$ 314,958</u>	<u>\$ 58,395</u>	<u>\$ 373,354</u>

16  
17 Excluding the allocated generation and transmission plant investment that are  
18 allocated using the P/T ratio, the Company has allocated \$171,300,000 of plant costs to  
19 Washington electric service. This represents approximately 8% of total electric plant  
20 costs (\$171,300/\$2,097,701) that have been allocated to Washington electric service.  
21 Excluding the costs that are allocated using the P/T ratio, this represents approximately  
22 17% of non-generation, transmission and power supply costs are allocated for electric

1 service in Washington (\$171,300/\$989,360). Therefore, approximately 83% of non-  
2 generation and transmission plant costs are directly assigned for electric service in  
3 Washington.

4 Excluding the allocated underground storage plant, the Company has allocated  
5 \$33,892,000 of plant costs to Washington natural gas service. This represents  
6 approximately 9% of total natural gas plant costs (\$33,892/\$373,354) that have been  
7 allocated to Washington natural gas service. Excluding the underground storage plant  
8 this represents approximately 10% of non-underground storage plant costs are allocated  
9 for natural gas service in Washington (\$33,892/\$348,851). Therefore, approximately  
10 90% of non-underground storage plant costs are directly assigned for natural gas service  
11 in Washington.

12 **Q. In summary, do you believe the allocation methodology used today by**  
13 **the Company is appropriate for allocating common costs?**

14 A. Yes, I do. We believe the method used by Avista produces a reasonable  
15 allocation of costs. The allocation factors are derived using actual, directly assigned costs  
16 and other actual data points that are updated annually with current data, so growth in each  
17 service or jurisdiction is factored into the current year allocation. It has been reviewed  
18 and accepted by all jurisdictions in which Avista serves and remains a sound, rational  
19 basis for allocating costs.

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

21 A. Yes, it does.

22



**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/12/2015
CASE NO.:	UG 239	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Ordonez	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 239	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

**REQUEST:**

For each of the officers listed by the Company in confidential file MS Excel file “Staff\_DR\_175C Confidential Attachment A,” where Avista provided the amounts directly assigned by the Company’s officers to non-utility operations or subsidiaries,<sup>1</sup> please:

- a. Provide the total compensation received by such officer for each year of the period beginning in 2012 through 2014; then break down the requested total compensation into two categories: utility operations and non-utility operations or subsidiaries;
- b. Reconcile each officer’s compensation that was directly assigned for non-utility operations or subsidiaries as part of question “a” of this data request, with the information provided in MS Excel file “Staff\_DR\_175C Confidential Attachment A”; if there is any difference in the requested reconciliation, please explain;

**RESPONSE:**

Please see the Company’s response in Staff\_DR\_239C for the requested information.  
Staff\_DR\_239C is **CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER.**

Please see Staff\_DR\_239C Confidential Attachment A for total direct compensation for the Company’s executive officers by FERC account and expenditure type (including notations of which expenses are non-utility operations). The amount of compensation for non-utility operations ties to the amounts provided in the Company’s response to Staff\_DR\_175C Confidential Attachment A.

<sup>1</sup> By “non-utility” operations or subsidiaries, Staff means the operations or subsidiaries to which the Company directly assigned the costs provided in confidential file MS Excel file “Staff\_DR\_175C Confidential Attachment A,” worksheet “Labor”. In other words, “all costs recorded for Avista subsidiaries and for costs recorded by Avista Corp. for subsidiary report” as referred in the Company response to Staff DR175, part “c”.

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## CONSOLIDATED STATEMENTS OF INCOME

*Avista Corporation*

For the Years Ended December 31

Dollars in thousands, except per share amounts

	2013	2012	2011
<b>Operating Revenues:</b>			
Utility revenues	\$ 1,402,195	\$ 1,352,385	\$ 1,441,522
Ecova revenues	176,761	155,664	137,848
Other non-utility revenues	39,549	38,953	40,410
Total operating revenues	<u>1,618,505</u>	<u>1,547,002</u>	<u>1,619,780</u>
<b>Operating Expenses:</b>			
Utility operating expenses:			
Resource costs	689,586	693,127	790,048
Other operating expenses	276,228	276,780	261,926
Depreciation and amortization	117,174	112,091	105,629
Taxes other than income taxes	88,435	83,409	83,347
Ecova operating expenses:			
Other operating expenses	148,023	139,173	109,738
Depreciation and amortization	15,434	13,519	7,193
Other non-utility operating expenses:			
Other operating expenses	38,651	38,041	33,117
Depreciation and amortization	581	792	778
Total operating expenses	<u>1,374,112</u>	<u>1,356,932</u>	<u>1,391,776</u>
Income from operations	244,393	190,070	228,004
Interest expense	78,755	76,894	73,876
Interest expense to affiliated trusts	467	541	332
Capitalized interest	(3,676)	(2,401)	(2,942)
Other income-net	(6,677)	(5,025)	(3,433)
Income before income taxes	175,524	120,061	160,171
Income tax expense	63,230	41,261	56,632
Net income	112,294	78,800	103,539
Less: Net income attributable to noncontrolling interests	(1,217)	(590)	(3,315)
Net income attributable to Avista Corporation shareholders	<u>\$ 111,077</u>	<u>\$ 78,210</u>	<u>\$ 100,224</u>
Weighted-average common shares outstanding (thousands), basic	59,960	59,028	57,872
Weighted-average common shares outstanding (thousands), diluted	59,997	59,201	58,092
<b>Earnings per common share attributable to Avista Corporation shareholders:</b>			
Basic	\$ 1.85	\$ 1.32	\$ 1.73
Diluted	<u>\$ 1.85</u>	<u>\$ 1.32</u>	<u>\$ 1.72</u>

*The Accompanying Notes are an Integral Part of These Statements.*

**AVISTA CORPORATION****NOTE 6. JOINTLY OWNED ELECTRIC FACILITIES**

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income. The Company's share of utility plant in service for Colstrip and accumulated depreciation were as follows as of December 31 (dollars in thousands):

	2013	2012
Utility plant in service	\$ 349,781	\$ 344,958
Accumulated depreciation	(239,538)	(234,126)

**NOTE 7. PROPERTY, PLANT AND EQUIPMENT**

The balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in thousands):

	2013	2012
Avista Utilities:		
Electric production	\$ 1,141,790	\$ 1,112,670
Electric transmission	569,056	546,019
Electric distribution	1,284,428	1,217,827
Electric construction work-in-progress (CWIP) and other	276,582	244,761
Electric total	3,271,856	3,121,277
Natural gas underground storage	41,248	40,890
Natural gas distribution	762,044	704,839
Natural gas CWIP and other	47,751	57,745
Natural gas total	851,043	803,474
Common plant (including CWIP)	327,888	272,991
Total Avista Utilities	4,450,787	4,197,742
Ecova (1)	31,865	30,138
Other (1)	20,132	22,690
Total	\$ 4,502,784	\$ 4,250,570

- (1) Included in other property and investments-net on the Consolidated Balance Sheets. Accumulated depreciation was \$26.4 million as of December 31, 2013 and \$23.4 million as of December 31, 2012 for Ecova and \$11.4 million as of December 31, 2013 and \$13.7 million as of December 31, 2012 for the other businesses. The decrease in accumulated depreciation for the other businesses was due to the retirement of a fully depreciated asset during 2013.

**NOTE 8. ASSET RETIREMENT OBLIGATIONS**

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. Upon retirement of the asset, the Company either settles the retirement obligation for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and asset retirement obligations recorded since asset retirement costs are recovered through rates charged to customers. The regulatory assets do not earn a return.

Specifically, the Company has recorded liabilities for future asset retirement obligations to:

- restore ponds at Colstrip,
- cap a landfill at the Kettle Falls Plant,
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease,
- remove asbestos at the corporate office building, and
- dispose of PCBs in certain transformers.

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## CONSOLIDATED STATEMENTS OF INCOME

*Avista Corporation*

For the Years Ended December 31

Dollars in thousands, except per share amounts

	2014	2013	2012
<b>Operating Revenues:</b>			
Utility revenues	\$ 1,433,343	\$ 1,402,195	\$ 1,352,385
Non-utility revenues	39,219	39,549	38,953
Total operating revenues	<u>1,472,562</u>	<u>1,441,744</u>	<u>1,391,338</u>
<b>Operating Expenses:</b>			
Utility operating expenses:			
Resource costs	678,244	689,586	693,127
Other operating expenses	286,832	276,228	276,780
Depreciation and amortization	129,570	117,174	112,091
Taxes other than income taxes	94,300	88,435	83,409
Non-utility operating expenses:			
Other operating expenses	30,418	38,651	38,041
Depreciation and amortization	610	581	792
Total operating expenses	<u>1,219,974</u>	<u>1,210,655</u>	<u>1,204,240</u>
Income from continuing operations	252,588	231,089	187,098
Interest expense	75,302	77,118	75,104
Interest expense to affiliated trusts	450	467	541
Capitalized interest	(3,924)	(3,676)	(2,401)
Other income-net	(11,346)	(5,167)	(2,713)
Income from continuing operations before income taxes	192,106	162,347	116,567
Income tax expense	72,240	58,014	39,764
Net income from continuing operations	119,866	104,333	76,803
Net income from discontinued operations (Note 5)	72,411	7,961	1,997
Net income	192,277	112,294	78,800
Net income attributable to noncontrolling interests	(236)	(1,217)	(590)
Net income attributable to Avista Corporation shareholders	<u>\$ 192,041</u>	<u>\$ 111,077</u>	<u>\$ 78,210</u>

*The Accompanying Notes are an Integral Part of These Statements.*



**AVISTA CORPORATION**

- energy marketing and trading companies.

In addition, the Company has concentrations of credit risk related to geographic location as it operates in the western United States and western Canada. These concentrations of counterparties and concentrations of geographic location may impact the Company's overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions.

The Company maintains credit support agreements with certain counterparties and margin calls are periodically made and/or received. Margin calls are triggered when exposures exceed contractual limits or when there are changes in a counterparty's creditworthiness. Price movements in electricity and natural gas can generate exposure levels in excess of these contractual limits. Negotiating for collateral in the form of cash, letters of credit, or performance guarantees is common industry practice.

**NOTE 7. JOINTLY OWNED ELECTRIC FACILITIES**

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income. The Company's share of utility plant in service for Colstrip and accumulated depreciation were as follows as of December 31 (dollars in thousands):

	2014	2013
Utility plant in service	\$ 350,518	\$ 349,781
Accumulated depreciation	(239,845)	(239,538)

**NOTE 8. PROPERTY, PLANT AND EQUIPMENT**

The balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in thousands):

	2014	2013
<b>Avista Utilities:</b>		
Electric production	\$ 1,171,002	\$ 1,141,790
Electric transmission	603,909	569,056
Electric distribution	1,360,185	1,284,428
Electric construction work-in-progress (CWIP) and other	311,807	276,582
Electric total	3,446,903	3,271,856
Natural gas underground storage	41,963	41,248
Natural gas distribution	810,487	762,044
Natural gas CWIP and other	57,088	47,751
Natural gas total	909,538	851,043
Common plant (including CWIP)	394,027	327,888
Total Avista Utilities	4,750,468	4,450,787
<b>Alaska Electric Light and Power Company:</b>		
Electric production	71,969	
Electric transmission	18,392	
Electric distribution	17,936	
Electric production held under long-term capital lease	71,007	
Electric CWIP and other	7,893	
Electric total	187,197	
Common plant	8,155	
Total Alaska Electric Light and Power Company	195,352	
<b>Ecova (1)</b>		31,865
<b>Other (1)</b>	25,803	20,132
Total	\$ 4,971,623	\$ 4,502,784

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	09/10/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Ordonez	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 287	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

**REQUEST:**

Based on the Company-provided confidential response to Staff Data Request 239 (i.e., workbook "Staff\_DR\_239C Confidential Attachment A ")” where Avista provided the total compensation of selected officers for the past three years broken down into utility and non-utility operations,<sup>1</sup> for Officer **Mr. Vermillion, Dennis**, please provide the following information:

- a. Title of such officer (if the title has changed during the requested period, please provide the titles including the date of changes if applicable); and
- b. Duties and responsibilities of such officer (e.g., position description documents or any other documents; if the job description has changed during the requested period, please provide all the versions of such position description);

If the supporting information requested above, was derived or obtained from other sources , please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format **indicating the specific page, section, etc.** of the relevant source document.

**RESPONSE:**

Dennis Vermillion is President of Avista Utilities. His title has not changed between 2012 and 2015.

Please see Avista’s confidential response to Staff\_DR\_286 for the job description of Dennis Vermillion. His job description is on page 5 of Staff\_DR\_286C – CONFIDENTIAL Attachment A.

<sup>1</sup> By “non-utility” operations or subsidiaries, Staff means the operations or subsidiaries to which the Company directly assigned the costs provided in confidential file MS Excel file “Staff\_DR\_175C Confidential Attachment A,” worksheet “Labor”. In other words, “all costs recorder for Avista subsidiaries and for costs recorded by Avista Corp. for subsidiary report” as referred in the Company response to Staff DR175, part “c”.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	08/12/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Ordonez	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 240	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

**REQUEST:**

Regarding sub-part “e” of part “e” of the Company’s response to Staff DR 175, where the Company represented:

*“Separate logs are not maintained to track time of employees [emphasis added]. The employees enter their time for each day [emphasis added] and submit it electronically to the Company’s payroll system every two weeks. This system is loaded into the Company’s accounting/financial system. The data provided in Staff DR\_175C Confidential Attachment A is an export from this accounting/financial system, so all [the] time [tracked by employees] has been provided in this attachment.”*

And,

Based on the Company-provided confidential file MS Excel file “Staff\_DR\_175C Confidential Attachment A,” where Avista provided the amounts directly assigned by the Company’s officers to non-utility operations or subsidiaries,<sup>1</sup> Staff has ranked in Table 1 below the following ten officers who allocated the most to non-utility or subsidiaries in year 2014:

Table 1

Non-confidential designation	Name of Officer
Officer 1	Morris, Scott L
Officer 2	Lafferty, Robert J
Officer 3	Thies, Mark T
Officer 4	Durkin, Marian McMahon
Officer 5	Rahn, Gregory
Officer 6	Woodworth, Roger D
Officer 7	Denniston, Timothy Glenn
Officer 8	Burmeister- Smith, Christy
Officer 9	Meister, Keri Marie
Officer 10	Sowl, Spencer W

<sup>1</sup> By “non-utility” operations or subsidiaries, Staff means the operations or subsidiaries to which the Company directly assigned the costs provided in confidential file MS Excel file “Staff\_DR\_175C Confidential Attachment A,” worksheet “Labor”. In other words, “all costs recorded for Avista subsidiaries and for costs recorded by Avista Corp. for subsidiary report” as referred in the Company response to Staff DR175, part “c”.

Please respond the following questions:

- a. Please provide a comprehensive explanation of why the Company does not maintain separate logs to track **employees'** time;
- b. Does the Company maintain separate logs to track the time of the **officers** referenced in Table 1 above? Please provide a comprehensive information of the Company response;
- c. For each of the officers referenced in Table 1 above and for each month of the last quarter of 2014 (i.e., October, November, and December of 2014), please:
  - i. Provide a detailed description of the daily activities performed by such officer including the number of hours and costs that resulted in such employee charging time to non-utility operations or subsidiaries;
  - ii. Reconcile the information provided in the preceding sub-question "i" with the number of hours and costs charged to non-utility operations or subsidiaries provided in Company-provided confidential file MS Excel file "Staff\_DR\_175C Confidential Attachment A".

Please provide any information available to each officer that justifies the number of hours and costs charged to non-utility operations or subsidiaries (e.g., officer's calendar, trip information, itinerary, meeting agenda, etc.)

#### **RESPONSE:**

- a. The Company understands the term "log" to represent an excel spreadsheet or hand-written tracking either daily or hourly by employee for every task an employee performs in the respective time-period. While the Company does not maintain this type of "log", the Company **does** maintain a timekeeping system within which each individual employee enters his/her time by day, by project (which includes FERC account) for a two week period. Records maintained within this system include projects which are specific to the individuals' area of responsibility, including the appropriate General Ledger account based upon the FERC Uniform System of Accounts. In some instances the employees' time would be very specific to a given project or functional area, whereas in other instances, the employee may be more generic based on the nature of the task performed. As an example, a Transmission Engineer would charge his/her time to a specific Transmission project, whereas a Subsidiary Accountant would charge the majority of his/her time to non-utility operations. This information is then reviewed and approved bi-weekly by the individual's supervisor to insure accuracy in project selection. The timekeeping system gathers this information, summarizes it into monthly amounts, and feeds it to the general ledger in order to query for reporting purposes. The information provided in the Company's response to Staff\_DR\_175C Confidential Attachment A is the summary, or output, of all the daily entries made by each employee for each work day. Finally, the Company's third-party independent auditor Deloitte and Touche annually audits the timekeeping system from timekeeping entry to general ledger and reporting to actual payroll.
- b. The process for tracking Executive Officer labor costs is the same process as all non-executive employees.
- c. As noted in part (a) above, the Company's general ledger does not maintain daily records for each employee in the General Ledger. Rather, the General Ledger houses the



monthly records which are a summation of the daily projects (including FERC account) the employee enters into the timekeeping system. The information provided in the Company's response to Staff\_DR\_175C Confidential Attachment A includes this information summarized on an annual basis. In order to obtain the monthly amount, please pull the "accounting month" selection from the database provided electronically into the pivot table provided in the Company's response to Staff\_DR\_175C Confidential Attachment A.

Please see the testimony of Company witness Smith Avista/500 page 15 lines 11-23 and page 16 lines 1-5 and the Company's response to Staff\_DR\_139 and Staff\_DR\_141 for additional information on executive officer allocation between utility and non-utility operations.

**AVISTA CORP.  
RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	09/10/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Ordonez	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 286	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

**REQUEST:**

Regarding Staff DR 240, where Staff requested the Company to provide an explanation of why the Company does not maintain separate logs to track officers' time and where Staff also requested the Company to provide a detailed description of the daily activities performed by ten officers, including the number of hours and costs that resulted from such officers charging time to non-utility operations or subsidiaries, including information available to such officers that justifies the number of hours and costs charged to non-utility operations or subsidiaries (e.g., officer's calendar, trip information, itineraries and meeting agendas, etc.)

To which the Company responded:

*“As noted in part (a) above, the Company’s general ledger does not maintain daily records for each employee in the General Ledger [emphasis added].”*

And,

Based on the Company-provided confidential response to Staff Data Request 239 (i.e., workbook "Staff\_DR\_239C Confidential Attachment A ") where Avista provided the total compensation of selected officers for the past three years broken down into utility and non-utility operations,<sup>1</sup> Staff has ranked in Table A below the following five officers whose respective compensations are the highest:

Table A

Non-confidential designation	Name of Officer
Officer 1	Morris, Scott
Officer 2	Durkin, Marian
Officer 3	Vermillion, Dennis
Officer 4	Feltes, Karen
Officer 5	Thies, Mark

Regardless of the fact that the “Company’s general ledger does not maintain daily records for each employee in the General Ledger,” for each officer listed in the above Table A, please provide the following information for the last three calendar years (i.e., 2012 through 2014): a list of the board meetings, including committees and subcommittees’ meetings, attended by such

<sup>1</sup> By “non-utility” operations or subsidiaries, Staff means the operations or subsidiaries to which the Company directly assigned the costs provided in confidential file MS Excel file “Staff\_DR\_175C Confidential Attachment A,” worksheet “Labor”. In other words, “all costs recorder for Avista subsidiaries and for costs recorded by Avista Corp. for subsidiary report” as referred in the Company response to Staff DR175, part “c”.

officer broken down by utility and non-utility operations. Please also include the date of each meeting and include copies of the minutes of each meeting.

If the supporting information requested above, was derived or obtained from other sources, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format **indicating the specific page, section, etc.** of the relevant source document.

**RESPONSE:**

Please see the Company's response in Staff\_DR\_286C for the requested information. Staff\_DR\_286C is **CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER.**

The Company has provided the job descriptions for all officers of Avista in Staff\_DR\_286C Confidential Attachment A. For the 5 offices listed above, their job descriptions have been provided on the following pages:

<u>Pages</u>	<u>Title</u>	<u>Name</u>
1 - 2	Chairman and CEO	Scott Morris
3 - 4	Sr. VP, General Counsel, and Chief Compliance Officer	Marian Durkin
5	President of Avista Utilities	Dennis Vermillion
6 - 7	Sr. VP Human Resources	Karen Feltes
8 - 10	Corporate Secretary	Karen Feltes
11 - 12	Sr. VP Treasurer	Mark Thies
13 - 14	CFO	Mark Thies

Included in Staff\_DR\_286C Confidential Attachment A at pages 15-27, all other officers' job descriptions not specifically requested have been provided.

The Company has also provided the following excel spreadsheets:

- Staff\_DR\_286C – CONFIDENTIAL Attachment B (2014 Data)
- Staff\_DR\_286C – CONFIDENTIAL Attachment C (2013 Data)
- Staff\_DR\_286C – CONFIDENTIAL Attachment D (2012 Data)

The data in Attachments B – D includes the hours recorded for each year by the 5 officers specifically requested in the data request. The officers' hours were summarized by the following: 1) Hours worked and recorded to non-utility; 2) Hours worked and recorded to utility; and 3) Hours not worked (i.e. vacation hours). The ratio of hours worked that were charged to non-utility were compared to total hours worked. This ratio was compared to the % of hours that the officers estimated would be recorded as non-utility. As an example, 2014 data is provided below:

<b>2014</b>	Durkin, Marian	Feltes, Karen S	Morris, Scott L	Thies, Mark T	Vermillion, Dennis P	Grand Total
Non-Utility	389	340	346	262	193	1,530
Non-Utility (Company 400)			2	13		15
Subtotal - Non-Utility	389	340	348	275	193	1,544
Utility	1,459	1,424	1,508	1,562	1,575	7,528
Non-Worked Hours (Recorded to Pool and Allocated)	232	316	224	244	312	1,328
<b>TOTAL</b>	<b>2,080</b>	<b>2,080</b>	<b>2,080</b>	<b>2,080</b>	<b>2,080</b>	<b>10,400</b>
Subtotal - Utility + Non-utility (Hours Worked)	1,848	1,764	1,856	1,836	1,768	9,072
% of Worked Labor Recorded as Non-utility	21%	19%	19%	15%	11%	17%
% of Non-utility Per Surveys	17%	13%	15%	11%	8%	
Non-utility Actual Recorded in excess of Survey	5%	6%	4%	4%	3%	

From the data above, it can be seen that in 2014, all 5 of the officers chosen actually recorded more time as non-utility than they had originally estimated.

Included in Attachments B – D, the hours recorded to non-utility have been provided for all 26 pay periods during each year. (As noted in the Company’s response to Staff\_DR\_239, the daily hours are entered into the Company’s timekeeping/payroll system and are summarized by two-week periods when imported into the general ledger.)

In 2014, Ecova (the largest operating subsidiary of Avista) was sold and AERC (Alaska property) was purchased. Therefore, all of the officers’ non-utility hours were greater than usual and greater than what can be expected in 2015 and 2016.

CASE: UG 288  
WITNESS: JORGE ORDONEZ

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1103**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**STAFF EXHIBIT 1103**

**IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE**

**ORDER NO. 15-141 IN UG 288**

CASE: UG 288  
WITNESS: LISA GORSUCH

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1200**

**Advertising**

**Opening Testimony**

**October 16, 2015**

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Lisa Gorsuch. My business address is 201 High Street, SE Suite  
3 100, Salem, Oregon 97301-3612.

4 **Q. Please describe your educational background and work experience.**

5 A. My Witness Qualification Statement is found in Exhibit Staff/1201.

6 **Q. Did you prepare exhibits for this docket?**

7 A. Yes. In addition to my Witness Qualification Statement found in Exhibit  
8 Staff/1201, I prepared Exhibit Staff/1202, consisting of 3 pages. This exhibit  
9 contains Avista Utilities (Avista or Company) response to Standard Data  
10 Request (SDR) No. 104.

11 **Q. How is your testimony organized?**

12 A. I discuss the historical ratemaking treatment of advertising and marketing  
13 expense, describe my analysis, and provide my recommendation.

14 **Q. What is your overall conclusion concerning Avista's proposed  
15 advertising expenses?**

16 A. I conclude that Avista has met the requirements contained in the Oregon  
17 Administrative Rules (OARs) to support including its advertising expenses in  
18 the revenue requirement as filed in Docket No. UG 288. Therefore, I  
19 recommend no adjustment to reduce the test year for advertising expenses.

20 **Q. Please set forth the Commission's rules that direct how to treat  
21 advertising-related expenses.**

22 A. OAR 860-026-0022 describes how advertising-related expenses are addressed  
23 in a rate case. Each type of advertising expense is classified by category



1 (Categories A-E) and each category has a different standard for how the  
2 expenses may be included in a company's rates. Accordingly, I used these  
3 Categories to analyze the Company's advertising expenses in this docket.

4 **Q. Please explain the meaning of these various Categories for advertising**  
5 **expense.**

6 A. Category A expenses are for utility service advertising expenses and utility  
7 information advertising expense.<sup>1</sup> These expenses are presumed reasonable if  
8 they are no more than 0.125 percent of the gross retail operating revenues  
9 determined in the rate proceeding.<sup>2</sup>

10 Category C expenses are "[i]nstitutional advertising expenses, promotional  
11 advertising expenses and any other advertising expenses not fitting into  
12 Category "A," [advertising regarding utility-service and utility information]  
13 programs,] "B," [legally-mandated advertising,] or "D"; [political advertising and  
14 non-utility advertising]."<sup>3</sup> There is no presumption that Category C advertising  
15 expenses are reasonable. OAR 860-026-0022(3)(c) provides "[t]he energy or  
16 large telecommunications utility shall carry the burden of showing that any  
17 advertising expenses in Category "C" are just and reasonable for rate-making  
18 purposes." The rules also require that in any rate filing under ORS 757.210  
19 and ORS 759.180, the utility shall separately state the amount of advertising  
20 expenses in Category C. Advertising expenses in Category "E" are energy

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<sup>1</sup> OAR 860-026-0022(2)(a).

<sup>2</sup> OAR 860-026-0022(3)(a).

<sup>3</sup> OAR 860-026-0022(2)(c).

1 efficiency or conservation advertising expenses that relate to a Commission-  
2 approved program.

3 **Q. What did Avista propose to spend in its initial filing on Category A**  
4 **advertising expense in its 2016 budget?**

5 A. For its 2016 advertising budget, Avista included \$119,953.<sup>4</sup> This amount is  
6 \$7,161 less than the \$127,114<sup>5</sup> allowed per the calculation described in OAR  
7 860-026-0022(3)(a), “presumed to be just and reasonable.”

8 **Q. Did Avista include Category B advertising expense in its 2016 budget in**  
9 **its initial filing?**

10 A. Yes. The Company included \$94,340.39<sup>6</sup> in Category B advertising expense.

11 **Q. Did Avista include Category C or Category D advertising expense in its**  
12 **2016 budget in its initial filing?**

13 A. No. The Company did not include Category C or Category D advertising  
14 expense in its 2016 budget in its filing. The exclusion of these two categories of  
15 advertising expense is consistent with historical ratemaking treatment of  
16 advertising and marketing expenses, and per OAR 860-026-0022(3)(c)-(d), as  
17 the Company did not support the inclusion of these two categories of  
18 advertising expense in testimony.

19 **Q. Did Avista include Category E advertising expense in its 2016 budget in**  
20 **its initial filing?**

21 A. Yes. The Company included \$2,698.91<sup>7</sup> Category E advertising expense.

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<sup>4</sup> See Avista’s response to Standard Data Request No. 104 Attachment A.

<sup>5</sup> See Avista’s response to Standard Data Request No. 104 Attachment A.

<sup>6</sup> See Avista’s response to Standard Data Request No. 104 Attachment A.

1 **Q. How did you perform your analysis of Avista's proposed advertising**  
2 **expenses?**

3 A. I reviewed the Company's response to a Standard Data Request and I  
4 reviewed all transactions in FERC accounts relating to advertising and  
5 marketing for the 2016 base year. In addition, I reviewed advertising expense  
6 included by Avista in its last two general rate case filings, Docket Nos. UG 246  
7 and UG 284. As a result of this review, I found that Avista's advertising  
8 expenses are just and reasonable per the applicable rules, and in line with the  
9 Company's historical advertising spending.

10 **Q. How do the advertising expenses proposed by Avista in its last general**  
11 **rate case filing<sup>8</sup> compare to its current proposed advertising expenses?**

12 A. As shown in the chart below, Avista's overall spending levels have remained  
13 very consistent when the 2013 Base Year amount of \$582,000 from Docket  
14 No. UG 284 is compared to the 2014 Base Year amount of \$584,000 from  
15 Docket No. UG 288. The larger variance can be seen in the \$599,000 historical  
16 2015 Test Year amount from Docket No. UG 284 versus the \$585,000  
17 historical 2016 Test Year in Docket No. UG 288.

18 In the chart below, the Base Year amount is per the Company's Results of  
19 Operations Report. The \$582,000 2014 Base Year amount is escalated by  
20 \$3,000, as shown in the restated 2016 Test Year amount in Docket No. UG  
21 288, resulting from a very small Consumer Price Index adjustment. As  
22 previously stated, Avista's advertising expenses have remained relatively flat

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<sup>7</sup> See Avista's response to Standard Data Request No. 104 Attachment A.

<sup>8</sup> Docket No. UG 284

1 from its 2013 Base Year to its 2014 Base year, which is illustrated in the chart  
2 below.

		<b>Historical 2015 Test Period (All numbers below are in thousands)</b>	<b>Base Year 2013</b>
<b>UG 284</b>			
CUSTOMER SERVICE & INFO EXPENSES:			
Customer Assistance Expenses		192	190
Advertising		351	340
Misc Customer Service & Info Exp		56	54
<b>CUSTOMER SVC &amp; INFO OPERATING EXP</b>	<b>Total</b>	<b>599</b>	<b>584</b>
		<b>Historical 2016 Test Period (All numbers below are in thousands)</b>	<b>Base Year 2014</b>
<b>UG 288</b>			
CUSTOMER SERVICE & INFO EXPENSES:			
Customer Assistance Expenses		175	175
Advertising		363	360
Misc Customer Service & Info Exp		47	47
<b>CUSTOMER SVC &amp; INFO OPERATING EXP</b>	<b>Total</b>	<b>585</b>	<b>582</b>

3

4 **Q. Do you recommend an adjustment to Avista's advertising expenses?**

5 A. No, I do not.

6 **Q. Does this conclude your testimony?**

7 A. Yes.

CASE: UG 288  
WITNESS: LISA GORSUCH

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1201**

**Witness Qualifications Statement**

**October 16, 2015**

### WITNESS QUALIFICATIONS STATEMENT

NAME: Lisa M. Gorsuch

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst/Energy Resources & Planning Division

ADDRESS: 201 High Street SE. Suite 100  
Salem, OR. 9730

EDUCATION: College-level coursework in financial accounting, business law, business management, and economics.

The Center for Public Utilities at New Mexico University.

The National Association of Regulatory Utility Commissioners' (NARUC) Annual Regulatory Studies Program at Michigan State University.

EXPERIENCE: Utility Analyst with the Public Utility Commission of Oregon (PUC) since April 2008. Primarily responsible for review of electric and natural gas company tariff filings, other electric and natural gas company rates and costs, and integrated resource planning. Serving as natural gas subcommittee member for NARUC from 2013 to present.

Compliance Specialist with the PUC from June 2004 until April 2008. Responsibilities included acting as a liaison between the public, regulated utilities and various Commission staff. Review of proposed tariffs, administrative rules, and policies for evaluation of the potential impact on consumers and the regulated utilities. Identified trends, services, and policies where no statute, rule or precedent applied and recommended the appropriate action.

OTHER EXPERIENCE: Senior Enforcement Agent with the Oregon Department of Revenue as a member of a multijurisdictional task force from 1999 - 2004. Responsibilities included, but were not limited to, investigating criminal cases for prosecution. In addition, served as liaison between task force and Oregon State Legislators.

CASE: UG 288  
WITNESS: LISA GORSUCH

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1202**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**AVISTA CORP.**  
**RESPONSE TO REQUEST FOR INFORMATION**

JURISDICTION:	Oregon	DATE PREPARED:	04/28/2015
CASE NO.:	UG ____	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff	RESPONDER:	Dana Anderson
TYPE:	Data Request	DEPT:	Energy Solutions
REQUEST NO.:	Staff – 104	TELEPHONE:	(509) 495-8199
		EMAIL:	dana.anderson@avistacorp.com

**REQUEST:**

For the questions below related to advertising expense, please see the definitions and descriptions in OAR 860-026-0022. For questions related to promotional activities or concessions, please see OAR 860-026-0015 & 0020.

- a. Please identify the Category A advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages;
- b. Please provide a work paper that shows the calculation of the Category A limit provided in OAR 860-026-0022 (3) (a);
- c. If the Test Year Category A advertising expense exceeds the OAR 860 026-0022 (3) (a) limit, please provide support for including the additional expense in rates;
- d. Please identify the Category B advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages;
- e. For any Category C advertising expense included in the Test Year revenue requirement that is associated with a promotional activity or a promotional concession program, please provide a summary table that includes:
  - i. A description of the activity or program, and justification for inclusion into rates;
  - ii. A breakout of the related expense by labor & non-labor; and
  - iii. The FERC and internal utility account to which the expense will be booked and include references to appropriate exhibit pages.
- f. Please identify any other budgeted advertising expense for the test year that will NOT be included in base rates, including below-the-line or nonutility expense, or advertising expense expected to be collected through a tariff. Please include how the expense is allocated between the categories identified in

OAR 860-026-0022(2). Please describe the activities and associated expense (broken out by labor & non- labor) associated with marketing research and sales activities (include fuel switching and retention of customers) that is included in the test year. Please include references to the testimony and exhibits, and to which FERC and internal utility accounts this expense is booked.



**RESPONSE:**

- a. Please see the Miscellaneous Restating Adjustment (1.02), in Smith workpapers, section G-MR-1 and MR-AD-1 through MR-AD-2. This adjustment restates actual test period results for miscellaneous restating items such as advertising, removal of non-utility related items, and reclassification of items to their appropriate service and jurisdiction. However, the analysis of the Company's Category A expenses determined there was no adjustment necessary pursuant to OAR 860-026-0022.

The Company spent approximately \$119,953 for Category A advertising. The Company determined that the Category A limit was approximately \$127,114, so there was no adjustment necessary. Please see Smith workpapers, adjustment 1.02, workpapers reference MR-AD-1 through MR-AD-2. Workpaper MR-AD-2 includes detailed listings of advertising costs, separately identified for Category A.

- b. Please see the Miscellaneous Restating Adjustment (1.02), in Smith workpapers, section MR-AD-1, for a calculation of the Category A limit provided in OAR 860-026-0022 (3)(a).
- c. The test year Category A advertising expense did not exceed the OAR 860-026-0022 (3)(a) limit included in the 2014 test year. Please see the Miscellaneous Restating Adjustment (1.02), in Smith workpapers, section G-MR-1 and MR-AD-1 through MR-AD-2, for the analysis of the Category A expenses.
- d. Please see Staff\_DR\_107, Attachment A, for all Category B advertising expenses included in the test year.
- e. No Category C advertising expenses were included in the forecasted test year. Please see Staff\_DR\_107, Attachment A, for Category C advertising expenses.
- f. All Category D and Category E costs are recorded based on direct assignment. The Company has not spent any money on political advertising (Category D Expenses). Please see Staff\_DR\_107, Attachment A, for program specific advertising expenses (Category E Expenses) during the test period.
- g. The Company also provides detail transactions for DSM expenses in a quarterly report filed by Avista and audited by the Oregon PUC.

Please see Staff\_DR\_107 Attachment A for a listing of all advertising expenses that were charged below the line to nonutility expense.

This information is in the form of an Excel file and can be found on the CD that was filed with the Filing Center or for Parties on Huddle as UG 288 Exhibit 102 pg 3 Gorsuch Attachment A.

CASE: UG 288  
WITNESS: GEORGE R. COMPTON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1300**

**Opening Testimony**

**October 16, 2015**

1

**STAFF OPENING TESTIMONY**

2

**Q. Please state your name, occupation, and business address.**

3

A. My name is George R. Compton. I have been employed by the Public Utility

4

Commission of Oregon (OPUC) since March of 2007. I am a Senior

5

Economist (half-time) within the Energy, Rates, Finance, and Audits Division.

6

My business address is 201 High St., Salem, Oregon 97301-3612.

7

**Q. Please describe your educational background and work experience.**

8

A. My Witness Qualification Statement is found in Exhibit Staff/1301.

9

**Q. What is the purpose of your testimony?**

10

A. This testimony addresses elements of cost allocations, rate spread (i.e. the

11

allocation of the overall revenue increase among the various customer

12

schedules), and pricing/rate design.

13

**Q. Does Staff possess a general philosophy or approach to these**

14

**subjects?**

15

A. Yes. As a general matter, pricing and customer cost allocations should reflect

16

"long-run-incremental cost" (LRIC) causation as much as possible. Achieving

17

that objective is tempered by long-recognized "rate shock" considerations

18

which may limit percentage increases to selected schedules' revenue

19

requirements and particular tariff elements.

20

**Q. Did you prepare exhibits for this docket?**

21

A. Yes. I prepared the following exhibits.

22

Exhibit 1302 Customer Costs and Customer Charge

23

Exhibit 1303 DR No. 296; Line Extension Averages; Rate Spread

24

Exhibit 1304 Ind. Rate Reductions' Impact on Res. Customers

1 **Q. How is your testimony organized?**

2 A. This testimony is organized as follows:

3 Topic 1: Residential and General Service Customer Charges.....3

4 Topic 2: Line Extension Footage Averages and Allocated Costs.....8

5 Topic 3: Industrial Schedule Rate Reductions.....15

6 **Q. Please provide an overview of your testimony.**

7 A. Over the years Avista Utilities' (Avista or Company) practices relating to my  
8 areas of responsibility have evolved in a mutually acceptable manner—being  
9 influenced by various parties, including Staff. In that regard Staff has no  
10 issue with the general costing and rate spread approaches taken by the  
11 Company in this case. However, some of the Company's estimates  
12 pertaining to customer schedules' average line extension footages—the  
13 dominant gas utility cost-causation factor—were challenged. This led to  
14 refinements in those estimates, which in turn had an effect on the final rate  
15 spread outcome.

16 On the subject of rate design, Staff's position is that although the  
17 proposed monthly customer charges for Residential Schedule 410 and  
18 General Service Schedule 420 have relatively sound cost-causation  
19 foundations, the respective two and six dollar increases are out of line  
20 percentage-wise with the general level of increase sought by Avista in this  
21 case. Staff supports increases of half those amounts.

22 As in the last general rate case for the Company (Docket 284), the cost  
23 of service conclusions that support substantial rate reductions for large  
24 industrial customers were corroborated by Staff's own studies. For various

1 reasons surrounding the notion of cost-based rates, Staff again supports  
2 selected rate reductions in this general rate case—on the condition that the  
3 expected overall increase, including natural gas costs, is modest, say no  
4 greater than four percent. Otherwise, and in the interest of rate shock  
5 mitigation for other customers when the average percentage increase is more  
6 substantial, Staff favors holding the affected large industrial customers to no  
7 increase.<sup>1</sup>

### 9 **Topic 1: Residential and General Service Customer Charges**

10 **Q. There is a common industry practice of categorizing costs as either**  
11 **demand, energy, or customer related. Would it be appropriate to**  
12 **recover all of customer costs through the monthly customer charge?**

13 A. No. The practice I am familiar with here in Oregon and which I have  
14 espoused my entire career is that, at most, customer-related costs  
15 appropriately recovered in the customer charge are costs that are confined to  
16 individual customers—i.e., not shared in any way. Those costs that are not  
17 shared would include each customer's meter and service line, meter reading,  
18 and preparing and mailing customer bills as well as processing the payment.  
19 Other customer related costs, such as the utility's information systems  
20 hardware and personnel, are shared among all customers—and for a host of  
21 functions besides billing customers. These, and other shared gas utility costs

---

<sup>1</sup> Staff did not assert this condition in the previous Avista general rate case.

1 that are categorized as neither demand- nor energy-related, are historically  
2 recovered through volumetric energy charges.

3 **Q. Has the Company provided estimates for Residential Schedule 410 and**  
4 **General Service Schedule 420 for the narrowly defined customer-related**  
5 **costs that you just described?**

6 A. Not quite. Line 30 of my Exhibit Staff/1302<sup>2</sup> displays the costs that the  
7 Company apparently believes should underlie the customer charge.<sup>3</sup> That  
8 line is labeled “Avg Cost Per Month for Meter Reading, Billing, Meters &  
9 Service.” The line 30 figures are constructed by adding the embedded cost  
10 figures on lines 21 and 22, and dividing by the customer-months (i.e., twelve  
11 times the customer counts shown on line 2). Lines 21 and 22 are labelled,  
12 respectively, “Meter Reading, Billing, Etc. [emphasis added] Costs,” and  
13 “Meters & Service Costs.” I believe the “Etc.” costs of line 21 take us well  
14 beyond the narrowly defined customer-related costs described above.

15 **Q. Please explain the basis for that belief.**

16 A. Two lines of evidence support my belief that the referenced line 30 goes  
17 beyond individual customer-specific costs. First, I compare line 21 with the  
18 lines 7 and 8 figures which sum to create an LRIC correlated with the  
19 embedded cost figures of line 21. (Line 7 is labeled “Meter Reading;” line 8 is  
20 labeled “Billing.”) Unless the line 21 costs went well beyond the narrowly  
21 defined items listed above, I would not expect the line 21 amounts to exceed

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<sup>2</sup> This exhibit consists of Avista/801, Miller/1, augmented with my lines 8a, 22a, and 30a.

<sup>3</sup> Unless indicated otherwise, the spreadsheet lines referenced for the next few pages of this testimony will refer to this same Exhibit Staff/1302.

1 the sum of lines 7 and 8. Instead, line 21 runs in excess of 40% above the  
2 sum of lines 7 and 8.

3 My second point is that I believe even the smaller line 8 elements  
4 overstate narrowly-defined billing costs. (I should note that the much smaller  
5 amounts shown on line 7 look plausible to me.) Defined narrowly, “billing”  
6 would involve a bill insert, an envelope, and a stamp, plus some labor to open  
7 the envelope and post the payment. Dividing the SCH 410, line 8 amount  
8 (\$2,151,696) by the number of customer-months (i.e., 12 x 87,065 [from line  
9 2]) yields a bit over \$2 per month. The cost of the bill insert, envelope, and  
10 metered “stamp” should not be much over 50 cents. I do not believe the  
11 individual computer and manual bill processing would amount to anything  
12 close to the additional \$1.50 per month. Something like 25 cents would seem  
13 conservative on the high side to cover the cost of those latter items.

14 **Q. What do you think would be a better estimate of meter reading and**  
15 **billing cost—narrowly defined as you would have them, and as applied**  
16 **to the contested schedules 410 and 420?**

17 A. For meter reading, I would hold with the Company (i.e., line 7); for billing, I  
18 would use the 75 cents referenced in my answer to the previous question.  
19 Multiplying 75 cents and the respective customer-months yields the figures  
20 shown in line 8a of the exhibit.

21 **Q. The Company used embedded costs on line 22 (“Meters & Services**  
22 **Costs”) in developing the customer-related costs shown on line 30.**  
23 **Should the Company instead have used the corresponding LRIC sums**



1           **of lines 9 and 10 (respectively, “Meters” and “Services”)? Those sums**  
2           **are more than twice the line 22 amounts.**

3           A.   Actually it is the attributable-embedded costs, not the larger LRIC costs,  
4           which each customer schedule will be required to recover. Also, what the  
5           Company is trying to justify is a conservative/minimum customer charge  
6           amount...not some feasible larger amount.<sup>4</sup> For that same reason I have  
7           preferred using the smaller, more justifiable LRIC amount for meter reading  
8           and an even smaller amount for billing.

9           **Q.   You have suggested how “Billing Costs” can go beyond your narrow**  
10           **definition by, for example, including generic information system costs.**  
11           **Are you concerned that the Meter, Services, and Meter Reading might**  
12           **be similarly expanded upon?**

13          A.   No, I believe the accounting codes for those items are sufficiently restrictive to  
14          not cause a problem. But I do have one caveat on this general subject. Other  
15          Staff members are providing evidence in this case for reducing Company  
16          salaries, benefits, and other expenses. Those adjustments would cause a  
17          slight reduction in the amounts that I will now be presenting to you.

18          **Q.   Would you now please reconstruct what would be your best estimate of**  
19          **minimally-construed customer costs that would be the candidates for**  
20          **including in the monthly customer charge? Please also place the**  
21          **amounts in a per-customer-month framework.**

---

<sup>4</sup> Another consideration: Large customer charges translate to smaller volumetric energy charges, which, in turn, go against the goal of encouraging energy conservation.

1 A. Line 22a of my Exhibit Staff/1302 is the sum of lines 7 (meter reading), 8a  
2 (billing), and 22 (meters and services). The per-customer, monthly Line 30a  
3 figures are obtained by dividing the line 22a figures by the associated  
4 customer-months (12 times line 2). These calculations yield a \$15.87 per  
5 month cost for Schedule 410 and \$19.94 per month for Schedule 420.

6 **Q. Avista is asking to increase its Schedule 410 customer charge from \$8**  
7 **to \$10 per month, and its Schedule 420 customer charge from \$14 to**  
8 **\$20. The minimally-construed customer costs which you just produced**  
9 **are, respectively, \$15.87 and \$19.94.<sup>5</sup> The first is well above what the**  
10 **Company seeks for its customer charge, the second is just a few cents**  
11 **below. But from your introduction I see that Staff would only concur**  
12 **with increases of half what the Company seeks. Please explain why.**

13 A. If Avista receives the revenue increases that it has applied for, then the  
14 average billed revenue increases for those two schedules will be,  
15 respectively, 8.9 percent and 9.5 five percent.<sup>6</sup> Raising the customer charges  
16 by, respectively, 25 percent and 43 percent in this context is too great given  
17 the overall price increase. This is especially true if the final overall increases  
18 are only about half of the Company's requested amounts.,

19 **Q. Given that Staff supports half the requested customer charge increases,**  
20 **is that without conditions?**

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<sup>5</sup> From line 30a of Exhibit Staff/1302.

<sup>6</sup> See column k of Avista/903, Ehrbar/3. That exhibit is replicated as the table found in my Exhibit Staff/1304.

- 1 A. No. The condition is that the customer charge increase for Schedules 410  
2 and 420 should be limited to where, if it were any greater, there would have to  
3 be a compensating decrease in the volumetric/energy rate. Unless there is to  
4 be a general rates decrease in this case, Staff would object to energy rate  
5 decreases for those two schedules.  
6

## 7 **Topic 2: Line Extension Footage Averages and Allocated Costs**

8 **Q. In your introduction you said you are generally accepting of the costing**  
9 **and rate spread approaches taken by the Company in this case. But**  
10 **you took exception to the line extension footages. Before telling us**  
11 **what caused you to reach that conclusion, would you please explain**  
12 **what line extensions are?**

13 A. Line extensions are the gas mains that run through the residential,  
14 commercial, and industrial neighborhoods. (*Core* mains take the gas into  
15 those neighborhoods.) The primary cost drivers for line extensions are the  
16 customers' frontages that must be passed by to get to the next customer and  
17 so on.

18 **Q. What caused you to take exception to the line extension footages**  
19 **submitted by the Company in its general rates relief application?**

20 A. Between the Avista's last general rate case docket (No. UG 284) and this  
21 one, the indicated per-customer average line extension footage for Schedule  
22 420 increased by almost 60%, and to a level that was almost 50% above the

1 average shown for Schedule 424.<sup>7</sup> Industrial/regulatory common sense was  
2 thereby defied in two respects: 1) With relatively large numbers of customers  
3 involved with Schedule 420 (more than eleven thousand), such a large move  
4 was simply implausible; and, 2) The small industrial/commercial enterprises  
5 that populate General Service Schedule 420 would not be expected to  
6 command lengthier line extensions than the larger enterprises that make up  
7 Schedule 424.

8 **Q. Did you submit a data request and make other inquiries to determine**  
9 **what was causing what you perceived as anomalous average line**  
10 **extension footage estimates?**

11 A. I did.

12 **Q. What did you learn?**

13 A. There were sampling discrepancies and a related disconnect between the  
14 construction information that has been compiled and what is most appropriate  
15 for cost-allocation purposes.

16 **Q. Please present the average footage estimates which you obtained from**  
17 **your inquiries and compare them with those from Avista's original filing.**

18 A. Page 1 of Staff/1303 is a replication of Avista's response to Staff's DR No.  
19 296 —augmented as indicated by the two shaded lines. It is based upon the  
20 installation of gas mains by the Company for the previous seven years. The  
21 initial focus here is on General Service Schedule 420. The original filing  
22 showed an average of 568 feet; I believe 436 feet constitutes a superior

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<sup>7</sup> The average footage estimates filed by Avista in this case are shown in line 8 of Avista/801, Miller/2.

1 estimate. Regarding the average shown for Residential Schedule 410, it is  
2 close to the original but requires some adjustment and is discussed below.  
3 Other information provided by the Company caused me to increase the  
4 average estimate for Large General Service Schedule 424 from 382 feet (in  
5 the original filing) to 494 feet. In the case of Schedules 440, 444, 447, and  
6 456 (whose combined customer count is less than one hundred) there was no  
7 data for the same seven-year period since all the customers in those  
8 schedules came into the system ahead of that time. Fortunately, the  
9 originally recorded line extension footages were available to be used for those  
10 schedules.

11 Line 8 of Page 2 of Staff/1303 shows what I believe are the more  
12 accurate line extension footage estimates. For reference, the line  
13 immediately above line 8 shows the figures used by Avista in its rate case  
14 application.

15 **Q. The context in which Oregon's utility cost studies are conducted usually**  
16 **focuses on the long run, i.e., LRIC (long-run incremental costs). Does**  
17 **your reliance upon historical footages rather than projected figures<sup>8</sup>**  
18 **constitute a violation of Staff's policy in this case?**

19 A. No. When the objective is to capture the costs of something—especially if the  
20 subject, such as Avista's inventory of customers, is relatively static in time—  
21 sampling of existing units rather than attempting a forecast of the costs of  
22 incremental, or new units, will often produce the most accurate measure of

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<sup>8</sup> Projections are typically extrapolations from the most recent experiences.

1 the entire population that is in place during the forecasted test period.<sup>9</sup> After  
2 all, the forecasted test period will be populated mostly with units that were  
3 installed in the past.

4 The theoretical underpinning for desiring forward-looking incremental  
5 costs is to achieve the economic ideal of marginal-cost pricing. When new  
6 equipment or other new resources are involved in the sale of a good or  
7 service, efficiency is fostered by having the price of that good or service  
8 reflect those new resources' costs. For existing equipment, current costs for  
9 that equipment should also be used in place of the original cost—both in  
10 pricing and in the initial, i.e., LRIC, cost-allocations phase.<sup>10</sup>

11 **Q. Return now to Page 1 of Staff/1303 and your two added lines regarding**  
12 **Schedule 410. On what grounds did you eliminate the results for year**  
13 **2009?**

14 A. At four times the average that includes those results, the average for the two  
15 customers shown constitutes a clear outlier—unrepresentative of the group  
16 as a whole. There is also the point that while the installations averaged over  
17 two thousand feet on a physical basis, for rate-making purposes the  
18 equivalent of a smaller number of feet should have gone into the rate base.<sup>11</sup>  
19 That is due to the standard, Company-followed utility policy of requiring a  
20 customer to pay for whatever portion of the main extension costs that are not

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<sup>9</sup> Test periods seldom go more than one calendar year beyond the date of the rate case application.

<sup>10</sup> Note 1: Line 10 of page 2 of Exhibit 1303 shows current unit costs of pipe. Note 2: Main extensions are not priced separately in the various customer tariffs. Instead, those costs are recovered through the volumetric (i.e., per therm) charges.

<sup>11</sup> It is the rate base that gets allocated among customer schedules, not necessarily the original construction costs (as subsequently depreciated).

1 expected to be covered, over time, by the volumetric basic distribution prices.  
2 That is the “disconnect” to which I made reference above. This same two-  
3 point rationale was employed to reduce the Company’s updated estimate of  
4 the Schedule 424 average main extension footage from 771 feet to 494 feet.

5 **Q. Referring to the Residential Schedule 410 average main extension**  
6 **footage estimate of 91 feet shown on line 8 of Page 2 of Staff/1303, I**  
7 **observe that it is beneath the Schedule 410 weighted average of 103 feet**  
8 **shown on Page 1 of Staff/1303. Please explain the basis for lower**  
9 **estimate.**

10 A. Schedule 410 represents over 87 thousand customers.<sup>12</sup> In estimating the  
11 per-customer average footage for that schedule the Company used the  
12 slightly over one thousand Schedule 410 installations which took place in the  
13 last seven years.<sup>13</sup> Making inferences from a sample can often be  
14 problematic. In this case there is potential problem in basing an estimated  
15 average which applies to 87 thousand customers upon only seven years and  
16 those one thousand customers. It is also true that with a relatively small  
17 sample size what is viewed as an unrepresentative year can lead to a major  
18 distortion in the estimated average. The years 2006 and 2007—which  
19 preceded the seven years to which I just referred—were regarded by the  
20 Company as unrepresentative insofar as those two years account for almost  
21 three-fourths of the residential customers added to the system in the last nine  
22 years, and the average footages for those years are very much below the

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<sup>12</sup> See Line 2 of Page 3 of Staff/1303.

<sup>13</sup> That average and each year’s installation record are shown on Page 1 of Staff/1303.

1 average for the subsequent seven years. But while the 2006/2007 years  
2 were unrepresentative of the Company's more recent experience, I was  
3 uncomfortable about simply disregarding them.

4 **Q. What caused the 2006/2007 years to have smaller average footages?**

5 A. Very large new development additions took place in those years. In the other  
6 years single family additions tended to dominate. With new developments  
7 there is the advantage of a given segment of main being able to serve both  
8 sides of the street.

9 **Q. Were you able to obtain data that would enable you to distinguish**  
10 **between new development main additions and single family additions**  
11 **going back far enough in time to obtain an accurate picture of the entire**  
12 **residential portion of the grid?**

13 A. No. This kind of data only goes back nine years, of which the earliest two  
14 years are the years judged by the Company as unrepresentative.

15 **Q. Would you expect that in the early development period for this utility**  
16 **that new developments would contribute relatively more to main**  
17 **extension additions than would be the case more recently?**

18 A. Many of the "new developments" meant taking the gas lines into existing  
19 neighborhoods. The average lengths per customer would depend upon what  
20 proportions of the neighborhoods became enrolled as utility customers. My  
21 expectation is that in the distant past new developments played a greater role  
22 than recently with regard to residential main additions.



1       **Q. With little more than an “expectation,” how do you intend to obtain an**  
2       **estimate of Residential Schedule 410 average main extensions that you**  
3       **can use in constructing a set of cost allocations that lend themselves to**  
4       **putting forth a defensible “spread of rates” among the customer**  
5       **schedules?**

6       A. If I were to simply use the 103 foot Residential Schedule 410 main extensions  
7       average found on page 1 of my Exhibit Staff/1303, the cost-of-service  
8       outcome would be a Residential Schedule 410 percentage rate increase that  
9       was significantly above that of General Service Schedule 420. My strategy is  
10      to reduce the Schedule 410 average footage estimate to the point—call it  
11      parity—where that Schedule and Schedule 420 receive the same billing  
12      percentage increase and then judge whether that estimate is plausible. The  
13      parity figure is the 91 feet shown on Line 8 of Page 2 Exhibit Staff/1303. Line  
14      34 of Page 3 Exhibit Staff/1303 shows Schedule 410 and 420 receiving the  
15      same percentage increase on a billings basis and assuming zero  
16      increases/decreases for the other schedules.

17      **Q. What is the point of targeting billing percentage increase parity between**  
18      **Schedules 410 and 420?**

19      A. In Staff’s view there is insufficient evidence to recommend either rate  
20      schedule having a smaller percentage increase than the other.

21      **Q. The Company’s application has Schedule 410 receiving a smaller cost**  
22      **allocation than Schedule 420<sup>14</sup> despite using a larger estimate of**

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<sup>14</sup> See Line 29 of Avista/801, Miller/1.

1           **Schedule 410 average main extensions, i.e., 112 feet versus your 91 feet.**  
2           **Please explain that apparent anomaly.**

3           A.   The difference is that the revised Schedule 420 average footage was 132 feet  
4           below the 568 figure shown in the application. The change in relative  
5           proportions between Schedule 410 and Schedule 420 is what caused more  
6           costs to be allocated to Residential Schedule 410.

7

8                           **Topic 3: Industrial Schedule Rate Reductions**

9           **Q.   I observe from Exhibit Avista/903, Ehrbar/Page 2 of 4 that the Company**  
10           **is seeking a 16% *margin* revenue increase, which translates to an 8%**  
11           **total *billed* revenue (or overall) increase. What is the distinction**  
12           **between those two revenue items?**

13           A.   The total billed revenue includes the recovery of the purchased gas costs; the  
14           margin is limited to the utility's own incurred costs (i.e., not including gas  
15           purchase costs), including a return on its capital. Since the standard natural  
16           gas utility is basically a gas distribution company, margin revenues are also  
17           referred to as "distribution revenues."<sup>15</sup>

18           **Q.   From that same Company exhibit I observe that Avista is proposing to**  
19           ***reduce* the margin revenues from some of the large customer schedules**  
20           **by seven percent. What is Staff's policy with regard to there being**  
21           **selective rate reductions in the presence of a general rates increase?**

---

<sup>15</sup> See, for example, Exhibit Avista/903, Ehrbar/3.

1 A. Staff's general orientation is that rates and schedules' revenue requirement  
2 shares should approximate a marginal cost construct as much as can be  
3 reasonably justified. The desire to move rates down to costs is tempered in  
4 the presence of a general billed revenue increase that is, say, well above  
5 general price inflation. In those cases, i.e., where there is a sizable increase,  
6 in order to mitigate the rate shock experienced by the schedules receiving the  
7 bulk of the revenue requirement increase, it is Staff's preference to substitute  
8 a zero percent increase for the decrease(s) otherwise justified by the cost of  
9 service studies.

10 **Q. Why do you apply the shock threshold to the billed revenue increase**  
11 **rather than the margin increase?**

12 A. It is what the customer pays—i.e., his billing—that may shock him, not some  
13 obscure tariff item buried in his bill.

14 **Q. Recalling that the Company is seeking a billed revenue increase of 8%,**  
15 **is that far enough above general inflation expectations for Staff to**  
16 **recommend no decreases regardless of the cost of service results?**

17 A. It is far enough. But bear in mind that, considering its many accounting and  
18 cost of capital adjustments, Staff is not expecting the Company to actually  
19 see that much of an increase.

20 **Q. What is a benchmark increase that would signal Staff's endorsements of**  
21 **rate reductions?**

22 A. If the overall total bill rate decrease is no more than four percent *and* there  
23 are compelling cost study results, Staff would be supportive of providing some

1 customers rate decreases while other schedules receive rate increases. Staff  
2 believes the more likely result in this rate proceeding is to achieve the four-  
3 percent condition. In that event Staff's cost studies clearly support reducing  
4 the target margin revenues for Schedules 424, 444, and 456 by as much as  
5 the Company's proffered seven percent.

6 **Q. Do you propose any limit on the size of the rate decreases if in fact**  
7 **there are compelling reasons to justify providing rate decreases to**  
8 **some customers and rate increases to others?**

9 A. Yes there should be some constraints on the level of rate decrease and it  
10 would be reflective of two considerations. First, if the authorized overall  
11 average billing percentage increase is four percent, the size of any non-  
12 transportation schedule's billing percentage decrease should be no greater  
13 than four percent.<sup>16</sup> When the overall rate decrease is smaller, then larger  
14 percentage decreases might be accommodated. The other consideration is  
15 that the rate decrease provided to some customers should not cause the total  
16 billed rate increase to any other customers to be more than two percent  
17 greater than what would otherwise have occurred. (Then, instead of allowing  
18 a rate decrease, the subject schedules would again be held to a zero percent  
19 rate increase.)

---

<sup>16</sup> An exception is made for transportation customers owing to the fact that, unlike the case of the other customers, transportation customers buy their gas from a third party and therefore the billing revenues for transportation customers is the same as the margin revenues. For these customers, the upper limit would be placed on the percentage decrease in margin revenues, and here the maximum would be the same as the largest percentage margin decrease allowed for non-transportation customers.

1 **Q. Have you prepared an exhibit which illustrates Staff's rate spread**  
2 **recommendations in your hypothetical sub-four percent average billings**  
3 **increase?**

4 A. Yes, it is Page 4 of Exhibit Staff/1303.

5 **Q. Assuming that all three of the schedules shown in Exhibit Avista/903,**  
6 **Ehrbar/3 as receiving the seven percent decreases actually got such,**  
7 **and that the "burden" of the decrease was shared uniformly percentage-**  
8 **wise across Schedules 410 and 420, what would be the impact on a**  
9 **typical residential customer?**

10 A. My calculation is that the impact would be about \$1.97 per year, or only 16  
11 cents a month. (Annual bills at current rates average \$763.)

12 **Q. Have you prepared an exhibit in support of those figures?**

13 A. Yes, Exhibit Staff/1304.

14 **Q. In supporting the original Settlement Stipulation in the last Avista**  
15 **general rate case<sup>17</sup> the Citizens' Utility Board (CUB) wanted "it to be**  
16 **clear that there is no precedent being established by the agreed-upon**  
17 **one-time rate spread contained within this Docket, and that...CUB...is**  
18 **not agreeing with the general proposition that when costs are generally**  
19 **increasing, some customers should receive price signals suggesting**  
20 **that costs are decreasing." First, is there some precedent for the OPUC**  
21 **to allow selective decreases in the context of a general increase?**

---

<sup>17</sup> Docket No. UG 284.

1 A. There is. Order No. 12-408 of Docket UG 221 allowed a five percent base  
2 margin decrease for industrial customers of Northwest Natural.

3 **Q. Do you see some kind of danger in this case in having large industrial**  
4 **customers “receiv[ing] price signals suggesting that costs are**  
5 **decreasing”?**

6 A. No. These customers have trained professionals watching the energy  
7 markets, and they will not be misled by a modest effort to bring gas utility  
8 margins in line with costs. Their companies’ profits depend on controlling  
9 costs, so a modest reduction will not lead to some kind of wasteful natural gas  
10 consumption.

11 **Q. In Avista’s last general rate case the Commission’s “questioning” of the**  
12 **selected rate reductions caused an amended stipulation to be submitted**  
13 **which changed the decreases to zero increases. While the Commission**  
14 **“acknowledged that rates may be misaligned relative to cost-of-service**  
15 **and that rate cases provide opportunities to make adjustments that**  
16 **more closely align rates with costs....[it stated that] without compelling**  
17 **evidence that those adjustments warrant more immediate action, ...we**  
18 **are not inclined to raise some rates while reducing others.”<sup>18</sup> Would**  
19 **you infer from that language that “more immediate action” was**  
20 **unnecessary due to the anticipation of there being another rate case**  
21 **filing in the near future which would provide the Commission with the**  
22 **opportunity to take the ultimately desired action?**

---

<sup>18</sup> See page 5 of Order No. 15 109.

1 A. I don't know, but a new case has been filed, and Staff sees no reason why  
2 industrial customers should await for some indefinite time in the future to *start*  
3 to see the rate reductions whose cost-causation basis was undisputed in the  
4 prior Avista general rate case and whose general magnitude is unlikely to be  
5 disputed in the current case. The small revenue shifts displayed in Staff/1304  
6 and on Page 4 of Staff/1303 are unlikely to have significant economic  
7 efficiency effects. But from the viewpoint of promoting social equity by  
8 reducing inter-class cross-subsidization, when Company and Staff evidence  
9 hold that margin percentage decreases should range from 19 to 35 percent,  
10 then the burden should be to produce a compelling reason why a mere 7  
11 percent industrial margin decrease *cannot* be part of the outcome of this  
12 case—especially when the impact on residential customers is only 0.3%.<sup>19</sup>

13 **Q. Does this conclude your direct testimony?**

14 A. Yes.

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<sup>19</sup> See Staff/1304

CASE: UG 288  
WITNESS: GEORGE R. COMPTON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1301**

**Witness Qualifications Statement**

**October 16, 2015**



**WITNESS QUALIFICATION STATEMENT**

**NAME:** George R. Compton

**EMPLOYER:** Public Utility Commission of Oregon

**TITLE:** Senior Economist  
Energy Rates, Finance & Audit Division

**ADDRESS:** 201 High Street, SE., Suite 100  
Salem, OR. 97301

**EDUCATION:** Doctor of Philosophy, Economics (1976)  
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)  
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)  
Brigham Young University – Provo, UT

**EXPERIENCE:** I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah’s Department of Commerce (formerly Department of Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah, I also taught Economics part-time for about ten years at BYU.

Prior to my utility regulatory career, I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California.

I joined the OPUC staff soon after “retiring” to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO<sub>2</sub> Risk Guideline (UM 1302), an Avista General Rate Case (UG 181 and 284), PGE General Rate Cases (UE 197, UE 215, UE 262, and UE 283), PacifiCorp General Rate Cases (UE 210, UE 246, and UE 263), the NW Natural General Rate Case (UG 221), and the Idaho Power General Rate Case (UE 233).

CASE: UG 288  
WITNESS: GEORGE R. COMPTON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1302**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

## Restricting the Cost Elements in the Customer Charge

Staff/1302  
Compton/1

AVISTA UTILITIES  
OREGON JURISDICTION  
LONG-RUN INCREMENTAL COST OF SERVICE STUDY  
TWELVE MONTHS ENDED DECEMBER 2016

**RESULT SUMMARY (Component Allocation)**

Line No.		OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
STATISTICS									
1	2016 ANNUAL THERM DELIVERIES	131,581,172	49,018,942	26,621,408	4,588,281	3,975,023	258,498	7,327,488	39,791,532
2	2016 CUSTOMERS	98,647	87,065	11,416	83	35	9	3	36
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
4	Gas Commodity Costs	\$ -	-	-	-	-	-	-	-
5	Gas Supply Department (Scheduling) 1.03189	\$ 56,322	25,593	13,699	2,396	2,075	135	1,901	10,323
6	Gas Supply Department (Non-Scheduling)	\$ 142,688	80,884	43,927	7,571	6,559	427	516	2,803
7	Meter Reading	\$ 116,123	102,489	13,439	98	41	11	4	42
8	Billing	\$ 2,437,937	2,151,696	282,139	2,051	865	222	74	690
8a	Billing -- Narrowly defined		783,582	102,746					
Customer Installation investment Cost									
9	Meters	\$ 4,860,423	3,441,492	1,263,699	48,968	35,115	6,118	13,066	51,945
10	Services	\$ 41,791,718	35,929,828	5,296,304	149,571	121,058	16,218	15,848	260,891
11	Main Extensions	\$ 107,857,825	63,792,293	42,572,013	331,741	229,674	35,972	16,573	877,559
12	Total Customer Installation Investment Cost	\$ 154,509,966	103,163,613	49,134,017	530,280	385,846	58,309	47,507	1,190,394
System Core Main Cost									
13	Capacity	\$ 12,287,370	5,911,318	2,892,256	233,556	212,495	-	224,968	2,812,777
14	Commodity	\$ 12,548,965	4,674,827	2,539,026	437,584	379,101	24,653	698,828	3,794,947
15	Total Core Main Cost	\$ 24,836,335	10,586,145	5,431,282	671,140	591,595	24,653	923,796	6,607,723
16	Underground Storage Cost	\$ 1,035,644	601,184	318,562	35,614	31,139	665	7,539	40,941
17	Long Run Incremental Distribution Cost	\$ 183,135,015	116,711,603	55,237,265	1,249,150	1,018,121	84,421	981,338	7,853,118
18	Distribution Margin Revenue at Present Rates	\$ 53,224,000	34,864,000	13,605,000	687,000	463,000	44,000	231,000	3,330,000
Proposed Cost by Functional Classification Assigned to Schedule by LRIC components									
19	Cost of Gas Commodity	\$ -	-	-	-	-	-	-	-
20	Gas Supply Department Costs	\$ 568,000	303,900	165,043	28,446	24,644	1,603	6,899	37,466
21	Meter Reading, Billing, Etc. Costs	\$ 3,686,000	3,253,222	426,575	3,101	1,308	336	112	1,345
22	Meters & Services Costs	\$ 18,599,000	15,696,325	2,616,101	79,152	62,262	8,905	11,535	124,719
22a	Meters, Services, Meter Reading, and Billing Costs Narrowly defined		16,582,396	2,732,286					
23	System Core Main Costs	\$ 37,367,000	20,945,160	13,517,845	282,414	231,271	17,072	265,373	2,107,874
24	Underground Storage Costs	\$ 1,561,000	906,149	480,161	53,880	46,934	1,002	11,364	61,709
26	Proposed Cost	\$ 61,781,000	41,104,746	17,205,725	446,794	366,419	28,919	295,284	2,333,113
25	LRIC Based Target Margin per Avista Application	\$ 61,781,000	\$ 41,104,746	\$ 17,205,725	\$ 446,794	\$ 366,419	\$ 28,919	\$ 295,284	\$ 2,333,113
26	Current Distribution Margin Revenue to Proposed Cost	0.86	0.85	0.79	1.54	1.26	1.52	0.78	1.43
27	Relative Margin to Cost at Present Rates	1.00	0.98	0.92	1.78	1.47	1.77	0.91	1.66
28	Component LRIC Target Increase by Schedule	\$ 8,557,000	\$ 6,240,746	\$ 3,600,725	\$ (240,206)	\$ (96,581)	\$ (15,081)	\$ 64,284	\$ (996,887)
29	Target Increase as a Percent of Present Distribution Margin Revenue	16.08%	17.90%	26.47%	-34.96%	-20.86%	-34.28%	27.83%	-29.94%
30	Avg Cost Per Month for Meter Reading, Billing, Meters & Services (Company)		\$ 18.14	\$ 22.21	\$ 82.58				\$ 291.82
30a	Avg Cost Per Month for Meter Reading, Billing, Meters & Services (Staff/Narrowly defined)		\$ 15.87	\$ 19.94					

**Notes:**

- Line 8a = \$0.75 x 12 x Line 2
- Line 22a = Line 7 + Line 8a + Line 22
- Line 30a = Line 22a / (12 x Line 2)

CASE: UG 288  
WITNESS: GEORGE R. COMPTON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1303**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

## Attachment A to Avista's Response to Staff's DR 296

### Schedule 410

	<u>Feet</u>	<u>Customers</u>	<u>Feet/Cust</u>	
2008 Residential	41,029	370	111	
2009 Residential	10,253	142	72	
2010 Residential	11,022	134	82	
2011 Residential	3,180	24	133	
2012 Residential	4,985	41	122	
2013 Residential	23,000	225	102	
2014 Residential	16,292	127	128	
Totals	109,761	1,063		<b>103 Weighted</b> <b>107 Non-weighted</b>

### Schedule 420

	<u>Feet</u>	<u>Customers</u>	<u>Feet/Cust</u>	
2008 Commercial	17,649	42	420	
2009 Commercial	4,158	2	2,079	
2010 Commercial	0	0	0	
2011 Commercial	3,344	7	0	
2012 Commercial	2,085	6	348	
2013 Commercial	3,212	5	642	
2014 Commercial	765	2	383	
Totals	31,213	64		<b>488 Weighted</b> <b>553 Non-weighted</b>
<i>Excluding 2009 (Staff Recommendation)</i>				
Totals	27,055	62		<b>436 Weighted</b>

# Updated Main Extension Average Footages

AVISTA UTILITIES  
OREGON JURISDICTION  
LONG-RUN INCREMENTAL COST OF SERVICE STUDY  
TWELVE MONTHS ENDED DECEMBER 2016

INCREMENTAL INVESTMENT COSTS

Line No.		Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	SERVICE INSTALLATIONS							
		48 yr life						
1	TYPICAL SERVICE PIPE SIZE	3/4"	3/4"	1 1/4" - 2"	1/2" - 1.25"	1 1/4" - 2"	3/4" - 2"	1/2" - 2"
2	AVERAGE SERVICE COST	\$ 2,342.11	\$ 2,633.95	\$ 10,227.33	\$ 19,629.92	\$ 10,227.33	\$ 29,981.42	\$ 41,129.20
3	LEVELIZED PLANT COST FACTOR	0.1762	0.1762	0.1762	0.1762	0.1762	0.1762	0.1762
4	ANNUAL REVENUE REQUIREMENT	\$ 412.68	\$ 464.10	\$ 1,802.06	\$ 3,458.79	\$ 1,802.06	\$ 5,282.73	\$ 7,246.97
	METERS & REGULATORS							
		36 yr life						
5	METERS & REGULATORS	\$ 216.00	\$ 604.88	\$ 3,223.91	\$ 5,482.40	\$ 3,714.67	\$ 23,836.64	\$ 7,884.75
6	LEVELIZED PLANT COST FACTOR	0.1830	0.1830	0.1830	0.1830	0.1830	0.1830	0.1830
7	ANNUAL REVENUE REQUIREMENT	\$ 39.53	\$ 110.69	\$ 589.98	\$ 1,003.28	\$ 679.78	\$ 4,362.11	\$ 1,442.91
	MAIN INVESTMENT							
		58 yr life						
	AVERAGE MAIN EXTENSION PER CUSTOMER	Original Filing	112	568	382	498	382	792
8	AVERAGE MAIN EXTENSION PER CUSTOMER	Updated	91	436	494	498	382	792
9	TYPICAL PIPE SIZE REQUIRED	2"	2"	sample	dedicated pit	same as 424	dedicated pit	dedicated pit
10	AVERAGE COST PER FOOT	\$ 37.23	\$ 37.23	\$ 50.29	\$ 74.74	\$ 50.29	\$ 44.36	\$ 118.66
11	MAIN EXTENSION INVESTMENT	\$ 3,387.93	\$ 16,232.28	\$ 24,843.26	\$ 37,221.25	\$ 19,210.78	\$ 35,133.12	\$ 138,238.90
12	ESTIMATED DESIGN DAY LOAD FACTOR	100%	22.35%	24.81%	52.95%	50.42%	0.00%	87.79%
13	INCR CAPACITY MAIN INVESTMENT PER THERM	0.152883	\$ 0.684040	\$ 0.616215	\$ 0.288731	\$ 0.303219	\$ -	\$ 0.174146
14	2016 AVERAGE THERMS PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,496
15	CAPACITY MAIN INVESTMENT	\$ 385.11	\$ 1,437.01	\$ 15,961.04	\$ 34,437.18	\$ -	\$ 425,351.54	\$ 443,180.27
16	INCR COMMODITY MAIN INVESTMENT PER THERM	0.540957	\$ 0.540957	\$ 0.540957	\$ 0.540957	\$ 0.540957	\$ 0.540957	\$ 0.540957
17	2016 AVERAGE THERMS PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,496
18	COMMODITY MAIN INVESTMENT	\$ 304.56	\$ 1,261.51	\$ 29,904.11	\$ 61,437.58	\$ 15,537.37	\$ 1,321,285.66	\$ 597,930.75
19	TOTAL MAIN INVESTMENT PER CUSTOMER	\$ 4,077.60	\$ 18,930.81	\$ 70,708.41	\$ 133,096.02	\$ 34,748.15	\$ 1,781,770.32	\$ 1,179,349.92
20	LEVELIZED PLANT COST FACTOR	58 yr life	0.1763	0.1763	0.1763	0.1763	0.1763	0.1763
21	ANNUAL REVENUE REQUIREMENT	\$ 718.88	\$ 3,337.50	\$ 12,465.89	\$ 23,464.83	\$ 6,126.10	\$ 314,126.11	\$ 207,919.39
	UNDERGROUND STORAGE INVESTMENT							
22	BALANCING INVESTMENT PER TOTAL THROUGHPUT THERM	\$ 0.005839	\$ 0.005839	\$ 0.005839	\$ 0.005839	\$ 0.005839	\$ 0.005839	\$ 0.005839
23	STORAGE INVESTMENT PER JANUARY SALES THERM	\$ 0.381926	\$ 0.381926	\$ 0.381926	\$ 0.381926	\$ 0.381926	\$ 0.381926	\$ 0.381926
24	2016 AVERAGE THERMS PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,496
25	2016 AVERAGE JANUARY SALES THERMS PER CUSTOMER		94	379	5,531	11,484	659	
26	UNDERGROUND STORAGE INVESTMENT	\$ 39.19	\$ 158.37	\$ 2,435.23	\$ 5,049.22	\$ 419.41	\$ 14,262.51	\$ 6,454.32
27	LEVELIZED PLANT COST FACTOR	48 yr life	0.1762	0.1762	0.1762	0.1762	0.1762	0.1762
28	ANNUAL REVENUE REQUIREMENT	\$ 6.91	\$ 27.90	\$ 429.09	\$ 889.67	\$ 73.90	\$ 2,513.05	\$ 1,137.25
29	TOTAL INCREMENTAL INVESTMENT COST PER CUSTOMER	\$ 1,177.99	\$ 3,940.20	\$ 15,287.01	\$ 28,816.57	\$ 8,681.84	\$ 326,283.99	\$ 217,746.52

Exhibit No. 801  
Miller / Avista  
Page 2 of 3

# Staff's LRIC Results and Rate Spread Given Main Extension Updates and No Schedule Decreases

Staff/1303  
Compton/Page 3 of 4

AVISTA UTILITIES  
OREGON JURISDICTION  
LONG-RUN INCREMENTAL COST OF SERVICE STUDY  
TWELVE MONTHS ENDED DECEMBER 2016

**RESULT SUMMARY (Component Allocation)**

Line No.	OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456		
<b>STATISTICS</b>										
1										
2		2016 ANNUAL THERM DELIVERIES	131,581,172	49,018,942	26,621,408	4,588,281	3,975,023	258,498	7,327,488	39,791,532
3		2016 CUSTOMERS	98,647	87,065	11,416	83	35	9	3	36
3		AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
4		Gas Commodity Costs	\$ -	-	-	-	-	-	-	-
5		Gas Supply Department (Scheduling)	1,03189 \$ 56,322	25,593	13,899	2,396	2,075	135	1,901	10,323
6		Gas Supply Department (Non-Scheduling)	\$ 142,688	80,884	43,927	7,571	6,559	427	516	2,803
7		Meter Reading	\$ 116,123	102,489	13,439	98	41	11	4	42
8		Billing	\$ 2,437,937	2,151,696	282,139	2,051	865	222	74	890
		Customer Installation Investment Cost								
9		Meters	\$ 4,860,423	3,441,492	1,263,699	48,968	35,115	6,118	13,086	51,945
10		Services	\$ 41,791,718	35,929,828	5,298,304	149,571	121,058	16,218	15,848	260,891
11		Main Extensions	\$ 86,193,139	52,003,034	32,670,464	363,529	229,674	30,482	18,582	877,375
12		Total Customer Installation Investment Cost	\$ 132,845,281	91,374,354	39,232,468	562,068	385,846	52,818	47,516	1,190,210
		System Core Main Cost								
13		Capacity	\$ 12,287,370	5,911,318	2,892,256	233,556	212,495	-	224,968	2,812,777
14		Commodity	\$ 12,548,965	4,674,827	2,539,026	437,584	379,101	24,653	698,828	3,794,947
15		Total Core Main Cost	\$ 24,836,335	10,586,145	5,431,282	671,140	591,595	24,653	923,796	6,607,723
16		Underground Storage Cost	\$ 1,035,644	601,184	318,562	35,614	31,139	665	7,539	40,941
17		Long Run Incremental Distribution Cost	\$ 161,470,329	104,922,344	45,335,716	1,280,937	1,018,121	78,931	981,347	7,852,933
18		Distribution Margin Revenue at Present Rates	\$ 53,224,000	34,864,000	13,605,000	687,000	463,000	44,000	231,000	3,330,000
		Proposed Cost by Functional Classification Assigned to Schedule by LRIC components								
19		Cost of Gas Commodity	\$ -	-	-	-	-	-	-	-
20		Gas Supply Department Costs	\$ 568,000	303,900	165,043	28,446	24,644	1,603	6,899	37,466
21		Meter Reading, Billing, Etc. Costs	\$ 3,686,000	3,253,222	426,575	3,101	1,308	336	112	1,345
22		Meters & Services Costs	\$ 18,599,000	15,696,325	2,616,101	79,152	62,262	8,905	11,535	124,719
23		System Core Main Costs	\$ 37,367,000	21,064,405	12,823,153	348,218	276,398	18,556	317,158	2,519,112
24		Underground Storage Costs	\$ 1,561,000	906,149	480,161	53,680	46,934	1,002	11,364	61,709
25		LRIC Based Target Margin	\$ 61,781,000	41,224,001	16,511,033	512,598	411,546	30,402	347,068	2,744,351
26		Current Distribution Margin Revenue to Proposed Cost	0.86	0.85	0.82	1.34	1.13	1.45	0.67	1.21
27										
28		<b>Component LRIC Target Increase by Schedule: Staff's Results</b>	\$ 8,557,000	\$ 6,360,001	\$ 2,906,033	\$ (174,402)	\$ (51,454)	\$ (13,598)	\$ 116,068	\$ (585,649)

**Margin Revenue Increases Assuming Application Revenue Requirement: Staff's Results**

29	LRIC Target Increase as a Percent of Present Distribution Margin Revenue -- Updated Main Extensions	16.077%	18.2%	21.4%	-25.4%	-11.1%	-30.9%	50.2%	-17.6%
30	Target Increase as a % of Present Distribution Margin Rev. -- Updated Main Extensions	16.077%	16.8%	19.9%	0.0%	0.0%	0.0%	0.0%	0.0%
31	Component Target Margin Increase by Schedule -- Updated Main Extensions	\$ 8,557,000	5,855,097	2,701,903	-	-	-	-	-
32a	Purchased Gas Cost (Schedule 461 -- per therm)		\$ 0.62069	\$ 0.62069	\$ 0.62069	\$ 0.41155	\$ 0.62069	N/A	N/A
32b	Purchased Gas Revenues	\$ 51,593,477	\$ 30,425,567	\$ 16,523,642	\$ 2,847,900	\$ 1,635,921	\$ 160,447		
33	Total Billed Revenues (Excluding Adjustment Schedules 462, 476, 478, 493, 497)	\$ 113,374,477	\$ 71,144,664	\$ 32,830,545	\$ 3,534,900	\$ 2,098,921	\$ 204,447	\$ 231,000	\$ 3,330,000
34	<b>Billed Revenues Percentage Increase/Decrease</b>	8.2%	9.0%	9.0%	0.0%	0.0%	0.0%	N/A	N/A

Staff's LRIC Results and Rate Spread Given Main Extension Updates and Three Schedules With Decreases

AVISTA UTILITIES  
OREGON JURISDICTION  
LONG-RUN INCREMENTAL COST OF SERVICE STUDY  
TWELVE MONTHS ENDED DECEMBER 2016  
RESULT SUMMARY (Component Allocation)

Line No.		OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
1	STATISTICS								
2	2016 ANNUAL THERM DELIVERIES	131,561,172	49,018,942	26,621,408	4,588,281	3,975,023	258,498	7,327,488	39,791,532
3	2016 CUSTOMERS	98,647	87,065	11,418	83	35	9	3	36
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,498	1,105,320
4	Gas Commodity Costs	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5	Gas Supply Department (Scheduling)	1.03189 \$ 56,322	25,593	13,899	2,396	2,075	135	1,901	10,323
6	Gas Supply Department (Non-Scheduling)	\$ 142,688	80,884	43,927	7,571	6,559	427	516	2,803
7	Meter Reading	\$ 116,123	102,489	13,439	98	41	11	4	42
8	Billing	\$ 2,437,937	2,151,696	282,139	2,051	865	222	74	890
9	Customer Installation Investment Cost	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10	Meters	\$ 4,860,423	3,441,492	1,263,699	48,968	35,115	6,118	13,086	51,945
11	Services	\$ 41,781,718	35,929,828	5,298,304	149,571	121,058	16,218	15,848	250,691
12	Main Extensions	\$ 86,193,139	52,003,034	32,670,464	363,529	229,674	30,482	18,582	877,375
12	Total Customer Installation Investment Cost	\$ 132,845,281	91,374,354	39,232,468	562,068	385,846	52,818	47,516	1,190,210
13	System Core Main Cost	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
14	Capacity	\$ 12,287,370	5,911,318	2,892,256	233,556	212,495	-	224,968	2,812,777
15	Commodity	\$ 12,548,965	4,674,827	2,539,026	437,584	379,101	24,653	698,828	3,794,947
15	Total Core Main Cost	\$ 24,836,335	10,586,145	5,431,282	671,140	591,595	24,653	923,796	6,607,723
16	Underground Storage Cost	\$ 1,035,644	601,184	318,562	35,614	31,139	665	7,539	40,941
17	Long Run Incremental Distribution Cost	\$ 161,470,329	104,922,344	45,335,716	1,280,937	1,018,121	78,931	981,347	7,852,933
18	Distribution Margin Revenue at Present Rates	\$ 53,224,000	34,864,000	13,605,000	687,000	463,000	44,000	231,000	3,330,000
19	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
20	Cost of Gas Commodity	\$ 568,000	303,900	165,043	28,446	24,644	1,803	6,899	37,466
21	Gas Supply Department Costs	\$ 3,686,000	3,253,222	426,575	3,101	1,308	396	112	1,345
22	Meter Reading, Billing, Etc. Costs	\$ 18,599,000	15,698,325	2,616,101	79,152	62,262	8,905	11,535	124,719
23	Meters & Services Costs	\$ 37,367,000	21,064,405	12,823,153	348,218	276,398	18,556	317,158	2,519,112
24	System Core Main Costs	\$ 1,561,000	906,149	480,161	53,680	46,934	1,002	11,364	61,709
25	Underground Storage Costs	\$ 61,781,000	41,224,001	16,511,033	512,598	411,546	30,402	347,068	2,744,351
25	LRIC Based Target Margin	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
26	Current Distribution Margin Revenue to Proposed Cost	0.86	0.85	0.82	1.34	1.13	1.45	0.67	1.21
27									
28	Component LRIC Target Increase by Schedule	\$ 8,557,000	\$ 6,360,001	\$ 2,906,033	\$ (174,402)	\$ (51,454)	\$ (13,598)	\$ 116,068	\$ (585,649)

Margin Revenue Increases Assuming Application Revenue Requirement									
29	LRIC Target Increase as a Percent of Present Distribution Margin Revenue - Updated Main Extensions	16.077%	18.2%	21.4%	-25.4%	-11.1%	-30.9%	50.2%	-17.6%
30	Target Increase as a % of Present Distribution Margin Rev. -- Updated Main Extensions	16.077%	16.8%	19.9%	0.0%	0.0%	0.0%	0.0%	0.0%
31	Component Target Margin Increase by Schedule -- Updated Main Extensions	\$ 8,557,000	\$ 5,855,097	\$ 2,701,903	-	-	-	-	-
Margin Revenue Increases Assuming Slightly Less Than Half the Applied for General Increase									
32	Target Increase	\$ 4,150,000							
33	Target Increase as a % of Present Distribution Margin Rev. -- Updated Main Extensions	7.8%	8.7%	10.3%	-7.0%	0.0%	-7.0%	0.0%	-7.0%
34	Component Target Margin Increase by Schedule -- Updated Main Extensions	\$ 4,150,000	\$ 3,034,133	\$ 1,400,137	\$ (48,090)	\$ -	\$ (3,080)	\$ -	\$ (233,100)
35	Purchased Gas Cost (Schedule 461 -- per therm)		\$ 0.62069	\$ 0.62069	\$ 0.62069	\$ 0.41155	\$ 0.62069	N/A	N/A
36	Purchased Gas Revenues	\$ 51,593,477	\$ 30,425,567	\$ 16,523,642	\$ 2,847,900	\$ 1,635,921	\$ 160,447		
37	Total Billed Revenues (Excluding Adjustment Schedules 462, 476, 478, 493, 497)	\$ 108,967,477	\$ 68,323,700	\$ 31,528,778	\$ 3,486,810	\$ 2,098,921	\$ 201,367	\$ 231,000	\$ 3,096,900
38	Billed Revenues Percentage Increase/Decrease	4.0%	4.6%	4.6%	-1.4%	0.0%	-1.5%	N/A	N/A



CASE: UG 288  
WITNESS: GEORGE R. COMPTON

**PUBLIC UTILITY COMMISSION  
OF  
OREGON**

**STAFF EXHIBIT 1304**

**Exhibits in Support  
Of Opening Testimony**

**October 16, 2015**

**Average Residential Customer Burden from Selected 7% Industrial Rate Reductions**

Staff/1304  
Compton/1

Avista Utilities  
Proposed Revenue Increase by Schedule  
Oregon - Gas  
Pro Forma 12 Months Ended December 31, 2016  
(000s of Dollars)

Table's Origin: Exhibit AVISTA/903, Ehrbar/Page 3 of 4

Line No.	Type of Service	Schedule Number	Distribution Revenue Under Present Rates	Proposed GRC Increase	Distribution Revenue Under Proposed Rates	Therms (000s)	Distribution/	Billed Revenue Under Present Rates	Proposed GRC Increase	Billed Revenue Under Proposed Rates	Billed Revenue
							Margin Revenue Percentage Increase				Percentage Increase
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Residential	410	\$34,864	\$5,924	\$40,788	49,019	17.0%	\$66,399	\$5,924	\$72,323	8.9%
2	General Service	420	13,605	2,917	16,522	26,621	21.4%	30,571	\$2,917	\$33,488	9.5%
3	Large General Service	424	687	(48)	639	4,588	-7.0%	3,611	(\$48)	\$3,563	-1.3%
4	Interruptible Service	440	463	0	463	3,975	0.0%	2,307	\$0	\$2,307	0.0%
5	Seasonal Service	444	44	(3)	41	258	-7.0%	209	(\$3)	\$206	-1.5%
6	Transportation Service	456	3,330	(233)	3,097	39,792	-7.0%	3,384	(\$233)	\$3,151	-6.9%
7	Special Contract	447	231	0	231	7,327	0.0%	231	\$0	\$231	0.0%
8	Total		\$53,224	\$8,557	\$61,781	131,581	16.1%	\$106,712	\$8,557	\$115,269	8.0%

**Derivations:**

- 1. Number of residential customers (from Exhibit No. 801, Miller/Avista, Page 1 of 3): 87,065
- 2. Revenue shift (x1000) from 7% reduction for Sch's 424, 444, and 456 -- i.e., .07 x (639 + 41 + 3,097): \$264
- 3. Per-thousand-therm price addition to Sch's 410 and 420 from 7% revenue shift -- i.e., \$264/(49,019 + 26,621): \$0.0035
- 4. Burden (x1000) to Sch 410 from per-thousand-therm price addition -- i.e., \$0.0035 x 49,019: \$171
- 5. Average annual burden per-customer in Sch 410 from selected 7% margin revenue shift -- i.e., (\$171 x 1000)/87,065: **\$1.97**
- 6. Sch 410 current annual average bill -- i.e., (\$66,399 x 1000)/87,065: \$763
- 7. Average annual burden per-customer in Sch 410 as a percentage of the annual bill, i.e., \$1.87/\$763: 0.3%

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CERTIFICATE OF SERVICE

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I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding through Huddle.

Dated this 16th day of October , 2015 at Salem, Oregon



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Mark Brown  
Public Utility Commission  
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Salem, Oregon 97301-3612  
Telephone: (503) 378-8287