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

AVISTA
Corp.

June 24, 2009

Public Utility Commission of Oregon
Attn: Filing Center
PO Box 2148
Salem, OR 97308-2148

Advice No. 09-03-G

RE: Request for General Rate Revision of Avista Corporation

In accordance with Oregon Administrative Rules, Avista Corp., dba Avista Utilities, respectfully submits an original and 25 copies of the Company's trial brief, testimony and associated exhibits in support of its request for a general rate revision.

Three (3) copies of supporting work papers have also been included with this filing. Please note that the Company has only included hardcopies of Mr. Avera's workpapers for the Commission. Due to the voluminous nature of these workpapers (817 pages), they are being provided in electronic format only on the enclosed CD for others on the service list.

Please direct any questions regarding this filing to Liz Andrews at (509) 495-8601.

Sincerely,

Kelly Norwood

Kelly O. Norwood
Vice President, State and Federal Regulation

Enclosure

c: See attached service list

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served Direct Testimony and Exhibits in the Oregon Natural Gas General Rate Case Filing of Avista Utilities, a division of Avista Corporation, (Advice No. 09-03-G) upon the parties listed below by mailing a copy thereof, postage prepaid and/or by electronic mail.

W Chad Stokes
Cable Huston Benedict
Haagensen & Lloyd, LLP
1001 SW 5th, Suite 2000
Portland, OR 97204-1136
cstokes@cablehuston.com

W Bob Jenks
Citizens' Utilities Board
610 SW Broadway, Suite 308
Portland, OR 97205-3404
Bob@OregonCUB.org
dockets@oregoncub.org

W Paula Pyron
Executive Director
Northwest Industrial Gas Users
4113 Wolfberry Court
Lake Oswego, OR 97035
ppyron@nwigu.org

W Edward Finklea
Energy Action Northwest
PO Box 8308
Portland, OR 97207
efinklea@energyactionnw.org

Judy Johnson
Public Utility Commission
PO Box 2148
550 Capitol St. NE, Suite 215
Salem, OR 97308-2148
Judy.johnson@state.or.us

David Hatton
Assistant Attorney General
1162 Court St. NE
Salem, OR 97301-4096
David.hatton@state.or.us

I declare under penalty of perjury that the foregoing is true and correct.

Dated at Spokane, Washington this 24th day of June 2009.

Patty Olsness
____
Patty Olsness
Rates Coordinator

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UG-___

In the matter of the Application of AVISTA CORPORATION, DBA AVISTA UTILITIES for a General Rate Revision	))))	TRIAL BRIEF OF AVISTA CORPORATION

Avista Corporation, doing business as Avista Utilities ("Avista" or "Company"), is filing tariff schedules, pursuant to ORS 757.205 and ORS 757.220, to effect a general revision for its natural gas customers in Oregon. This brief is submitted to meet the requirements of OAR 860-013-0075.

1.

Avista provides natural gas service in the State of Oregon and is a public utility subject to the Public Utility Commission of Oregon's jurisdiction under ORS 757.005(1)(a)(A). Avista provides natural gas distribution service in southwestern and northeastern Oregon. The Company also provides electric and natural gas service within a 26,000 square mile area of eastern Washington and northern Idaho. As of December 31, 2008, Avista supplied retail electric service to an average of approximately 355,000 customers and retail natural gas service to approximately 315,000 customers, including approximately 95,000 customers in Oregon who will be affected by the proposed rate revision. Avista's principal place of business is located in Spokane, Washington.

2.

Avista requests that all notices, pleadings, and correspondence regarding this filing be sent to the following:

David J. Meyer, Esq.
Chief Counsel for Regulatory and Governmental Affairs
Avista Corporation
P.O. Box 3727
1411 E. Mission Avenue, MSC-13
Spokane, Washington 99220-3727
Telephone: (509) 495-4316
Facsimile: (509) 495-8851
E-mail: david.meyer@avistacorp.com

Kelly Norwood
Vice President, State and Federal Regulation
Avista Corporation
P.O. Box 3727
1411 E. Mission Avenue, MSC-13
Spokane, Washington 99220-3727
Telephone: (509) 495-4267
Facsimile: (509) 495-8851
E-mail: kelly.norwood@avistacorp.com

3.

The test period being used by the Company is the twelve months ended December 31, 2010, presented on a forecasted basis. The Company's pro forma results of operations for the test period indicate that, at the current rate levels, Avista would earn a return on equity ("ROE") of 3.30 percent. This ROE is clearly not sufficient to provide Avista with a fair and reasonable return or allow the Company to attract capital at reasonable rates.

Avista's revised tariff schedules effect an increase in rates for Oregon retail customers of $14,205,000, or 11.6 percent, which would produce an overall rate of return of 8.96 percent and a return on equity of 11.00 percent. Pursuant to ORS 757.220, the revised schedules contain an effective date of July 27, 2009.

4.

The Company acquired its Oregon natural gas operations from CP National in 1991. In the past 18 years that Avista has operated these properties, its base rates have previously increased only three times. A combination of capital additions, declining margins and increases in general business expense now require the Company to request an increase in overall base retail rates of $14,205,000.

The Company used the cost of service results as a guide in the proposed spread of the requested increase to the various customer rate schedules. As described in Company witness Knox's testimony, two cost of service studies were prepared. The results of both studies were generally consistent, i.e., showing generally the same margin-to-cost ratio for each schedule. As a result, the proposed rate spread would result in an increase of 12.5% to residential customers, and increases ranging between 3.4% and 34.4% to other rate schedules.

5.

Avista's direct case consists of the testimony and exhibits of the following witnesses:

(a) Policy and Operations – Exhibit 100. **Scott L. Morris**, Chairman of the Board, President and Chief Executive Officer of Avista Corporation, presents an overview of the filing and identifies the cost increases that make this filing necessary. Mr. Morris provides a history of the Company's general rate changes in Oregon, describes efforts to reduce operating costs, and explains the Company's customer support programs that are in place to assist customers.

(b) Financial Overview, Capital Structure, and Overall Rate of Return – Exhibit 200. **Mark T. Thies**, Senior Vice President and Chief Financial Officer, will address the Company's capital structure, the proposed cost of embedded debt and the overall rate of return. He will explain the actions the Company has taken to acquire needed capital and improve Avista's financial condition in recent years.

(c) Return on Equity – Exhibit 300. **William E. Avera**, as President of Financial Concepts and Applications (FINCAP), Inc., has been retained to present testimony with respect to the reasonableness of the Company's proposed overall capital structure and will testify in support of an 11.0% return on equity.

(d) Capital Projects – Exhibit 400. **Mr. Dave Defelice**, Senior Business Analyst, will describe the adjustments for capital expenditures, as well as the rising cost of essential materials specific to the utility industry that is causing significant increases in capital project funding requirements.

(e) Revenue Requirement and Allocations – Exhibit 500. **Elizabeth M. Andrews,** Manager, Revenue Requirements, will discuss the Company's overall revenue requirement proposals. In addition, her testimony and exhibits will cover accounting and financial data in support of the Company's need for the proposed increase in rates and the allocation methodologies. She will also explain forecasted operating results, including expense and rate base adjustments made to actual operating results and rate base.

(f) Long-Run Incremental Cost of Service – Exhibit 600. **Tara L. Knox**, Senior Regulatory Analyst, sponsors the long-run incremental cost study for Oregon natural gas service. Ms. Knox discusses her study results and how each schedule's present and proposed rates compare to the indicated cost.

(g) Rate Design and Rate Spread – Exhibit 700. **Brian J. Hirschkorn**, Manager, Retail Pricing, discusses the spread of the annual revenue changes among the Company's general service schedules and related rate design. Mr. Hirschkorn also discusses the forecasted revenue adjustment.

6.

The following exhibits are attached pursuant to OAR 860-13-0075:

(a) Exhibit A. The information required by OAR 860-013-0075(1)(b)(A)-(F).

(b) Exhibit B. From Ms. Andrew's Exhibit 501, page 1, which shows the results of operations for Avista's Oregon jurisdiction before and after the proposed rate change, as required by OAR 860-013-0075(1)(b)(G).

(c) Exhibit C. This exhibit shows the effect of the proposed rate change on each class of customers as required by OAR 860-013-0075(1)(b)(H). Exhibit C also contains information required by OAR 860-022-0030(1). Specifically, the exhibit shows, for each tariff schedule, the total number of customers affected, the total annual revenue derived under the existing schedule, and the amount of estimated revenue derived from applying the proposed rate revisions. For each tariff schedule, the exhibit also shows the average monthly use and resulting bills under both existing rates and proposed rates for characteristic customers.

7.

Avista Corporation respectfully requests that the Commission issue an order granting the rate relief requested in this filing and approving the proposed tariff schedules.

DATED: June 24, 2009.

David J. Meyer
Chief Counsel for Regulatory and Governmental Affairs
Avista Corporation

EXHIBIT A

INFORMATION REQUIRED BY OAR 860-013-0075(1)(b)(A)-(F)

A. The dollar amount of total revenues that would be collected under the proposed rates is $137,007,000.

B. The dollar amount of revenue change requested is $14,205,000.

C. The percentage change in revenues requested is 11.6 percent.

D. The forecasted test period proposed is January 1, 2010 to December 31, 2010.

E. The requested overall rate of return is 8.96 percent and the requested return on equity is 11.00 percent.

F. The rate base proposed in this filing is $147,649,000.

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON JURISDICTION FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
Line No.	DESCRIPTION	Actual Per Results Report (EOP)	Total Adjustments	Forecasted Total	Proposed Revenues & Related Exp	Forecasted Proposed Total (AMA)
	a	*b*	*c*	*d*	*e*	*f*
	OPERATING REVENUES					
1	Total General Business	$128,123	$ (7,706)	$120,417	$14,205	$134,622
2	Total Transportation	2,391	(5)	2,386		2,386
3	Other Revenues	67,985	(67,836)	149		149
4	Total Operating Revenues	198,499	(75,547)	122,952	14,205	137,157
	OPERATING EXPENSES					
5	Gas Purchased	160,985	(71,958)	89,027		89,027
6	Operation and Maintenance	11,597	(934)	10,663	91	10,754
7	Administration & General	7,006	571	7,577	46	7,623
8	Taxes Other than Income	5,931	(542)	5,389	300	5,689
9	Depreciation & Amortization	3,325	2,174	5,499		5,499
10	Total Operating Expenses	188,844	(70,689)	118,155	437	118,592
11	OPERATING INCOME BEFORE FIT	9,655	(4,858)	4,797	13,768	18,565
	INCOME TAXES					
12	Current Federal Income Taxes	236	(1,765)	(1,529)	4,501	2,972
13	Deferred Federal Income Taxes	1,346	4	1,350		1,350
14	State Income Taxes	(161)	267	106	909	1,015
15	Total Income Taxes	1,421	(1,494)	(73)	5,410	5,337
16	NET OPERATING INCOME	$8,234	($3,364)	$4,870	$8,358	$13,228
	RATE BASE					
17	Utility Plant in Service	230,167	36,321	266,488		266,488
18	Less: Accum Depr and Amort	(88,453)	(7,336)	(95,789)	0	(95,789)
19	Net Utility Plant	141,714	28,985	170,699	0	170,699
20	Accumulated Deferred FIT	(21,987)	(3,214)	(25,201)		(25,201)
21	Inventory and Other	5,137	(2,986)	2,151	0	2,151
22	TOTAL RATE BASE	$124,864	$22,785	$147,649	$0	$147,649
23	RATE OF RETURN	6.59%		3.30%		8.96%

EXHIBIT C

Avista Utilities
Docket No. UG-___
Rate Spread Summary
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2010

Type of Service	Schedule Number	Avg. No. of Customers	Annual Therms	Avg. Use per Customer per Month	Revenue at Pres. Rates ($000's)	Avg. Bill Under Pres. Rates	Revenue Percentage Increase	Revenue Increase ($000's)	Avg. Increase per Customer per Month	Revenue at Prop. Rates ($000's)	Avg. Bill Under Prop. Rates
Residential	410	84,314	49,542,068	49	$73,837	$73.31	12.5%	$9,258	$9.15	$83,095	$82.46
General Service	420	11,208	27,280,991	203	36,343	$270.42	10.6%	3,867	$28.77	40,209	$299.19
Large General Service	424	98	4,082,190	3,489	4,876	$4,168	4.4%	213	$182	5,089	$4,350
Interruptible Service	440	40	5,776,303	12,084	5,143	$10,760	3.4%	175	$366	5,318	$11,126
Seasonal Service	444	3	184,605	4,989	217	$5,866	4.7%	10	$278	227	$6,144
Transportation Service	456	34	26,600,962	65,198	1,983	$4,859	34.4%	682	$1,672	2,665	$6,532
Special Contract	447	5	3,135,262	52,254	404	$6,728	0.0%	0	$0	404	$6,728
Total		95,702	116,602,382		$122,802		11.6%	$14,205		$137,007	

Exhibit B

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON JURISDICTION FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
Line No.	**DESCRIPTION**	**Actual Per Results Report (EOP)**	**Total Adjustments**	**Forecasted Total**	**Proposed Revenues & Related Exp**	**Forecasted Proposed Total (AMA)**
	a	*b*	*c*	*d*	*e*	*f*
	OPERATING REVENUES					
1	Total General Business	$128,123	$ (7,706)	$120,417	$14,205	$134,622
2	Total Transportation	2,391	(5)	2,386		2,386
3	Other Revenues	67,985	(67,836)	149		149
4	Total Operating Revenues	198,499	(75,547)	122,952	14,205	137,157
	OPERATING EXPENSES					
5	Gas Purchased	160,985	(71,958)	89,027		89,027
6	Operation and Maintenance	11,597	(934)	10,663	91	10,754
7	Administration & General	7,006	571	7,577	46	7,623
8	Taxes Other than Income	5,931	(542)	5,389	300	5,689
9	Depreciation & Amortization	3,325	2,174	5,499		5,499
10	Total Operating Expenses	188,844	(70,689)	118,155	437	118,592
11	OPERATING INCOME BEFORE FIT	9,655	(4,858)	4,797	13,768	18,565
	INCOME TAXES					
12	Current Federal Income Taxes	236	(1,765)	(1,529)	4,501	2,972
13	Deferred Federal Income Taxes	1,346	4	1,350		1,350
14	State Income Taxes	(161)	267	106	909	1,015
15	Total Income Taxes	1,421	(1,494)	(73)	5,410	5,337
16	NET OPERATING INCOME	$8,234	($3,364)	$4,870	$8,358	$13,228
	RATE BASE					
17	Utility Plant in Service	230,167	36,321	266,488		266,488
18	Less: Accum Depr and Amort	(88,453)	(7,336)	(95,789)	0	(95,789)
19	Net Utility Plant	141,714	28,985	170,699	0	170,699
20	Accumulated Deferred FIT	(21,987)	(3,214)	(25,201)		(25,201)
21	Inventory and Other	5,137	(2,986)	2,151	0	2,151
22	TOTAL RATE BASE	$124,864	$22,785	$147,649	$0	$147,649
23	RATE OF RETURN	6.59%		3.30%		8.96%

Avista Utilities
Oregon - Gas
Pro Forma Revenue Under Present and Proposed Base Tariff Rates
Year Ended 12/31/08

WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PRESENT BILL DETERMINANTS								
	THERMS								
BJH-5	BLOCK 1		49,542,068	27,280,991	4,082,190	5,776,303	184,605	3,897,200	
BJH-5	BLOCK 2							6,486,906	1,184,555
BJH-5	BLOCK 3							4,415,618	
BJH-5	BLOCK 4							11,583,266	1,500,000
BJH-5	BLOCK 5							217,972	450,707
	SUBTOTAL	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	ADJUSTMENT TO ACTUAL								
	TOTAL BEFORE ADJUSTMENT	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	WEATHER & UNBILLED REV. ADJ.								
	TOTAL PROFORMA THERMS	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
BJH-5	TOTAL BILLS		1,011,771	134,496	1,170	478	37	408	60
	TOTAL MINIMUM BILLS								
	PROPOSED BILL DETERMINANTS								
	THERMS								
	BLOCK 1		49,542,068	27,280,991	4,082,190	5,776,303	184,605	3,897,200	
	BLOCK 2							6,486,906	1,184,555
	BLOCK 3							4,415,618	
	BLOCK 4							11,583,266	1,500,000
	BLOCK 5							217,972	450,707
	SUBTOTAL	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	ADJUSTMENT TO ACTUAL								
	TOTAL BEFORE ADJUSTMENT	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	WEATHER & UNBILLED REV. ADJ.								
	TOTAL PROFORMA THERMS	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	TOTAL BILLS		1,011,771	134,496	1,170	478	37	408	60
	TOTAL MINIMUM BILLS								

Avista Utilities
Oregon - Gas
Pro Forma Revenue Under Present and Proposed Base Tariff Rates
Year Ended 12/31/08

WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PRESENT RATES								
Exh 701	BASIC CHARGE		$6.00	$8.00	$46.00			$187.50	
BJH-7	ANNUAL MINIMUM								$317,482
Exh 701	BLOCK 1 PER THERM		$1.36785	$1.29272	$1.18131	$0.89041	$1.17586	$0.13148	$0.02700
Exh 701	BLOCK 2 PER THERM							$0.07906	$0.02500
Exh 701	BLOCK 3 PER THERM							$0.06496	$0.04694
Exh 701	BLOCK 4 PER THERM							$0.05080	$0.02750
Exh 701	BLOCK 5 PER THERM							$0.02568	$0.03400
	PROPOSED RATES								
	BASIC CHARGE		$6.75	$8.75	$50.00			$250.00	
	ANNUAL MINIMUM								$317,482
	BLOCK 1 PER THERM		$1.53940	$1.43076	$1.23236	$0.92068	$1.23153	$0.17679	$0.02700
	BLOCK 2 PER THERM							$0.10630	$0.02500
	BLOCK 3 PER THERM							$0.08735	$0.04694
	BLOCK 4 PER THERM							$0.06831	$0.02750
	BLOCK 5 PER THERM							$0.03453	$0.03400

Avista Utilities
Oregon - Gas
Pro Forma Revenue Under Present and Proposed Base Tariff Rates
Year Ended 12/31/08

WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PRESENT REVENUE								
	BASE TARIFF REVENUE								
	BASIC CHARGE	$7,276,914	$6,070,626	$1,075,968	$53,820			$76,500	
	ANNUAL MINIMUM	$317,482							$317,482
	BLOCK 1	$113,727,885	$67,766,118	$35,266,683	$4,822,332	$5,143,278	$217,070	$512,404	
	BLOCK 2	$542,469						$512,855	$29,614
	BLOCK 3	$286,839						$286,839	
	BLOCK 4	$629,680						$588,430	$41,250
	BLOCK 5	$20,922						$5,598	$15,324
	ANNUAL MINIMUM	$0							
	SUBTOTAL	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670
	ADJUST TO ACTUAL	$0							
	TOTAL BASE TARIFF REVENUE	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670
	ADJUSTMENT REVENUE								
	UNBILLED REVENUE ADJUSTMENT								
	UNBILLED THERMS	0							
Exh 701	UNBILLED RATE		$1.36785	$1.29272	$1.18131		$1.17586		
	UNBILLED REVENUE	$0	$0	$0	$0		$0		
	WEATHER NORMALIZATION ADJ								
	WEATHER-SENSITIVE THERMS	0	0	0					
Exh 701	WEATHER-SENSITIVE RATE		$1.36785	$1.29272					
	WEATHER-SENSITIVE REVENUE	$0	$0	$0					
	OTHER ADJUSTMENTS								
	TOTAL ADJUSTMENT REVENUE	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL BASE TARIFF REVENUE	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670
	TOTAL PRESENT REVENUE	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670

Avista Utilities
Oregon - Gas
Pro Forma Revenue Under Present and Proposed Base Tariff Rates
Year Ended 12/31/08

WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PROPOSED REVENUE								
	BASE TARIFF REVENUE								
	BASIC CHARGE	$8,166,794	$6,829,454	$1,176,840	$58,500			$102,000	
	ANNUAL MINIMUM	$317,482							$317,482
	BLOCK 1	$126,562,791	$76,265,060	$39,032,551	$5,030,728	$5,318,127	$227,347	$688,979	
	BLOCK 2	$719,199						$689,585	$29,614
	BLOCK 3	$385,683						$385,683	
	BLOCK 4	$832,453						$791,203	$41,250
	BLOCK 5	$22,850						$7,526	$15,324
	ANNUAL MINIMUM	$0							
	SUBTOTAL	$137,007,254	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977	$403,670
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	$137,007,254	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977	$403,670
	ADJUST TO ACTUAL	$0							
	TOTAL BASE TARIFF REVENUE	$137,007,254	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977	$403,670
	ADJUSTMENT REVENUE								
	UNBILLED REVENUE ADJUSTMENT								
	UNBILLED THERMS	0	0	0	0		0		
BJH-2	UNBILLED RATE		$1.53940	$1.43076	$1.23236		$1.23153		
	UNBILLED REVENUE	$0	$0	$0	$0		$0		
	WEATHER NORMALIZATION ADJ								
	WEATHER-SENSITIVE THERMS	0	0	0					
BJH-2	WEATHER-SENSITIVE RATE		$1.53940	$1.43076					
	WEATHER-SENSITIVE REVENUE	$0	$0	$0					
	OTHER ADJUSTMENTS								
	TOTAL ADJUSTMENT REVENUE	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL BASE TARIFF REVENUE	$137,007,254	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977	$403,670
	TOTAL PROPOSED REVENUE	$137,007,254	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977	$403,670
	TOTAL PRESENT REVENUE	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670
	TOTAL INCREASED REVENUE	**$14,205,064**	**$9,257,770**	**$3,866,740**	**$213,076**	**$174,849**	**$10,277**	**$682,353**	**$0**
	PERCENT REVENUE INCREASE	**11.57%**	**12.54%**	**10.64%**	**4.37%**	**3.40%**	**4.73%**	**34.42%**	**0.00%**

	TOTAL	SCHED. 410	SCHED. 420	SCHED. 424	SCHED. 440	SCHED. 444	SCHED. 456
Proposed Rate Workup - from Pres & Prop Rev tab							
THERMS							
BLOCK 1	90,763,358	49,542,068	27,280,991	4,082,190	5,776,303	184,605	3,897,200
BLOCK 2	6,486,906						6,486,906
BLOCK 3	4,415,618						4,415,618
BLOCK 4	11,583,266						11,583,266
BLOCK 5	217,972						217,972
ADJ. TO ACTUAL							
WEATHER & U/B THERMS							
TOTAL PROFORMA THERMS	113,467,120	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962
TOTAL BILLS		1,011,771	134,496	1,170	478	37	408
		84,314	11,208	98	40	3	34
Proposed Revenue	$136,603,520	$83,094,398	$40,209,455	$5,089,226	$5,318,116	$227,347	$2,664,977
Targeted Rate Increase							
Present Basic/Min Charge		$6.00	$8.00	$46.00			$187.50
BASIC/MIN CHARGE		$6.75	$8.75	$50.00			$250.00
% Δ in Basic Charge		12.5%	9.4%	8.7%			33.3%
Basic Charge Revenue	$8,166,794	$6,829,454	$1,176,840	$58,500			$102,000
Present Block 1 Rate		$1.36785	$1.29272	$1.18131	$0.89041	$1.17586	$0.13148
Present Block 2 Rate							$0.07906
Present Block 3 Rate							$0.06496
Present Block 4 Rate							$0.05080
Present Block 5 Rate							$0.02568
1) Flat Rate Increase		$1.00000	$1.00000	$1.00000	$1.00000	$1.00000	-$0.13689
2) % Rate Increase		12.54%	10.68%	4.32%	3.40%	4.73%	34.46%
Method --->		**2**	**2**	**2**	**2**	**2**	**2**
BLOCK 1 PER THERM		$1.53940	$1.43076	$1.23236	$0.92068	$1.23153	$0.17679
BLOCK 2 PER THERM							$0.10630
BLOCK 3 PER THERM							$0.08735
BLOCK 4 PER THERM							$0.06831
BLOCK 5 PER THERM							$0.03453
BLOCK 1 PER THERM		$1.53940	$1.43076	$1.23236	$0.92068	$1.23153	$0.17679
BLOCK 2 PER THERM							$0.10630
BLOCK 3 PER THERM							$0.08735
BLOCK 4 PER THERM							$0.06831
BLOCK 5 PER THERM							$0.03453
Blocks 1-5 Revenue	$128,436,726	$76,264,944	$39,032,615	$5,030,726	$5,318,116	$227,347	$2,562,977
Adj. to Actual Revenue		$0	$0	$0	$0	$0	$0
Weather & U/B Revenue		$0	$0	$0	$0	$0	$0
Revenue Remaining	$0	$0	$0	$0	$0	$0	$0
Revenue Remaining - ¢/Th	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
check - < $4k is rounding	-$63	-$116	$64	-$1	-$11	$0	$0
Proposed Target	**$136,603,520**	$83,094,398	$40,209,455	$5,089,226	$5,318,116	$227,347	$2,664,977
Proposed Actual	**$136,603,583**	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977
	$63	$116	-$64	$1	$11	$0	$0
Rate Δ Check							
Basic/Min Charge	11.7%	12.5%	9.4%	8.7%	#DIV/0!	#DIV/0!	33.3%
Adj. to Actual Revenue	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Weather & U/B Revenue	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Block Therm Charges	11.6%	12.5%	10.7%	4.3%	3.4%	4.7%	34.5%
Overall Revenue	**11.6%**	**12.5%**	**10.6%**	**4.4%**	**3.4%**	**4.7%**	**34.4%**
Avg. Usage		49	203	3,489	12,084	4,989	65,198

Avista Utilities
Docket No. UG-___
Rate Spread Summary
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2010

Type of Service	Schedule Number	Avg. No. of Customers	Annual Therms	Avg. Use per Customer per Month	Revenue at Pres. Rates ($000's)	Avg. Bill Under Pres. Rates	Revenue Percentage Increase	Revenue Increase ($000's)	Avg. Increase per Customer per Month	Revenue at Prop. Rates ($000's)	Avg. Bill Under Prop. Rates
Residential	410	84,314	49,542,068	49	$73,837	$73.31	12.5%	$9,258	$9.15	$83,095	$82.46
General Service	420	11,208	27,280,991	203	36,343	$270.42	10.6%	3,867	$28.77	40,209	$299.19
Large General Service	424	98	4,082,190	3,489	4,876	$4,168	4.4%	213	$182	5,089	$4,350
Interruptible Service	440	40	5,776,303	12,084	5,143	$10,760	3.4%	175	$366	5,318	$11,126
Seasonal Service	444	3	184,605	4,989	217	$5,866	4.7%	10	$278	227	$6,144
Transportation Service	456	34	26,600,962	65,198	1,983	$4,859	34.4%	682	$1,672	2,665	$6,532
Special Contract	447	5	3,135,262	52,254	404	$6,728	0.0%	0	$0	404	$6,728
Total		95,702	116,602,382		$122,802		11.6%	$14,205		$137,007	

EXHIBIT C

Avista Utilities
State of Oregon
Comparison of Natural Gas Usage
2006 & 2008 Weather-Normalized & 2010 Forecast

Line No.		Actual Usage	Weather & Unbilled Adj.	Normalized Usage	Avg. Customers	Annual Use/ Customer	Monthly Use/ Customer
	Residential Sch 410						
1	2006	49,257,514	525,049	**49,782,563**	81,424	611.4	**50.9**
2	2008	50,560,635	(3,921,539)	46,639,096	83,541	558.3	46.5
3	2010			**49,542,068**	84,314	587.6	**49.0**
	Commercial Sch 420						
4	2006	28,301,835	252,099	**28,553,934**	10,808	2,642	220
5	2008	28,271,134	(1,993,020)	26,278,114	11,026	2,383	199
6	2010			**27,280,991**	11,208	2,434	203
	Industrial Sales Schs. 424, 440 & 444						
7	2006			7,251,357	134	54,115	4,510
8	2008			9,935,547	137	72,522	6,044
9	2010			10,043,098	140	71,736	5,978
	Total Sales Volumes						
10	2006			85,587,854	92,366		
11	2008			82,852,757	94,704		
12	2010			86,866,157	95,662		
	Transport Schs. 447 & 456						
13	2006			**40,985,407**	41	999,644	83,304
14	2008			29,736,224	39	762,467	63,539
15	2010			**29,736,224**	39	762,467	63,539
	Total Throughput						
16	2006			**126,573,261**			
17	2008			112,588,981			
18	2010			**116,602,381**			

Avista Utilities
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2010

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	CURRENT REVENUE	$ 122,802,190	$ 73,836,744	$ 36,342,651	$ 4,876,152	$ 5,143,278	$ 217,070	$ 403,670	$ 1,982,625
2	COST OF GAS	$ 91,846,926	$ 53,305,263	$ 29,320,596	$ 4,387,386	$ 4,635,274	$ 198,407	$ -	$ -
3	CURRENT MARGIN	$ 30,955,264	$ 20,531,481	$ 7,022,055	$ 488,766	$ 508,004	$ 18,663	$ 403,670	$ 1,982,625
4	% of Current Margin excl Sch 447	100.00%	67.20%	22.98%	1.60%	1.66%	0.06%		6.49%
5	Total Revenue Requirement	$ 14,205,000							
6	Revenue Requirement as a Percent of Margin Revenue	45.89%							
7	Percentage Applied to Overall Margin Increase		98.26%	120.00%	95.00%	75.00%	120.00%		75.00%
8	Increase as a Percent of Total Current Margin		45.09%	55.07%	43.59%	34.42%	55.07%		34.42%
9	**PROPOSED MARGIN REVENUE INCREASE**	**$ 14,205,000**	**$ 9,257,654**	**$ 3,866,804**	**$ 213,074**	**$ 174,838**	**$ 10,277**		**$ 682,352**
10	**Proposed Revenue Increase**	**11.57%**	**12.54%**	**10.64%**	**4.37%**	**3.40%**	**4.73%**		**34.42%**
	Cost of Service Method I								
10	Proposed Margin	$ 45,160,264	$ 29,789,135	$ 10,888,859	$ 701,840	$ 682,842	$ 28,940	$ 403,670	$ 2,664,977
11	LRIC Based Target Margin (Line 25 of Knox Exhibit 601 Page 1 of 4)	$ 45,160,264	$ 28,380,574	$ 12,564,145	$ 642,001	$ 532,101	$ 36,564	$ 629,468	$ 2,375,411
12	**Relative Margin to Cost at Present Rates (Method I - Line 21A of Knox Exhibit 601 Page 1 of 4)**	**1.00**	**1.06**	**0.82**	**1.11**	**1.39**	**0.74**		**1.22**
13	**Relative Margin to Cost at Proposed Rates**	**1.00**	**1.05**	**0.87**	**1.09**	**1.28**	**0.79**		**1.12**
	Cost of Service Method II								
14	Proposed Margin	$ 45,160,264	$ 29,789,135	$ 10,888,859	$ 701,840	$ 682,842	$ 28,940	$ 403,670	$ 2,664,977
15	LRIDC Based Target Margin (Line 27 of Knox Exhibit 601 Page 2 of 4)	$ 45,161,000	$ 30,432,009	$ 11,158,026	$ 569,446	$ 481,847	$ 34,349	$ 508,003	$ 1,977,319
16	**Relative Margin to Cost at Present Rates (Method II - Line 29A of Knox Exhibit 601 Page 2 of 4)**	**1.00**	**0.98**	**0.92**	**1.25**	**1.54**	**0.79**		**1.46**
17	**Relative Margin to Cost at Proposed Rates**	**1.00**	**0.98**	**0.98**	**1.23**	**1.42**	**0.84**		**1.35**
18	**Average of Two Methods - Present Rates**	**1.00**	**1.02**	**0.87**	**1.18**	**1.47**	**0.77**		**1.34**
19	**Average of Two Methods - Proposed Rates**	**1.00**	**1.01**	**0.93**	**1.16**	**1.35**	**0.82**		**1.24**

Avista Utilities
Proposed Revenue Increase by Schedule
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2010
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Revenue Under Present Rates	Increase/ (Decrease)	Revenue Under Proposed Rates	Therms (000s)	Increase/ (Decrease) Per Therm	**Revenue Percentage Increase**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	410	$73,837	$9,258	$83,095	49,542	18.69¢	**12.5%**
2	General Service	420	36,343	3,867	40,209	27,281	14.17¢	**10.6%**
3	Large General Service	424	4,876	213	5,089	4,082	5.22¢	**4.4%**
4	Interruptible Service	440	5,143	175	5,318	5,776	3.03¢	**3.4%**
5	Seasonal Service	444	217	10	227	185	5.57¢	**4.7%**
6	Transportation Service	456	1,983	682	2,665	26,601	2.57¢	**34.4%**
7	Special Contract	447	404	0	404	3,135	0.00¢	**0.0%**
8	Total		$122,802	$14,205	$137,007	116,602	12.18¢	**11.6%**

Avista Utilities
Comparison of Present & Proposed Gas Rates
Oregon - Gas

Present Rates	Change	Proposed Rates
Residential Service Schedule 410		
$6.00 Customer Charge	$0.75/month	$6.75 Customer Charge
All Therms - $1.36785/Therm	$0.17155/therm	All Therms - $1.53940/Therm
General Service Schedule 420		
$8.00 Customer Charge	$0.75/month	$8.75 Customer Charge
All Therms - $1.29272/Therm	$0.13804/therm	All Therms - $1.43076/Therm
Large General Service Schedule 424		
$46.00 Customer Charge	$4.00/month	$50.00 Customer Charge
All Therms - $1.18131/Therm	$0.05105/therm	All Therms - $1.23236/Therm
Interruptible Service Schedule 440		
All Therms - $0.89041/Therm	$0.03027/therm	All Therms - $0.92068/Therm
Seasonal Service Schedule 444		
All Therms - $1.17586/Therm	$0.05567/therm	All Therms - $1.23153/Therm
Transportation Service Schedule 456		
$187.50 Customer Charge	$62.50/month	$250.00 Customer Charge
1st 10,000 Therms - $0.13148/Therm	$0.04531/therm	1st 10,000 Therms - $0.17679/Therm
Next 20,000 Therms - $0.07906/Therm	$0.02724/therm	Next 20,000 Therms - $0.10630/Therm
Next 20,000 Therms - $0.06496/Therm	$0.02239/therm	Next 20,000 Therms - $0.08735/Therm
Next 200,000 Therms - $0.05080/Therm	$0.01751/therm	Next 200,000 Therms - $0.06831/Therm
Over 250,000 Therms - $0.02568/Therm	$0.00885/therm	Over 250,000 Therms - $0.03453/Therm

Avista Utilities
Oregon - Gas
Usage & Billings by Rate Schedule
Pro Forma Year Ended 12/31/10

	Total therms (1)	Billings
Schedule 410	49,542,068	1,011,771
Schedule 420	27,280,991	134,496
Schedule 424	4,082,190	1,170
Schedule 440	5,776,303	478
Schedule 444	184,605	37
Schedule 447		
Biomass One	0	12
Collins Products	1,184,555	12
Douglas Forest Products	0	12
Murphy Plywood	1,500,000	12
Roseburg Forest Products	450,707	12
Total Sch. 447	3,135,262	60

	First 10000 thms	Next 20000 thms	Next 20000 thms	Next 200000 thms	>250000 thms	Total therms	Billings
Schedule 456	3,897,200	6,486,906	4,415,618	11,583,266	217,972	26,600,962	408

(1) from Company load forecast for 2010, 4/16/09;
Sch. 447 & Sch. 456 from normalized 2008
(2) shown on workpapers BJH-10
(3) shown on workpaper BJH-7
(4) shown on workpaper BJH-8
(5) shown on workpaper BJH-9

	Total therms	Billings
This worksheet	116,602,382	95,702
Load Forecast		
Schs. 410 - 444	85,843,372	95,662
Schs. 447 & 456	29,137,694	41
	114,981,066	95,703
ignore 2010 447 & 456	-29,137,694	-41
use 2008 447 & 456	29,736,224	39
	115,579,596	95,701
Add Sabroso to load forecast	1,022,786	1
	116,602,382	95,702

Avista Utilities
Oregon - Gas
Year Ended December 31, 2008

Alcan	226563	10,248	10,809	9,653	8,682	10,018	11,646	10,506	12,763	12,727	13,257	14,317	6,971	131,597	
BH Mint	450116435									50,021	2,756			52,777	
Boise Cascade LLC Inland Region	730084103	2,752	4,024	2,339	1,967	1,526	360	103	21	19	21	707	1,575	15,414	
Boise Cascade LLC Medford 4003	180268	1,529	1,833	1,632	1,483	1,733	1,552	1,535	1,500	1,463	1,524	1,431	1,306	18,521	
Borden Chemical Co	109631	13,733	16,803	13,178	10,777	14,024	11,453	7,825	10,434	7,892	9,107	12,190	11,140	138,556	
Dancer Lumber Company	130102623	9,312	15,218	12,167	8,474	15,053	13,445	12,983	12,091	10,308	11,012	14,277	12,063	146,403	
Department of Veterans Affairs	129504	100,784	99,722	94,961	76,774	90,590	58,109	37,771	30,348	25,755	32,088	59,174	77,170	783,246	
Department of Veterans Affairs	217907	59,471	59,724	59,005	54,597	62,719	44,930	41,955	34,990	32,695	40,557	47,073	43,509	581,225	
Grande Ronde Hospital	100086	24,538	33,588	28,056	24,581	24,963	15,408	13,682	13,359	11,831	14,287	17,406	23,612	245,311	
Hamann Angus Ranch	570046355									39,575	25,004			64,579	
Knife River Materials	173985					153						733	1,013	1,899	
Knife River Materials	570117080	2,230									4,772	12,133	2,830	21,965	
Knife River Materials - Roseburg	225016	3,700	4,186	3,710	3,825	4,774	4,472	13,737	7,037	4,472	6,418	4,589	3,208	64,128	
Lagrande School District	101277	29,636	40,475	27,055	21,078	23,082	8,880	3,252	85		476	13,216	17,429	184,664	
Lagrande School District	101870	215	201	217	213	235	220	189	121	138	318	2,542	3,421	8,030	
Medford School Dist 549C	129490	15,389	18,709	18,084	11,186	11,907	4,218	256	5	60	677	6,162	15,966	102,619	
Medford School Dist 549C	133731	9,662	11,219	12,554	7,218	9,151	3,500	1,289	191	190	741	2,414	5,123	63,252	
Medford School Dist 549C	135016	17,489	21,120	18,890	8,259	11,875	3,680	1,379	359	248	645	7,910	12,345	104,199	
Medford School Dist 549C	151901	9,500	10,729	8,965	6,584	8,474	2,472	655	189	172	572	3,584	7,363	59,259	
Orcutt;Dave	770106925									83	26,259			26,342	
Oregon Linen Inc	212741	7,862	7,534	7,786	5,608	6,584	5,812	5,657	6,406	6,349	7,505	8,083	6,615	81,801	
Pinnacle Health Care	290074125	4,938	5,594	4,461	3,939	3,923	3,237	3,286	2,855	2,746	3,584	3,840	3,553	45,956	
Premier Mint Oils, Inc.	690046355									41,866	28,686			70,552	
Sabroso Co 5710-110	157503	94,006	51,872	81,664	53,632	30,427	114,996	297,274	298,915	236,206	217,199	205,073	160,822	1,842,086	
Sky Lakes Medical Center	243178	8,330	8,988	8,204	8,275	9,074	8,533	8,510	8,502	16,654	15,629	13,501	9,429	123,629	
Umpqua Community College	221337	15,610	21,218	16,395	13,213	18,265	8,703	6,948	3,280	2,734	4,557	8,691	9,607	129,221	
Umpqua Dairy	213236	16,769	18,817	17,670	15,989	18,138	14,575	13,211	13,192	11,641	14,738	16,910	14,855	186,505	
VSS Emultech	157430	7,513	13,924	24,147	16,169	13,648	11,802	16,427	15,981	14,758	14,739	11,045	6,595	166,748	
Weishaar Brothers	410046355									28,622	30,091	62		58,775	
Westfarm Foods	129772	10,083	9,413	10,157	6,754	10,405	8,859	7,543	7,586	6,481	8,430	8,537	7,861	102,109	
Total OR Sch 440 therms		475,299	485,720	480,950	369,277	400,741	360,862	505,973	480,210	565,706	535,649	495,600	465,381	5,621,368	
Total Billings		38	37	37	37	38	37	37	36	41	42	40	39	459	
Revenue Runs		382,730	433,647	399,069	315,432	370,079	245,646	208,510	180,546	565,568	535,331	517,908	465,381	4,619,847	
plus Adjustments															From / To
Lagrande School District	101870	215	201	217	213	235	220	189	121	138	318			2,067	420 Oct '08 only
Rogue Valley Manor	157502											-24,850		-24,850	didn't switch to 440 fr 456
Sabroso Co 5710-110	157503	94,006	51,872	81,664	53,632	30,427	114,996	297,274	298,915					1,022,786	Sch 456 / 440
other unknown		-1,652							628			2,542		1,518	
Subtotal Adjustments		92,569	52,073	81,881	53,845	30,662	115,216	297,463	299,664	138	318	-22,308		1,001,521	
Revenue Run therms after adjustments		475,299	485,720	480,950	369,277	400,741	360,862	505,973	480,210	565,706	535,649	495,600	465,381	5,621,368	

ANNUAL USAGE, Sch 444	**Cust No**	**JAN08**	**FEB08**	**MAR08**	**APR08**	**MAY08**	**JUN08**	**JUL08**	**AUG08**	**SEP08**	**OCT08**	**NOV08**	**DEC08**	**Total**
Agri Star Inc	114300								1	3	2,753	172		2,929
City of Grants Pass	189716						3,433	776	934	1,394				6,537
Ferguson Ranch	410101104								5,028	2,745				7,773
N Valley Mint Distillers	112799									13,620	8,171			21,791

Avista Utilities
Oregon - Gas
Year Ended December 31, 2008

Oregon Trail Mint	112009									14,089	30,588			44,677
Rogers Asphalt & Paving	103914		14	20	11	2,369	2,722	6,054	5,722	692	9,012	2,914	3,960	33,490
Rovey Farms	770097678									29,310	8,116			37,426
Willow Creek Mint	113309									22,772	7,413			30,185
Total OR Sch 444 therms			14	20	11	2,369	6,155	6,830	11,685	84,625	66,053	3,086	3,960	184,808
Total Billings		0	1	1	1	1	2	2	4	8	6	2	1	29
Revenue Runs			14	20	11	2,369	6,155	6,830	6,656	86,909	68,798	2,914	3,960	184,636
unknown adjustments												172		172
Revenue Run therms after adjustments			14	20	11	2,369	6,155	6,830	6,656	86,909	68,798	3,086	3,960	184,808

ANNUAL USAGE, Sch 447	**Cust No**	**JAN08**	**FEB08**	**MAR08**	**APR08**	**MAY08**	**JUN08**	**JUL08**	**AUG08**	**SEP08**	**OCT08**	**NOV08**	**DEC08**	**Total**
Bio Mass One LP	164412													
Collins Products	243184	90,844	156,516	129,035	104,200	124,841	97,425	124,405	86,500	49,942	110,712	66,292	43,843	1,184,555
Douglas Co Forest Products	219268													
Murphy Plywood Co	450109789	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	1,500,000
Roseburg Forest Products LVL	490049120	24,200	55,721	46,050	33,728	40,325	31,409	26,186	36,921	37,792	46,140	42,742	29,493	450,707
Total OR Sch 447 therms		240,044	337,237	300,085	262,928	290,166	253,834	275,591	248,421	212,734	281,852	234,034	198,336	3,135,262
Total Billings		5	5	5	5	5	5	5	5	5	5	5	5	60
Revenue Runs		121,415	230,911	257,691	277,394	332,915	278,842	310,880	260,258	231,475	249,178	229,637	133,463	2,914,059
normalize Murphy for test period		118,629	106,326	42,394	-14,466	-42,749	-25,008	-35,289	-11,837	-18,741	32,674	4,397	64,873	221,203
Revenue Run therms after adjustments		240,044	337,237	300,085	262,928	290,166	253,834	275,591	248,421	212,734	281,852	234,034	198,336	3,135,262

Sch. 447 Revenue														
Bio Mass One LP	$0.02700	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Collins Products	$0.04694	4,264	7,347	6,057	4,891	5,860	4,573	5,840	4,060	2,344	5,197	3,112	2,058	55,603
Douglas Co Forest Products	$0.03400													
Murphy Plywood	$0.02750	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	41,250
Roseburg Forest Products LVL	$0.02500	605	1,393	1,151	843	1,008	785	655	923	945	1,154	1,069	737	11,268
Total OR Sch 447 usage revenue		$8,307	$12,177	$10,646	$9,172	$10,306	$8,796	$9,932	$8,421	$6,727	$9,788	$7,618	$6,233	$108,121

Sch. 447 Annual Min. Charge calc.			Total
Bio Mass One LP	$38,000	$38,000	$38,000
Collins Products	$0		55,603
Douglas Co Forest Products	$157,000	157,000	157,000
Murphy Plywood	$75,000	33,750	75,000
Roseburg Forest Products LVL	$100,000	88,732	100,000
Total OR Sch 447 annual min. rev.		$317,482	$425,603

Avista Utilities
Oregon - Gas
Year Ended December 31, 2008

ANNUAL USAGE, Sch 456	Cust No	JAN08	FEB08	MAR08	APR08	MAY08	JUN08	JUL08	AUG08	SEP08	OCT08	NOV08	DEC08	Total	1st 10,000 thms/mo
Albina Asphalt	243182	60,095	52,312	36,073	39,540	67,902	113,292	75,921	82,139	84,838	75,723	66,365	40,851	795,051	120,000
American Linen	144478	26,495	27,580	24,586	25,641	26,268	24,013	25,239	26,355	24,840	24,837	25,231	22,694	303,779	120,000
Amy's Kitchen	650100771	67,332	96,547	87,704	90,641	85,352	71,529	54,734	42,942	49,939	57,596	87,747	92,776	884,839	120,000
Aqua Glass West Inc	257144	33,528	39,749	32,103	26,866	24,317	17,921	8,583	2,463	2,267	6,663	13,758	18,294	226,512	99,976
Asante Health System	130040311	35,186	35,596	32,132	31,954	28,710	25,461	21,113	19,200	19,383	20,556	25,798	28,121	323,210	120,000
Bear Creek Operations	157185	57,728	60,639	49,636	50,622	46,181	34,935	32,019	31,044	27,751	33,706	45,602	55,271	525,134	120,000
Boise Cascade LLC Inland Region	109632	161,408	170,480	151,085	110,053	107,496	83,054	83,378	96,770	119,377	114,226	86,131	72,682	1,356,140	120,000
Boise Cascade LLC Inland Region	110939	119,275	108,721	101,926	117,605	26,834	157							474,518	50,157
Boise Cascade LLC Inland Region	730084103	31,842	29,138	24,825	20,634	16,348	14,546	14,768	11,447	12,277	11,911	15,284	18,606	221,626	120,000
Boise Cascade LLC Medford 4003	129502	26,278	36,265	23,176	12,697	20,906	23,425	47,199	43,081	30,471	34,961	34,405	22,235	355,099	120,000
Boise Cascade LLC Medford 4003	156840	52,644	79,714	74,147	61,963	64,302	52,093	30,682	35,342	29,277	39,343	44,645	34,333	598,485	120,000
Boise Cascade LLC Medford 4003	180268	23,242	27,468	25,020	34,214	37,264	38,329	32,955	37,249	32,100	33,499	37,264	32,093	390,697	120,000
C&D Lumber Co	268178	7,316	17,416	19,354	26,168	9,860	3,088		1,231	4,698	2,956	3,827	20,639	116,553	72,976
Carestream Health Inc	130105718	197,670	237,909	217,221	200,308	196,046	184,969	166,604	162,543	157,393	177,772	195,921	172,997	2,267,353	120,000
Certainteed	188444	54,782	95,158	89,752	99,303	102,899	67,857	68,703	75,828	66,587	82,453	75,302	81,583	960,207	120,000
Columbia Forest Products	243187	97,216	184,850	192,465	175,283	192,509	169,683	171,409	155,753	129,625	131,040	85,850	84,854	1,770,537	120,000
E O U	109630	75,365	93,513	70,855	66,534	51,751	35,281	16,420	259	97	10,388	43,405	51,071	514,939	100,356
Green Diamond Sand Products	266363	27,323	49,848	36,974	48,813	41,490	34,301	46,084	46,668	36,458	44,344	52,867	22,964	488,134	120,000
Jeld Wen Inc	256941	136,201	176,435	142,077	125,106	91,820	71,833	82,575	86,418	64,128	17,070	54,492	35,704	1,083,859	120,000
Knife River Materials	173985	5,910	5,670	4,879	6,452	5,479	5,345	95,983	129,591	60,413	61,348	58,076	15,942	455,088	93,735
Master Brand Cabinets	199303	46,731	66,019	58,697	55,265	51,995	33,445	22,202	11,461	10,056	19,735	45,313	42,720	463,639	120,000
Medite Div Sierrapine Ltd	157182	97,846	159,687	187,312	194,279	191,776	163,399	149,600	119,809	103,713	119,687	134,024	183,171	1,804,303	120,000
Mercy Healthcare Inc	224950	36,185	35,618	31,012	31,908	28,733	25,598	25,088	23,897	23,839	25,556	28,150	28,645	344,229	120,000
Murphy Plywood Co	530067699	136,171	158,869	157,988	163,871	138,612	120,535	125,492	119,587	107,919	118,398	133,288	94,209	1,574,939	120,000
Nordic Veneer Inc	226144	67,393	87,188	96,462	90,103	77,787	68,154	62,205	59,292	64,147	77,147	76,296	52,310	878,484	120,000
Providence Medical Center	157183	66,399	66,315	58,867	61,305	54,423	49,845	44,960	40,659	40,600	43,969	54,200	60,323	641,865	120,000
Rogue Valley Manor	157502	47,960	48,472	37,991	37,773	30,392	21,814	17,377	11,036	12,884	15,707	25,464	36,055	342,925	120,000
Rogue Valley Medical Ctr	157030	102,079	103,253	91,878	95,527	88,483	83,900	69,557	65,152	69,692	73,017	85,206	90,750	1,018,494	120,000
Roseburg Forest Products Plant 4	370117415	14,730	14,730	14,730	14,730	14,730	14,730	14,730	14,730	16,415	16,179	16,575	11,435	178,441	120,000
Southern Oregon University	122751	89,616	113,191	94,781	91,858	79,975	50,817	30,227	25,212	24,863	25,379	54,864	80,348	761,131	120,000
Timber Products	157180	205,285	303,407	296,854	279,692	282,728	263,785	261,569	262,508	229,542	243,009	267,429	224,763	3,120,571	120,000
Timber Products	50077265	26,968	34,161	28,309	25,311	24,796	25,762	18,741	20,785	20,713	27,582	28,139	17,930	299,197	120,000
Western Veneer & Slicing	157327	18,899	20,442	13,897	17,291	10,162	13,571	15,990	17,215	19,281	16,364	17,100	12,657	192,869	120,000
White City Plywood	157188	99,257	141,505	102,190	105,216	106,782	93,595	93,780	72,980	12,582	13,681	15,151	11,396	868,115	120,000
Total OR Sch 456		2,352,355	2,977,865	2,706,958	2,634,526	2,425,108	2,100,062	2,025,887	1,950,646	1,708,165	1,815,802	2,033,169	1,870,422	26,600,962	3,897,200
Total Billings		34	34	34	34	34	34	34	34	34	34	34	34	408	
Revenue Runs		2,505,685	3,094,864	2,842,025	2,736,504	2,440,805	2,200,328	2,308,431	2,234,831	1,693,435	1,815,802	2,008,319	1,870,422	27,751,451	
plus Adjustments															From / To
Panel Products	730095677	-74,054	-79,857	-68,133	-63,076									-285,120	closed
Rogue Valley Manor	157502											24,850		24,850	Sch 440 / 456
Roseburg Forest Products Plant 4	370117415	14,730	14,730	14,730	14,730	14,730	14,730	14,730	14,730	14,730				132,567	new; full yr est.
Sabroso Co 5710-110	157503	-94,006	-51,872	-81,664	-53,632	-30,427	-114,996	-297,274	-298,915					-1,022,786	Sch 456 / 440
Subtotal Adjustments		-153,330	-116,999	-135,067	-101,978	-15,697	-100,266	-282,544	-284,185	14,730		24,850		-1,150,489	
Revenue Runs after adjustments		2,352,355	2,977,865	2,706,958	2,634,526	2,425,108	2,100,062	2,025,887	1,950,646	1,708,165	1,815,802	2,033,169	1,870,422	26,600,962	

Revenue Meters Report by Location Twelve Months Ended for Report Date : '09/30/2008'

Service	State C	Rate S	Rate Schedule Desc	RevClsDesc	200812 Meters	Usage	Revenue	TME Avg Meters	Usage	Revenue				
Gas	OR	410	410 RESIDENTIAL NATURAL G	01 RESIDENTIAL	84,077	6,159,374	8,846,115	83,541	50,560,635	76,927,287	G	OR	410	01
				21 FIRM COMMERCIAL	0	0	0	0	0	0	G	OR	410	21
				Sum	84,077	6,159,374	8,846,115	0	50,560,635	76,927,287	G	OR	410	
		420	420 GENERAL NATURAL GAS S	01 RESIDENTIAL	37	4,527	6,113	35	37,537	52,892	G	OR	420	01
				21 FIRM COMMERCIAL	11,003	3,270,330	4,296,152	10,962	28,138,915	38,494,301	G	OR	420	21
				31 FIRM- INDUSTRIAL	15	6,840	8,920	15	80,601	109,041	G	OR	420	31
				80 INTERDEPARTMENT REVEN	15	1,440	1,972	15	16,148	22,840	G	OR	420	80
				Sum	11,070	3,283,137	4,313,157	0	28,273,201	38,679,074	G	OR	420	
		424	424 LARGE GENERAL AND IND	21 FIRM COMMERCIAL	94	375,654	445,573	94	3,915,612	4,883,470	G	OR	424	21
				31 FIRM- INDUSTRIAL	2	6,703	7,957	2	118,536	147,059	G	OR	424	31
				Sum	96	382,357	453,530	0	4,034,148	5,030,530	G	OR	424	
		440	440 INTERRUPTIBLE NATURAL	22 INTERRUPTIBLE COMMERC	26	389,349	344,465	25	3,269,524	3,040,414	G	OR	440	22
				41 INTERRUPTIBLE-INDUSTRIA	12	76,032	67,267	13	1,350,323	1,256,369	G	OR	440	41
				Sum	38	465,381	411,732	0	4,619,847	4,296,783	G	OR	440	
		444	444 SEASONAL NATURAL GAS	21 FIRM COMMERCIAL	0	0	0	1	6,537	7,984	G	OR	444	21
				31 FIRM- INDUSTRIAL	1	3,960	4,628	3	178,099	217,377	G	OR	444	31
				Sum	1	3,960	4,628	0	184,636	225,361	G	OR	444	
		447B	447B SPECIAL CONTRACT - BI	92 INDUSTIAL-TRANS OF GAS	1	0	0	1	0	38,000	G	OR	447B	92
				Sum	1	0	0	0	0	38,000	G	OR	447B	
		447D	447D SPECIAL CONTRACT - D	92 INDUSTIAL-TRANS OF GAS	1	0	0	1	0	156,998	G	OR	447D	92
				Sum	1	0	0	0	0	156,998	G	OR	447D	
		447M	447M SPECIAL CONTRACT - M	92 INDUSTIAL-TRANS OF GAS	1	60,127	1,653	1	1,278,797	35,167	G	OR	447M	92
				Sum	1	60,127	1,653	0	1,278,797	35,167	G	OR	447M	
		447R	447R SPECIAL CONTRACT - R	92 INDUSTIAL-TRANS OF GAS	1	29,493	737	1	450,707	76,817	G	OR	447R	92
				Sum	1	29,493	737	0	450,707	76,817	G	OR	447R	
		447W	447W SPECIAL CONTRACT - C	92 INDUSTIAL-TRANS OF GAS	1	43,843	2,058	1	1,184,555	55,614	G	OR	447W	92
				Sum	1	43,843	2,058	0	1,184,555	55,614	G	OR	447W	
		456	456 TRANSPORTATION SERVI	22 INTERRUPTIBLE COMMERC	0	0	0	0	0	0	G	OR	456	22
				91 COMMERCIAL-TRANS OF G	8	398,277	33,220	8	4,566,909	370,413	G	OR	456	91
				92 INDUSTIAL-TRANS OF GAS	28	1,472,145	112,238	28	23,184,542	1,635,131	G	OR	456	92
				Sum	36	1,870,422	145,458	0	27,751,451	2,005,544	G	OR	456	
		460	TAX ADJUSTMENT IN TERRIT	01 RESIDENTIAL	0	0	142,569	0	0	1,244,601	G	OR	460	01
				21 FIRM COMMERCIAL	0	0	76,131	0	0	699,284	G	OR	460	21
				22 INTERRUPTIBLE COMMERC	0	0	5,999	0	0	40,221	G	OR	460	22
				31 FIRM- INDUSTRIAL	0	0	228	0	0	2,334	G	OR	460	31
				41 INTERRUPTIBLE-INDUSTRIA	0	0	1,062	0	0	13,984	G	OR	460	41
				80 INTERDEPARTMENT REVEN	0	0	0	0	0	3	G	OR	460	80
				91 COMMERCIAL-TRANS OF G	0	0	741	0	0	7,868	G	OR	460	91
				92 INDUSTIAL-TRANS OF GAS	0	0	1,056	0	0	15,042	G	OR	460	92
				Sum	0	0	227,785	0	0	2,023,337	G	OR	460	
		499	499 REPORTING SCHED NUMB	19 THEFT OF SERVICE-GAS	0	0	1,167	0	0	12,534	G	OR	499	19
				88 MISC-SERVICING CUSTOME	0	0	9,975	0	0	122,645	G	OR	499	88
				Sum	0	0	11,142	0	0	135,179	G	OR	499	
		Sum			95,323	12,298,094	14,417,997	0	118,337,977	129,685,690	G	OR	Sum	

Summary by Rate Schedule

Total 410 RESIDENTIAL NATURAL GAS SERVICE	GOR410	84,077	6,159,374	8,846,115	83,541	50,560,635	76,927,287	
Total 420 GENERAL NATURAL GAS SERVICE	GOR420	11,070	3,283,137	4,313,157	11,027	28,273,201	38,679,074	
Total 424 LARGE GENERAL AND INDUSTRIAL SERVI	GOR424	96	382,357	453,530	96	4,034,148	5,030,530	
Total 424J LARGE GENERAL SERVICE - JACKSON CO	GOR424J	0	0	0	0	0	0	
Total 440 INTERRUPTIBLE NATURAL GAS SERVICE	GOR440	38	465,381	411,732	38	4,619,847	4,296,783	
Total 444 SEASONAL NATURAL GAS SERVICE	GOR444	1	3,960	4,628	3	184,636	225,361	
Total 447B SPECIAL CONTRACT - BIOMAS	GOR447B	1	0	0	1	0	38,000	
Total 447D SPECIAL CONTRACT - DOUGLAS COUNTY	GOR447D	1	0	0	1	0	156,998	
Total 447M SPECIAL CONTRACT - MURPHY PLYWOO	GOR447M	1	60,127	1,653	1	1,278,797	35,167	
Total 447R SPECIAL CONTRACT - ROSEBURG FOREST	GOR447R	1	29,493	737	1	450,707	76,817	
Total 447W SPECIAL CONTRACT - COLLINS	GOR447W	1	43,843	2,058	1	1,184,555	55,614	
Total 456 TRANSPORTATION SERVICE - INTERRUPTI	GOR456	36	1,870,422	145,458	36	27,751,451	2,005,544	
Total 460 TAX ADJUSTMENT IN TERRITORY SERVED	GOR460	0	0	227,785	0	0	2,023,337	
Total 499 REPORTING SCHED NUMBER FOR MISC GA	GOR499	0	0	11,142	0	0	135,179	
	Total	95,323	12,298,094	14,417,997	94,746	118,337,977	129,685,690	
	GORSum	95,323	12,298,094	14,417,997	94,746	118,337,977	129,685,690	
	Diff	0	0	0	0	0	0	

Summary by Rate Class - 12 Mos.

		Meters	Usage
Res	OR01	83,576	50,598,172
Theft	OR19	0	0
Comm	OR21	11,056	32,061,064
Comm-Int	OR22	25	3,269,524
Ind	OR31	20	377,236
Ind-Int	OR41	13	1,350,323
Intdpt	OR80	15	16,148
Misc Svc	OR88	0	0
Comm-Tra	OR91	8	4,566,909
Ind-Tra	OR92	33	26,098,601
Total OR		94,746	118,337,977
Other Rev (493)			
Total OR excl Unbi		94,746	118,337,977
		0	0
Retail		94,746	118,337,977
Unbilled			782,702
Total OR		94,746	119,120,679

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF SCOTT L. MORRIS
REPRESENTING THE AVISTA CORPORATION

Policy and Operations

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Scott L. Morris and I am employed as the Chairman of the Board, President, and Chief Executive Officer of Avista Corporation (Company or Avista), at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you briefly describe your educational background and professional experience?

A. Yes. I am a graduate of Gonzaga University with a Bachelors degree and a Masters degree in organizational leadership. I have also attended the Kidder Peabody School of Financial Management.

I joined the Company in 1981 and have served in a number of roles including customer service manager. In 1991, I was appointed general manager for Avista Utilities' Oregon and California natural gas utility business. I was appointed President and General Manager of Avista Utilities, an operating division of Avista Corporation, in August 2000. In February 2003, I was appointed Senior Vice-President of Avista Corporation, and in May 2006, I was appointed as President and Chief Operating Officer. Effective January 1, 2008, I assumed the position of Chairman of the Board, President, and Chief Executive Officer.

I am a member of the Western Energy Institute board of directors, a member of the Gonzaga University board of trustees, a member of Edison Electric Institute board of directors, a member of the American Gas Association board of directors, a member of ReliOn board of directors, and board director of the Washington Roundtable. I also serve on the board of trustees of the Greater Spokane Incorporated, which was formerly two separate organizations, the Spokane Area Economic Development Council and the Spokane Regional Chamber of Commerce.

During my time as general manager in Oregon, I was appointed by then-Governor John Kitzhaber as a board member of the Oregon Economic and Community Development Commission. I served as a member of the board of directors and as board president of Southern Oregon Regional Economic Development Inc. I served as a director and board president of the Medford/Jackson County Chamber of Commerce. I was a board member and served as board president of the Providence Community Health Foundation. I have also served as a member of the board of directors and a board president for the Medford YMCA, as a member of the board for the Oregon Shakespeare Festival, and the Rogue Valley College Regional Advisory Board.

Q. While general manager in Oregon, what were your responsibilities?

A. As general manager in Oregon, my responsibilities included accountability for all aspects of business operations for our Oregon properties.

Q. What is the scope of your testimony?

A. I am testifying as the policy witness for the Company. I provide an overview of Avista Utilities' rate filing and overall utility operations and will summarize the major factors driving the Company's need for general rate relief. I will also discuss the Company's customer support programs that are in place to assist our customers. Finally, I introduce each of the other witnesses providing testimony on the Company's behalf.

Q. Are you sponsoring exhibits in this proceeding?

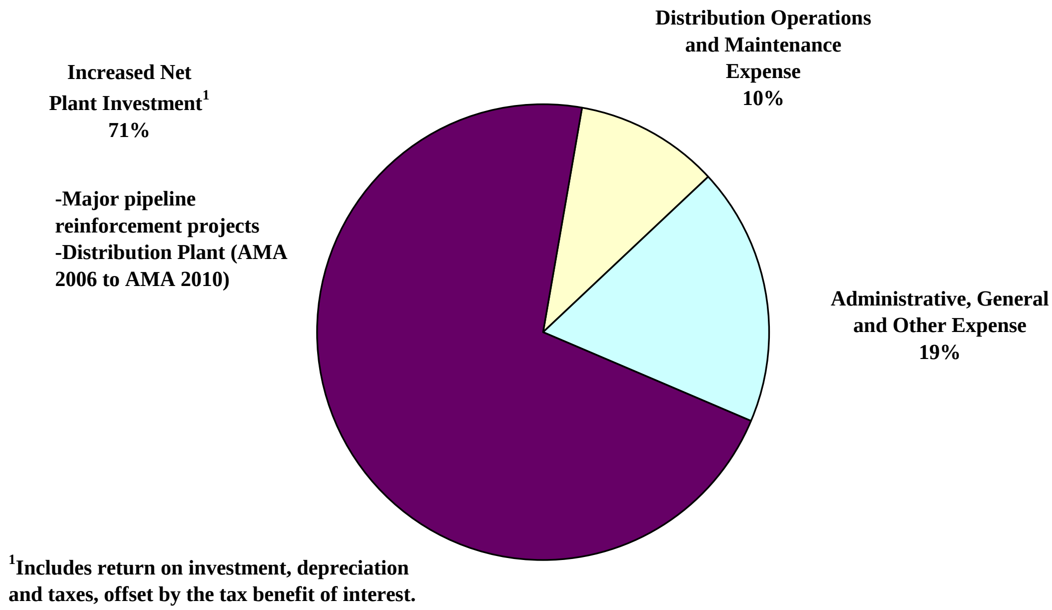
A. Yes. I am sponsoring Exhibit No. 101, page 1, which includes a map of the total company service territories, page 2 includes a map of Avista's natural gas service areas, gas fields, trading hubs and major pipelines, and page 3, which includes a diagram of Avista's current corporate structure. These exhibits were prepared under my direction.

Q. Would you please provide an overview of Avista Utilities' request in this filing?

A. Yes. A combination of declining margins and increases in general business expenses requires the Company to request an overall increase in base retail rates of $14,205 million or 11.6%. This request is based on a proposed rate of return of 8.96%, with a capital structure of 51.45% common equity at a 11.0% return on equity. The Company is utilizing a forecasted test period for the twelve months ended December 31, 2010. The forecasted test period was selected to best reflect the conditions during which time the new rates will be in effect, as discussed further by Company witness Ms. Andrews. The Company used the results of a long-run incremental cost study as a starting point in the proposed spread of the requested increase to the various customer rate schedules. Company witness Mr. Hirschkorn testifies to these rate spread issues.

Illustration 1:

Oregon Primary Components of Revenue Requirement



Q. What are the major elements of the requested increase?

A. Although there are a number of increases and decreases in revenue, expense and rate base items, there are a few major components that drive the requested rate increase. As shown in Illustration 1 above, the Company's natural gas increase is primarily driven by increased net plant investment. The Company has four major capital projects that will be completed in Oregon and that have been included in this filing:

- East Medford Reinforcement Project - The East Medford Reinforcement Project will provide a strategic high pressure pipeline encirclement of the Greater Medford Area for long-term natural gas supply to the eastern portions of the city. The project will allow for additional natural gas delivery from either TransCanada at the Company's Phoenix Road Gate Station or Northwest Pipeline at Grants Pass. It provides reinforcement of the system in anticipation of future load growth in Medford.

- Roseburg Reinforcement Project - The Roseburg Reinforcement Project improves the delivery pressure and capacity of natural gas supplies into central and east Roseburg by extending a high pressure natural gas supply. The existing system is marginally capable of meeting customer load on a design day.

- Gas ERT Battery Replacement Project - This project will replace Gas ERT's that are greater than 10 years old, which is their economic life.

- Grants Pass Reinforcement Project - The Grants Pass Reinforcement Project will replace the existing High Pressure (HP) source into the greater Grants Pass area. Due to growth in the area the existing HP main is capacity constrained on a design day and replacement is required to ensure adequate natural gas deliveries during high system demand.

The average numbers of customers have increased by over 3.5%, from 92,406 in 2006 to approximately 96,000 forecasted in 2010. During that time period O&M and A&G costs increased $4 million and gross utility plant increased $76.1 million.

The Company has experienced an expanding customer base requiring new plant investment, while at the same time experiencing lower natural gas usage on a per customer basis. Company witness Ms. Andrews testifies to this increased plant investment and other factors in arriving at the Company's revenue requirement in this case.

Further, Company witness Mr. Thies and Company witness Mr. Avera discuss in detail the Company's weighted cost of capital of 8.96%, including a requested return on equity of 11.0%. The Company's forecasted rate of return under present rates is 3.3%, which is well below what would be considered to be a reasonable rate of return.

II. OVERVIEW OF AVISTA UTILITIES

Q. Please briefly describe Avista Utilities.

A. Avista Utilities provides natural gas distribution service in southwestern and northeastern Oregon. The Company, headquartered in Spokane, Washington, also provides electric and natural gas service within a 26,000 square mile area of eastern Washington and northern Idaho. Of the Company's approximately 355,000 electric and 315,000 natural gas customers (as of December 31, 2008), 95,000 were Oregon customers. A map showing Avista's total electric and natural gas service areas is provided on page 1 of Exhibit No. 101.

As of December 31, 2008, Avista Utilities had total assets (electric and natural gas) of approximately $3.4 billion (on a system basis), with electric retail revenues of $636 million (system) and natural gas retail revenues of $448 million (system). As of December 2008, the Utility had 1,482 full-time employees.

Q. Please describe Avista Utilities' natural gas utility operations in Oregon.

A. Of the Company's 315,000 natural gas customers, approximately 95,000 are served in Oregon. The Company serves the Oregon areas of Medford, Klamath Falls, Roseburg, and LaGrande. Lumber and wood products manufacturing is the dominant industry in our Oregon service area. During 2008, Avista delivered approximately 489 million therms to its retail natural gas customers. Of this total, 118 million were delivered to Oregon customers. The mix of customers by rate schedule and their proportionate share of usage and revenues at present rates are summarized in the table below by rate schedule:

Rate Schedule	% Revenues	No. of Customers	% Therms Delivered
410 — Residential	60.1%	83,541	42.5%
420 — General Service	29.6%	11,026	23.4%
424 — Large General Service	4.0%	96	3.5%
440 — Interruptible	4.2%	21	5.0%
444 — Seasonal	0.2%	8	0.2%
456 — Transportation	1.6%	34	22.8%
447 — Special Contract	0.3%	5	2.6%

Q. Please describe Avista's current business focus for its utility operations.

A. Our strategy continues to focus on our energy and utility-related businesses, with our primary emphasis on the electric and natural gas utility business. There are four distinct components to our business focus for the utility, which we have referred to as the four legs of a stool, with each leg representing customers, employees, the communities we serve, and our financial investors. For the stool to be level, each of these legs must be in balance by having the proper emphasis. This means we must maintain a strong utility business by delivering efficient, reliable and high quality service, at a reasonable price, to our customers and the communities we serve, and provide the opportunity for sustained employment for our employees, while providing an attractive return to our investors.

The Company recently received upgrades to its corporate credit ratings to investment grade by FitchRatings in May 2009. Previously, upgrades were received by Moody's Investors Service in December 2007 and Standard & Poor's in February 2008. Even with these upgrades, we are still only at the lowest investment grade status. Accordingly, although we are continuing to make progress in improving the Company's financial condition, we are still not as strong financially as we need to be. Timely rate relief through this filing is an important element in continuing to gain financial strength and improving our credit rating.

With higher levels of capital spending required over the next several years (i.e., approximately $420 million during 2009-2010), it is more important than ever that the Company remain financially healthy in order to attract capital investment and financing at the lowest cost possible. Company witness Mr. Thies will discuss further actions taken by the

Company to improve cash flow, reduce debt, and our continuing efforts to improve our financial condition.

Q. Would you please comment on the Company's commitment to customer satisfaction?

A. Yes, I am pleased with the dedication of Avista Utilities' employees and their commitment to provide quality service to our customers. While we continue to maintain tight controls on capital and O&M budgets, our customer service surveys indicate that customer satisfaction remains high. Our recent first quarter 2009 customer survey results show an overall customer satisfaction rating of 94% in our Oregon, Washington, and Idaho operating divisions. This rating reflects a positive experience for the majority of customers who have contacted Avista related to the customer service they received. These results can be achieved only with very committed and competent employees.

Q. Please briefly describe Avista's subsidiary businesses.

A. Avista Corp.'s primary subsidiary is the information and technology business, Advantage IQ, described below, which is headquartered in Spokane, Washington. In 2007, Avista completed the sale of the operations of Avista Energy to Coral Energy Holding, L.P., and certain of its subsidiaries, a subsidiary of Shell. Avista currently holds a 6.18% share in Avista Labs' successor company, ReliOn, which is held under Avista Capital. A diagram of Avista's corporate structure is provided on page 3 of Exhibit No. 101.

Q. Please provide an overview of Advantage IQ.

A. Advantage IQ, formerly known as Avista Advantage, commenced operations in 1998 and is a provider of utility bill processing, payment and information services to multi-site customers. Advantage IQ analyzes and presents consolidated bills on-line, and pays utility and other facility-related expenses for multi-site customers throughout North America. Customers include, CSK Auto, Jack in the Box, Staples, and Big Lots, to name a few. Information gathered from invoices, providers and other customer-specific data allows Advantage IQ to provide its customers with in-depth analytical support, real-time reporting and consulting services with regard to facility-related energy, waste, repair and maintenance, and telecom expenses. In 2008, Advantage IQ was awarded the ENERGY STAR® Sustained Excellence Award in recognition of its continued leadership in protecting our environment through energy efficiency.

Q. What is the status of the formation of a holding company?

A. In February 2006, Avista filed for regulatory approval of the proposed formation of a holding company (reorganization) with the Federal Energy Regulatory Commission (FERC) and the public utility commissions in Washington, Idaho, Oregon and Montana, conditioned on approval by shareholders. On April 18, 2006, FERC issued its "Order Authorizing Disposition of Jurisdictional Facilities" in Docket No. EC06-85-000, approving the Company's reorganization. Shareholder approval of the reorganization was granted at Avista Corp.'s Annual Shareholder meeting May 11, 2006. On June 30, 2006, the Idaho Public Utilities Commission issued an order approving Avista's reorganization application, based on a settlement in that state. On February 28, 2007, the Washington Utilities and Transportation Commission issued an order approving Avista's reorganization application, based on a settlement in that state. The Montana Commission has yet to act on Avista's Reorganization application, and the procedural schedule for consideration of the

Company's application in Oregon has been suspended by agreement of the parties to allow additional time for discussion among the parties

III. HISTORY

Q. What is Avista Utilities' rate history in Oregon?

A. In 1991, the Company, then known as The Washington Water Power Company, doing business as WP Natural Gas (WPNG), acquired the Oregon and California natural gas service territory of CP National. WPNG implemented a 0.50% decrease in base rates at that time and instituted a four and one-half year rate freeze. Upon the end of this rate stability period, a 2.94% general rate decrease was implemented effective December 1, 1995. Thereafter, the Company again implemented a base rate decrease of 2.1% effective December 1, 1997. In October 2003, the Company implemented a 9.9% increase in base rates. In 2008, the Company implemented a general rate increase in two increments totaling 1.8%. Thus, Avista has had only three general rate increases since we acquired the properties eighteen years ago.

Q. Has the Company considered the possible economic impacts of the Company's rate proposals in its service territory?

A. We recognize that these increases in costs will result in natural gas bills that will be more difficult for some of our customers to pay. I can assure you that we are not just sitting on the sidelines as our costs go up.

I will explain a number of cost-cutting and efficiency measures that we have undertaken recently in an effort to mitigate the overall cost impacts to our customers. In addition, we have a history of making it a priority within our Company to maintain meaningful programs to assist our customers that are least able to pay their energy bills, including working cooperatively with our local community action agencies.

We will continue to aggressively manage costs to achieve the appropriate balance in providing safe and reliable service at cost-effective rates, and a high level of customer satisfaction, while preserving the financial health of the utility.

Q. What measures has the Company taken?

A. The measures below are among some of the recent and historical examples of cost management and efficiency efforts the Company has taken to mitigate the impact of increased costs on our customers:

Limitations on Capital Spending

- Avista approved a lower capital budget than was requested by the Company's Engineering and Operations personnel. The original capital projects requested for approval for completion in 2009 consisted of projects totaling over $269 million. The Capital Prioritization Committee reduced the list of projects recommended to be completed by $60 million to the $210 million capital budget approved by the Board.
- After approval by the Board, the Company decreased its capital budget spend an additional $8 million (from $210 million down to $202 million) as follows: $2 million decrease in electric customer hookup costs (ER 1000) and $6 million decrease in distribution transformers due primarily to fewer transformers for new customers (ER 1003).
- The majority of capital spending included in the Company's $158.1 million system (the Company excluded $47.5 million of revenue producing capital) are for activities that are being constructed to meet compliance requirements (such as NERC, mandatory reliability standards, environmental compliance, etc.), improve system reliability and service to our customers, replace broken or aging equipment, and/or provide avoided cost savings in the future.

Salaries & Benefits

- Avista provided no salary increases for officers for 2009, and reduced the Company's non-officer average salary increase planned for 2009 from 3.8% to 2.5%.
- Retirees are now picking up the full premium increases on the health insurance coverage. A few years ago retirees under age 65 were paying 10% of the health insurance premiums and now they pay 50% on average.

- The Defined Benefit Pension Plan's benefit formulas were reduced (approximately 28%) for all new hires effective January 1, 2006 and forward. This applies to all new hires except those in the IBEW Local #77 Bargaining Unit.
- Bargaining units wages are competitive with neighboring investor-owned utilities and PUDs.

Hiring Restriction

- The Company is currently operating under a hiring restriction which requires approval by the Chairman, President & CEO, CFO, and Sr. VP for Human Resources for all replacement or new hire positions.

Delayed the Reardan Wind Project

- We have recently delayed the construction of the $125+ million Reardan Wind Project to 2013, due, in part, to the current high cost of wind turbines and other materials.

Cancelled Ross Court Office Space

- Avista's main office building was constructed in 1958, and expanded in 1978. Even though Avista's ratio of the number of customers served per employee continues to increase, we have needed additional office space for some time. In 2008, in order to reduce costs, we cancelled plans to build additional office space adjacent to the main office, and instead chose to remodel existing space formerly used by Horizon Credit Union nine miles from the main office.

Billing Contract and Disaster Recovery

- Avista recently contracted its bill printing and mailing services with an offsite provider, and at the same time complied with requirements related to disaster-recovery for billing data. The objectives were to move bill printing, inserting and mailing offsite and leverage core competencies of the provider, to obtain disaster recovery and avoid the cost of duplicate data storage, ensure daily print volume flexibility, and reduce the cost of our billing operation.

Additional On-line Service Offerings

- In January 2008 the Company completed the redesign of *www.avistautilities.com*. The primary objectives of this project were to lower costs and enhance customer satisfaction through the deployment of additional self- service options, such as open/close/move, reporting and making payment arrangements, enrolling in Comfort Level Billing, and/or Automatic Payment Service (APS). Customers also have access to tools to help analyze their bills and are provided with meaningful information to make informed energy management choices. The cost-saving objective is to achieve a 10% reduction in the Company's Contact Center total call volume, which results in lower staffing and lower costs to customers.

Q. Has Avista considered additional measures to mitigate increased costs?

A. Yes. In recent years Avista has run its operations with attention to minimizing expenses while providing reliable service and a high level of customer satisfaction. Following the energy crisis of 2000/2001, we cut our operating expenses as we worked toward regaining an investment grade credit rating. Since that time we have continued to pay particular attention to limiting the growth in these costs, while meeting important reliability and environmental compliance requirements, and preserving a high level of customer satisfaction.

Q. The proposed rate increase is related to changes in the costs of providing natural gas service to customers. Is the Company proposing any changes to natural gas commodity costs in this case?

A. No. Avista is not proposing changes in this filing to the natural gas commodity costs included in customers' current rates. Changes in commodity costs are addressed in the annual purchased gas adjustment (PGA) filings. As of late, gas prices have declined significantly, and our next PGA filing this Fall will reflect a substantial decrease assuming we continue to experience lower gas prices. Based on current projections, it is our current belief that this decrease will offset most, if not all of this rate increase for our customers.

V. CUSTOMER SUPPORT PROGRAMS

Q. Please explain the customer support programs that Avista provides for its customers in Oregon.

A. Avista Utilities offers a number of programs for its Oregon customers, such as energy efficiency programs, the Low Income Rate Assistance Program (LIRAP), Project Share for emergency assistance to customers, the Customer Assistance Referral and Evaluation Service (CARES) program, level pay plans, and payment arrangements. Some of these programs will serve to mitigate the impact on customers of the proposed rate increase.

Q. Please describe Avista Utilities' demand-side management (DSM) or energy efficiency programs.

A. Avista Utilities' energy efficiency programs in Oregon have provided for the consistent delivery of comprehensive conservation services. Avista Utilities offers energy efficiency services to residential, commercial, and industrial customers. Programs include both audits and direct incentives for residential weatherization, high-efficiency furnace and water heaters, and commercial qualifying gas-efficiency projects.

Q. What is the Company's Low Income Rate Assistance Program or LIRAP?

A. The low-income rate assistance program (LIRAP), collects approximately $230,000 (or .438 cents per therm annually) from a 0.50% distribution charge on natural gas service. These funds are distributed by community action agencies in a manner similar to the Federal and State-sponsored Low Income Heating Energy Assistance Program (LIHEAP). Avista Utilities' LIRAP program supplements the reach of available LIHEAP funds. The Company, with the assistance of community action agencies and the Commission, directed this program toward those members of the community least able to pay for natural gas service.

Q. Please describe the recent results of the Company's Project Share efforts?

A. Project Share is a community-funded program Avista sponsors to provide one-time emergency support to families in the Company's region. Avista customers and shareholders help support the fund with voluntary contributions that are distributed through local community action agencies to customers in need. Grants are available to those in need without regard to their heating source. Avista Utilities has consistently had relatively high per-customer contributions when compared to other utilities with Project Share programs.

Q. Does the Company offer a bill-averaging program?

A. Yes. Comfort Level Billing helps smooth out the seasonal highs and lows of customers' energy usage and provides the customer with the option to pay the same bill amount each month of the year. This allows customers to more easily budget for energy bills and it also avoids higher winter bills. This program has been well-received by participating customers. Over 7,517 (or 8%) of Oregon natural gas customers are on Comfort Level Billing.

In addition, the Company's Contact Center Representatives work with customers to set up payment arrangements to pay energy bills. In 2008, 23,654 Oregon customers were provided with over 69,810 such payment arrangements.

Q. Please summarize Avista's CARES program.

A. In Oregon, Avista is currently working with over 474 special needs customers in the CARES program. Specially-trained representatives provide referrals to area agencies and churches for customers with special needs for help with housing, utilities, medical assistance, etc.

In the 2007/2008 heating season, 5,237 Oregon customers received $1,295,063 in various forms of energy assistance (Avista LIRAP, Federal LIHEAP program, Project Share, and local community funds). This program and the partnerships we have formed have been invaluable to customers who often have nowhere else to go for help.

Q. Are there other noteworthy items that you would like to address?

A. Yes. There are several items of which I am particularly proud. The Company's contact center has been recognized nationally for its quality and efficiency. The Medford call center is networked with call centers in Lewiston, Idaho, Coeur d'Alene, Idaho, and Spokane, Washington. In 2008, this allowed a total of 50 full-time equivalent call center employees to effectively respond to over 870,863 calls from natural gas and electric customers in our three state service territory.

I am also very pleased with the previously discussed LIRAP and energy efficiency programs. I appreciate the community action agencies' collaboration and the Commission's approval to effectuate and support the LIRAP program.

VI. OTHER COMPANY WITNESSES

Q. Would you please provide a brief summary of the testimony of the other witnesses representing Avista in this proceeding?

A. Yes. The following additional witnesses are presenting direct testimony on behalf of Avista.

Mr. Mark Thies, Senior Vice President and Chief Financial Officer, will address the Company's capital structure, the proposed cost of embedded debt and the overall rate of return. He will explain the actions the Company has taken to acquire needed capital and improve Avista's financial condition in recent years.

Mr. William E. Avera, as President of Financial Concepts and Applications (FINCAP), Inc., has been retained to present testimony with respect to the reasonableness of the Company's proposed overall capital structure and will testify in support of an 11.0% return on equity.

Mr. Dave DeFelice, Senior Business Analyst, will describe the adjustments for capital expenditures, as well as the rising cost of essential materials specific to the utility industry that is causing significant increases in capital project funding requirements.

Ms. Elizabeth Andrews, Manager, Revenue Requirements, will discuss the Company's overall revenue requirement proposals. In addition, her testimony and exhibits will cover accounting and financial data in support of the Company's need for the proposed increase in rates and the allocation methodologies. She will also explain forecasted operating results, including expense and rate base adjustments made to actual operating results and rate base.

Ms. Tara Knox, Senior Regulatory Analyst, sponsors the long-run incremental cost study for Oregon natural gas service. Ms. Knox discusses her study results and how each schedule's present and proposed rates compare to the indicated cost.

Mr. Brian Hirschkorn, Manager, Retail Pricing, discusses the spread of the annual revenue changes among the Company's general service schedules and related rate design. Mr. Hirschkorn also discusses the forecasted revenue adjustment.

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

A. Yes.

AVISTA/101
Morris

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

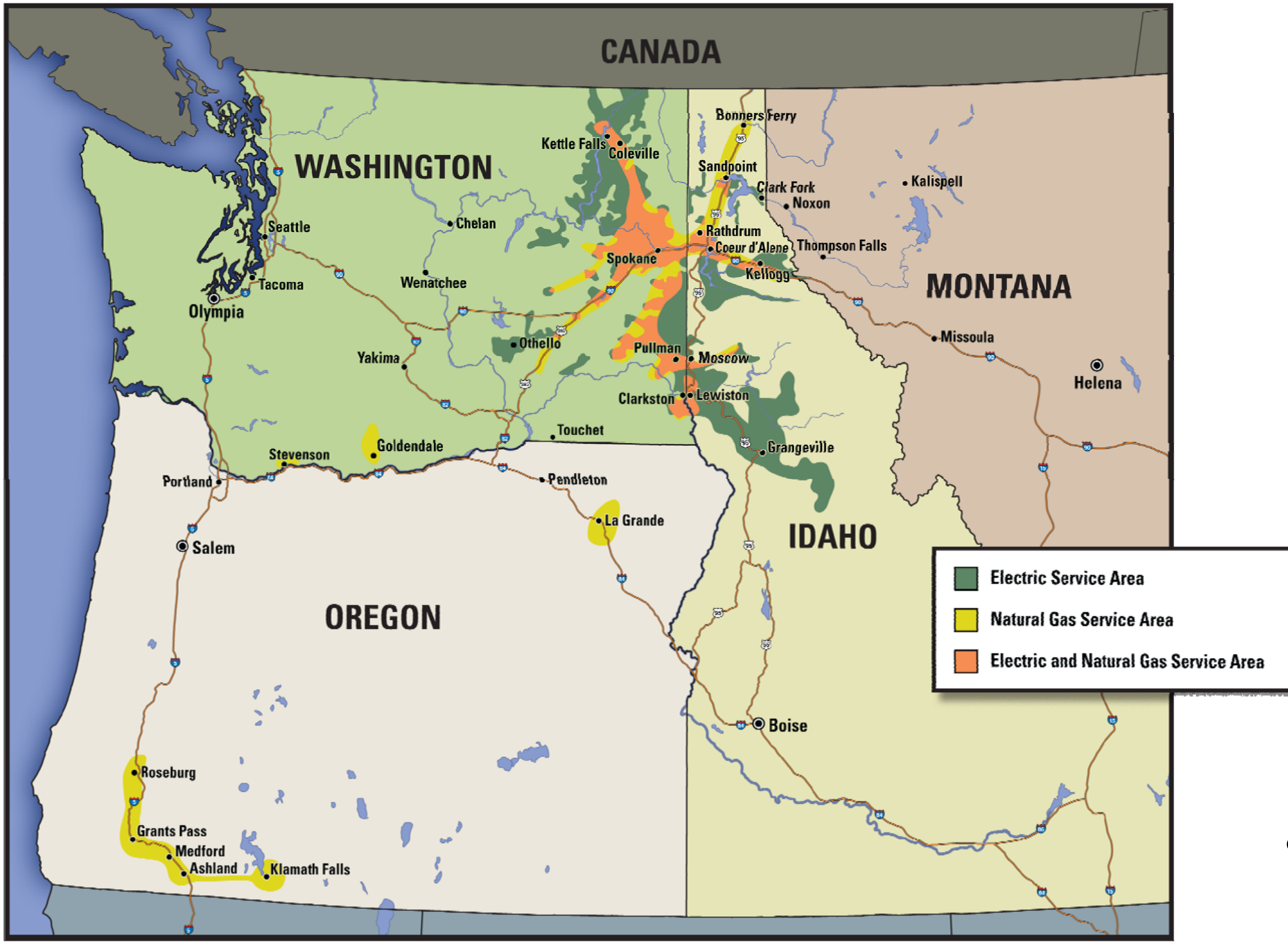
DOCKET NO. UG-___

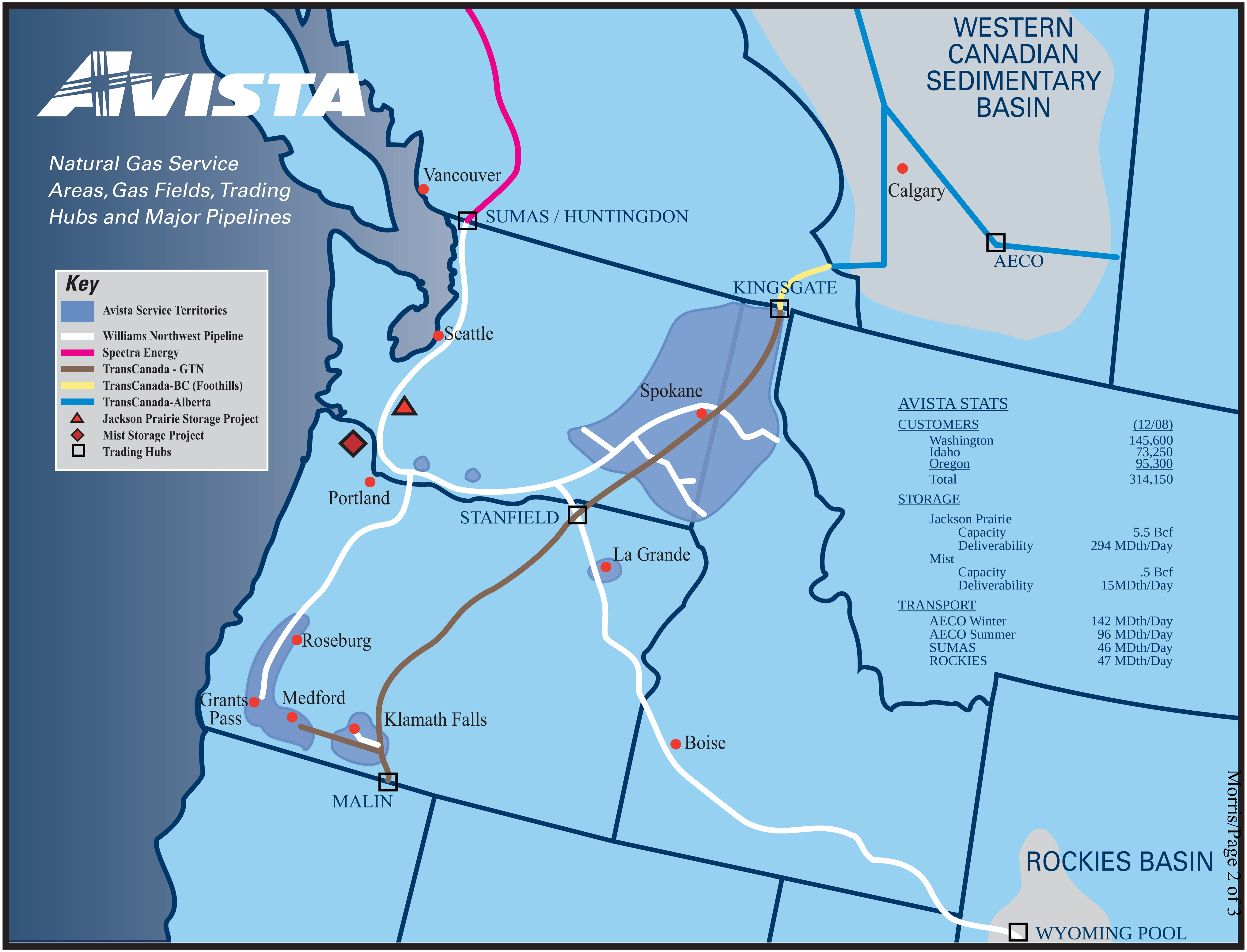
AVISTA CORP

SCOTT L. MORRIS
Exhibit No. 101

Policy and Operations

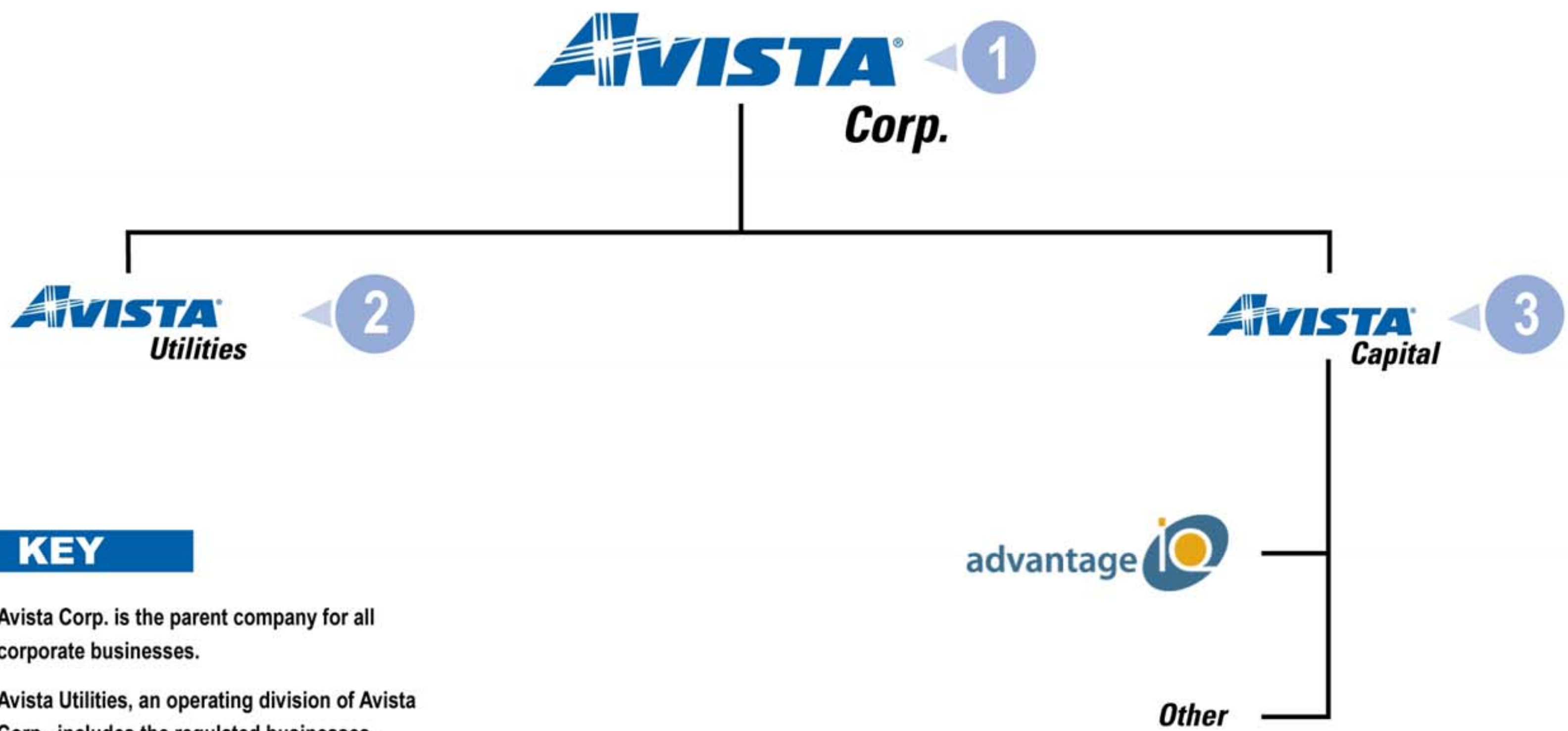
Avista's Electric and Natural Gas Service Areas




AVISTA
Natural Gas Service Areas, Gas Fields, Trading Hubs and Major Pipelines
Key
Avista Service Territories
Williams Northwest Pipeline
Spectra Energy
TransCanada - GTN
TransCanada-BC (Foothills)
TransCanada-Alberta
Jackson Prairie Storage Project
Mist Storage Project
Trading Hubs
WESTERN CANADIAN SEDIMENTARY BASIN
Calgary
AECO
Vancouver
SUMAS / HUNTINGDON
KINGSGATE
Seattle
Spokane
Portland
STANFIELD
La Grande
Roseburg
Grants Pass
Medford
Klamath Falls
MALIN
Boise
ROCKIES BASIN
WYOMING POOL
AVISTA STATS
CUSTOMERS (12/08)
Washington 145,600
Idaho 73,250
Oregon 95,300
Total 314,150
STORAGE
Jackson Prairie
Capacity 5.5 Bcf
Deliverability 294 MDth/Day
Mist
Capacity .5 Bcf
Deliverability 15MDth/Day
TRANSPORT
AECO Winter 142 MDth/Day
AECO Summer 96 MDth/Day
SUMAS 46 MDth/Day
ROCKIES 47 MDth/Day

Avista Corporation Overview

Avista Corporate Business Organizational Structure



KEY

1. Avista Corp. is the parent company for all corporate businesses.
2. Avista Utilities, an operating division of Avista Corp., includes the regulated businesses, serving customers in Washington, Idaho, and Oregon.
3. Avista Capital is the parent company of all non-regulated subsidiaries. Avista Capital is a wholly owned subsidiary of Avista Corp.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF MARK T. THIES
REPRESENTING AVISTA CORPORATION

Financial Overview, Capital Structure and Overall Rate of Return

I. INTRODUCTION

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

A. My name is Mark Thies. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed by Avista Corporation as Senior Vice President and Chief Financial Officer.

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

A. I received Bachelor of Arts degrees in Accounting and Business Administration from Saint Ambrose College in Davenport, Iowa, and became a Certified Public Accountant in 1987. I have extensive experience in finance, risk management, accounting and administration within the utility sector, primarily in the Midwest.

I joined Avista in September of 2008 as Senior Vice President and Chief Financial Officer (CFO). Prior to joining Avista, I was Executive Vice President and CFO for Black Hills Corporation, a diversified energy company, providing regulated electric and natural gas service to areas of South Dakota, Wyoming and Montana. I joined Black Hills Corporation in 1997 upon leaving InterCoast Energy Company in Des Moines, Iowa, where I was the manager of accounting. Previous to that I was a senior auditor for Arthur Anderson & Co. in Chicago, Illinois.

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

A. I will provide a financial overview of the Company and will explain the overall rate of return proposed by the Company in this filing for its natural gas operation. The proposed rate of return is derived from Avista Utilities' costs of debt (including long-term debt and long-term debt to affiliated trusts), and common equity, weighted in proportion to the proposed capital structure.

I will address the proposed capital structure, as well as the proposed cost of debt and equity in this filing. Company witness Dr. Avera will provide additional testimony related to the appropriate return on equity for Avista, based on the specific circumstances of the Company, together with the current state of the financial markets.

In brief, I will provide information that shows:

- Avista's plans call for significant capital expenditure requirements for the utility over the next two years to assure reliability in serving growth in the number of customers and customer demand. Capital expenditures of approximately $420 million are planned for 2009-2010 for customer growth, necessary maintenance and replacements of our natural gas utility systems, and investment in generation, transmission and distribution facilities for the electric utility business. Avista needs adequate cash flow from operations to fund these requirements, together with access to capital from external sources under reasonable terms.

- Avista's corporate credit rating from Standard & Poor's is currently BBB- and Baa3 from Moody's. Avista Utilities needs to operate at a level that will support a strong investment grade corporate credit rating, meaning "BBB" or "BBB+", in order to access capital markets at reasonable rates, which will decrease long-term financing costs to customers. Maintaining solid credit metrics and credit ratings will also help support a stock price necessary to issue equity to fund capital requirements.

- The Company has proposed an overall rate of return of 8.96%, including a 51.45% equity ratio and an 11.00% return on equity. We believe the 11.00% provides a reasonable balance of the competing objectives of continuing to improve our financial health, and the impacts that increased rates have on our customers.

The Company's initiatives to carefully manage its operating costs and capital expenditures are an important part of improving performance, but are not sufficient without revenues from the general rate request for our natural gas business in this case. Adequate cash flows from operations can only be achieved with the continued support of regulators in allowing the timely recovery of costs and the ability to earn a fair return on investment. A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring Exhibit No. 201, which was prepared under my direction. Avista's credit ratings by the three principal rating agencies are summarized on page 1. Page 2 includes Avista's actual capital structure at December 31, 2008 and the forecasted capital structure utilized for this case, which was calculated using a five quarter average of the period fourth quarter 2009 through fourth quarter 2010. Pages 3 through 7 are supporting documentation for page 2.

II. FINANCIAL OVERVIEW

Q. Please provide an overview of Avista's financial situation.

A. The Company has made solid progress in improving its financial health in recent years, as demonstrated by improved financial ratios. Avista has reduced investments in unregulated subsidiaries and redeployed the majority of the proceeds from the sales of the unregulated subsidiaries to the Utility. The Company has been able to improve its debt ratio and balance the overall debt / equity ratio by paying down debt, issuing additional common stock, and through additional retained earnings. Although we have made progress in improving the Company's financial condition, we are still not as strong as we need to be given the volatility in capital markets, which may continue for some time.

Avista's goal is to operate at a level that will support a strong corporate credit rating of BBB / BBB+, and move away from the "cliff" of the investment grade rating scale. Operating at a higher rating will help reduce long-term financing costs to customers. It will also reduce collateral requirements and allow us to maintain access to more counterparties for acquisition of natural gas and electricity. We expect that a continued focus on the regulated utility, conservative financing strategies (including the issuance of common equity over time) and a continued supportive regulatory environment will contribute to an overall improved financial situation that should allow us to move up from the current BBB- rating.

Q. What additional steps is the Company taking to improve its financial health?

A. We are working to assure we have adequate funds for operations, capital expenditures and debt maturities. In November 2008 we acquired a new $200 million 364-day line of credit from our banks at reasonable rates that has allowed us to avoid the debt capital markets at a volatile time when rates were very high. In December 2008, we also obtained a $30 million private placement of five-year debt at favorable rates as compared to the public markets.

We are maintaining our original $320 million line of credit, which will expire in April 2011, as well as our Accounts Receivable Sales program. The Company plans to obtain a portion of our capital requirements through equity issuance when our stock is priced at or above book value. We also maintain an ongoing dialogue with the rating agencies regarding the measures taken by the Company to improve our credit rating.

Additionally, the Company is working through regulatory processes to recover our costs in a timely manner so that earned returns are closer to those allowed by regulators in each of the states we serve. This is one of the key determinants from the rating agencies' standpoint when they are reviewing our overall credit standing.

Q. In addition to having credit ratings that will allow Avista to attract debt capital under reasonable terms, is it also necessary to attract capital from equity investors?

A. It is absolutely essential. Avista has two primary sources of external capital – debt lenders and equity investors. Avista currently has approximately $2.3 billion of net investment in place to serve its customers. Approximately half of that investment is funded by debt holders, and half is funded by equity investors. Therefore, even though there tends to be a lot of emphasis on maintaining credit metrics and credit ratings that will provide access to debt capital under reasonable terms, access to equity capital is equally important.

Additional equity capital generally comes in two forms – retained earnings and new equity issuances. Retained earnings represent the annual earnings (return on equity) of the Company that is not paid out to investors in dividends. The retained earnings are reinvested by the Company in utility plant, and other capital requirements, to serve customers, which avoids the need to issue new debt. Occasionally it is necessary to issue new common stock to maintain the proper balance of debt and equity in the capital structure, which allows Avista access to both debt and equity markets under reasonable terms, on a sustainable basis. Because of the large capital requirements at Avista in the near-term, it is imperative that Avista have ready-access to both the debt and equity markets at reasonable costs.

Q. Are the debt and equity capital markets a competitive market?

A. Yes. Our ability to attract new capital, especially equity capital, under reasonable terms is dependent on our ability to offer a risk/reward opportunity that is better than the equity investors' other alternatives. We are competing with not only other utilities, but businesses in other sectors of the economy. As an example, if an equity investor believes, or perceives, that the risk/reward opportunity is better with WalMart than with Avista, or the utility industry in general, the investor will put the equity dollars in WalMart stock. Demand for the stock supports the stock price, which provides the opportunity to issue additional stock under reasonable terms to fund capital investment requirements.

To the extent that the equity investor holds a diversified portfolio of companies that includes utilities and other energy companies, we would be competing with those companies to attract those equity dollars.

In the debt markets, utilities are the third largest issuers, right behind governments and financial services. Therefore, it is a very competitive market and the Company must be able to attract debt investors as well as equity investors.

Q. What is Avista doing to attract equity investment?

A. Avista is carrying a capital structure that provides the opportunity to have financial metrics that offer a risk/reward proposition that is competitive and/or attractive for equity holders.

We have increased our dividend for common shareholders, and have publicly stated that we intend to work toward a dividend payout ratio that is comparable to other utilities in the industry. This is an essential element in providing a competitive risk/reward opportunity for equity investors.

We are operating the business efficiently to keep costs as low as practicable for our customers, while at the same time ensuring that our energy service is reliable, and results in a high level of customer satisfaction. An efficient, well-run business is not only important to our customers, but also to investors.

We are employing tracking mechanisms such as the Purchased Gas Adjustment (PGA), approved by the regulatory commissions, to balance the risk of owning and operating the business in a manner that places us in a position to offer a risk/reward opportunity that is competitive with not only other utilities, but with businesses in other sectors of the economy.

We are seeking rate relief to provide timely recovery of costs and earned returns closer to those allowed by regulators. If we are not able to achieve a reasonable, actual, earned return on our equity investment, we will not be able to attract equity dollars that are absolutely necessary to support this business going forward.

Dr. Avera provides additional testimony related to the appropriate return on equity for Avista, which would allow the Company access to equity capital under reasonable terms, and on a sustainable basis.

Q. Do you believe there are misconceptions about the earnings of the Company related to the equity investment in the Company?

A. Yes I do. I believe some of our customers believe that the earnings of the Company that we report publicly each quarter are "profits" that are over and above the dollars necessary to own and operate the utility, which we know is simply not true. Just as we must pay interest to debt holders in exchange for the use of their dollars, we must also provide a return on investment for the equity holder, or the equity holder will take his or her dollars somewhere else.

I believe some do not understand that the quarterly earnings or profits are the return or "interest" to the shareholder, and without it we would not have the funds necessary to run the business – i.e., it is, in fact, one of the essential costs of owning and operating the business.

As we process this rate filing, it is imperative that we work toward recovery of the costs to provide service to customers, and a meaningful opportunity to earn a return closer to the allowed return, so that we can have access to debt and equity capital under reasonable terms.

III. CREDIT RATINGS

Q. How important are credit ratings for Avista?

A. Utilities need ready access to capital markets in all types of economic environments. I believe few, if any, would have predicted the kind of financial markets we have experienced beginning the latter part of 2008. The nature of our business with long-term capital projects, our obligation to serve, and the potential for high volatility in fuel and purchased power and natural gas markets, necessitates the ability to tap the financial markets under reasonable terms on a regular basis.

In the past six to nine months we have seen ample evidence of the benefit of having a higher credit rating. As an example, in December 2008, El Paso Electric, a BB credit, issued bonds at an effective cost of 15%.

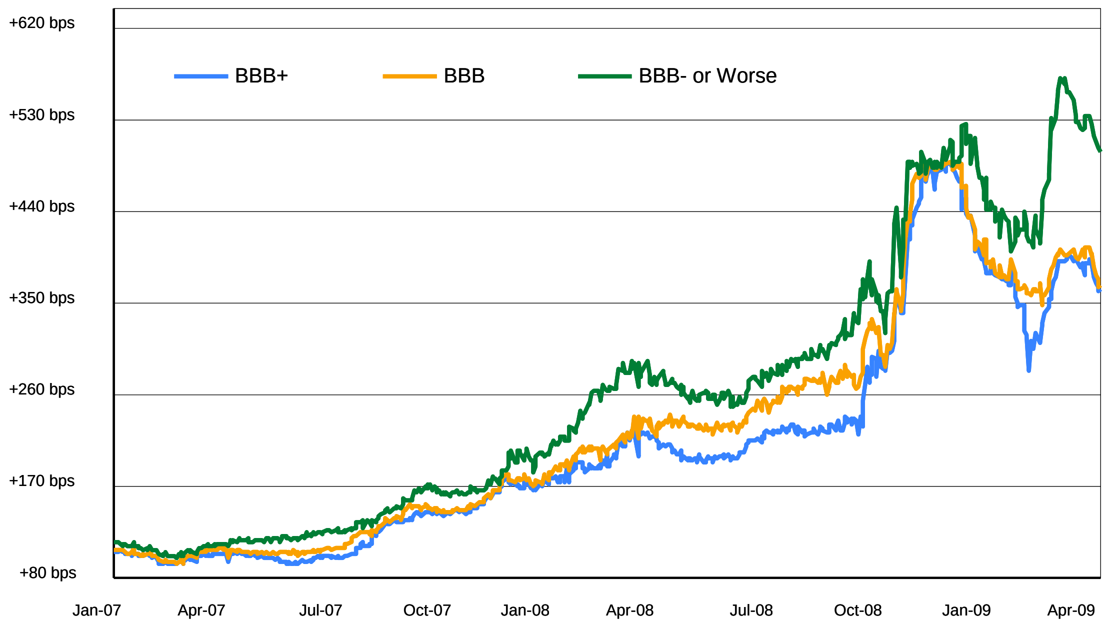
In the fall of 2008 we had planned to issue an additional $100 million of long-term debt. In April 2008 we issued $250 million of 10-year debt at 5.95%. In the fall of 2008, however, because of the unrest in the financial markets, there were times when we could not issue debt at any interest rate, and when it was available, the all-in interest rates were 9.5% or higher. Fortunately, we were able to negotiate the acquisition of an additional credit line of $200 million for a period of 364 days, under favorable terms, and avoid issuing new long-term debt at these high rates – at least for now. We believe that financial markets will be more stable as we move toward the latter part of 2009, and our financial circumstances will be such that we will have access to new long-term debt at reasonable rates.

Q. Yields on US Treasuries decreased significantly the last several months of 2008, but have been on an erratic upward trend in 2009. What has this done to utility bond interest rates?

A. The interest rate spreads between utility bonds and Treasuries that debt holders are demanding increased dramatically due to the unrest in the financial system and the economy in the last quarter of 2008. The spreads declined in the early part of 2009 but have been fluctuating up and down since that time. As an illustration, quotes from our bankers the week of May 4 indicated spreads were in the range of +300-425 bps, and as of the week of May 25 spreads had deceased to a range of +225-250 bps. This demonstrates the high volatility that has been occurring. The following graph illustrates this volatility and shows the dramatic gap between the yields on Treasuries and utility bonds rated BBB+, BBB, and BBB- or below. The graph also illustrates the significantly higher cost of debt for companies at or below the lowest rung of the investment grade ladder (BBB- or below), versus a credit rating of BBB, only one step higher than Avista's current rating of BBB-.

Illustration No. 1:

Average Utility Bond Spread to U.S. Treasury



Q. Please explain the credit ratings for Avista's debt securities,

A. Rating agencies are independent agencies that assess risks for investors. The three most widely recognized rating agencies are Standard & Poor's (S&P), Moody's Investors Service (Moody's) and FitchRatings (Fitch). These rating agencies assign a credit rating to companies and their securities so investors can more easily understand the risks associated with investing in their debt and preferred stock. Avista's credit ratings by the three principal rating agencies are summarized on page 1 of Exhibit No. 201. Additionally, the following rating actions occurred since 2007:

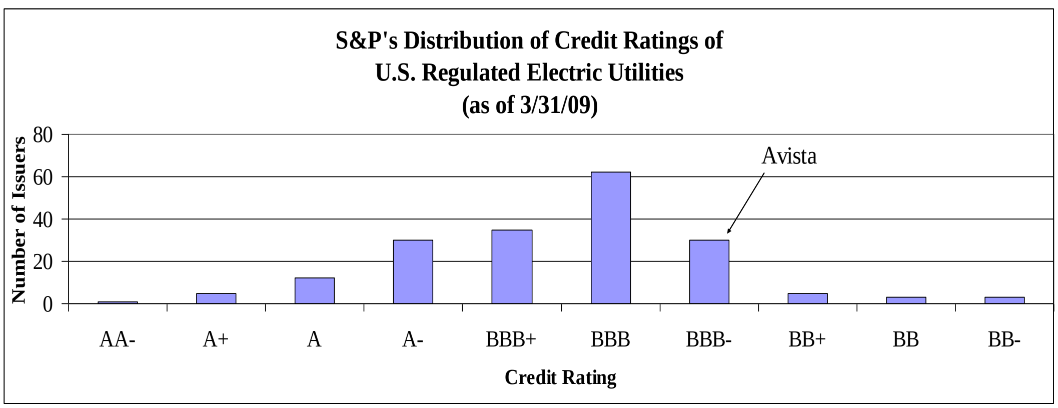
a. S&P upgraded Avista's corporate credit rating to BBB- from BB+ (February 2008) and Avista's secured debt rating to BBB+ from BBB- (September 2007 and affirmed in September 2008).

b. Moody's upgraded Avista's corporate credit rating to Baa3 from Ba1 and Avista's secured rating to Baa2 from Baa3 (December 2007).

c. Fitch upgraded Avista's long-term issuer default rating to BBB- from BB+ and its secured debt rating to BBB+ from BBB (May 2009).

As shown in Illustration No. 2 below, Avista is on the lowest rung of the investment grade credit rating scale. As I noted earlier, I believe it is important that we move up the scale to at least a BBB or BBB+, so that we are not on the edge of the investment grade cliff.

Illustration No. 2:



Q. Please explain the implications of the credit ratings in terms of the Company's ability to access financial markets.

A. Credit ratings impact investor demand and expected return. More specifically, when the company issues debt, the credit rating helps determine the interest rate at which the debt will be issued. The credit rating also determines the type of investor who will be interested in purchasing the debt. For each type of investment a potential investor could make, the investor looks at the quality of that investment in terms of the risk they are taking and the priority they would have in the event that the organization experiences severe financial stress. Investment risks include the likelihood that a company will not meet all of its debt obligations in terms of timeliness and amounts owed for principal and interest. Secured debt receives the highest ratings and priority for repayment and, hence, has the lowest relative risk. In challenging credit markets, where investors are less likely to buy corporate bonds, a higher credit rating will attract more investors, and a lower credit rating could shrink or eliminate the number of potential investors. Thus, lower credit ratings may result in a company having more difficulty accessing financial markets and/or incur significantly higher financing costs.

Q. What credit rating does Avista Corporation believe is appropriate?

A. The move to investment grade for Avista Corp last year was a significant step in improving the ability to access capital at a reasonable cost. However, a credit rating at the bottom of investment grade is not appropriate for Avista. In adverse conditions – whether unique to Avista or by all market participants – a downgrade from BBB- (investment grade) to BB+ (high-yield) is significantly harder to overcome than a downgrade from BBB to BBB-. As Avista experienced, it took approximately six years for the Company to regain its investment grade rating from S&P after it was downgraded during the energy crisis. The difference between investment grade and non-investment grade is not only a matter of debt pricing, it can be a matter of any access at all. During the period from mid-September to mid-December 2008, the credit markets were essentially closed to non-investment grade issuers. In order to be able to weather a potential downgrade, Avista Utilities should operate at a level that will support a strong corporate investment grade credit rating, meaning a "BBB" or a "BBB+," using S&P's rating scale.

A solid investment grade credit rating would also allow the Company to post less collateral with counterparties than would otherwise be required with a lower credit rating. This results in lower costs. It also increases financial flexibility since the credit line capacity would not be reduced for outstanding letters of credit.

Financially healthy utilities have lower financing costs which, in turn, benefit customers. In addition, financially healthy utilities are better able to invest in the needed infrastructure over time to serve their customers, and to withstand the challenges and risks facing the industry.

Q. What financial metrics are used by the rating agencies to establish credit ratings?

A. S&P modified its electric and natural gas utility rankings in November 2007 to conform to the "business risk/financial risk" matrix used by their corporate ratings group. The change by S&P was designed to present their rating conclusions in a clear and standardized manner across all corporate sectors.

S&P's financial ratio benchmarks used to rate companies such as Avista are set forth in Illustration No. 3 below.

Illustration No. 3:

Standard & Poor's Financial Risk Indicative Ratios - US Utilities	FFO/Debt (%)	FFO/Interest (x)	Debt Ratio (%)
Modest	40 - 60	4.0 - 6.0	25 - 40
Intermediate	25 - 45	3.0 - 4.5	35 - 50
Aggressive	10 - 30	2.0 - 3.5	45 - 60
Highly leveraged	Below 15	2.5 or less	Over 50
12 Month End 12/31/08 Ratios:			
Avista Adjusted*	18.4	4.0	55.6

* Calculated as of 12/31/08 based on last known S&P methodology

The ratios above are utilized to determine the financial risk profile. Currently, Avista is in the "Aggressive" category. The financial risk category along with the business risk profile (Avista is in the Strong category) is then utilized in Illustration No. 4 below to determine a company's rating. S&P currently has Avista's corporate credit rating as a BBB-, as indicated in the following illustration.

Illustration No. 4:

Standard & Poor's Business Risk / Financial Risk Matrix

	Financial Risk Profile				
Business Risk Profile	Minimal	Modest	Intermediate	Aggressive	Highly leveraged
Excellent	AAA	AA	A	BBB	BB
Strong	AA	A	A-	BBB-	BB-
Satisfactory	A	BBB+	BBB	BB+	B+
Weak	BBB	BBB-	BB+	BB-	B
Vulnerable	BB	B+	B+	B	B-

The other rating agencies (Moody's and Fitch) use a similar methodology to analyze and determine utility credit ratings.

Q. Please describe how these ratios are calculated and what they mean?

A. The first ratio, "Funds from operations/total debt (%)", calculates the amount of cash from operations as a percent of total debt. The ratio indicates the company's ability to fund debt obligations. The second ratio, "Funds from operations/interest coverage (x)", calculates the amount of cash from operations that is available to cover interest requirements. This ratio indicates how well a company's earnings can cover interest payments on its debt. The third ratio, "Total debt/total capital (%)", is the amount of debt in our total capital structure. The ratio is an indication of the extent to which the company is using debt to finance its operations. S&P looks at many other financial ratios; however, these are the three most important ratios they use when analyzing our financial profile.

Q. Do rating agencies make adjustments to the financial ratios that are calculated directly from the financial statements of the Company?

A. Yes. Rating agencies make adjustments to debt to factor in off-balance sheet commitments (including, for example, the accounts receivable program, purchased power agreements and the unfunded status of pension and other post-retirement benefits, in addition to other small adjustments) that negatively impact the ratios. Based on the last known S&P methodology, the adjustments to Avista's debt totaled approximately $130 million to arrive at the ratios shown for Avista in Illustration No. 3 above.

Q. Where does Avista fall within those coverage ratios?

A. Avista's cash flow ratios have improved as a result of the refinancing of the high cost debt that matured in June 2008. Moody's and S&P took this into account when they upgraded Avista in December 2007 and February 2008, respectively. Progress in increasing the cash flow ratios in recent years has been slower than anticipated due to below normal stream flows affecting hydro generation, higher thermal fuel costs than the amount included in rates and the resulting inability to eliminate electric deferral balances, higher capital expenditures that require cash up front before we can recover the costs from customers, and a lag in the recovery of other operating costs. Each has an impact on the Company by reducing the amount of available cash flow from operations, requiring external financing and ultimately resulting in higher debt and lower cash flow ratios.

In order to improve the cash flow ratios, Avista must reduce its total debt balances and increase its available funds from operations. Although the Company has continued to work towards paying down its total debt, the negative impacts to cash flow referenced above have adversely affected Avista's progress in improving the cash flow ratios.

Q. Do the rating agencies look at any other factors when evaluating a company's credit quality?

A. Yes. In addition to financial ratios and metrics, rating agencies also look at a number of qualitative factors which directly or indirectly may affect a company's cash flow. These factors include:

- Regulation
- Markets
- Operations

- Competitiveness, and
- Management

In evaluating these factors, the rating agencies look for regulatory actions that are supportive of cost recovery and that eliminate or minimize volatility of cash flows. They also consider the strength and growth of the economy in our service territory, operations' ability to control costs, whether our service is competitive, and the effectiveness of management.

Therefore, while the ratios are utilized in their quantitative evaluation of a company, they are not the only factors that are taken into account.

Q. What risks are Avista and the utility sector facing that may impact credit ratings?

A. Avista's credit ratings are impacted by risks that could negatively affect the company's cash flows. These risks include, but are not limited to, the level and volatility of wholesale electric and natural gas market prices, liquidity in the wholesale market (fewer counterparties and tighter credit restrictions), recoverability of natural gas and power costs, stream flow and weather conditions, changes in legislative and governmental regulations, relicensing hydro projects, rising construction and raw material costs, customers' ability to timely pay their bills, and access to capital markets at a reasonable cost.

Credit ratings for the utility sector are also adversely impacted by large capital expenditures for environmental compliance, and the need for new utility infrastructure. The utility sector is in a cycle of significant capital spending, which will likely be funded by large issuances of debt and equity. This increases the competition for financial capital at a time when the average utility credit rating is just above investment grade.

Given the downturn in the economy and the tightened credit markets, the rating agencies are keeping closer tabs on all companies in order to make sure there is sufficient liquidity in case the credit markets are inaccessible. Not having sufficient sources of cash for potential cash requirements could prompt a credit rating downgrade.

The increased capital spending needs and resulting increased debt issuances make regulation supporting the full and timely recovery of prudently incurred costs even more critical to the utility sector than in previous years.

Q. How important is the regulatory environment in which a Company operates?

A. The regulatory environment in which a company operates is a major qualitative factor in determining a company's creditworthiness. Moody's stated the following regarding Avista's regulatory environment in a December 2008 credit ratings report:

> "Avista benefits from credit supportive ratemaking practices in all three of its jurisdictions, which include periodic mechanisms to account for variations in the power and natural gas costs incurred as compared to the levels included in rates." However, Moody's also pointed out that "Failure to obtain adequate and timely support for recovery of and return on core utility investments through pending and expected future regulatory proceedings, or any unexpected material deviation from the back-to-basics strategy, are among the more important factors that could have negative rating implications."[1]

Due to the major capital expenditures planned by Avista, the continued supportive regulatory environment will be critical to Avista's financial health. Additionally, although Avista has natural gas and electric tracking mechanisms to provide recovery of the majority of the variability in commodity costs, these changes in costs must be financed until the costs are

[1] Moody's Investor Service, *Moody's Upgrades Avista Corp* (December 3, 2008)

recovered from customers. Investors and rating agencies are concerned about regulatory lag and cost-recovery related to these items.

IV. CASH FLOW

Q. What are the Company's sources to fund capital requirements?

A. The Company utilizes cash flow from operations, long-term debt and common stock issuances to fund its capital expenditures. Additionally, on an interim basis, the Company utilizes its credit facilities to fund working capital needs and capital expenditures until longer-term financing can be obtained.

Q. What are the Company's near-term capital requirements?

A. As a combination electric and natural gas utility, over the next few years, capital will be required for customer growth, necessary maintenance and replacements of our natural gas utility systems, and investment in generation, transmission and distribution facilities for the electric utility business.

The amount of capital expenditures planned for 2009-2010 is approximately $420 million. For 2009 alone, these costs equate to a total of $210 million. Ratebase at December 31, 2008 was $1.8 billion for the total Company; therefore, these planned capital additions represent substantial new investments given the relative size of the Company.

Q. What are the Company's long-term capital requirements?

A. Major capital expenditures are a normal part of utility operations. Customers are added to the service area, roads are relocated and require existing facilities to be moved, and facilities continue to wear out and need replacement. These and other requirements create the need for significant capital expenditures each year. Access to capital at reasonable rates is dependent upon the Company maintaining a strong capital structure, sufficient interest coverage, and investment grade credit ratings.

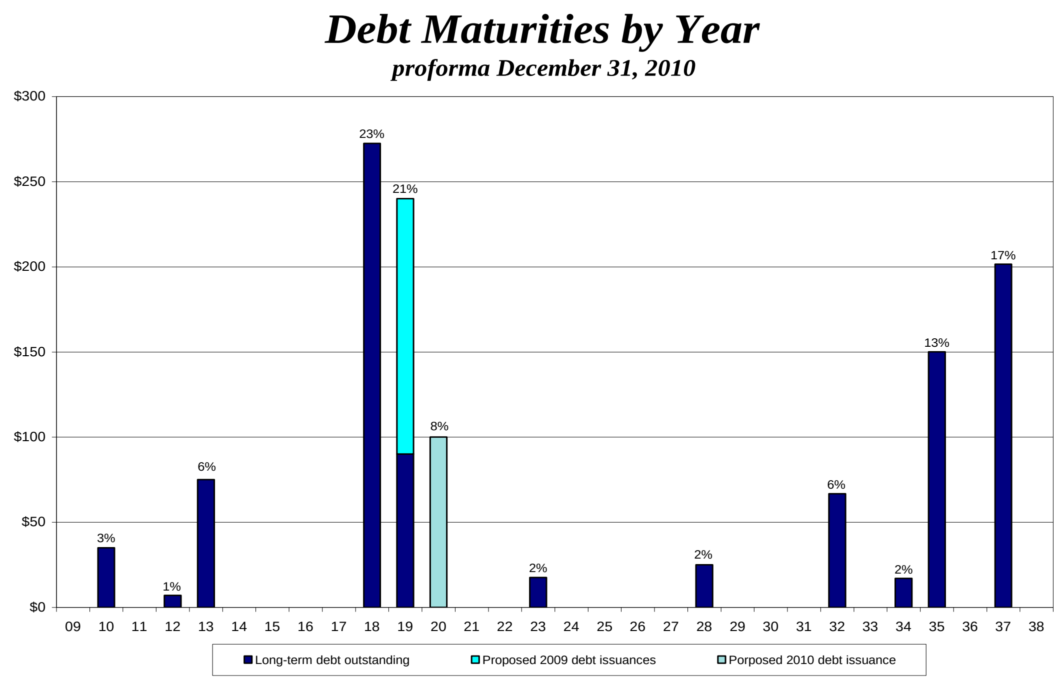
Q. What are the Company's near-term plans related to its debt?

A. During 2008 the Company issued $250 million of secured debt in April but, as explained earlier, chose not to go forward with a planned issuance of $100 million in long-term debt in September 2008 due to unfavorable conditions in the debt capital markets. The Company instead sought out and was able to establish a second bank line of credit in the amount of $200 million for 364 days (ending November 24, 2009) to ensure continued adequate liquidity. The Company was also offered and accepted a private placement of $30 million of First Mortgage Bond secured five-year debt.

The Company currently plans to issue at least $150 million of secured, fixed rate bonds during 2009. The proceeds from the issuance of the securities will be utilized to fund capital expenditures and repay funds borrowed under our credit facilities. The Company has no long-term debt scheduled to mature in 2009; however, it redeemed $61.9 million of Trust Preferred Securities on April 1, 2009.

Illustration No. 5 below shows the amount of debt maturities for Avista each year:

Illustration No. 5:



Q. Has the Company taken any steps to address the uncertainty related to interest rate exposure for the planned debt issuances in 2009 and 2010?

A. Yes. In late 2008 and early 2009 the Company entered into four forward-starting interest rate swaps for a total of $100 million as a hedge on a portion of the interest payments on the long-term debt we are planning to issue in 2009. In March 2009 the company also entered into two forward-starting interest rate swaps for a total of $50 million as a hedge on a portion of the interest payments on the long-term debt we are planning to issue in 2010.

Q. What is the status of the Company's lines of credit secured by first mortgage bonds and its accounts receivable program?

A. The Company has a $320 million line of credit that expires in April 2011, and a $200 million line of credit that expires November 24, 2009. The Company has the option of increasing the $320 million line by $100 million (up to $420 million) at any time during the term of the agreement, subject to additional fees and obtaining bank commitments. The agreement includes the option to release the first mortgage bond security when the Company has an investment grade credit rating. The Company also has the option of renewing or upsizing the $200 million deal to $250 million under certain circumstances. Additionally, the Company has an $85 million accounts receivable funding program that expires in March 2010. This agreement has been renewed on a year-to-year basis, and we expect to continue extending the agreement into the future.

The facilities have been sized to allow the Company to maintain a liquidity cushion of at least $125 million at all times to cover required working capital, counterparty collateral requirements, and avoid issuing debt in unfavorable market conditions if they persist through 2009. Our liquidity is strong and we are confident that our current agreements give us flexibility while facing both the volatile financial markets and volatile energy commodity prices.

Many purchases of natural gas, or contracts for pipeline capacity to provide natural gas transportation, require collateral, and/or prepayments, based upon the Company's credit rating. Upgrades to Avista's credit ratings during 2007 and 2008 have reduced the amount of collateral required to be posted with counterparties. If Avista is upgraded above its current credit ratings, the Company should see an increase in the number of counterparties willing to do business with us and the collateral requirements are expected to decrease even further, resulting in reduced borrowing costs. The lines of credit and accounts receivable program are our primary sources of immediate cash for borrowing to meet these needs and for supporting the use of letters of credit. A line of credit is required to manage daily cash flow since the timing of cash receipts versus cash disbursements is never totally balanced.

Q. What are Avista's plans regarding common equity and why is this important?

A. Avista will continue to monitor the common equity ratio of its capital structure, and assess the need to issue additional common equity. Avista entered into a sales agency agreement in December 2006 to issue up to two million shares of our common stock from time to time. During the third quarter of 2008, we issued 750,000 shares of common stock under this agreement. Our common stock price is currently below book value, and at this time we do not plan to issue additional stock in 2009. In the longer term, we will continue to monitor the equity markets and will issue additional common stock as needed to support the equity ratio, when it is economic to do so.

To the extent that we are not able to access the equity market, there will be increased pressure on our lines of credit, and an increased need to issue long term debt, which is likely to unfavorably impact our cost of debt and debt to equity ratio. It is important to the rating agencies for Avista to maintain a balanced debt/equity ratio in order to minimize the risk of default on required debt interest payments.

As Dr. Avera explains in his testimony, the 51.45 percent common equity ratio requested by Avista in this case is consistent with the range of equity ratios maintained by the firms in the Utility Proxy Group.

Dr. Avera also discusses Moody's warning to investors of the risks associated with debt leverage and fixed obligations and their advice to utilities to not squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties. Moody's noted that, absent a thicker equity layer, utilities would be faced with lower credit ratings in the face of rising business and operating risks:

> There are significant negative trends developing over the longer-term horizon. This developing negative concern primarily relates to our view that the sector's overall business and operating risks are rising – at an increasingly fast pace – but that the overall financial profile remains relatively steady. A rising risk profile accompanied by a relatively stable balance sheet profile would ultimately result in credit quality deterioration.[2]

This is especially the case for Avista, which faces the dual challenge of financing significant capital expansion plans in a turbulent market while at the same time endeavoring to improve its credit standing. Recovery of costs, together with the opportunity to earn a competitive return on equity through this general rate case, is critically important for the company continuing to have access to debt and equity capital under reasonable terms on a sustainable basis.

Q. What are Avista's plans regarding preferred equity and other financing structures (for example, hybrid instruments)?

A. Avista does not have any preferred equity or other financing structures outstanding at May 31, 2009. Currently, Avista does not plan to issue preferred equity or other financing structures, but will continue to evaluate the appropriateness of these financing vehicles.

V. CAPITAL STRUCTURE

Q. Please explain the capital structure proposed by Avista in this case.

A. Avista's current capital structure consists of a blend of long-term debt, long-term debt to affiliated trusts and common equity necessary to support the assets and operating capital of the Company. Short-term debt carried on the Company's line of credit has been excluded from the capital structure. The proportionate shares of Avista Corp.'s actual capital structure on December 31, 2008, are shown on page 2 of Exhibit No. 201. Page 2 also includes Avista's forecasted capital structure utilized for this case, which was calculated using a five quarter average of the period fourth quarter 2009 through fourth quarter 2010. The forecasted capital structure shown in the Exhibit reflects expected changes for the periods ending December 31, 2009 and December 31, 2010. Supporting workpapers provide additional details related to these adjustments.

The rate of return to be applied to rate base in this proceeding is equal to the weighted average cost of capital, taking into account the pro forma adjusting items. As shown on page 2 of Exhibit No. 201, Avista Utilities is proposing an overall rate of return of 8.96%.

Q. How does Avista conduct its financing as a multi-jurisdictional and multi-service utility?

A. Avista provides natural gas distribution service in Oregon, Washington, and Idaho. Avista generates, transmits and distributes electricity in Washington and Idaho. Funding for these jurisdictions is provided through a central treasury function. A central treasury function is utilized as it is more efficient and cost-effective to pool our resources across jurisdictions.

---

[2] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

The cost of funds for each jurisdiction is the same. Likewise, we provide shared services across all jurisdictions that result in a benefit of scale to each of the jurisdictions. The benefits of being a multi-service utility, that operates in a geographic region spanning parts of three states, results in customers sharing in the costs of service, cost of capital, and the level of service provided. Reasonable allocations can be made to determine the fair sharing of costs among jurisdictions, however, all jurisdictions use the same pool of financial resources for these items and it is not possible to specifically assign many of the dollars for shared resources directly to specific jurisdictions.

The capital requirements for the entire utility are managed as a whole. Capital for customer demands is driven by the needs of customers in each respective jurisdiction and is provided from a shared funding pool. Any distinctions between the cost of capital among our jurisdictions would be difficult to determine and unsupportable by the facts of how capital is obtained and used for the entirety of utility operations.

The selection of debt financing comes from a combination of financial market dynamics, funding needs, financial flexibility and judgment. We continuously review our existing debt obligations and review what may be available in the financial markets. Our goal is to provide the lowest cost debt structure possible while preserving long-term and short-term flexibility and access to needed funds.

VI. COST OF DEBT

Q. How have you determined the cost of debt?

A. Cost of debt in the Company's proposed capital structure includes both long-term debt and long-term debt to affiliated trusts. Short-term debt carried on the Company's line of credit has been excluded from the capital structure. As shown on page 2 of Exhibit No. 201, the actual weighted average cost of total debt outstanding on December 31, 2008 was 6.92%. The size and mix of debt funding changes over time based upon the actual financing completed. The forecasted cost of debt utilized for this case was calculated using a five quarter average for the quarters fourth quarter 2009 through fourth quarter 2010. Forecasted adjustments to long-term debt reflect expected maturities of outstanding debt and the issuance of new debt.

VII. COST OF COMMON EQUITY

Q. What rate of return on common equity is the Company proposing in this proceeding?

A. As further explained by Dr. Avera, the cost of equity has increased since the conclusion of Avista's last general rate case. Difficult economic conditions and increased volatility in the financial markets have caused a flight to quality among investors, meaning that they have a preference for investments with very low risk, such as U.S. Treasury bonds, and they are demanding a higher premium (return) for taking additional risk. As explained earlier in my testimony, the interest rate spreads between US Treasuries and utility bonds increased dramatically in the latter part of 2008. Equity investments inherently contain more risk, and our cost of equity has also increased since our last rate case.

The Company is proposing an 11.0% return on common equity (ROE), at the lower end of Dr. Avera's recommended range of required return on equity. Dr. Avera testifies to analyses related to the cost of common equity with an ROE range of 11.0% to 12.5%. In his testimony Dr. Avera states that:

> My evaluation indicates that Avista's requested ROE of 11.0 percent represents a conservative estimate of investors' required rate of return. Given the fact that the Company's requested ROE falls at the lower boundary of my recommended range, it should be viewed as an absolute floor in establishing rates for Avista. This conclusion is reinforced by the need to buttress the Company's credit standing, which remains relatively weak, as well as the fact that Avista's investment risks exceed those of the proxy groups used to estimate the cost of equity. The reasonableness of a minimum 11.0 percent ROE for Avista is also supported by the fact that my recommended ROE range does not consider flotation costs. (P. 66, L. 13 -20)

Q. Dr. Avera suggests an ROE range of 11.0% to 12.5%. Why is Avista requesting an ROE at the lower end of the range?

A. As I have testified, Avista has made solid progress towards improving its financial health. If Avista can earn an 11.0% ROE, I believe our financial condition would continue to improve and would further strengthen the credit ratings ratios.

Furthermore, as the Company has worked toward improving its financial condition over the last several years, it has done so with the customer in mind. Avista is attempting to balance the ability to continue to improve our financial health and access capital markets under reasonable terms with the impacts that increased retail rates have on its customers. In this case, although we believe an ROE greater than 11.0% is supported and is warranted, we also believe the 11.0% provides a reasonable balance of the competing objectives.

Q. Please summarize the proposed capital structure and the cost components for debt and common equity.

A. As also shown on page 2 of Exhibit No.201, the following illustration shows the capital structure and cost components proposed by the Company.

<u>Illustration No. 6:</u>

Q4 09 - Q4-10 Avg.
Cost of Capital

	Amount	Percent of Total Capital	Cost	Component
Total Debt	$1,126,800,000	48.55%	6.80%	3.30%
Common Equity	1,193,973,066	51.45%	**11.00%** (1)	5.66%
TOTAL	$2,320,773,066	100.00%		**8.96%**

(1) Proposed Return on Common Equity - See Avera testimony

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

A. Yes.

AVISTA CORPORATION
Long-term Securities Credit Ratings

	Standard & Poor's		Moody's		Fitch	
Last Reviewed	February 2008		December 2007		August 2007	
Credit Outlook	Stable		Stable		Positive	
	A+		**A1**		**A+**	
	A		**A2**		**A**	
	A-		**A3**		**A-**	
	BBB+	First Mortgage Bonds Secured Medium-Term Notes	**Baa1**		**BBB+**	
	BBB		**Baa2**	First Mortgage Bonds Secured Medium-Term Notes	**BBB**	First Mortgage Bonds Secured Medium-Term Notes
	BBB-	Avista Corp./Corporate rating Senior Corporate Notes 9.75%	**Baa3**	Avista Corp./Issuer rating Senior Corporate Notes 9.75%	**BBB-**	Senior Corporate Notes 9.75%
	INVESTMENT GRADE					
	BB+		**Ba1**	Trust-Originated Preferred Securities	**BB+**	Avista Corp./Issuer rating Trust-Originated Preferred Securities
	BB	Trust-Originated Preferred Securities	**Ba2**		**BB**	
	BB-		**Ba3**		**BB-**	

AVISTA CORPORATION
Capital Structure and Overall Rate of Return

FORECASTED Cost of Capital as Q4 '09 -Q4 '10 Avg.	Amount	Percent of Total Capital	Cost		Component
Total Debt *	$1,126,800,000	48.55%	6.80%		3.30%
Common Equity	1,193,973,066	51.45%	**11.00%**	(1)	5.66%
TOTAL	$2,320,773,066	100.00%			**8.96%**

EMBEDDED Cost of Capital as of December 31, 2008	Amount	Percent of Total Capital	Cost	Component
Total Debt	$1,005,800,000	49.73%	6.92%	3.44%
Common Equity	1,016,663,291	50.27%	**10.20%**	5.13%
TOTAL	$2,022,463,291	100.00%		**8.57%**

* Excludes Short -Term Debt
(1) Proposed Return on Common Equity - See Avera testimony
See supporting documentation
All costs are shown before tax

Assumptions
1. Started with 12-31-2008 actual
2. Proforma through 12-31-2009 and 12-31-2010
3. The forecasted equity and debt numbers come from forecast DEC11 model run
4. Equity is adjusted for Other Comprehensive Income and capital stock expense of $23.4M
5. Forecasted issuance of $31 million of equity during 2010 using different company programs

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF WILLIAM E. AVERA
REPRESENTING AVISTA CORPORATION

Return on Equity

DIRECT TESTIMONY OF WILLIAM E. AVERA

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. Please describe your educational background and professional experience.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit 302.

A. Overview

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

A. The purpose of my testimony is to present to the Public Utility Commission of Oregon ("OPUC") my independent evaluation of the fair rate of return on equity ("ROE") for the jurisdictional gas utility operations of Avista Corp. ("Avista" or "the Company").

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this case.

A. As is common and generally accepted in my field of expertise, I have accessed and used information from a variety of sources. I am familiar with the organization, finances, and operations of Avista from my participation in prior proceedings before the OPUC, Washington Utilities and Transportation Commission ("WUTC"), and the Idaho Public Utilities Commission ("IPUC"). In connection with the present filing, I considered and relied upon corporate disclosures and management discussions, publicly available financial reports and filings, and other published information relating to Avista. I also reviewed information relating generally to current capital market conditions and specifically to current investor perceptions, requirements, and expectations for Avista's gas utility operations. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for Avista, and they form the basis of my analyses and conclusions.

Q. What is the practical test of the reasonableness of the ROE used in setting a utility's rates?

A. The ROE compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to: (1) fairly compensate investors for capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. How did you develop your conclusions regarding a fair rate of return for Avista?

A. I first reviewed the general conditions in capital markets, as well as the operations and finances of Avista and industry-specific risks perceived by investors. With this

[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

as a background, I conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), as well as reference to expected earned rates of return. Based on the cost of equity estimates indicated by my analyses, the Company's ROE was evaluated taking into account the specific risks and economic requirements for Avista.

B. Summary of Conclusions

Q. What are your findings regarding the fair rate of return on equity for Avista?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend that Avista be authorized an ROE in the range of 11.0 percent to 12.5 percent. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with Avista's jurisdictional utility operations, my analyses focused on a proxy group of eleven other natural gas utilities. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of companies in the non-utility sector of the economy;
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied both the discounted cash flow ("DCF") and capital asset pricing model ("CAPM") methods, as well as the comparable earnings approach, to estimate a fair ROE for Avista:
  - My application of the constant growth DCF model considered four alternative growth measures based on projected earnings growth, as well as the sustainable, "br+sv" growth rate for each firm in the respective proxy groups;
  - My DCF analyses implied a cost of equity estimates of **10.8 percent and 11.6 percent** for the proxy group of gas utilities and **13.6 percent and 12.4 percent** for the group of non-utility companies;
  - Application of the CAPM approach using forward-looking data that best reflects the underlying assumptions of this approach implied a cost of equity of **10.3 percent** for the proxy group of gas utilities and **11.5 percent**

- for the firms in the non-utility proxy group;
  - My evaluation of earned rates of return expected for utilities suggested a cost of equity on the order of **11.0 to 12.5 percent**;
  - Based on these results, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the **11.0 percent to 12.5 percent** range.
  - While this range does not incorporate an explicit adjustment to account for the impact of common equity flotation costs, they are a legitimate consideration in evaluating a fair rate of return on equity for Avista.

Q. What did you conclude with respect to the reasonableness of Avista's requested ROE?

A. Considering investors' expectations for capital markets and the need to support financial integrity and fund crucial capital investment even under adverse circumstances, I concluded that Avista's requested ROE of 11.0 percent is reasonable and, if anything, understated. Based on my evaluation, I determined that:

- Because Avista's requested ROE of 11.0 percent is at the bottom end of my recommended range, it represents a conservative estimate of investors' required rate of return;
- The reasonableness of an 11.0 percent minimum ROE for Avista is also supported by the need to consider the Company's credit standing, which remains relatively weak:
  - Standard and Poor's Corporation ("S&P") ranks Avista as 161 out of a total 175 utilities with investment grade credit ratings, with only 14 companies in the industry having a credit profile weaker than Avista's;
  - Given Avista's present credit ratings, an inadequate rate of return imposed in this proceeding would further pressure the Company's financial flexibility and credit standing;
  - The reasonableness of an 11.0 percent ROE for Avista is also supported by the greater risks associated with the Company's lower credit ratings as compared with the proxy groups and the fact that my recommended ROE range does not consider flotation costs.
  - My conclusion that an 11.0 percent ROE for Avista is a conservative estimate of investors' required return is also reinforced by the lack of a weather normalization adjustment mechanism ("WNA") in Oregon for Avista, and the fact that, unlike some utilities in Oregon, Avista does not benefit from a decoupling mechanism that provides recovery of fixed costs

as customer usage changes.

Q. What other evidence did you consider in evaluating your recommended ROE range in this case?

A. My recommendation was reinforced by the following findings:

- The turmoil in financial markets has resulted in a fundamental shift in investors' risk perceptions, which has increased the cost of capital for utilities such as Avista:
  - The dramatic sell-off in common stocks and prolonged increase in utility bond yields associated with uncertain credit markets and economic recession are indicative of a significant revision in investors' willingness to assume risks, which has led to higher costs for long-term capital;
  - Because of the "flight to quality", government bond yields have fallen sharply at the same time that the required returns for other asset classes, such as common stocks and public utility bonds, have moved sharply higher to compensate for increased perceptions of risk. As a result recent downward trends in Treasury bond yields are associated with an upward trend in the long-term capital costs for utilities in the current capital market climate; and,
  - Since the third-quarter of 2008, the observable yields on utility bonds have soared and because investors can now earn higher interest from the relative safety of a utility bond, they require even higher compensation to put their money at risk in a utility stock.
- Sensitivity to regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity; and,
- Providing Avista with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs.

Since the 1930s, there has not been a time when the domestic and global financial markets have experienced the degree of challenges and uncertainty as they are now undergoing. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse economic and capital market conditions. The investment risks faced by utilities and their investors have only been exacerbated in this uncertain environment. In turn, the need for supportive regulation and an adequate ROE may never have been greater.

Q. What is your conclusion as to the reasonableness of Avista's capital structure?

A. Based on my evaluation, I concluded that a common equity ratio of 51.45 percent represents a reasonable basis from which to calculate Avista's overall rate of return. This conclusion was based on the following findings:

- Avista's proposed common equity ratio is entirely consistent with the range of common equity ratios maintained by the proxy group of natural gas utilities. It is also below the 53.9 percent and 57.5 percent average equity ratios for the proxy utilities, based on year-end 2008 data and near-term expectations, respectively;
- Avista's requested capitalization is consistent with the trend towards lower financial leverage expected for the industry and the Company's need to strengthen its credit standing and financial flexibility as it seeks to raise additional capital to fund system investments; and,
- For a utility with an obligation to provide reliable service, ongoing industry uncertainties highlight the necessity of preserving flexibility, even during periods of adverse capital market conditions.

II. CAPITAL MARKET CONDITIONS

Q. What is the purpose of this section?

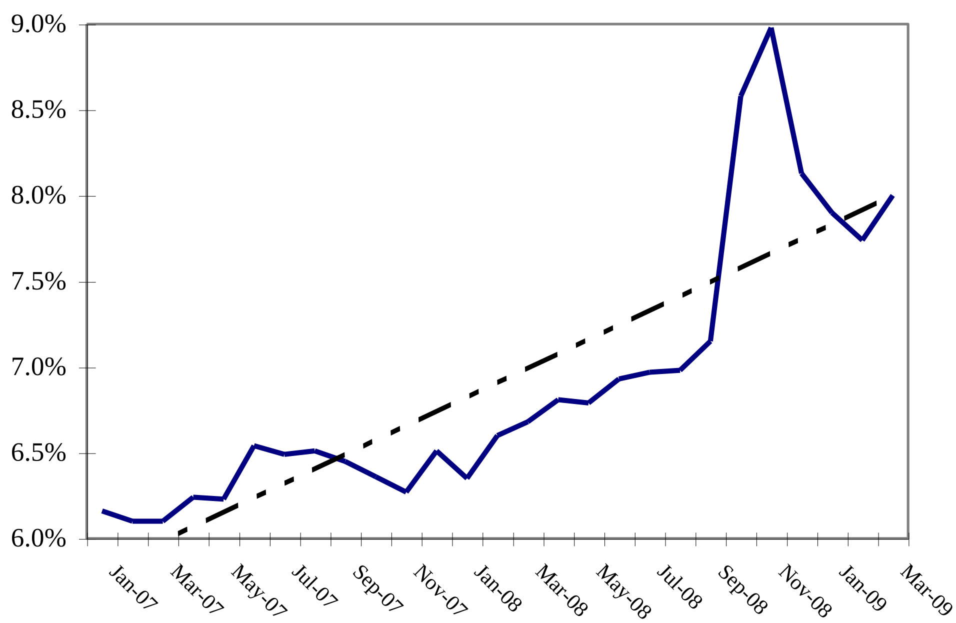
A. This section evaluates the impact of recent capital market trends on the appropriate allowed ROE for Avista. In addition, I examine the implications of Avista's relatively weak credit standing and discuss why it is critical to support improvement in the Company's finances on an ongoing basis.

A. Long-term Capital Costs Have Increased

Q. What are the implications of recent capital market conditions?

A. Recent volatility in the debt and equity markets linked to the ongoing financial crisis and the economic downturn evidences investors' trepidation to commit capital. Because price volatility that investors have endured since the third-quarter of 2008 implies greater risk, it also marks a significant upward revision in their required returns. With respect to utilities specifically, as of March 31, 2009, the Dow Jones Utility Average stock index had declined over 36 percent since June 2008, while yields on utility bonds have experienced significant volatility and increased precipitously. Figure WEA-1 plots the monthly average yield on triple-B rated public utility bonds reported by Moody's Investors Service ("Moody's") from January 2007 through March 2009:

FIGURE WEA-1
TRIPLE-B PUBLIC UTILITY BOND YIELD
JANUARY 2007 – MARCH 2009)



As illustrated above, the upward trajectory for the yields on triple-B rated public utility debt has been sharp and sustained, with the average yield being 8.0 percent in April 2009.

Q. What does this evidence indicate with respect to establishing a fair ROE for Avista?

A. The sell-off in common stocks and the increase in utility bond yields are indicative of higher costs for long-term capital, reflecting the fact that the utility industry has not been immune to the impact of financial market turmoil and the ongoing economic downturn. For example, utilities have been forced to draw on short-term credit lines to meet debt retirement obligations because of uncertainties regarding the availability and high cost of long-term capital.[3] In fact, as explained by Mr. Thies, in November 2008 Avista acquired a new $200 million bank credit that allowed the Company to avoid issuing long-term debt capital markets at a time when effective yields would have 9.5 percent or higher. As the Edison Electric Institute ("EEI") noted in a letter to Congressional representatives at the outset of the financial crisis, capital market uncertainties have serious implications for utilities and their customers:

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[4]

---

[3] Riddell, Kelly, "Cash-Starved Companies Scrap Dividends, Tap Credit," Pittsburgh Post-Gazette (Oct. 2, 2008).

[4] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).

Similarly, an October 1, 2008, *Wall Street Journal* report confirmed that utilities had been forced to delay borrowing or pursue more costly alternatives to raise funds.

An October 2008 report on the implications of credit market upheaval for utilities noted that, while high-quality companies can still issue debt, "they now have to pay an unusually high risk premium over Treasuries."[5] S&P concluded in a December 2008 review of the electric utility industry that "the abnormally low interest rate environment of the 2000's … is a distant memory."[6] Meanwhile, a Managing Director with Fitch Ratings Ltd ("Fitch") observed that with debt costs at present levels, "<u>significantly higher regulated returns will be required to attract equity capital.</u>"[7] More recently, Fitch confirmed "sharp repricing of and aversion to risk in the investment community," and noted that the disruptions in financial markets and the fundamental shift in investors' risk perceptions has increased the cost of capital for utilities such as Avista:

> The broad credit markets are in shambles and access to credit is restrictive, particularly at lower credit ratings. While credit is available to investment-grade issuers in the utilities, power and gas sectors, it is more expensive, particularly when viewed against the easy money environment which prevailed for most of this decade.[8]

Fitch concluded, "The sharp increase in the cost of equity capital is a negative credit development."[9]

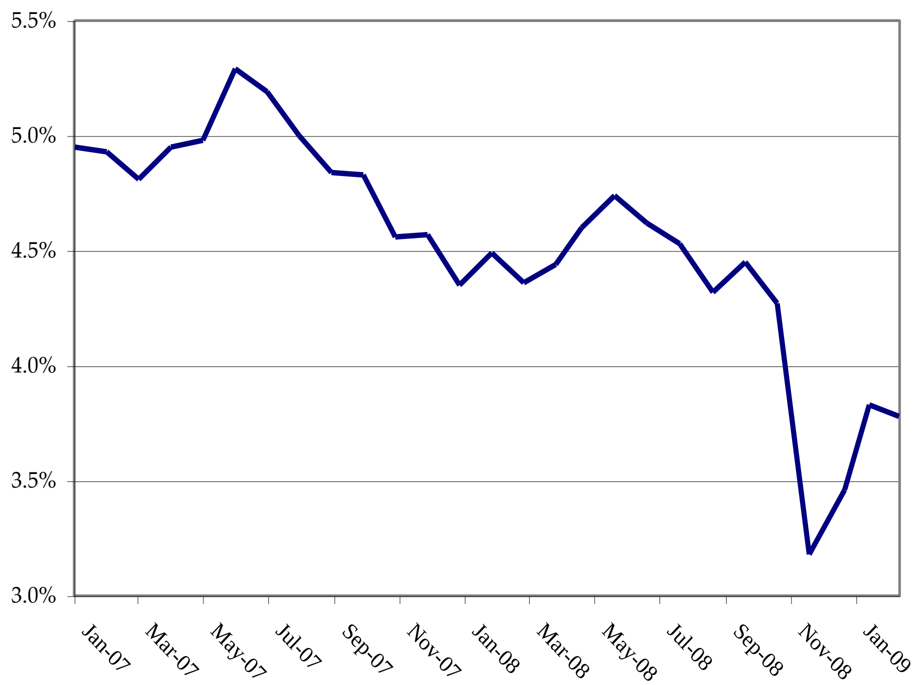
---

[5] *Rudden's Energy Strategy Report* (Oct. 1, 2008).
[6] Standard & Poor's Corporation, "Industry Report Card: U.S. Electric Utility Credit Quality Remains Strong Amid Continuing Economic Downturn," *RatingsDirect* (Dec. 19, 2008).
[7] Fitch Ratings Ltd., "EEI 2008 Wrap-Up: Cost of Capital Rising," *Global Power North America Special Report* (Nov. 17, 2008) (emphasis added).
[8] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22. 2008).
[9] *Id.*

Q. Do trends in the yields on Treasury notes and bonds accurately reflect the expectations and requirements of Avista's equity investors?

A. No. Monthly average yields on 20-year Treasury bonds are plotted in Figure WEA-2, below:

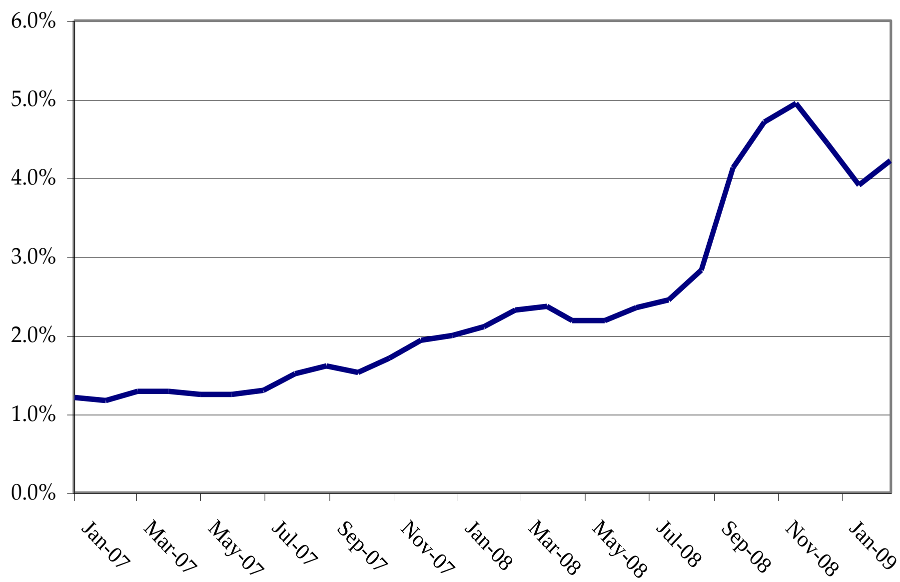
FIGURE WEA-2
20-YEAR TREASURY BOND YIELD
(JANUARY 2007 – MARCH 2009)



As shown above, beginning in the third quarter of 2007, the yields on 20-year Treasury bonds began a general decline. In response to accelerating concerns over economic uncertainties and the Federal Reserve's actions to increase liquidity in the face of a profound crisis in credit markets, the fall in Treasury bond yields became increasingly pronounced, with daily yields on 20-year notes falling below 3 percent in December 2008. Meanwhile, the price of 3-month Treasury bills rose high enough to push yields negative for the first time in history.[10]

While the yields on Treasury securities have fallen significantly, the required returns for common stocks and public utility bonds have moved sharply higher to compensate for increased perceptions of risk. This "flight to quality" has caused the spread between the observable yields on public utility bonds and 20-year Treasury bonds to spike dramatically. Figure WEA-3 plots the monthly spread between triple-B public utility bond yields and 20-year Treasury bond yields since January 2007.

FIGURE WEA-3
YIELD SPREAD – BBB UTILITY V. 20-YEAR TREASURY BONDS
(JANUARY 2007 – MARCH 2009)



As illustrated above, the gap between the yields on these two debt instruments has widened significantly, reflecting the extent of the uncertainties facing investors. During 2007,

[10] Kruger, Daniel and Cordell Eddings, "Treasury Bills Trade at Negative Rates as Haven Demand Surges," www.bloomberg.com (Dec. 9, 2008).

this yield spread averaged 142 basis points, versus 288 basis points in 2008 and 419 basis points for the first quarter of 2009. As Standard & Poor's recently observed:

> With speculative-grade defaults accelerating, a higher preponderance of credit downgrades, and a general malaise about the future of the economy, we expect spreads to remain at their elevated levels for some time as investors, the credit markets, and the economy cautiously tread through the current recessionary period.[11]

Q. What does this imply with respect to the ROE for a utility such as Avista?

A. Because of the increased uncertainty in the financial markets, investors have sought a safe haven in government-backed securities, such as Treasury bonds. While the required returns for other asset classes, such as common stocks and public utility bonds, have moved higher to compensate for increased perceptions of risk, the yields on Treasury securities have fallen significantly. As evidenced above, the spread between the observable yields on utility bonds and Treasury securities has spiked dramatically. As a result, recent downward trends in Treasury bond yields are associated with an upward trend in the long-term capital costs for utilities in the current capital market climate.

In other words, focusing solely on the decrease in Treasury bond yields experienced since 2007 might suggest that investors' required returns have fallen, but the exact opposite is true. Treasury bond yields have declined because of a "flight to quality" as investors' risk perceptions have mounted in the face of the ongoing financial crisis. As the Wall Street Journal noted, "Real-world borrowing costs are in a different universe from Treasury yields

---

[11] Standard & Poor's Corporation, "Credit Trends: U.S. Composite Credit Spreads Daily (April 1, 2009)," *RatingsDirect* (Apr. 1, 2009).

and Fed rates."[12] The fact that prices of Treasury bonds have been driven sharply higher is the mirror image of <u>higher</u>, not lower returns for more risky asset classes, such as the common stock of utilities like Avista.

Q. Does the ongoing economic recession imply lower capital costs?

A. No. Investors' required rates of return for Avista and other financial assets are a function of risk, with greater exposure to uncertainty requiring higher – not lower – rates of return to induce long-term investment. This has been vividly demonstrated in numerous segments of the debt markets where heightened uncertainties regarding risk exposure have resulted in the almost complete inability of borrowers to access credit at reasonable rates.

It is important not to confuse investors' expectations for future growth and cash flows, which is one consideration in estimating the cost of common equity, with their required rate of return. In fact, trends in growth rates say nothing at all about investors' overall risk perceptions. The fact that investors' required rates of return for long-term capital can rise in tandem with expectations of declining growth that would accompany an economic slowdown is demonstrated in the bond markets, where perceptions of greater risks have pushed yields on long-term utility bonds sharply higher.

Similarly, the uncertainty over future trends in corporate earnings and stock prices has led investors to sharply reevaluate what they are willing to pay for common stocks. While the precipitous decline in utility stock prices may in part be attributed to somewhat diminished expectations of future cash flows, there is also every indication that investors' discount rate, or

[12] Gongloff, Mark, "Ahead of the Tape: The Shocks Are Getting A Workout," *The Wall Street Journal* at C1 (Sep. 17, 2008).

cost of common equity, has moved significantly higher to accommodate the greater risks they now associate with equity investments.

The idea that the current recession would lead the rate of return demanded by equity investors to decline is also contrary to economic logic. As documented above, the required yield on long-term utility bonds has increased substantially in response to investors' heightened risk perceptions. A drop in the cost of common equity would imply that the risk premium between common stocks and bonds has declined. The notion that equity risk premiums would be declining at a time of unprecedented capital market turmoil runs counter to common sense. Investors require a higher rate of return to assume more risk and common stocks have the lowest priority claim on a company's cash flows. Given the significant increase in utility bond yields documented earlier, the dramatic widening of the yield spreads between risk-free Treasury bonds and corporate debt instruments, and investors heightened sensitivity to risk, there is no evidence to suggest that the return demanded by equity investors has declined.

Q. Would it be reasonable to disregard current capital market conditions in establishing a fair ROE for Avista?

A. Absolutely not. They reflect the reality of the situation in which Avista and other businesses must attract and retain capital. As noted earlier, the standards underlying a fair rate of return require that Avista's authorized ROE reflect a return competitive with other investments of comparable risk and preserve the Company's ability to maintain access to capital on reasonable terms. This standard can only be met by considering the requirements of investors in today's capital markets.

While the events since the fall of 2008 undoubtedly mark a significant transition in investors' expectations, there has been little indication that the challenges confronting the economy and financial markets will be resolved quickly. As Fitch recently concluded, "higher corporate interest rates are likely to prevail through 2009 and into the foreseeable future."[13] Moreover, the fact that market volatility may complicate the evaluation of the cost of common equity provides no basis to ignore the dramatic upward shift in investors' risk perceptions and required rates of return for long-term capital. Capital markets are continuously responding to current information and investors are incessantly revising their forward-looking expectations accordingly. It is for this very reason that it becomes even more critical to focus on current expectations, rather than backward-looking or "normalized" data.

Q. What are the implications of disregarding actual capital market conditions in setting the allowed ROE?

A. If the increase in investors' required rate of return on long-term capital is not incorporated in the allowed rate of return on equity, the results will fail to meet the comparable earnings standard that is fundamental in determining the cost of capital. From a more practical perspective, failing to provide investors with the opportunity to earn a rate of return commensurate with Avista's risks will only serve to weaken its financial integrity, while hampering the Company's ability to attract the capital needed to meet the economic and reliability needs of its service area.

[13] Grabelsky, Glen, "Surviving the Present, Preparing for the Future," *Fitch Ratings' 20th Annual Global Power Breakfast* (Nov. 10, 2008).

Q. Is it possible that the current financial crisis is a temporary aberration that will soon abate?

A. No one knows the future of our complex global economy. We know that this crisis has been building for a long time and few predicted that the economy would fall as rapidly as it has, or that corporate bond yields would rise as rapidly as they have. But it would be imprudent to gamble the interests of customers and the economy of Oregon in the hope that the harsh economic reality will pass quickly. Avista must raise capital in the real world of financial markets. To ignore the current reality would be unwise given the importance of reliable utility service for customers and the economy.

B. Support For Avista's Credit Standing

Q. What credit ratings have been assigned to Avista?

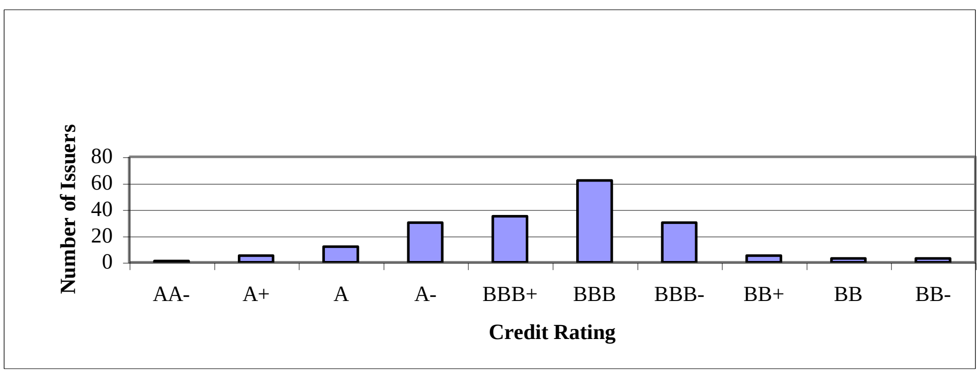
A. On February 7, 2008, S&P raised the Company's corporate credit rating from "BB+" to "BBB-", while Moody's Investors Service ("Moody's") upgraded Avista's issuer credit rating from "Ba1" to "Baa3" in December 2007.[14] Fitch Ratings, Ltd. ("Fitch") recently followed suit, upgrading its issuer default rating for Avista one notch to "BBB-" on May 19, 2009.[15] The ratings assigned to Avista represent the lowest rung on the ladder of the investment grade scale.

[14] Moody's Investors Service, "Credit Opinion: Avista Corp.," *Global Credit Research* (Dec. 21, 2007).
[15] Fitch Ratings, Ltd, "Fitch Upgrades Avista Corp.'s IDR to 'BBB-; Outlook Stable," *Press Release* (May 19, 2009).

Q. How have investors' risk perceptions for firms involved in the utility industry evolved?

A. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. As illustrated in Figure WEA-5, below, S&P reports that the majority of the companies in the utility sector now fall in the "BBB" rating category:[16]

FIGURE WEA-5
S&P'S DISTRIBUTION OF CREDIT RATINGS OF
U.S. REGULATED ELECTRIC UTILITIES



Fitch recently concluded that the short- and long-term outlook for investor-owned electric utilities is negative.[17] Similarly, Moody's observed, "Material negative bias appears to be developing over the intermediate and longer term due to rapidly rising business and operating risks."[18]

[16] Standard & Poor's Corporation, "Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest," *RatingsDirect* (Mar. 31, 2009).
[17] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).
[18] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

Q. How does Avista's relative credit standing compare with others in the utility industry?

A. Avista's senior credit ratings remain at the very bottom of the investment grade scale. In a recent report by S&P ranking U.S. regulated utilities from strongest to weakest, Avista was ranked 161 out of the total 175 companies with investment grade credit ratings.[19] In other words, only 14 companies in the utility industry with investment grade ratings have a credit profile weaker than Avista's.

Q. What are the implications of Avista's relative credit standing, given the current climate in the capital markets?

A. As documented earlier and in the testimony of Mr. Mark Thies, the current environment poses significant challenges with respect to a utility's ability to raise capital on reasonable terms. For Avista, these concerns are magnified by the fact that its credit standing remains relatively weak. The Company's efforts to regain investment grade credit ratings have been successful, but Avista's finances remain pressured.

Fitch recently observed that in current credit markets, "'flight to quality' is selective within the [utility] sector, favoring companies at higher rating levels."[20] Because Avista's ratings are at the very bottom of the investment grade barrel, there is no backstop in the event of a prolonged and/or worsening crisis and reduced flexibility to respond to other challenges. As Mr. Thies confirms in his testimony, regulatory support will be a key driver in securing additional progress towards restoring the Company's financial health. Further strengthening

[19] Standard & Poor's Corporation, "Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest," *RatingsDirect* (Mar. 31, 2009).

Avista's financial integrity and continued progress in raising the Company's credit standing is imperative to ensure the capability to maintain an investment grade rating while confronting potential challenges.

Moreover, the negative impact of declining credit quality on a utility's capital costs and financial flexibility becomes more pronounced as debt ratings move down the scale from investment to non-investment grade. In a 2008 report, Fitch noted the penalty associated with speculative grade ratings:

> The yield and spread differential of 219 basis points between the BBB Index and the BB Index underscores the considerably lower cost of capital incurred by investment grade companies relative to speculative grade companies in the public debt markets at present. In addition to a lower cost of capital, investment grade companies also typically enjoy significantly fewer covenant constraints in bond indentures and loan agreements as well as less security in the form of collateral than their speculative grade counterparts[21]

Since that time, speculative grade yield spreads have increased dramatically. S&P recently reported that the premium paid on speculative debt issues is currently now more than twice the five-year moving average and exceeded 1,100 basis points.[22]

As the Chairman of the New York State Public Service Commission recently noted in his role as spokesman for the National Association of Regulatory Utility Commissioners:

> While there is a large difference between A and BBB, there is an even brighter line between Investment Grade (BBB-/Baa3 bond ratings by S&P/Moody's, and higher) and non-Investment Grade (Junk) (BB+/Ba1 and lower). The cost of issuing non-investment grade debt, assuming the market is receptive to it, has in some cases been hundreds of basis points over the yield on investment

---

[20] *Id.*

[21] Fitch Ratings Ltd., "Borderline Credits – Part II," *Leveraged Finance US Special Report* (June 24, 2008).

[22] Standard & Poor's Corporation, "U.S. Composite Credit Trends Daily (May 5, 2009)," *RatingsDirect* (May 5, 2009).

> grade securities. To me this suggests that you do not want to be rated at the lower end of the BBB range because an unexpected shock could move you outside the investment grade range.[23]

With Avista's credit ratings poised on the precipice between investment grade and junk bond status, the stakes associated with an inadequate rate of return are increased dramatically. In turn, the need for supportive regulation and an adequate ROE may never have been greater.

Q. What are the implications of disregarding actual capital market conditions in setting the allowed rate of return on equity?

A. If the increase in investors' required rate of return on long-term capital is not incorporated in the allowed rate of return on equity, the results will fail to meet the comparable earnings standard that is fundamental in determining the cost of capital. From a more practical perspective, failing to provide investors with the opportunity to earn a rate of return commensurate with Avista's risks will only serve to further weaken its financial integrity, while hampering the Company's ability to attract the capital needed under reasonable terms to meet the economic and reliability needs of its service area.

III. Fundamental Analysis

Q. What is the purpose of this section?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews Avista 's operations and finances and examines the risks and prospects for the natural gas industry as a whole. An understanding of the fundamental factors driving the risks and

[23] Brown, George, "Credit and Capital Issues Affecting the Electric Power Industry," *Federal Energy Regulatory Commission Technical Conference* (Jan. 13, 2009).

prospects of gas utilities is essential in developing an informed opinion of investors' expectations and requirements, which form the basis of a fair rate of return.

A. Avista

Q. Briefly describe the operations and finances of Avista.

A. Avista is engaged primarily in the procurement, transmission, and distribution of natural gas and electric energy, as well as other energy-related businesses. The Avista Utilities operating division is comprised of state-regulated utility activities, including retail natural gas and electric distribution and transmission services and energy generation. In addition to providing gas distribution service in northeast and southwest Oregon, Avista's utility segment also provides natural gas and electric utility service within a 26,000 square mile area of eastern Washington and northern Idaho.

Q. Please describe Avista's gas utility operations.

A. At December 31, 2008, Avista supplied natural gas to approximately 315,000 customers in parts of Oregon, Idaho, and Washington. Natural gas sales to residential customers accounted for approximately 60 percent of total retail gas deliveries, while commercial customers made up 37 percent. Avista transports gas for large industrial customers, which purchase their own natural gas requirements through other parties. Several of Avista's largest natural gas customers are served under individual transportation contracts, which are subject to regulatory review and approval. During 2008, transportation sales accounted for approximately 18 percent of total natural gas deliveries. Avista obtains its gas supply from a variety of domestic and Canadian sources, through both long-term and spot market purchases. As well as owning a one-third interest in the Jackson Prairie natural gas storage facilities, Avista contracts with Northwest Natural Gas Company to obtain storage service from its Mist facility and has contracted for capacity delivery rights on five pipeline networks. Avista's retail gas distribution operations are subject to the jurisdiction of the OPUC, WUTC, and the IPUC. While Avista has natural gas trackers in place that allow it to pass-through a portion of changes in natural gas costs to customers, it currently does not have any adjustment mechanisms to adjust for the impact of abnormal weather on earnings, or for changes in retail loads related to energy efficiency or price elasticity.

B. Natural Gas Utility Industry

Q. How have investors' risk perceptions for the utility industry evolved?

A. Beginning in approximately 1980, the natural gas industry was buffeted by decreasing demand and prices, a natural gas glut, an ever-changing federal regulatory environment, and increased competition among participants and with other fuels. These developments spawned striking structural changes, not only within the pipeline segment of the industry, but for natural gas local distribution companies ("LDCs") as well, with both experiencing "bypass" as large commercial, industrial, and wholesale customers sought to acquire gas supplies at the lowest possible cost. Structural changes within the utility industry have forced electric utilities and LDCs to confront new complexities and risks entailed in actively contracting for economical and secure energy supplies.

Implementation of structural change and related events caused investors to rethink their assessment of the relative risks associated with the utility industry. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. Fitch recently reported that the short- and long-term outlook for investor-owned utilities is negative.[24] Similarly, Moody's observed, "Material negative bias appears to be developing over the intermediate and longer term due to rapidly rising business and operating risks."[25]

Q. Is the potential for energy market volatility an ongoing concern for investors?

A. Yes. In recent years LDCs and their customers have had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets. S&P concluded that "natural gas prices have proven to be very volatile" and warned of a "turbulent journey" due to the uncertainty associated with future fluctuations in energy costs,[26] with Moody's warning investors of ongoing exposure to "extremely volatile" energy commodity costs, including purchased power prices, which are heavily influenced by fuel costs.[27] Fitch has also highlighted the challenges that fluctuations in commodity prices can have for utilities and recently noted that:

> From their September 2007 low of $5.29, spot natural gas prices as reported at Henry Hub rose 150% to $13.31 in early July 2008 and declined 57% to $5.68 per million British thermal unit (mmBtu) on Dec. 10, 2008. The sharp run-up and subsequent collapse of natural gas prices in 2008 is emblematic of the

[24] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).
[25] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).
[26] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).
[27] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* at 6 (Aug. 2007).

> extreme price volatility that characterizes the commodity and is likely to persist in the future.[28]

S&P recognized that price spikes can "encourage users to substitute alternative fuels and discourage potential new customers from choosing natural gas,"[29] and concluded that:

> [C]urrent high gas prices will remain a challenge for all LDCs and may further pressure ratings for those LDCs that have a negative outlook and whose financial measures are somewhat stretched for their current rating.[30]

Moody's echoed this sentiment, concluding that rising natural gas prices represent a challenge for LDCs because of reduced demand and margins.[31] As a result, a senior Fitch analysts concluded that investors "should exercise greater caution" when evaluating companies in the gas utility sector.[32] This becomes especially relevant when the utility does not benefit from a WNA or decoupling mechanism, as is the case for Avista's jurisdictional gas utility operations.

Q. Do recent conditions ameliorate investors' concerns regarding the potential for gas price volatility?

A. No. In July 2008 spot natural gas prices in the Pacific Northwest were predicted to reach $12.59 per MMBtu for the coming winter season, exceeding prior year levels by upwards of 70 percent.[33] While lower consumption brought about by the economic

---

[28] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North American Special Report* (Dec. 22, 2008).
[29] Standard & Poor's Corporation, "Natural Gas Distribution", *Industry Surveys*, p. 1 (Nov. 29, 2001).
[30] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk For U.S. Gas Distribution Companies," *RatingsDirect* (Jan. 17, 2006).
[31] Moody's Investors Service, "North American Natural Gas Transmission & Distribution," *Industry Outlook* (Sep. 2007).
[32] Lapson, Ellen, "Rising Unit Costs & Credit Quality: Warning Signals," *Public Utilities Fortnightly* (Feb. 1, 2006).
[33] Oregon Public Utility Commission, *2008 Natural Gas Outlook Meeting* (July 15, 2008).

slowdown and higher production levels have contributed to a significant decline in gas costs, investors recognize that the continuing prospect of further volatility in energy markets cannot be discounted. As the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy, noted:

> A high degree of price volatility seems inherent in natural gas markets owing to the nature of the commodity, supply capacity constraints, and the sensitivity of peak day demands to temperatures.[34]

The EIA concluded, "Volatile prices create uncertainty and financial risk in the market and may increase the cost of capital, causing pipeline and other infrastructure investment to be more expensive".[35]

Similarly, in a 2006 report the OPUC Staff noted that "the dynamics and operation of the US and Northwest natural gas markets have changed dramatically," and concluded that these developments "have placed great pressure on state commissions as well as the LDCs."[36] The ongoing realities characterizing today's natural gas markets prompted the Staff to conclude that:

> The Oregon PGA mechanism in place today was designed to meet LDC needs in a stable, lower priced, and more predictable natural gas market. That market no longer exists.[37]

[34] Energy Information Administration, *An Analysis of Price Volatility in Natural Gas Markets* (Aug. 2007).
[35] Energy Information Administration, *An Analysis of Price Volatility in Natural Gas Markets* (Aug. 2007).
[36] Public Utility Commission of Oregon, *Staff Report* (Nov. 21, 2006).
[37] *Id.*

IV. CAPITAL STRUCTURE

Q. Is an evaluation of the capital structure maintained by a utility relevant in assessing its return on equity?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash slow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more creditors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. What common equity ratio will be used to establish the company's overall rate of return?

A. Avista's capital structure is presented in the testimony of Mr. Thies. As summarized in his testimony, the pro-forma common equity ratio used to compute Avista's overall rate of return was 51.45 percent in this filing.

Q. How does this compare with common equity ratios maintained by other gas utilities?

A. In evaluating Avista's capital structure, and in estimating the cost of equity, it is customary to examine data for publicly traded firms engaged in similar business activities. In order to reflect the risks and prospects associated with Avista's jurisdictional gas utility operations, my analyses focused on a reference group of other publicly traded LDCs included by Value Line in their Natural Gas Utility industry group. Excluded from the group was one firm that is expected to cut its common dividend payments (NiSource Inc.). I refer to the resulting group of eleven companies as the "Gas Utility Proxy Group". Given that these utilities are all engaged in gas utility operations and classified by Value Line as gas utilities, investors are likely to regard this group as facing similar market conditions and having comparable risks and prospects.

Schedule WEA-1 presents capital structure ratios for the Gas Utility Proxy Group. As shown there, common equity ratios for the individual firms in the proxy group of gas utilities ranged from a low of 43.3 percent to a high of 66.1 percent at year-end 2008, with the average being 53.9 percent.

Q. What capitalization is representative for the proxy group of gas utilities going forward?

A. As shown on Schedule WEA-1, Value Line expects an average common equity ratio for the Gas Utility Proxy Group of 57.5 percent for its three-to-five year forecast horizon, with the individual common equity ratios ranging from 49.0 percent to 74.0 percent.

Q. How does Avista's common equity ratio compare with those maintained by the reference group of gas utilities?

A. The 51.45 percent common equity ratio requested by Avista is entirely consistent with the range of equity ratios maintained by the firms in the Gas Utility Proxy Group and falls below the 53.9 percent and 57.5 percent average equity ratios at year-end 2008 and based on Value Line's near-term expectations, respectively.

Q. What implication does the increasing risk of the utility industry have for the capital structures maintained by utilities?

A. As discussed earlier, gas utilities are facing energy market volatility, rising cost structures, and ongoing regulatory risks. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Moody's has warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[38] Moody's noted that, "maintaining unfettered access to capital markets will be crucial," and cited the importance of forestalling future downgrades by bolstering utility balance sheets.[39] As Moody's concluded:

> Our concerns are clearly growing, but we believe utilities have adequate time to adjust and revise their corporate finance polices and strengthen balance sheets, thereby improving their ability to manage volatility and address uncertainty.[40]

Coupled with the ongoing turmoil in capital markets, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment.

---

[38] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).
[39] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).
[40] *Id.*

Q. What other factors do investors consider in their assessment of capital structure?

A. Depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating Avista's financial risk. For example, S&P reaffirmed its practice of adjusting reported results to reflect the debt equivalent impact of operating leases, post-retirement benefit obligations, and asset retirement obligations, among other factors.[41] Additionally, because energy purchase agreements typically obligate the utility to make specified minimum contractual payments akin to those associated with traditional debt financing, investors consider a portion of these commitments as debt in evaluating total financial risks. Further, changes in financial accounting standards also result in adjustments that have the effect of further increasing financial leverage. Because bond ratings agencies and investors adjust for these various commitments in assessing a utility's financial position, they imply greater risk and reduced financial flexibility.

Q. What does this evidence suggest with respect to Avista's proposed capital structure?

A. Based on my evaluation, I concluded that a capital structure consisting of approximately 51.45 percent common equity represents a reasonable mix of capital sources from which to calculate Avista's overall rate of return. While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and

[41] Standard & Poor's Corporation, "Credit FAQ: S&P Introduces Reconciliation Tables to Show Analytical Adjustments To Global Utilities' Financial Statements," *RatingsDirect* (Oct.

prospects it faces, as well its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital under reasonable terms so that it can meet the service requirements of its customers. Moody's recently concluded that its ratings for Avista anticipate "conservative financing strategies."[42]

Avista's capital structure reflects the financial and operating challenges it faces, as well as the Company's ongoing efforts to strengthen its credit standing and support access to capital on reasonable terms. The need for access becomes even more important when the company has capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

V. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. In this section, a fair rate of return on common equity for Avista is developed. First, I examine the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe quantitative analyses conducted to estimate the cost of equity for reference groups of comparable risk firms.

11, 2006).

[42] Moody's Investors Service, "Credit Opinion: Avista Corp.," *Global Credit Research* (Dec. 3, 2008).

A. Economic Standards

Q. What role does the rate of return on common equity play in a utility's rates?

A. The return on common equity is the cost of inducing and retaining equity investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. They will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. What fundamental economic principle underlies this cost of equity concept?

A. Underlying the concept of the cost of equity is the fundamental notion that investors are risk averse, and will willingly bear additional risk only if they expect compensation for doing so. The required rate of return for a particular asset at any point in time is a function of: 1) the yield on risk-free assets, and 2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk. Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can be generally expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return; and
RP_i = Risk premium required to hold risky asset i.

Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. Is the cost of equity observable in the capital markets?

A. No. Unlike debt capital, there is no contractually guaranteed return on common equity capital since shareholders are the residual owners of the utility. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' current required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. Did you rely on a single method to estimate the cost of equity for Avista?

A. No. In my opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[43]

Similarly, the OPUC has also considered the results of alternative methods in establishing allowed ROEs for utilities under its jurisdiction. Therefore, I used both the DCF and CAPM methods to estimate the cost of common equity. In addition, I also evaluated a fair ROE using an earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic.

[43] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* at Part 2, p. 4 (1997).

B. Proxy Groups

Q. How did you implement these quantitative methods to estimate the cost of common equity for Avista's jurisdictional gas utility operations?

A. Application of the DCF model and other quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk comparable.

Q. What specific proxy group of utilities did you rely on for your analysis?

A. In order to reflect the risks and prospects associated with Avista's jurisdictional gas utility operations, my analyses focused on the same group of eleven publicly traded gas utilities identified earlier.

Q. What other proxy group did you consider in evaluating a fair ROE for Avista?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criteria in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. As noted in *Regulatory Finance: Utilities' Cost of Capital,* "It should be emphasized that the definition of a comparable risk class of companies does not entail similarity of operation, product lines, or environmental conditions, but rather similarity of experienced business risk and financial risk."[44] Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group".

Q. What criteria did you apply to develop the Non-Utility Proxy Group?

A. My comparable risk proxy group was composed of those U.S. companies followed by Value Line that: 1) pay common dividends; 2) have a Safety Rank of "1"; 3) have investment grade credit ratings from S&P, and 4) have an S&P Stock Quality Ranking of "B" or higher. In addition, I also included only those firms with published earnings per share ("EPS") growth projections from at least two of the following sources: Value Line, Thomson I/B/E/S ("IBES"), First Call Corporation ("First Call"), and Zacks Investment Research ("Zacks").[45]

[44] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 58 (1994).
[45] Thomson Financial, an arm of Thomson Reuters, separately compiles and publishes consensus securities analyst growth rates under the IBES and First Call brands.

Q. Do these criteria provide objective evidence to evaluate investors' risk perceptions?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "A+") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. S&P's Quality Ranking, which has been published since 1956, is designed to capture the long-term growth and stability of a company's earnings and dividends. The Quality Ranking system for solvent firms is based on letter classifications from "A+" (highest) to "C" (lowest).

Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors.

Q. How do the overall risks of your proxy groups compare with Avista?

A. As shown below, Table WEA-1 compares the Utility Proxy Group and Non-Utility Proxy Group with Avista across four key indicators of investment risk:

TABLE WEA-1
COMPARISON OF RISK INDICATORS

	S&P		Value Line	
Proxy Group	**Credit Rating**	**Quality Ranking**	**Safety Rank**	**Beta**
Gas Utility	A	A-	2	0.67
Non-Utility	A+	A-	1	0.80
Avista	BBB-	B	3	0.70

Considered together, a comparison of these objective measures indicates that the risks investors associate with Avista generally exceed those of the proxy groups. As a result, the cost of equity estimates indicated by my analyses provide a conservative estimate of investors' required rate of return for Avista.

C. Discounted Cash Flow Analyses

Q. How are DCF models used to estimate the cost of equity?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price.

Q. What market valuation process underlies DCF models?

A. DCF models are based on the assumption that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return.

Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form. This constant growth form of the DCF model is customarily used to estimate the cost of equity in rate cases: [46]

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;

[46] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

K_e = Cost of equity; and,
g = Investors' long-term growth expectations.

The cost of equity (K_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

The constant growth DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0), and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. How is the constant growth form of the DCF model typically used to estimate the cost of equity?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

Q. How was the dividend yield for the Gas Utility Proxy Group determined?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Gas Utility Proxy Group are presented on Schedule WEA-2. As shown there, dividend yields for the firms in the Gas Utility Proxy Group ranged from 3.4 percent to 6.7 percent.

Q. What is the next step in applying the constant growth DCF model?

A. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. Are historical growth rates likely to be representative of investors' expectations for utilities?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term growth for the utility industry or the expectations that investors have incorporated into current market prices. As a result, historical growth measures for utilities do not currently meet the requirements of the DCF model.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, with the payout ratio for gas utilities falling from approximately 75 percent historically to on the order of 60 percent.[47] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a

[47] The Value Line Investment Survey (Mar. 29, 1996 at 472, Mar. 13, 2009 at 446).

> filter through which we assess management, and a crystal ball in which we try to foretell future performance.[48]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[49]

The fact that investment advisory services focus primarily on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[50] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[51]

---

[48] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview" at 1 (Dec. 4, 1996).
[49] The Value Line Investment Survey, *Subscriber's Guide* at 53.
[50] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[51] *Id.* at 88.

More recently, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[52]

Q. Do the growth rate projections of security analysts consider historical trends?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. What are security analysts currently projecting in the way of growth for the firms in the Gas Utility Proxy Group?

A. The earnings growth projections for each of the firms in the Gas Utility Proxy Group reported by Value Line, IBES, First Call, and Zacks are displayed on Schedule WEA-2, along with the average earnings growth rate for each company. [53]

Q. Some argue that analysts' assessments of growth rates are biased. Is there any reason to believe these projections are inappropriate for estimating investors' required return using the DCF model?

A. No. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in

[52] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 at 56 (March/April 2007).
[53] Thomson Financial, an arm of Thomson Reuters, separately compiles and publishes consensus securities analyst growth rates under the IBES and First Call brands.

current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, it would be irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (e.g., Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *Regulatory Finance: Utilities' Cost of Capital*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts also exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. … Published studies in the academic literature demonstrate that growth forecasts made by securities analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. … Cragg and Malkiel (1982) presented detailed empirical evidence that the average analyst's expectation is more similar to expectations being reflected in the marketplace than are historical growth rates, and that they represent the best possible source of DCF growth rates.[54]

Q. How else are investors' expectations of future long-term growth prospects often estimated when applying the constant growth DCF model?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are seldom, if ever, met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

Accordingly, while I believe that analysts' forecasts provide a superior and more direct guide to investors' growth expectations, I have included the "sustainable growth" approach for

---

[54] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 154-155 (1994).

completeness. The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. What is the purpose of the "sv" term?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. What growth rate does the earnings retention method suggest for the Gas Utility Proxy Group?

A. The sustainable, "br+sv" growth rates for each firm in the Gas Utility Proxy Group are summarized on Schedule WEA-2, with the underlying details being presented on Schedule WEA-3. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. What cost of common equity estimates are implied by your DCF results for the Gas Utility Proxy Group?

A. As shown on Schedule WEA-2, application of the constant growth DCF model using projected earnings and "br+sv" growth rates resulted in average cost of equity estimates for the Gas Utility Proxy Group of 10.8 percent and 11.6 percent, respectively.

Q. What cost of common equity estimates were implied for the Non-Utility Proxy Group using the DCF model?

A. I applied the DCF model to the Non-Utility Proxy Group in exactly the same manner described earlier for the Utility Proxy Group. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on Schedule WEA-4.

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate estimates that are implausibly low?

A. Yes. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF results for the Non-Utility

Proxy Group must be adjusted to eliminate estimates that are determined to be extreme outliers.

Q. Have similar tests been applied by regulators?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. In a 2002 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[55]

More recently, in its March 27, 2009 decision in *Pioneer*, FERC concluded that it would exclude low-end ROEs "within about 100 basis points above the cost of debt."[56]

Q. What does this test of logic imply with respect to the DCF results for the Non-Utility Proxy Group?

A. As noted earlier, S&P has assigned Avista a corporate credit rating of "BBB-". Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 8.0 percent

---

[55] *Southern California Edison Company*, 92 FERC ¶ 61,070 (2000) at p. 22.

[56] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at P 94 (2009) ("*Pioneer*").

in April 2009.[57] As highlighted on Schedule WEA-4, three of the individual cost of equity estimates for the firms in the Non-Utility Proxy Group exceeded this threshold by 100 basis points or less. In light of the risk-return tradeoff principle and the test applied in *Pioneer,* it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of economic logic applied by FERC, these values provide little guidance as to the returns investors require from an investment in Avista's common stock and should be excluded.

Q. Do you also recommend excluding estimates at the high end of the range of DCF results?

A. Yes. The upper end of the cost of common equity range produced by the DCF analysis presented in Schedule WEA-4 was set by an estimate of 25.3 percent. In addition to this extreme outlier, I determined that, when compared with the balance of the remaining estimates, other high-end DCF estimates should also be excluded in evaluating the results of the DCF model for the Utility Proxy Group. This is also consistent with the precedent adopted by FERC, which has established that estimates found to be "extreme outliers" should be disregarded in interpreting the results of the DCF model.[58]

Q. What were the results of your DCF analysis for the Non-Utility Proxy Group?

A. As shown on Schedule WEA-4, after eliminating illogical low- and high-end values, application of the constant growth DCF model using projected earnings and "br+sv"

[57] Moody's Investors Service, www.credittrends.com.
[58] See, *e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

growth rates resulted in average cost of equity estimates for the Non-Utility Proxy Group of 13.6 percent and 12.4 percent, respectively. As discussed earlier, reference to the Non-Utility Proxy Group is consistent with established regulatory principles and required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

D. Capital Asset Pricing Model

Q. Please describe the CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Because investors are assumed to be fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where:
R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. How did you apply the CAPM to estimate the cost of common equity?

A. Application of the CAPM to the Gas Utility Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on

Schedule WEA-6. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was obtained from Value Line, with the growth rate being equal to the average of the earnings growth projections for each firm published by Value Line, IBES, First Call, and Zacks, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 347 individual firms, current estimates imply an average growth rate over the next five years of 9.1 percent. Combining this average growth rate with a dividend yield of 4.4 percent results in a current cost of common equity estimate for the market as a whole of approximately 13.5 percent. Subtracting a 3.8 percent risk-free rate based on the average yield on 20-year Treasury bonds for April 2009 produced a market equity risk premium of 9.7 percent.

Q. What was the source of the beta values you used to apply the CAPM?

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *Regulatory Finance: Utilities' Cost of Capital*:

> Value Line betas are computed on a theoretically sound basis using a broadly-based market index, and they are adjusted for the regression tendency of betas to converge to 1.00. . . . Value Line is the largest and most widely circulated independent investment advisory service, and exerts influence on a large number of institutional and individual investors and on the expectations of these investors.[59]

As shown on Schedule WEA-6, multiplying the 9.7 percent market risk premium by the average Value Line beta for the Gas Utility Proxy Group, and then adding the resulting risk premium to the average long-term Treasury bond yield, results in an indicated cost of equity of 10.3 percent.

Q. What cost of common equity was indicated for the Non-Utility Proxy Group based on this forward-looking application of the CAPM?

A. As shown on Schedule WEA-7, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group results in an average implied cost of common equity of 11.5 percent.

Q. Do you have any observations regarding these CAPM results?

A. Yes. Applying the CAPM is complicated by the impact of the unprecedented financial crisis on investors' risk perceptions and required returns. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. As discussed earlier, investors have sought a safe haven in Treasury bonds and this "flight to safety" has caused the yield spreads for corporate debt to spike to levels not seen since the Great Depression. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased

[59] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports*

dramatically. Thus, the recent financial turmoil may cause CAPM cost of common equity estimates to understate investors' required returns for common stocks, particularly when historical data are used to calculate the market risk premium. While my application of the CAPM makes every effort to incorporate investors' forward-looking expectations, the full effect of the "flight to safety" may not be captured in my market risk premium estimate. One other obvious limitation of CAPM estimates is that beta values are customarily calculated based solely on historical data and may not accurately reflect investor's forward-looking rate of return requirements, particularly during periods of financial turmoil.

Q. Did your CAPM analysis rely on either geometric or arithmetic means in arriving at an equity risk premium?

A. No. Reference to arithmetic or geometric mean risk premiums is associated with applications of the CAPM that depend on historical data. In order to derive an estimate of the market equity risk premium under this approach, historical average returns on Treasury bonds are typically subtracted from those for common stocks. These average rates of return based on backward-looking data for historical time periods can be derived using both arithmetic and geometric means.

As discussed above, however, my application of the CAPM was a purely forward-looking approach, which is consistent with the underlying assumptions of this method and the standards underlying a determination of a fair rate of return. Because I looked directly at investors' current expectations in the capital markets – and not at historical rates of return –

---

at 65 (1994).

my CAPM analysis did not need to reference either the arithmetic or geometric mean of historical rates of return.

Q. Are there selected academic studies or other sources that might measure an equity risk premium that is less than what is indicated based on investors' current expectations for the stocks in the S&P 500?

A. There are a plethora of studies that examine what investors have actually realized in terms of equity returns versus stocks. Similarly, there are articles suggesting what investors should expect based on "building blocks" or other techniques. Further, there are surveys of corporate executives and others about what they expect the return differential to be over various horizons. Finally, there are projections that the managers of utility pensions funds use for actuarial purposes.

None of these values are comparable to the risk premium as I have applied it in my forward-looking CAPM analysis, which is based not on some generic notion of the equity risk premium but is derived from contemporaneous projections for individual stocks in the S&P 500. Average realized risk premiums computed over some selected time period may be an accurate representation of what was actually earned in the past, but they don't answer the question as to what risk premium investors were actually expecting to earn on a forward-looking basis during these same time periods. Similarly, calculations of the equity risk premium developed at a point in history – whether based on actual returns in prior periods or contemporaneous projections – are not the same as the forward-looking expectations of today's investors, which are premised on an entirely different set of capital market and economic expectations.

The purpose of my analysis was to determine an allowed return that would meet the regulatory requirement of allowing Avista to attract capital and maintain its financial integrity. The most appropriate benchmark for a meaningful forward-looking estimate of the return investors require from Avista is what investors are currently requiring for other investments with which Avista must compete for capital. The risk premium used in my CAPM is derived from current market data and is forward-looking in the sense of using the projected earnings estimates used by investors. It does not depend on analysis of past historical data on risk premiums nor does it purport to identify what investors will actually realize in the future, or what they should reasonably expect over the long-term. Rather it is an estimate of what investors currently require when they allocate their capital to competing investments. These current forward-looking required returns are the touchstone of whether an authorized ROE can meet the economic standards of capital attraction and maintaining financial integrity.

Q. Why is this key distinction especially important in today's capital markets?

A. Applying the CAPM using a historical risk premium, however determined, incorrectly assumes that investors' assessment of the relative risk differences, and their required risk premium, between Treasury bonds and common stocks is constant and equal to some historical average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely.

As discussed earlier, as a result of the turmoil and uncertainty spreading through financial markets, investors have sought a safe haven in government-backed securities, such as Treasury bonds, at the same time that required returns for other asset classes have moved sharply higher. As illustrated in Figure WEA-4, this "flight to quality" has caused the spread between the observable yields on public utility bonds and 20-year Treasury bonds to spike dramatically. In other words, risk premiums over current Treasury bond yields have widened significantly. Meanwhile, applying the CAPM by adding a fixed, historical risk premium to current yields on government bonds entirely fails to account for the significantly higher risk premiums that investors now require from utility bonds and common stocks. As a result, historical CAPM approaches fail to reflect the view of real-world investors in today's capital markets and violate the standards underlying a fair rate of return, which is predicated on the opportunity to earn a return commensurate with other investments of comparable risk.

E. Expected Earnings Approach

Q. What other analyses did you conduct to estimate the cost of equity?

A. As I noted earlier, I also evaluated the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. What rates of return on equity are indicated for utilities based on the expected earnings approach?

A. Value Line reports that its analysts anticipate an average rate of return on common equity for the natural gas utility industry of 11.0 percent over its 2012-2014 forecast horizon.[60] Meanwhile, Value Line expects that electric utilities will earn an average rate of return on common equity of 12.5 percent over this same period.[61] For the firms in the Gas Utility Proxy Group specifically, the returns on common equity projected by Value Line over its three-to-five year forecast horizon are shown on Schedule WEA-8. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier. As shown on Schedule WEA-8, Value Line's projections for the Gas Utility Proxy Group suggested an average ROE of 12.1 percent.

F. Flotation Costs

Q. What other considerations are relevant in setting the return on equity for Avista?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for

[60] The Value Line Investment Survey at 446 (Mar. 13, 2009).
[61] The Value Line Investment Survey at 687 (Mar. 27, 2009).

selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of common equity being the most logical mechanism.

Q. What is the magnitude of the adjustment to the "bare bones" cost of common equity to account for issuance costs?

A. While there are a number of ways in which a flotation cost adjustment can be calculated, one of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[62]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6 percent.[63]

Issuance costs are a legitimate consideration in setting the return on equity for a utility, and applying these expense percentages to a representative dividend yield for a utility of 6.5 percent implies a flotation cost adjustment on the order of 23 to 65 basis points.

VI. RECOMMENDED RETURN ON EQUITY

Q. What is the purpose of this section?

A. In addition to summarizing the results of my analyses, this section examines other factors that should be considered in evaluating a fair rate of return for the Company and presents my recommended ROE range for Avista.

---

[62] Roger A. Morin, "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* (1994) at 166.

[63] Application of Yankee Gas Services Company for a Rate Increase, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

A. Summary of Quantitative Results

Q. Please summarize the results of your quantitative analyses.

A. The cost of equity estimates implied by my quantitative analyses are summarized in Table 3 below:

TABLE 3
SUMMARY OF QUANTITATIVE RESULTS

	Gas Utility	Non-Utility
DCF		
Projected Earnings	10.8%	13.6%
br+sv	11.6%	12.4%
CAPM	10.3%	11.5%
Expected Earnings		
Gas Utilities - 2012-14	11.0%	
Electric Utilities - 2012-14	12.5%	
Gas Utility Proxy Group	12.1%	

Based on my assessment of the relative strengths and weaknesses inherent in each method, I concluded that the cost of common equity indicated by my analyses is in the 11.0 percent to 12.5 percent range.

B. Other Factors

Q. How do Avista's investment risks compare to the reference groups used to estimate the cost of equity?

A. As noted earlier, the "BBB-" corporate credit rating assigned to Avista occupies the lowest rung on the investment grade ladder. Avista's credit ratings are indicative of significantly higher investment risks than the proxy groups of gas utilities and non-utility firms, which have average corporate credit ratings of "A" and "A+", respectively. Similarly, as illustrated earlier in Table 2, a comparison of key risk indicators for common stocks also confirms that investors would conclude that Avista's risks exceed those of the proxy groups used to estimate the cost of equity. Because investors require a higher rate of return to compensate them for bearing more risk, the greater investment risks implied for Avista suggests that the cost of equity is correspondingly higher than for the proxy groups.

Q. How does the lack of a weather normalization adjustment impact Avista's rate of return on equity relative to the Gas Utility Proxy Group?

A. As indicated earlier, Avista does not have a weather normalization adjustment mechanism in place to account for the impacts of abnormal weather on its Oregon-jurisdictional gas utility operations. A WNA moderates the impact of extreme weather on customers and, at the same time, dampens the volatility of a gas utility's revenues. Indeed, all but one of the eleven LDCs in the proxy group used to estimate the cost of equity have some form of weather mitigant, including adjustment clauses, insurance, or rate design features that make the LDC less susceptible to variations in gas consumption due to weather. As Value Line noted, "Weather abnormalities can hurt results," concluding, "Many of these businesses have weather-adjusted rate mechanisms that are used to hedge the risk of unseasonable weather."[64] As a result, while Avista remains exposed to the risks associated with abnormal weather, the reduced uncertainties associated with a WNA are at least partially accounted-for by investors and reflected in my cost of equity estimates.

[64] The Value Line Investment Survey at 446 (Mar. 13, 2009).

Q. What other considerations are relevant in determining a reasonable rate of return on equity for Avista's jurisdictional gas utility operations?

A. In evaluating a reasonable rate of return on equity, it is also important to note that, unlike some utilities in Oregon, Avista does not benefit from elasticity or decoupling mechanisms that insulate utility margins from declining usage. As the OPUC noted in its September 2002 Order adopting a proposed stipulation for NW Natural:

> The stipulation provides that an elasticity adjustment will be applied to the rates of all of NW Natural's residential and commercial customers beginning on October 1, 2002. …This adjustment will help account for the affect that rate changes have on customers usage. Under this elasticity adjustment, NW Natural will recover, on a prospective basis only, the margin shortfalls in each customer category by developing rate increments and applying them in permanent rates for each class as of October 1, 2002.
>
> …Also on October 1, 2002, NW Natural will implement a partial decoupling mechanism, under which it will defer and subsequently amortize 90 percent of the margin differentials in the residential and commercial customer groups.[65]

Avista's jurisdictional gas utility operations have experienced declines in customer usage that have translated into reduced margins. As a result, Avista's continued exposure to the uncertainties associated with the impact of price elasticity and other fluctuations in customer usage implies a level of risk in excess of that faced by other Oregon utilities.

[65] In the Matter of Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization, Public Utility Commission of Oregon, Order No. 02-634 (Sep. 12, 2002) at 3.

Q. What does this evidence suggest with respect to Avista's cost of equity relative to the proxy group results?

A. The higher investment risks associated with Avista's lower credit ratings and the lack of WNA or decoupling mechanism suggest that investors' required return for Avista exceeds that of the proxy groups used to estimate the cost of equity. Competition for capital resources is intense and investors are free to invest their funds wherever they choose. Denying investors the opportunity to earn a return that is commensurate with Avista's investment risks would stymie the Company's efforts to improve its credit standing and hamper its future ability to attract capital under reasonable terms, especially during periods of adverse capital market conditions.

Q. What role does regulation play in ensuring that Avista has access to capital under reasonable terms and on a sustainable basis?

A. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. Fitch noted that:

> Regulatory risk remains a recurring theme for this year's outlook, as the pressure of a weak economic backdrop could result in political push-back to rate increase requests.[66]

The report went on to conclude, "Fitch is concerned that the recent rapid escalation in the cost of capital will not be reflected on a timely basis in utility rates."[67]

---

[66] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).
[67] *Id.*

Moody's has emphasized the need for regulatory support "in an era of broadly rising costs," noting that as cost pressures have escalated for electric utilities, so too has the importance of timely recovery through the regulatory process and the risks associated with regulatory lag.[68] S&P concluded "the quality of regulation is at the forefront of our analysis of utility creditworthiness,"[69] and recently observed that its risk analysis focuses on the utility's ability to consistently earn a reasonable return:

> Notably, the analysis does not revolve around "authorized" returns, but rather on actual earned returns. We note the many examples of utilities with healthy authorized returns that, we believe, have no meaningful expectation of actually earning that return because of rate case lag, expense disallowances, etc.[70]

Similarly, with respect to Avista specifically, the major bond rating agencies have explicitly cited the potential that adverse regulatory rulings could compromise the Company's credit standing. Of particular concern to investors is the impact of regulatory lag and cost-recovery on Avista's ability to earn its authorized ROE and maintain its financial metrics, with Moody's concluding that:

> Failure to obtain adequate and timely support for recovery of and return on core utility investments through pending and expected future regulatory proceedings … could have negative ratings implications.[71]

S&P observed that rate relief will remain critical to Avista's credit outlook,[72] and concluded

---

[68] Moody's Investors Service, "Regulatory Pressures Increase For U.S. Electric Utilities," *Special Comment* (March 2007).
[69] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).
[70] *Id.*
[71] Moody's Investors Service, "Credit Opinion: Avista Corp.," *Global Credit Research* (Dec. 3, 2008).
[72] Standard & Poor's Corporation, "U.S. Electric Utility Credit Quality Remains Strong Amid

that:

> Regulatory lag has been a consistent issue for Avista Utilities, with the utility operations (consisting of electric and gas service in parts of Washington, Idaho, and Oregon) collectively unable on a consolidated basis to earn its authorized return on equity (ROE). On a consolidated basis, average earned ROE since 2003 has been just under 6%, based on Standard & Poor's calculations.[73]

For Avista, these concerns are magnified by the fact that its credit standing is poised on the precipice between investment and speculative grade ratings. While the Company's efforts to regain an investment grade credit rating have been successful, Avista's financial metrics remain pressured. As Mr. Thies confirms in his testimony, regulatory support will be a key driver in securing additional improvement in the Company's financial health. Further strengthening Avista's financial integrity is imperative to ensure that the Company has the capability to maintain an investment grade rating while confronting potential challenges.

Q. Do customers benefit by enhancing the utility's financial flexibility?

A. Yes. While providing an ROE that is sufficient to maintain Avista's ability to attract capital, even in times of financial and market stress, is consistent with the economic requirements embodied in the U.S. Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure reliable service. By the same token, customers also bear a significant burden when the ability of the utility to attract necessary capital is impaired and service quality is compromised.

Continuing Economic Downturn," *RatingsDirect* (Dec. 19, 2008).

[73] Standard & Poor's Corporation, "Summary: Avista Corp.," *RatingsDirect* (Feb. 27, 2009).

C. Return on Equity Recommendation

Q. What then is your conclusion as to a fair rate of return on equity range for Avista?

A. As explained above, based on the capital market oriented analyses for the utility and non-utility proxy groups described in my testimony, I concluded that the fair rate of return on equity range was 11.0 percent to 12.5 percent. Considering capital market expectations, the potential exposures faced by Avista, and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that this represents a fair and reasonable ROE range for Avista.

Q. Based on the results of your evaluation, what is your opinion regarding the reasonableness of the ROE requested by Avista in this case?

A. My evaluation indicates that Avista's requested ROE of 11.0 percent represents a conservative estimate of investors' required rate of return. Given the fact that the Company's requested ROE falls at the lower boundary of my recommended range, it should be viewed as an absolute floor in establishing rates for Avista. This conclusion is reinforced by the need to buttress the Company's credit standing, which remains relatively weak, as well as the fact that Avista's investment risks exceed those of the proxy groups used to estimate the cost of equity. The reasonableness of a minimum 11.0 percent ROE for Avista is also supported by the fact that my recommended ROE range does not consider flotation costs.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

CAPITAL STRUCTURE

		At Fiscal Year-End 2008 (a)			Value Line Projected (b)		
	Company	**Long-term Debt**	**Preferred**	**Common Equity**	**Long-term Debt**	**Other**	**Common Equity**
1	AGL Resources, Inc.	50.3%	0.0%	49.7%	45.0%	0.0%	55.0%
2	Atmos Energy Corp.	50.8%	0.0%	49.2%	49.0%	0.0%	51.0%
3	Laclede Group	44.4%	0.1%	55.5%	47.0%	0.0%	53.0%
4	New Jersey Resources	41.5%	0.0%	58.5%	33.0%	0.0%	67.0%
5	Nicor, Inc.	33.8%	0.0%	66.1%	26.0%	0.0%	74.0%
6	Northwest Natural Gas	44.9%	0.0%	55.1%	47.0%	0.0%	53.0%
7	Piedmont Natural Gas	48.2%	0.0%	51.8%	47.0%	0.0%	53.0%
8	South Jersey Industries	40.9%	0.0%	59.1%	40.5%	0.0%	59.5%
9	Southwest Gas	51.2%	4.3%	44.5%	51.0%	0.0%	49.0%
10	UGI Corp.	56.7%	0.0%	43.3%	47.0%	0.0%	53.0%
11	WGL Holdings, Inc.	38.7%	1.6%	59.7%	34.0%	1.5%	64.5%
	Average	**45.6%**	**0.5%**	**53.9%**	**42.4%**	**0.1%**	**57.5%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Mar. 13, 2009).

DCF MODEL

GAS UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)
		Dividend Yield			Earnings Growth Projections					br+sv	Cost of Equity Estimates	
	Company	Price	Dividends	Yield	V Line	IBES	First Call	Zacks	Average	Growth	Earnings	br+sv
1	AGL Resources, Inc.	$ 25.92	$ 1.73	6.7%	3.0%	4.3%	4.3%	5.3%	4.2%	8.5%	10.9%	15.2%
2	Atmos Energy Corp.	$ 20.24	$ 1.33	6.6%	4.0%	5.0%	5.0%	6.0%	5.0%	5.4%	11.6%	12.0%
3	Laclede Group	$ 38.10	$ 1.55	4.1%	3.5%	NA	NA	10.0%	6.8%	7.8%	10.8%	11.9%
4	New Jersey Resources	$ 32.25	$ 1.24	3.8%	5.5%	7.0%	7.0%	8.0%	6.9%	6.6%	10.7%	10.5%
5	Nicor, Inc.	$ 29.17	$ 1.86	6.4%	2.5%	4.5%	4.5%	6.5%	4.5%	5.4%	10.9%	11.8%
6	Northwest Natural Gas	$ 38.95	$ 1.62	4.2%	7.0%	4.8%	4.8%	7.5%	6.0%	6.1%	10.2%	10.2%
7	Piedmont Natural Gas	$ 22.46	$ 1.04	4.6%	7.5%	7.0%	7.0%	7.3%	7.2%	5.7%	11.8%	10.4%
8	South Jersey Industries	$ 33.42	$ 1.20	3.6%	5.5%	7.0%	7.0%	8.6%	7.0%	9.9%	10.6%	13.5%
9	Southwest Gas	$ 18.15	$ 0.95	5.2%	4.5%	6.0%	6.0%	8.0%	6.1%	5.4%	11.4%	10.6%
10	UGI Corp.	$ 22.65	$ 0.77	3.4%	6.5%	6.0%	6.0%	7.0%	6.4%	8.9%	9.8%	12.3%
11	WGL Holdings, Inc.	$ 28.99	$ 1.44	5.0%	4.0%	4.0%	4.0%	6.7%	4.7%	4.5%	9.6%	9.4%
	Average										**10.8%**	**11.6%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Mar. 13, 2009).
(b) The Value Line Investment Survey (Mar. 13, 2009).
(c) Thomson Reuters, *Company in Context Report* (Apr. 24, 2009).
(d) *First Call Earnings Valuation Report* (Apr. 26, 2009).
(e) www.zacks.com (retrieved Apr. 27, 2009).
(f) Average of (b), (c), (d), and (e).
(g) See Exhibit WEA-3.
(h) Sum of dividend yield and respective growth rate.

GAS UTILITY PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
		2012-14 Market Price			2012-14 Projections				
	Company	High	Low	Avg.	EPS	DPS	BVPS	b	r
1	AGL Resources, Inc.	$55.00	$40.00	$47.50	$3.20	$1.88	$ 21.75	41.3%	14.7%
2	Atmos Energy Corp.	$40.00	$30.00	$35.00	$2.50	$1.40	$ 26.90	44.0%	9.3%
3	Laclede Group	$60.00	$45.00	$52.50	$3.00	$1.70	$ 28.05	43.3%	10.7%
4	New Jersey Resources	$45.00	$35.00	$40.00	$2.85	$1.40	$ 25.75	50.9%	11.1%
5	Nicor, Inc.	$65.00	$40.00	$52.50	$3.30	$1.86	$ 27.05	43.6%	12.2%
6	Northwest Natural Gas	$70.00	$55.00	$62.50	$3.45	$2.00	$ 30.50	42.0%	11.3%
7	Piedmont Natural Gas	$45.00	$35.00	$40.00	$2.15	$1.25	$ 15.85	41.9%	13.6%
8	South Jersey Industries	$50.00	$35.00	$42.50	$3.10	$1.50	$ 21.20	51.6%	14.6%
9	Southwest Gas	$40.00	$30.00	$35.00	$2.30	$1.15	$ 26.00	50.0%	8.8%
10	UGI Corp.	$40.00	$30.00	$35.00	$2.65	$0.94	$ 21.25	64.5%	12.5%
11	WGL Holdings, Inc.	$45.00	$35.00	$40.00	$2.75	$1.60	$ 26.45	41.8%	10.4%

GAS UTILITY PROXY GROUP

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
		2008			2012-14			Adjusted "r"		
			No.	Common		No.	Common	Chg in	Adj.	Adj.
	Company	BVPS	Shares	Equity	BVPS	Shares	Equity	Equity	Factor	r
1	AGL Resources, Inc.	$21.48	76.90	$1,652	$21.75	85.00	$1,849	2.3%	1.0113	14.9%
2	Atmos Energy Corp.	$22.60	90.81	$2,052	$26.90	110.00	$2,959	7.6%	1.0366	9.6%
3	Laclede Group	$22.12	21.99	$486	$28.05	26.00	$729	8.4%	1.0405	11.1%
4	New Jersey Resources	$17.28	42.06	$727	$25.75	45.00	$1,159	9.8%	1.0466	11.6%
5	Nicor, Inc.	$21.55	45.13	$973	$27.05	45.00	$1,217	4.6%	1.0224	12.5%
7	Northwest Natural Gas	$23.70	26.50	$628	$30.50	28.00	$854	6.3%	1.0307	11.7%
8	Piedmont Natural Gas	$12.11	73.26	$887	$15.85	73.00	$1,157	5.5%	1.0266	13.9%
9	South Jersey Industries	$17.33	29.73	$515	$21.20	33.00	$700	6.3%	1.0306	15.1%
10	Southwest Gas	$23.48	44.19	$1,038	$26.00	50.00	$1,300	4.6%	1.0225	9.0%
11	UGI Corp.	$13.20	107.40	$1,418	$21.25	111.00	$2,359	10.7%	1.0509	13.1%
12	WGL Holdings, Inc.	$20.99	49.92	$1,048	$26.45	50.00	$1,323	4.8%	1.0233	10.6%

GAS UTILITY PROXY GROUP

		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2008	2012-14	Change	Ratio	s	v	sv	br + sv
1	AGL Resources, Inc.	76.90	85.00	2.02%	2.18	0.0442	0.5421	2.40%	8.5%
2	Atmos Energy Corp.	90.81	110.00	3.91%	1.30	0.0509	0.2314	1.18%	5.4%
3	Laclede Group	21.99	26.00	3.41%	1.87	0.0638	0.4657	2.97%	7.8%
4	New Jersey Resources	42.06	45.00	1.36%	1.55	0.0211	0.3563	0.75%	6.6%
5	Nicor, Inc.	45.13	45.00	-0.06%	1.94	(0.0011)	0.4848	-0.05%	5.4%
7	Northwest Natural Gas	26.50	28.00	1.11%	2.05	0.0227	0.5120	1.16%	6.1%
8	Piedmont Natural Gas	73.26	73.00	-0.07%	2.52	(0.0018)	0.6038	-0.11%	5.7%
9	South Jersey Industries	29.73	33.00	2.11%	2.00	0.0423	0.5012	2.12%	9.9%
10	Southwest Gas	44.19	50.00	2.50%	1.35	0.0337	0.2571	0.87%	5.4%
11	UGI Corp.	107.40	111.00	0.66%	1.65	0.0109	0.3929	0.43%	8.9%
12	WGL Holdings, Inc.	49.92	50.00	0.03%	1.51	0.0005	0.3388	0.02%	4.5%

(a) The Value Line Investment Survey (Mar. 13, 2009).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding.
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity)
(h) Product of year-end "r" for 2012-14 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2012-14 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(g)
		Dividend	Earnings Growth Projections					br+sv	Cost of Equity Estimates	
	Company	Yield	V Line	IBES	First Call	Zacks	Average	Growth	Earnings	br+sv
1	3M Company	4.80%	4.0%	10.3%	11.0%	9.1%	8.6%	16.0%	13.4%	20.8%
2	Abbott Labs.	3.13%	11.5%	11.5%	12.0%	11.4%	11.6%	13.4%	14.7%	16.5%
3	Allergan, Inc.	0.56%	14.0%	13.7%	13.5%	13.8%	13.8%	17.2%	14.3%	17.8%
4	AT&T Inc.	7.27%	11.0%	4.4%	5.0%	6.4%	6.7%	4.1%	14.0%	11.4%
5	Automatic Data Proc.	4.02%	10.0%	12.4%	12.0%	12.4%	11.7%	8.5%	15.7%	12.5%
6	Bard (C.R.)	0.86%	13.0%	14.8%	14.5%	14.7%	14.3%	13.0%	15.1%	13.8%
7	Baxter Int'l Inc.	2.02%	13.5%	12.5%	12.5%	4.3%	10.7%	13.1%	12.7%	15.1%
8	Becton, Dickinson	2.07%	11.0%	12.7%	12.0%	12.3%	12.0%	13.1%	14.1%	15.2%
9	Bemis Co.	5.23%	5.0%	7.7%	7.0%	9.5%	7.3%	6.1%	12.5%	11.4%
10	Boeing	5.72%	14.5%	8.5%	8.5%	10.0%	10.4%	16.3%	16.1%	22.0%
11	Brown-Forman 'B'	2.82%	7.5%	8.4%	6.3%	NA	7.4%	12.1%	10.2%	14.9%
12	Chevron Corp.	4.61%	7.0%	9.1%	7.4%	9.4%	8.2%	13.8%	12.8%	18.5%
13	Chubb Corp.	3.75%	2.0%	7.8%	7.5%	10.5%	7.0%	5.8%	10.7%	9.5%
14	Coca-Cola	4.02%	8.0%	8.1%	8.2%	9.8%	8.5%	10.9%	12.5%	14.9%
15	Colgate-Palmolive	2.86%	12.0%	11.0%	11.0%	9.2%	10.8%	19.6%	13.7%	22.4%
16	ConocoPhillips	5.31%	4.0%	8.1%	7.0%	8.4%	6.9%	15.4%	12.2%	20.7%
17	Costco Wholesale	1.62%	9.0%	12.3%	13.0%	12.1%	11.6%	8.9%	13.2%	10.5%
18	Disney (Walt)	2.19%	13.5%	9.5%	8.6%	9.6%	10.3%	7.9%	12.5%	10.1%
19	Du Pont	9.66%	3.5%	9.0%	8.3%	9.0%	7.5%	7.4%	17.1%	17.1%
20	Eaton Corp.	6.31%	4.5%	11.0%	11.0%	11.0%	9.4%	16.6%	15.7%	22.9%
21	Ecolab Inc.	1.86%	12.0%	13.5%	13.5%	13.0%	13.0%	23.5%	14.9%	25.3%
22	Emerson Electric	5.23%	6.5%	10.3%	10.0%	11.7%	9.6%	5.3%	14.9%	10.5%
23	Exxon Mobil Corp.	2.57%	5.5%	7.4%	7.0%	7.6%	6.9%	15.5%	9.4%	18.1%
24	Gen'l Dynamics	3.75%	13.0%	9.0%	10.0%	10.2%	10.6%	10.9%	14.3%	14.6%
25	Gen'l Mills	3.44%	10.0%	8.8%	8.8%	8.5%	9.0%	8.4%	12.5%	11.8%
26	Grainger (W.W.)	2.59%	11.0%	12.4%	12.0%	10.4%	11.5%	8.6%	14.0%	11.2%
27	Heinz (H.J.)	5.31%	7.5%	7.8%	7.8%	NA	7.7%	10.1%	13.0%	15.4%
28	Hewlett-Packard	1.18%	13.0%	11.1%	11.0%	11.6%	11.7%	9.7%	12.9%	10.8%
29	Home Depot	4.96%	9.0%	9.5%	10.0%	10.1%	9.7%	8.3%	14.6%	13.2%
30	Honeywell Int'l	5.06%	10.0%	9.9%	10.0%	10.0%	10.0%	13.1%	15.0%	18.2%
31	Hormel Foods	2.59%	12.5%	8.8%	9.0%	8.3%	9.7%	10.4%	12.2%	13.0%
32	Illinois Tool Works	4.74%	7.5%	8.8%	10.0%	9.0%	8.8%	8.2%	13.6%	12.9%
33	Int'l Business Mach.	2.29%	12.5%	9.8%	10.0%	10.0%	10.6%	5.4%	12.9%	7.7%
34	ITT Corp.	2.56%	12.0%	13.0%	13.0%	12.2%	12.6%	11.4%	15.1%	14.0%
35	Johnson & Johnson	3.86%	7.5%	8.3%	8.0%	9.7%	8.4%	7.5%	12.2%	11.4%

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(g)
		Dividend	Earnings Growth Projections					br+sv	Cost of Equity Estimates	
	Company	Yield	V Line	IBES	First Call	Zacks	Average	Growth	Earnings	br+sv
36	Kellogg	3.70%	10.0%	8.8%	9.0%	8.8%	9.2%	13.7%	12.9%	17.4%
37	Kimberly-Clark	5.43%	7.0%	8.0%	8.0%	7.8%	7.7%	13.7%	13.1%	19.1%
38	Lilly (Eli)	7.14%	4.5%	5.4%	4.5%	6.6%	5.3%	10.7%	12.4%	17.9%
39	Lockheed Martin	3.81%	12.5%	11.5%	10.0%	10.8%	11.2%	11.7%	15.0%	15.6%
40	McDonald's Corp.	3.93%	11.0%	8.9%	9.0%	12.4%	10.3%	6.1%	14.3%	10.0%
41	Medtronic, Inc.	2.91%	10.0%	11.4%	11.5%	12.3%	11.3%	8.7%	14.2%	11.6%
42	Microsoft Corp.	3.41%	12.0%	10.2%	11.0%	11.1%	11.1%	2.8%	14.5%	6.3%
43	NIKE, Inc. 'B'	2.50%	11.5%	13.1%	14.5%	12.7%	13.0%	9.5%	15.5%	12.0%
44	Northrop Grumman	4.57%	13.0%	12.8%	10.0%	10.0%	11.5%	7.7%	16.0%	12.3%
45	PepsiCo, Inc.	3.70%	11.0%	9.4%	9.6%	11.4%	10.4%	8.3%	14.1%	12.0%
46	PPG Inds.	7.44%	4.0%	6.9%	6.9%	9.0%	6.7%	9.8%	14.1%	17.3%
47	Procter & Gamble	3.52%	9.0%	9.5%	10.0%	10.0%	9.6%	7.2%	13.1%	10.7%
48	Raytheon Co.	3.13%	14.0%	12.4%	10.0%	11.0%	11.9%	8.0%	15.0%	11.1%
49	Sigma-Aldrich	1.78%	8.0%	9.0%	9.1%	8.8%	8.7%	17.6%	10.5%	19.4%
50	Sysco Corp.	4.73%	9.5%	12.0%	12.0%	10.3%	11.0%	6.6%	15.7%	11.4%
51	TJX Companies	2.05%	15.5%	13.0%	12.0%	12.8%	13.3%	9.7%	15.4%	11.8%
52	Torchmark Corp.	3.27%	8.0%	8.1%	8.0%	NA	8.0%	11.2%	11.3%	14.4%
53	United Parcel Serv.	4.50%	6.0%	11.7%	11.5%	11.3%	10.1%	12.7%	14.6%	17.2%
54	United Technologies	4.06%	10.0%	9.5%	10.0%	9.8%	9.8%	10.3%	13.9%	14.3%
55	Verizon Communic.	6.59%	6.0%	5.1%	6.0%	6.9%	6.0%	6.6%	12.6%	13.2%
56	Walgreen Co.	2.06%	9.5%	11.6%	12.0%	12.9%	11.5%	11.1%	13.6%	13.2%
57	Wal-Mart Stores	1.91%	8.0%	11.5%	11.0%	10.7%	10.3%	12.2%	12.2%	14.1%
58	Waste Management	4.62%	8.5%	12.0%	12.0%	10.3%	10.7%	7.2%	15.3%	11.9%
59	Wyeth	2.94%	6.0%	3.8%	3.7%	4.6%	4.5%	14.4%	7.5%	17.4%
	Average (h)								**13.6%**	**12.4%**

(a) www.valueline.com (retrieved Mar. 12, 2009).
(b) Thomson Reuters, *Company in Context Report* (Mar. 11, 2009).
(c) *First Call Earnings Valuation Report* (Mar. 12, 2009).
(d) www.zacks.com (retrieved Mar. 12, 2009).
(e) Average of (a), (b), (c), and (d).
(f) See Exhibit WEA-6.
(g) Sum of dividend yield and respective growth rate.
(h) Excludes highlighted figures.

NON-UTILITY PROXY GROUP

		2011-13 Market Price			2011-13 Projections				
		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
	Company	High	Low	Avg.	EPS	DPS	BVPS	b	r
1	3M Company	$110.00	$90.00	$100.00	$6.25	$2.20	$21.85	64.8%	28.6%
2	Abbott Labs.	$100.00	$80.00	$90.00	$5.05	$2.10	$21.40	58.4%	23.6%
3	Allergan, Inc.	$105.00	$90.00	$97.50	$3.75	$0.30	$23.95	92.0%	15.7%
4	AT&T Inc.	$65.00	$55.00	$60.00	$4.25	$2.60	$24.35	38.8%	17.5%
5	Automatic Data Proc.	$85.00	$70.00	$77.50	$3.30	$1.35	$20.75	59.1%	15.9%
6	Bard (C.R.)	$175.00	$140.00	$157.50	$7.85	$0.94	$39.20	88.0%	20.0%
7	Baxter Int'l Inc.	$120.00	$95.00	$107.50	$6.00	$1.70	$20.00	71.7%	30.0%
8	Becton, Dickinson	$125.00	$105.00	$115.00	$7.15	$1.95	$39.20	72.7%	18.2%
9	Bemis Co.	$45.00	$35.00	$40.00	$2.30	$1.04	$20.80	54.8%	11.1%
10	Boeing	$140.00	$115.00	$127.50	$8.50	$2.50	$34.60	70.6%	24.6%
11	Brown-Forman 'B	$75.00	$60.00	$67.50	$3.95	$1.20	$21.05	69.6%	18.8%
12	Chevron Corp.	$140.00	$110.00	$125.00	$12.50	$3.00	$57.55	76.0%	21.7%
13	Chubb Corp.	$85.00	$70.00	$77.50	$6.30	$2.80	$56.25	55.6%	11.2%
14	Coca-Cola	$90.00	$70.00	$80.00	$3.80	$1.88	$17.30	50.5%	22.0%
15	Colgate-Palmolive	$130.00	$105.00	$117.50	$5.80	$2.30	$13.75	60.3%	42.2%
16	ConocoPhillips	$130.00	$105.00	$117.50	$12.50	$2.00	$69.40	84.0%	18.0%
17	Costco Wholesale	$90.00	$70.00	$80.00	$4.00	$0.80	$28.30	80.0%	14.1%
18	Disney (Walt)	$55.00	$45.00	$50.00	$3.30	$0.54	$25.25	83.6%	13.1%
19	Du Pont	$70.00	$55.00	$62.50	$3.50	$1.92	$18.85	45.1%	18.6%
20	Eaton Corp.	$140.00	$115.00	$127.50	$8.00	$3.10	$45.90	61.3%	17.4%
21	Ecolab Inc.	$65.00	$55.00	$60.00	$3.15	$0.85	$11.20	73.0%	28.1%
22	Emerson Electric	$60.00	$50.00	$55.00	$3.25	$1.75	$13.75	46.2%	23.6%
23	Exxon Mobil Corp.	$125.00	$100.00	$112.50	$9.35	$1.85	$35.55	80.2%	26.3%
24	Gen'l Dynamics	$140.00	$115.00	$127.50	$9.00	$2.25	$53.35	75.0%	16.9%
25	Gen'l Mills	$95.00	$80.00	$87.50	$5.10	$2.25	$23.55	55.9%	21.7%
26	Grainger (W.W.)	$150.00	$120.00	$135.00	$7.90	$2.00	$45.70	74.7%	17.3%
27	Heinz (H.J.)	$65.00	$55.00	$60.00	$3.65	$2.08	$10.75	43.0%	34.0%
28	Hewlett-Packard	$85.00	$70.00	$77.50	$4.85	$0.45	$25.15	90.7%	19.3%
29	Home Depot	$45.00	$35.00	$40.00	$2.50	$1.10	$17.25	56.0%	14.5%
30	Honeywell Int'l	$80.00	$55.00	$67.50	$4.60	$1.60	$19.00	65.2%	24.2%
31	Hormel Foods	$75.00	$60.00	$67.50	$3.75	$1.20	$23.50	68.0%	16.0%
32	Illinois Tool Works	$75.00	$65.00	$70.00	$4.25	$1.40	$20.60	67.1%	20.6%
33	Int'l Business Mach.	$220.00	$180.00	$200.00	$12.50	$3.25	$25.90	74.0%	48.3%
34	ITT Corp.	$100.00	$85.00	$92.50	$5.75	$1.15	$40.30	80.0%	14.3%
35	Johnson & Johnson	$115.00	$95.00	$105.00	$6.25	$2.50	$35.80	60.0%	17.5%
36	Kellogg	$85.00	$70.00	$77.50	$4.45	$1.54	$14.00	65.4%	31.8%
37	Kimberly-Clark	$95.00	$89.00	$92.00	$5.85	$2.95	$17.75	49.6%	33.0%
38	Lilly (Eli)	$70.00	$55.00	$62.50	$4.20	$2.16	$20.05	48.6%	20.9%
39	Lockheed Martin	$210.00	$170.00	$190.00	$12.70	$3.50	$43.50	72.4%	29.2%
40	McDonald's Corp.	$95.00	$75.00	$85.00	$4.95	$2.85	$18.25	42.4%	27.1%
41	Medtronic, Inc.	$100.00	$80.00	$90.00	$4.70	$1.20	$20.85	74.5%	22.5%
42	Microsoft Corp.	$50.00	$45.00	$47.50	$2.65	$0.80	$7.60	69.8%	34.9%
43	NIKE, Inc. 'B'	$110.00	$90.00	$100.00	$5.15	$1.50	$23.85	70.9%	21.6%
44	Northrop Grumman	$140.00	$115.00	$127.50	$9.00	$2.10	$76.00	76.7%	11.8%
45	PepsiCo, Inc.	$110.00	$90.00	$100.00	$5.00	$2.00	$17.60	60.0%	28.4%
46	PPG Inds.	$85.00	$65.00	$75.00	$5.35	$2.28	$31.45	57.4%	17.0%
47	Procter & Gamble	$110.00	$90.00	$100.00	$4.75	$1.95	$27.90	58.9%	17.0%
48	Raytheon Co.	$95.00	$80.00	$87.50	$5.80	$1.75	$41.80	69.8%	13.9%
49	Sigma-Aldrich	$70.00	$60.00	$65.00	$3.60	$0.70	$15.00	80.6%	24.0%
50	Sysco Corp.	$60.00	$45.00	$52.50	$2.50	$1.25	$7.30	50.0%	34.2%
51	TJX Companies	$55.00	$45.00	$50.00	$3.90	$0.80	$9.50	79.5%	41.1%
52	Torchmark Corp	$100.00	$85.00	$92.50	$8.00	$0.75	$50.65	90.6%	15.8%
53	United Parcel Serv.	$130.00	$110.00	$120.00	$5.45	$2.00	$21.50	63.3%	25.3%
54	United Technologies	$115.00	$95.00	$105.00	$6.50	$1.85	$40.30	71.5%	16.1%
55	Verizon Communic	$65.00	$50.00	$57.50	$3.25	$1.96	$18.75	39.7%	17.3%
56	Walgreen Co.	$70.00	$60.00	$65.00	$3.05	$0.68	$21.40	77.7%	14.3%
57	Wal-Mart Stores	$85.00	$70.00	$77.50	$4.65	$1.15	$26.30	75.3%	17.7%
58	Waste Management	$55.00	$45.00	$50.00	$3.25	$1.50	$15.90	53.8%	20.4%
59	Wyeth	$75.00	$60.00	$67.50	$4.60	$1.40	$23.50	69.6%	19.6%

NON-UTILITY PROXY GROUP

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
		2007			2011-13			Adjusted "r"		
	Company	BVPS	No. Shares	Common Equity	BVPS	No. Shares	Common Equity	Chg in Equity	Adj. Factor	Adj. r
1	3M Company	$16.56	709.16	$11,744	$21.85	680.00	$14,858	4.8%	1.0235	29.3%
2	Abbott Labs.	$11.47	1549.90	$17,777	$21.40	1520.00	$32,528	12.8%	1.0603	25.0%
3	Allergan, Inc.	$12.22	305.91	$3,738	$23.95	315.00	$7,544	15.1%	1.0701	16.8%
4	AT&T Inc.	$19.09	6043.50	$115,370	$24.35	5500.00	$133,925	3.0%	1.0149	17.7%
5	Automatic Data Proc.	$9.61	535.80	$5,149	$20.75	520.00	$10,790	15.9%	1.0738	17.1%
6	Bard (C.R.)	$19.60	99.00	$1,940	$39.20	90.00	$3,528	12.7%	1.0597	21.2%
7	Baxter Int'l Inc.	$10.13	615.00	$6,230	$20.00	550.00	$11,000	12.0%	1.0568	31.7%
8	Becton, Dickinson	$20.30	243.08	$4,935	$39.20	237.00	$9,290	13.5%	1.0632	19.4%
9	Bemis Co.	$15.54	100.52	$1,562	$20.80	100.00	$2,080	5.9%	1.0286	11.4%
10	Boeing	$12.22	736.68	$9,002	$34.60	700.00	$24,220	21.9%	1.0986	27.0%
11	Brown-Forman 'B	$11.44	150.74	$1,724	$21.05	145.00	$3,052	12.1%	1.0570	19.8%
12	Chevron Corp.	$42.37	2045.30	$86,659	$57.55	1800.00	$103,590	3.6%	1.0178	22.1%
13	Chubb Corp.	$38.56	374.65	$14,447	$56.25	345.00	$19,406	6.1%	1.0295	11.5%
14	Coca-Cola	$9.38	2318.00	$21,743	$17.30	2290.00	$39,617	12.7%	1.0599	23.3%
15	Colgate-Palmolive	$4.10	509.03	$2,087	$13.75	480.00	$6,600	25.9%	1.1146	47.0%
16	ConocoPhillips	$56.60	1475.00	$83,485	$69.40	1475.00	$102,365	4.2%	1.0204	18.4%
17	Costco Wholesale	$19.73	437.01	$8,622	$28.30	405.00	$11,462	5.9%	1.0285	14.5%
18	Disney (Walt)	$15.67	1962.20	$30,748	$25.25	1650.00	$41,663	6.3%	1.0304	13.5%
19	Du Pont	$12.38	899.30	$11,133	$18.85	875.00	$16,494	8.2%	1.0393	19.3%
20	Eaton Corp.	$35.42	146.00	$5,171	$45.90	170.00	$7,803	8.6%	1.0411	18.1%
21	Ecolab Inc.	$6.55	240.00	$1,572	$11.20	245.00	$2,744	11.8%	1.0556	29.7%
22	Emerson Electric	$11.14	787.23	$8,770	$13.75	715.00	$9,831	2.3%	1.0114	23.9%
23	Exxon Mobil Corp.	$22.71	4976.00	$113,005	$35.55	4300.00	$152,865	6.2%	1.0302	27.1%
24	Gen'l Dynamics	$29.13	403.98	$11,768	$53.35	370.00	$19,740	10.9%	1.0517	17.7%
25	Gen'l Mills	$15.64	340.00	$5,318	$23.55	315.00	$7,418	6.9%	1.0333	22.4%
26	Grainger (W.W.)	$26.40	79.46	$2,098	$45.70	70.00	$3,199	8.8%	1.0422	18.0%
27	Heinz (H.J.)	$6.04	312.56	$1,888	$10.75	295.00	$3,171	10.9%	1.0518	35.7%
28	Hewlett-Packard	$14.93	2580.00	$38,519	$25.15	2100.00	$52,815	6.5%	1.0316	19.9%
29	Home Depot	$10.48	1690.00	$17,711	$17.25	1675.00	$28,894	10.3%	1.0489	15.2%
30	Honeywell Int'l	$12.35	746.55	$9,220	$19.00	700.00	$13,300	7.6%	1.0366	25.1%
31	Hormel Foods	$13.89	135.68	$1,885	$23.50	132.00	$3,102	10.5%	1.0498	16.8%
32	Illinois Tool Works	$17.64	530.10	$9,351	$20.60	470.00	$9,682	0.7%	1.0035	20.7%
33	Int'l Business Mach.	$20.55	1385.20	$28,466	$25.90	1100.00	$28,490	0.0%	1.0001	48.3%
34	ITT Corp.	$21.73	181.57	$3,946	$40.30	177.00	$7,133	12.6%	1.0591	15.1%
35	Johnson & Johnson	$16.75	2750.00	$46,063	$35.80	2500.00	$89,500	14.2%	1.0663	18.6%
36	Kellogg	$6.48	390.05	$2,528	$14.00	355.00	$4,970	14.5%	1.0675	33.9%
37	Kimberly-Clark	$12.41	420.90	$5,223	$17.75	405.00	$7,189	6.6%	1.0319	34.0%
38	Lilly (Eli)	$12.05	1134.30	$13,668	$20.05	1135.00	$22,757	10.7%	1.0509	22.0%
39	Lockheed Martin	$23.97	409.00	$9,804	$43.50	350.00	$15,225	9.2%	1.0440	30.5%
40	McDonald's Corp.	$11.85	1100.00	$13,035	$18.25	1015.00	$18,524	7.3%	1.0351	28.1%
41	Medtronic, Inc.	$12.25	1115.00	$13,659	$20.85	975.00	$20,329	8.3%	1.0397	23.4%
42	Microsoft Corp.	$3.32	9380.00	$31,142	$7.60	7500.00	$57,000	12.9%	1.0604	37.0%
43	NIKE, Inc. 'B'	$13.94	503.80	$7,023	$23.85	455.00	$10,852	9.1%	1.0435	22.5%
44	Northrop Grumman	$52.35	337.83	$17,685	$76.00	300.00	$22,800	5.2%	1.0254	12.1%
45	PepsiCo, Inc.	$10.71	1605.00	$17,190	$17.60	1450.00	$25,520	8.2%	1.0395	29.5%
46	PPG Inds.	$25.34	163.80	$4,151	$31.45	163.00	$5,126	4.3%	1.0211	17.4%
47	Procter & Gamble	$20.87	3131.90	$65,363	$27.90	2950.00	$82,305	4.7%	1.0230	17.4%
48	Raytheon Co.	$29.43	426.20	$12,543	$41.80	390.00	$16,302	5.4%	1.0262	14.2%
49	Sigma-Aldrich	$10.66	129.38	$1,379	$15.00	125.00	$1,875	6.3%	1.0307	24.7%
50	Sysco Corp.	$5.36	611.84	$3,279	$7.30	560.00	$4,088	4.5%	1.0220	35.0%
51	TJX Companies	$4.98	427.95	$2,131	$9.50	320.00	$3,040	7.4%	1.0355	42.5%
52	Torchmark Corp	$36.07	92.18	$3,325	$50.65	75.00	$3,799	2.7%	1.0133	16.0%
53	United Parcel Serv.	$12.20	995.00	$12,139	$21.50	950.00	$20,425	11.0%	1.0520	26.7%
54	United Technologies	$21.76	981.52	$21,358	$40.30	925.00	$37,278	11.8%	1.0556	17.0%
55	Verizon Communic	$17.62	2871.00	$50,587	$18.75	2850.00	$53,438	1.1%	1.0055	17.4%
56	Walgreen Co.	$11.20	991.14	$11,101	$21.40	975.00	$20,865	13.5%	1.0630	15.2%
57	Wal-Mart Stores	$16.26	3973.00	$64,601	$26.30	3800.00	$99,940	9.1%	1.0436	18.5%
58	Waste Management	$12.05	490.70	$5,913	$15.90	447.00	$7,107	3.7%	1.0184	20.8%
59	Wyeth	$13.61	1337.80	$18,207	$23.50	1340.00	$31,490	11.6%	1.0547	20.6%

NON-UTILITY PROXY GROUP

		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2007	2011-13	Change	Ratio	s	v	sv	br + sv
1	3M Company	709.16	680.00	-0.84%	4.58	(0.0383)	0.7815	-2.99%	16.0%
2	Abbott Labs.	1549.90	1520.00	-0.39%	4.21	(0.0164)	0.7622	-1.25%	13.4%
3	Allergan, Inc.	305.91	315.00	0.59%	4.07	0.0239	0.7544	1.80%	17.2%
4	AT&T Inc.	6043.50	5500.00	-1.87%	2.46	(0.0460)	0.5942	-2.73%	4.1%
5	Automatic Data Proc.	535.80	520.00	-0.60%	3.73	(0.0223)	0.7323	-1.63%	8.5%
6	Bard (C.R.)	99.00	90.00	-1.89%	4.02	(0.0759)	0.7511	-5.70%	13.0%
7	Baxter Int'l Inc.	615.00	550.00	-2.21%	5.38	(0.1188)	0.8140	-9.67%	13.1%
8	Becton, Dickinson	243.08	237.00	-0.51%	2.93	(0.0148)	0.6591	-0.98%	13.1%
9	Bemis Co.	100.52	100.00	-0.10%	1.92	(0.0020)	0.4800	-0.10%	6.1%
10	Boeing	736.68	700.00	-1.02%	3.68	(0.0374)	0.7286	-2.73%	16.3%
11	Brown-Forman 'B	150.74	145.00	-0.77%	3.21	(0.0248)	0.6881	-1.71%	12.1%
12	Chevron Corp.	2045.30	1800.00	-2.52%	2.17	(0.0548)	0.5396	-2.96%	13.8%
13	Chubb Corp.	374.65	345.00	-1.64%	1.38	(0.0225)	0.2742	-0.62%	5.8%
14	Coca-Cola	2318.00	2290.00	-0.24%	4.62	(0.0112)	0.7838	-0.88%	10.9%
15	Colgate-Palmolive	509.03	480.00	-1.17%	8.55	(0.0998)	0.8830	-8.81%	19.6%
16	ConocoPhillips	1475.00	1475.00	0.00%	1.69	-	0.4094	0.00%	15.4%
17	Costco Wholesale	437.01	405.00	-1.51%	2.83	(0.0427)	0.6463	-2.76%	8.9%
18	Disney (Walt)	1962.20	1650.00	-3.41%	1.98	(0.0675)	0.4950	-3.34%	7.9%
19	Du Pont	899.30	875.00	-0.55%	3.32	(0.0181)	0.6984	-1.27%	7.4%
20	Eaton Corp.	146.00	170.00	3.09%	2.78	0.0859	0.6400	5.49%	16.6%
21	Ecolab Inc.	240.00	245.00	0.41%	5.36	0.0221	0.8133	1.80%	23.5%
22	Emerson Electric	787.23	715.00	-1.91%	4.00	(0.0763)	0.7500	-5.72%	5.3%
23	Exxon Mobil Corp.	4976.00	4300.00	-2.88%	3.16	(0.0911)	0.6840	-6.23%	15.5%
24	Gen'l Dynamics	403.98	370.00	-1.74%	2.39	(0.0416)	0.5816	-2.42%	10.9%
25	Gen'l Mills	340.00	315.00	-1.52%	3.72	(0.0563)	0.7309	-4.12%	8.4%
26	Grainger (W.W.)	79.46	70.00	-2.50%	2.95	(0.0739)	0.6615	-4.89%	8.6%
27	Heinz (H.J.)	312.56	295.00	-1.15%	5.58	(0.0642)	0.8208	-5.27%	10.1%
28	Hewlett-Packard	2580.00	2100.00	-4.03%	3.08	(0.1243)	0.6755	-8.40%	9.7%
29	Home Depot	1690.00	1675.00	-0.18%	2.32	(0.0041)	0.5688	-0.23%	8.3%
30	Honeywell Int'l	746.55	700.00	-1.28%	3.55	(0.0455)	0.7185	-3.27%	13.1%
31	Hormel Foods	135.68	132.00	-0.55%	2.87	(0.0158)	0.6519	-1.03%	10.4%
32	Illinois Tool Works	530.10	470.00	-2.38%	3.40	(0.0808)	0.7057	-5.70%	8.2%
33	Int'l Business Mach.	1385.20	1100.00	-4.51%	7.72	(0.3480)	0.8705	-30.29%	5.4%
34	ITT Corp.	181.57	177.00	-0.51%	2.30	(0.0117)	0.5643	-0.66%	11.4%
35	Johnson & Johnson	2750.00	2500.00	-1.89%	2.93	(0.0554)	0.6590	-3.65%	7.5%
36	Kellogg	390.05	355.00	-1.87%	5.54	(0.1033)	0.8194	-8.46%	13.7%
37	Kimberly-Clark	420.90	405.00	-0.77%	5.18	(0.0398)	0.8071	-3.21%	13.7%
38	Lilly (Eli)	1134.30	1135.00	0.01%	3.12	0.0004	0.6792	0.03%	10.7%
39	Lockheed Martin	409.00	350.00	-3.07%	4.37	(0.1340)	0.7711	-10.33%	11.7%
40	McDonald's Corp.	1100.00	1015.00	-1.60%	4.66	(0.0743)	0.7853	-5.84%	6.1%
41	Medtronic, Inc.	1115.00	975.00	-2.65%	4.32	(0.1143)	0.7683	-8.78%	8.7%
42	Microsoft Corp.	9380.00	7500.00	-4.37%	6.25	(0.2734)	0.8400	-22.97%	2.8%
43	NIKE, Inc. 'B'	503.80	455.00	-2.02%	4.19	(0.0846)	0.7615	-6.44%	9.5%
44	Northrop Grumman	337.83	300.00	-2.35%	1.68	(0.0394)	0.4039	-1.59%	7.7%
45	PepsiCo, Inc.	1605.00	1450.00	-2.01%	5.68	(0.1142)	0.8240	-9.41%	8.3%
46	PPG Inds.	163.80	163.00	-0.10%	2.38	(0.0023)	0.5807	-0.14%	9.8%
47	Procter & Gamble	3131.90	2950.00	-1.19%	3.58	(0.0426)	0.7210	-3.07%	7.2%
48	Raytheon Co.	426.20	390.00	-1.76%	2.09	(0.0368)	0.5223	-1.92%	8.0%
49	Sigma-Aldrich	129.38	125.00	-0.69%	4.33	(0.0297)	0.7692	-2.29%	17.6%
50	Sysco Corp.	611.84	560.00	-1.76%	7.19	(0.1262)	0.8610	-10.87%	6.6%
51	TJX Companies	427.95	320.00	-5.65%	5.26	(0.2973)	0.8100	-24.08%	9.7%
52	Torchmark Corp	92.18	75.00	-4.04%	1.83	(0.0738)	0.4524	-3.34%	11.2%
53	United Parcel Serv.	995.00	950.00	-0.92%	5.58	(0.0514)	0.8208	-4.22%	12.7%
54	United Technologies	981.52	925.00	-1.18%	2.61	(0.0307)	0.6162	-1.89%	10.3%
55	Verizon Communic	2871.00	2850.00	-0.15%	3.07	(0.0045)	0.6739	-0.30%	6.6%
56	Walgreen Co.	991.14	975.00	-0.33%	3.04	(0.0100)	0.6708	-0.67%	11.1%
57	Wal-Mart Stores	3973.00	3800.00	-0.89%	2.95	(0.0261)	0.6606	-1.73%	12.2%
58	Waste Management	490.70	447.00	-1.85%	3.14	(0.0581)	0.6820	-3.96%	7.2%
59	Wyeth	1337.80	1340.00	0.03%	2.87	0.0009	0.6519	0.06%	14.4%

(a) www.valueline.com (retrieved Mar. 12, 2009)
(b) Average of High and Low expected market prices
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity
(h) Product of year-end "r" for 2011-13 and Adjustment Factor
(i) Average of High and Low expected market prices divided by 2011-13 BVPS
(j) Product of change in common shares outstanding and M/B Ratio
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v"
(m) Product of average "b" and adjusted "r", plus "sv

CAPITAL ASSET PRICING MODEL

GAS UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	4.4%	
Growth Rate (b)	9.1%	
Market Return (c)		13.5%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		3.8%
Market Risk Premium (e)		9.7%
Utility Proxy Group Beta (f)		0.67
Utility Proxy Group Risk Premium (g)		6.5%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		3.8%
Implied Cost of Equity (h)		**10.3%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Mar. 13, 2009).
(b) Weighted average of Value Line, IBES, First Call, and Zacks earnings growth rates for the dividend paying firms in the S&P 500 based on data from www.valueline.com (retrieved Mar. 13, 2009), Thomson Reuters, *Company in Context Report* (Mar. 16, 2009), *First CallValuation Report* (Mar. 16, 2009), and www.zacks.com (retrieved Mar. 16, 2009).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for April 2009 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) The Value Line Investment Survey (Mar. 13, 2009).
(g) (e) x (f).
(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

NON-UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	4.4%	
Growth Rate (b)	9.1%	
Market Return (c)		13.5%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		3.8%
Market Risk Premium (e)		9.7%
Non-Utility Proxy Group Beta (f)		0.80
Non-Utility Proxy Group Risk Premium (g)		7.7%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		3.8%
Implied Cost of Equity (h)		**11.5%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Mar. 13, 2009).
(b) Weighted average of Value Line, IBES, First Call, and Zacks earnings growth rates for the dividend paying firms in the S&P 500 based on data from www.valueline.com (retrieved Mar. 13, 2009), Thomson Reuters, Company in Context Report(Mar. 16, 2009), First CallValuation Report (Mar. 16, 2009), and www.zacks.com (retrieved Mar. 16, 2009).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for April 2009 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) www.valueline.com (retrieved Mar. 12, 2009).
(g) (e) x (f).
(h) (d) + (g).

EXPECTED EARNINGS APPROACH

GAS UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	AGL Resources, Inc.	14.5%	1.0113	14.7%
2	Atmos Energy Corp.	9.5%	1.0366	9.8%
3	Laclede Group	11.0%	1.0405	11.4%
4	New Jersey Resources	11.0%	1.0466	11.5%
5	Nicor, Inc.	12.0%	1.0224	12.3%
6	Northwest Natural Gas	11.0%	1.0307	11.3%
7	Piedmont Natural Gas	13.5%	1.0266	13.9%
8	South Jersey Industries	14.5%	1.0306	14.9%
9	Southwest Gas	9.0%	1.0225	9.2%
10	UGI Corp.	12.5%	1.0509	13.1%
11	WGL Holdings, Inc.	11.0%	1.0233	11.3%
	Average			**12.1%**

(a) 3-5 year projections from The Value Line Investment Survey (Mar. 13, 2009).
(b) See Exhibit WEA-4. An adjustment is necessary to reflect Value Line's use of year-end capital balances
(c) (a) x (b).

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

WILLIAM E. AVERA
Exhibit No. 302

Return on Equity

EXHIBIT 302

QUALIFICATIONS OF WILLIAM E. AVERA

Q. What is the purpose of this exhibit?

A. This exhibit describes my background and experience and contains the details of my qualifications.

Q. What are your qualifications?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas (PUCT) as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal

Communications Commission ("FCC"), the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in 39 states.

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached.

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River
Austin, Texas 78751
(512) 458–4644
FAX (512) 458–4768
fincap@texas.net

Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal,
FINCAP, Inc.
(Sep. 1979 to present)

Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 150 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.

Director, Economic Research Division,
Public Utility Commission of Texas
(Dec. 1977 to Aug. 1979)

Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.

Manager, Financial Education,
International Paper Company
New York City
(Feb. 1977 to Nov. 1977)

Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, President of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts

Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 250 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.
State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 41 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (86 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

"The Geometric Mean Strategy and Common Stock Investment Management," with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

"Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth (Mar. 1979)

"Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF DAVE B. DEFELICE
REPRESENTING THE AVISTA CORPORATION

Capital Projects

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Dave DeFelice. I am employed by Avista Corporation as a Senior Business Analyst. My business address is 1411 East Mission, Spokane, Washington.

Q. Please briefly describe your education background and professional experience.

A. I graduated from Eastern Washington University in June of 1983 with a Bachelor of Arts Degree in Business Administration majoring in Accounting. I have served in various positions within the Company, including Analyst positions in the Finance Department (Rates Section and Plant Accounting) and in the Marketing/Operations Departments, as well. In 1999, I accepted the Senior Business Analyst position that focuses on economic analysis of various project proposals as well as evaluations and recommendations pertaining to business policies and practices.

Q. As a Senior Business Analyst, what are your responsibilities?

A. As a Senior Business Analyst, I am involved in financial analysis of numerous projects within various departments such as Engineering, Operations, Marketing/Sales and Finance.

Q. What is the scope of your testimony?

A. My testimony in this proceeding will cover the Company’s proposed regulatory treatment of capital investments in utility plant through 2010.

II. CAPITAL INVESTMENT RECOVERY

Q. What does the Company's request for rate relief include regarding new

investment in utility plant to serve customers?

A. In this filing, we are proposing to include in retail rates the costs associated with utility plant that will be used to provide energy service to our customers during the 2010 forecasted test period. Including the costs associated with this investment in retail rates provides a proper "matching" of revenues from customers, with the costs associated with providing service to customers (including the cost of utility plant to serve customers).

Q. How was rate base for the forecasted test year developed for this filing?

A. Avista started with rate base using historical accounting information, which for this case is the end of period (EOP) balances for the twelve months ended December 31, 2008. Adjustments were made to the plant in service at December 31, 2008 to accumulated depreciation and deferred federal income taxes (DFIT) to restate to the average of monthly averages (AMA) amounts for the twelve months ended December 31, 2010. In addition, adjustments were made to reflect 2009 and 2010 plant additions and associated accumulated depreciation and DFIT through December 2010 on an AMA basis, such that the proposed rate base reflects the net plant in service that will be used to serve customers during the 2010 forecasted test year. The 2010 major plant additions described later in my testimony are reflected at cost.

Q. What ratemaking objective is being served by your adjustments to rate base?

A. The objective is to include in retail rates the investment, or rate base, that is providing service to customers, and ensure that there is a proper matching of revenues and expenses during the period that rates are in effect.

In prior general rate cases we have used a rate base amount from a historical test year as the starting point for the pro forma rate year. If there were no major plant additions between the historical test year and the upcoming pro forma rate year, the historical test year rate base amount would be used for the pro forma rate year as being representative of the net plant used to serve customers.

However, if there were known major plant additions that would be in service for the pro forma rate year, such as the major reinforcement upgrades, then rate base for the pro forma rate year is adjusted for these major investments, so that rate base for the pro forma rate year is representative of the level of investment used to serve customers.

In this docket, the Company's adjustment for new investment in plant includes all forecasted capital additions in 2009 and 2010 to restate rate base from the historical test period to the forecasted test year. The end result is to reflect in retail rates the level of net plant investment that is used to serve customers during the forecasted test year, and to have a proper matching of revenues and expenses.

Q. What are Avista's 2009 and 2010 capital expenditures that have been included in this case?

A. As shown in Table 1 below, Avista forecasts system-wide general plant capital expenditures of $36.535 million in 2009 and $29.413 million in 2010 (Oregon share totals $3.2 million and $2.5 million for 2009 and 2010, respectively.) As shown in Table 2 below, Avista forecasts Oregon natural gas distribution capital expenditures of $17.819 million in 2009 and $19.222 million in 2010.

Table 1
General Plant Capital Expenditures in 000's

Project	2009 System	2009 Oregon Allocated	2010 System	2010 Oregon Allocated
Next Generation Radio System	$ 1,500	$ 129	$ 1,500	$ 129
Structures & Improvements	3,360	289	3,205	276
Tools Lab & Shop Equipment	1,285	111	1,523	131
Central Operating Facility HVAC Improvement	4,159	358	3,327	286
Central Operating Facility - Crescent Realignment	1,500	129	-	-
Transportation Equipment	9,635	830	5,982	515
Information Technology Refresh Projects-Software	4,410	380	4,967	428
Information Technology Expansion Projects-Software	981	84	1,105	95
AFM Product Development Program-Software	1,115	96	1,256	108
Technology Projects Minor - Software	346	30	3,005	259
Small Technology Projects	5,102	439	2,611	225
Small General Projects	3,142	271	932	80
TOTAL	$ 36,535	$ 3,146	$ 29,413	$ 2,532

Table 2
Oregon Gas Distribution Capital Expenditures in 000's

Project	2009	2010
Oregon - Gas Revenue Projects	$ 5,561	$ 5,555
Replace Deteriorating Gas System	850	893
Gas Replace - Street & Highway	660	693
Gas Distribution Non-Revenue Projects	1,000	1,235
Overbuilt Pipe Replacement Projects	410	361
East Medford Reinforcement	4,451	4,700
Roseburg Reinforcement	0	1,932
Grants Pass Reinforcement Project	16	2,000
Replace Gas ERTs	2,000	0
Small Natural Gas Distribution Projects	2,871	1,853
TOTAL	$ 17,819	$ 19,222

Q. How does this level of capital expenditures compare to recent years?

A. As shown in Table 3 below, Avista's Oregon direct distribution and general capital expenditures (not including general plant that is assigned to Oregon) have increased significantly over the past several years. This is due primarily to major distribution reinforcement projects, which are explained in detail below.

Table 3 Oregon Direct Capital Expenditures History in $000's		
Year		
2005	$	10,388
2006	$	15,405
2007	$	24,297
2008	$	23,589
2009 Forecasted	$	17,819
2010 Forecasted	$	19,222

Q. What is driving the significant investment in new utility plant in Oregon?

A. The Company is being required to add significant new distribution facilities due to customer growth in our service area, reliability requirements, and capacity upgrades. Other issues driving the need for capital investment include an aging infrastructure, physical degradation, and municipal compliance issues (i.e., street/highway relocations), etc. Detailed explanations of the three major reinforcement projects (East Medford, Roseburg, and Grants Pass) that are included in this docket are described below.

In addition, although in recent months the rapid increase in the cost of materials (concrete, copper, steel, etc.) has subsided, they are still orders of magnitude higher than what they were even a few years ago, causing the cost of these new facilities to be significantly higher than in the past. Because the cost of adding new facilities is significantly higher than the original cost of existing facilities, the investment in new facilities will be significantly higher than the annual depreciation expense on the existing facilities.

Q. What is causing the substantial increase in raw materials for Avista, and the utility industry in general?

A. In September 2007, The Edison Foundation commissioned a study from The

Brattle Group titled, "Rising Utility Construction Costs: Sources and Impacts," which identified cost trends specifically related to the utility industry pertaining to critical materials and equipment, as well as labor support services used for building capital infrastructure. The study identifies the reasons for drastic cost increases in critical raw materials, such as global competition and an aging domestic utility infrastructure as well as the need for additional infrastructure to accommodate growth in the near future.

Q. What are some of the key cost drivers that are cited in the study?

A. The study, at page 16, cites four major cost drivers, "(1) material input costs, including the cost of raw physical inputs, such as steel and cement as well as increased costs of components manufactured from these inputs; (2) shop and fabrication capacity for manufactured components (relative to current demand); (3) the cost of construction field labor, both unskilled and craft labor; and (4) the market for large construction project management, i.e., the queuing and bidding for projects." The study goes on to compare cost trends for various raw materials, critical equipment and labor services relative to the general inflation rate (GDP deflator). In addition, a cost trend is summarized by three key utility functional plant categories, including generation, transmission, and distribution plant. The study concludes that these inflation impacts have been outside the utility industry's control and there are no immediate indications of cost relief in the near future.

Q. Is there specific evidence that Avista is experiencing cost escalations similar to that indicated in the study?

A. Yes. The Company tracks the cost of polyethylene (PE) and steel pipe that Avista routinely uses in order to support various natural gas infrastructure construction efforts that are part of the Company's annual capital requirements of purchases made from 2003 through 2009. The cost summary indicated that the cost of the materials tracked has risen sharply from 2003 to 2008. It also indicates that while costs have come down during 2009 from the peaks in 2008, the average cost is still significantly above the 2003 – 2004 levels. Illustration 1 below shows the cost trend line for the PE pipe, the average annual escalation impact from 2003 through 2009 is approximately 11%, which is equal to a cumulative increase over the five-year period of 55%. Illustration 2 below shows the cost trend line for the steel pipe, the average annual escalation impact from 2005 through 2009 is approximately 25%, which is equal to a cumulative increase over the four-year period of 100%.

Illustration 1:

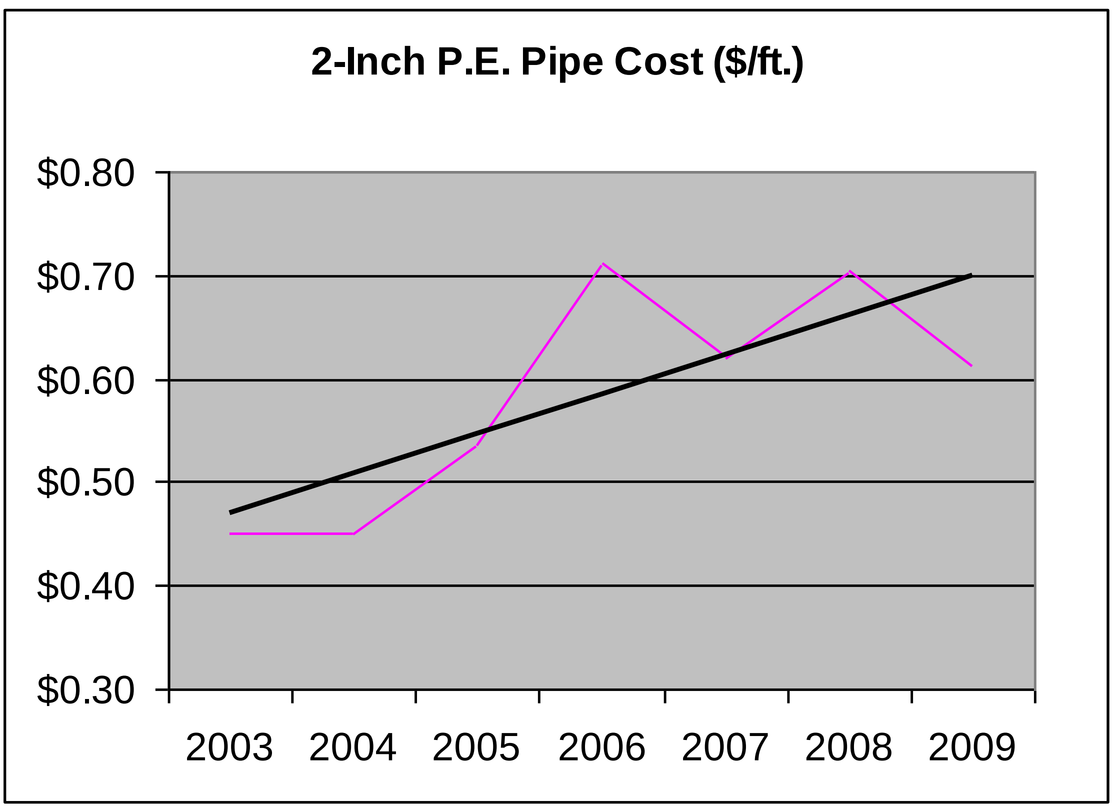
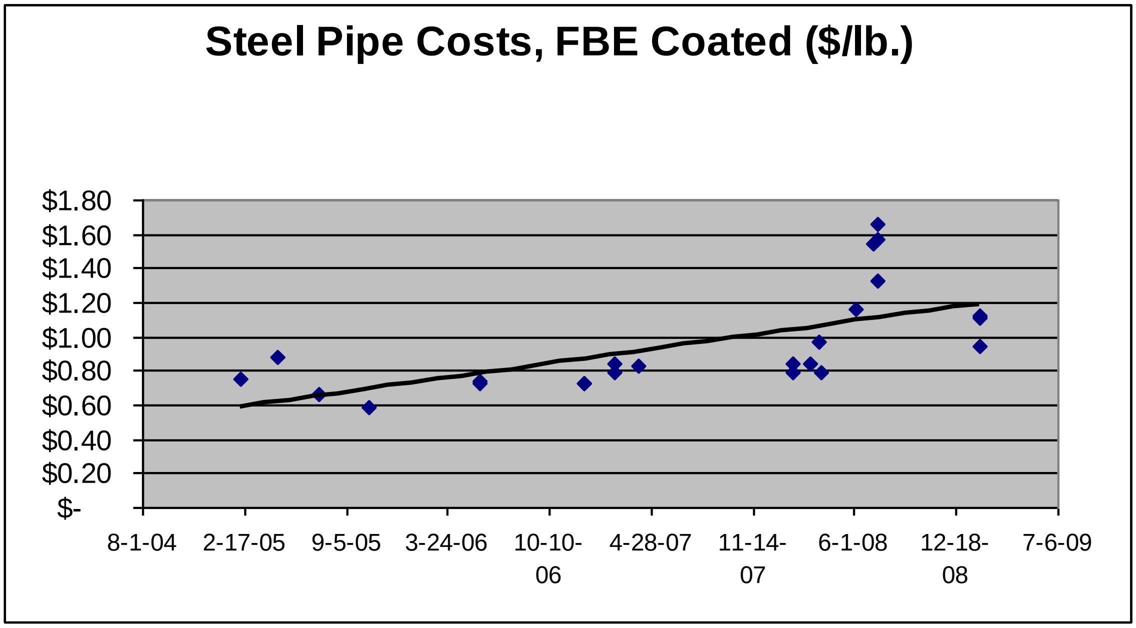


Illustration 2:



Q. What is the likelihood that Avista's capital investment will continue at this level?

A. There are many factors that will influence capital expenditures going forward. One factor is that the cost of raw materials is expected to continue to inflate over time and the fact that there is more demand for capital projects for such things as compliance work with municipal highway and road projects, sewer projects, etc. Also, as critical systems age, there will be more utility plant that will be reaching the end of physical life. (

III. DESCRIPTION OF CAPITAL PROJECTS

Q. For the 2009 and 2010 capital projects pro formed in this filing, please provide a description of the projects.

A. Tables 1 and 2 above details the capital projects that will be transferred to plant in service in 2009 and 2010 and included in this filing. A short description of these projects and their costs allocated to Oregon follows:

General (Oregon):

ER 5106 - Next Generation Radio System – 2009: $129,000; 2010: $129,000
Antiquated radio system technology necessary to operate the business is being refreshed to comply with changing FCC regulation.

ER 7001 - Structures and Improvements – 2009: $289,000; 2010: $276,000
This is a group of capital maintenance projects that Facilities Management coordinates at the Spokane Central Operating Facilities and Avista branch facilities - offices and service centers. For 2009, some of the projects include: roof replacements, land acquisition for facility expansion, HVAC system replacement at some branch offices, energy efficiency projects, security projects, emergency generators, asphalt overlays and replacement, and office furniture additions and replacement.

ER 7006 - Tools, Lab & Shop Equipment – 2009: $111,000; 2010: $131,000
Expenditures in this category include all large tools and instruments used throughout the company for natural gas and/or electric construction and maintenance work, distribution, transmission, or generation operations, telecommunications, and some fleet equipment (hoists, winch, etc) not permanently attached to the vehicle.

ER 7101 - HVAC Renovation Project – 2009: $358,000; 2010: $286,000
The heating, ventilating, and air conditioning systems throughout the Spokane Central Operating Facilities at the main campus are approximately fifty years old and are in need of replacement. The project involves replacing central air handling units and distribution systems in three buildings at the main campus - the Spokane Service Center, the General Office Building, and the Cafeteria Auditorium Building. The building envelope of the General Office Building will also be renovated with high efficiency glass and insulation. New controls will also be installed which will enable energy conservation.

ER 7109 - Spokane Central Operating Facility North Crescent Realignment – 2009: $129,000
Vacate a city street that bisects the Spokane campus to eliminate public traffic across parking lots and operating facilities, improving facility safety and security.

Other Small Projects – 2009: $271,000; 2010: $80,000
These projects include communication and security initiatives, radio equipment, telephone systems, office and other general facility upgrades.

Transportation (Oregon):

ER 7000 - Transportation Equipment – 2009: $830,000; 2010: $515,000
Expenditures are for the scheduled replacement of trucks, off-road construction equipment and trailers that meet the company's guidelines for replacement including age, mileage, hours of use and overall condition. In addition, includes additions to the fleet for new positions or crews working to support the maintenance and construction of our electric and natural gas operations.

Technology (Oregon):

ER 5005 - Information Technology Refresh Projects – 2009: $380,000; 2010: $428,000
A program to replace obsolete technology according to Avista's refresh cycles that are generally driven by hardware/software manufacturer and industry trends to maintain business operations.

ER 5006 - Information Technology Expansion Projects – 2009: $84,000; 2010: $95,000
A program to deliver technology associated with expansion of existing solutions.

ER 5007 - AFM Product Development Program – 2009: $96,000; 2010: $108,000
Deliver enhancements to the electric and natural gas Facility Management technology system.

ER 5111 – Technology Projects Minor Software – 2009: $30,000; 2010: $259,000
A program to deliver new technology.

Other Small Technology Projects – 2009: $439,000; 2010: $225,000
These projects include various small technology projects including, technology to provide for field office use of Learning Management System, a Meter Data Management solution, a work management technology system to the Generation Production and Substation Support organization, and replacement of existing Real Estate permits application which is end-of-life with Valumation Contract Management System.

Natural Gas Distribution (Oregon):

ER 1000 - Gas Revenue Projects – 2009: $5,561,000; 2010: $5,555,000
This annual project will install sections of gas piping, meters, regulators, etc. that are directly linked to new revenue.

ER 3001 - Replace Deteriorated Pipe – 2009: $850,000; 2010: $892,500
This annual project will replace sections of existing gas piping that are suspect for

failure or have deteriorated within the gas system. This project will address the replacement of sections of gas main that no longer operate reliably and/or safely. Sections of the gas system require replacement due to many factors including material failures, environmental impact, increased leak frequency, or coating problems. This project will identify and replace sections of main to improve public safety and system reliability.

ER 3003 - Gas Replacement Street and Highways – 2009: $660,000; 2010: $693,000
This annual project will replace sections of existing gas piping that require replacement due to relocation or improvement of streets or highways in areas where gas piping is installed. Avista installs many of its facilities in public right-of-way under established franchise agreements. Avista is required under the franchise agreements, in most cases, to relocate its facilities when they are in conflict with road or highway improvements.

ER 3005 - Gas Non-Revenue Projects – 2009: $1,000,000; 2010: $1,234,800
This annual project will replace sections of existing gas piping that require replacement to improve the operation of the gas system but are not directly linked to new revenue. The project includes relocation of main related to overbuilds [customer constructed improvements (i.e. decks, driveways, etc.) that restricts the Company's access to pipe], improvement in equipment and/or technology to improve system operation and/or maintenance, replacement of obsolete facilities, replacement of main to improve cathodic performance, and projects to improve public safety and/or improve system reliability.

ER 3006 - Overbuild Pipe Replacement Projects – 2009: $410,000; 2010: $361,000
This annual project will replace sections of existing gas piping that have experienced encroachment or have been overbuilt. It will address the replacement of sections of gas main that no longer can be operated safely and will identify and replace sections of main to improve public safety. All types of overbuilds will be addressed with the primary focus of the project being overbuilds in manufactured home developments.

ER 3203 - East Medford Reinforcement Project – 2009: $4,451,000; 2010: $4,700,000
This Oregon natural gas distribution project is described later in my testimony.

ER 3204 - Roseburg Reinforcement Project –2010: $1,932,000
This Oregon natural gas distribution project is described later in my testimony.

ER 3240 – Grants Pass Reinforcement Project – 2009: $16,000; 2010: $2,000,000
This Oregon natural gas distribution project is described later in my testimony.

ER 3265 - Replace Gas ERT's w/ Batteries >10yrs – 2009: $2,000,000
This project will replace Gas ERT's that are greater than 10 years old, which is their economic life. ERT battery life is finite and although that life is greater than 10 years,

it is cost effective to replace the ERTS's prior to them failing in the field. This project will ensure continued reliable metering operation by ensuring the ERT technology operates properly. Approximately 12,000 ERT's will be replaced in Washington and 21,000 in Oregon.

Other Small Projects – 2009: $2,871,000; 2010: $1,853,000
Please refer to the workpapers of Company witness Ms. Andrews for detailed listing of projects.

IV. Major Natural Gas Distribution Reinforcement Capital Projects

Q. Please describe the Company's East Medford Reinforcement Project and the costs that are included in this filing.

A. The East Medford Reinforcement Project will provide a strategic high pressure pipeline encirclement of the Greater Medford Area for long-term natural gas supply to the eastern portions of the city. The project will allow for additional natural gas delivery from either TransCanada at the Company's Phoenix Road Gate Station or Northwest Pipeline at Grants Pass. It provides reinforcement of the system in anticipation of future load growth in Medford. One could liken it to a high pressure "beltway" around the east side of Medford, thereby providing pressure support to this entire segment of Avista's distribution system.

This project will be completed over a three-year period. Phase I provided reinforcement of the existing distribution system by extending high pressure piping and installing a regulator station. The high pressure system will be further extended during subsequent phases to complete the looping of the system. Phase I capital costs totaled approximately $5.952 million, were completed in November 2008 and were approved in Docket No. UG-181. Phase II will extend high pressure piping from the Phase I reinforcement and north from the existing Phoenix Rd. Gate Station to further reinforce portions of the east Medford distribution system. Phase III will complete the looping of the high pressure system on the east side of Medford by connecting Phase I and Phase II reinforcements. Each of the prospective phases provides an increased level of benefit to customers by reinforcement of the local distribution system. Phase II and Phase III capital costs are currently estimated at approximately $4.451 million and $4.7 million, respectively, and will be completed in November 2009 and November 2010, respectively. Both Phase II and III costs have been included in this filing. Ms. Andrews incorporates these costs in her testimony and exhibits.

Q. Please describe the Company's Roseburg Reinforcement Project and the costs that are included in this filing.

A. The Roseburg Reinforcement Project improves the delivery pressure and capacity of natural gas supplies into central and east Roseburg by extending a high pressure natural gas supply. The existing system is marginally capable of meeting customer load on a design day. The only natural gas supplies in the Roseburg area are received on the west side of town. Due to growth and increase in customer demand, especially on the east side of Roseburg, the system must be reinforced to meet customer demand during high system demand. The project will install a new high pressure (HP) distribution source by extending piping and installing three new regulator stations. Phase I included extending piping from a pressure-limited source that will subsequently be upgraded during Phase III.

This project will be completed in three phases over a four-year period. Phase I capital costs totaled approximately $1.893 million, were completed in September 2008 and were approved in Docket No. UG-181.

Phase II will extend the Phase I reinforcement from central Roseburg to the east Roseburg city limits. The reinforcement will include the installation of a regulator station to reinforce the local distribution system. Phase II capital costs are currently estimated at approximately $1.932 million, will be completed in November 2010 and such costs have been pro formed into this filing. Ms. Andrews incorporates these costs in her testimony and exhibits. Phase III will replace the existing capacity constrained source between the Jackie Street Gate station and the south Roseburg city limits. Phase III capital costs are currently estimated at approximately $3.400 million and will be completed in October 2011. Phase III has not been included in this filing.

Q. Please describe the Company's Grants Pass Reinforcement Project and the costs that are included in this filing.

A. The Grants Pass Reinforcement Project will replace the existing High Pressure (HP) source into the greater Grants Pass area. Due to growth in the area the existing HP main is capacity constrained on a design day basis and replacement is required to ensure adequate natural gas deliveries during high system demand. This project will install a new larger HP source from the nearby Jones Creek Gate station into east central Grants Pass. The existing HP main will be converted to intermediate pressure distribution piping to provide an incremental reinforcement to the local distribution system. An additional benefit to the public is the elimination of a number of High Consequence Areas (HCA's) as defined by the recent integrity management regulation. Elimination of the HCA's will improve public safety and mitigate future costs associated with management of the HCA's. The capital cost is approximately $2.0 million, will be completed November 2010, and such costs have been pro formed into this filing. Ms. Andrews incorporates these costs in her testimony and exhibits.

V. CONCLUSION

Q. What is the impact of using forecasted capital additions in this filing?

A. The use of forecasted capital additions in determining the forecasted test year will result in a proper matching of revenues to cost of service to customers at the time new rates go into effect at the conclusion of this general rate proceeding and for the 2010 rate period. Without the forecasted capital additions, the Company would not have the opportunity to earn its allowed rate of return on investment during the rate year.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF ELIZABETH M. ANDREWS
REPRESENTING THE AVISTA CORPORATION

Revenue Requirement and Allocations

INTRODUCTION

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

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

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

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

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

A. As Manager of Revenue Requirements, aside from special projects, I am responsible for the preparation of normalized revenue requirement, pro forma studies, and forecasted studies for the various jurisdictions in which the Company provides utility services. During the last nine years I have assisted or lead the Company's electric and/or natural gas general rate filings in Washington, Idaho and Oregon.

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

A. My testimony and exhibits in this proceeding will generally cover accounting and financial data in support of the Company's need for the proposed increase in rates. I will explain forecasted operating results including expense and rate base adjustments made to actual operating results and rate base.

The forecasted net operating income and rate base that serve as the basis for the overall revenue requirement in this filing incorporate not only those adjustments prepared by myself, but also by Company witnesses Mr. DeFelice and Mr. Hirschkorn. I will cover the revenue adjustment briefly, while Ms. Hirschkorn will provide more in-depth discussion. I will also provide a summary of the Company's forecasted 2009 and 2010 capital additions, while Mr. DeFelice will present more detail in his testimony. Finally, I will provide an overview of the Company's system and jurisdictional allocation methodologies that have been in place since 1994.

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

A. Yes. I am sponsoring Exhibit No. 501, which was prepared under my direction. Exhibit 501 consists of worksheets, which show historical actual 2008 operating results, forecasted results for 2010, proposed natural gas operating results and rate base for the Company's Oregon jurisdiction, the Company's calculation of the general revenue requirement, the derivation of the net operating income to gross revenue conversion factor, and the forecasted adjustments proposed in this filing.

REVENUE REQUIREMENT AND RATE REQUEST PROPOSAL

Q. Would you please summarize the results of the Company's forecasted study for its natural gas operating system for the Oregon jurisdiction?

A. Yes. After taking into account all standard earnings test adjustments, as well as additional forecast adjustments, the forecasted natural gas rate of return ("ROR") for the Company's Oregon jurisdictional operations is 3.30%, as shown on Exhibit No. 501, page 1. This return level is below the Company's requested rate of return of 8.96%. The incremental revenue requirement for base retail rates, necessary to give the Company an opportunity to earn its requested ROR is $14,205,000. The overall base natural gas increase associated with the Company's request is 11.6%[1].

Q. What was the Company's rate of return that was last authorized by this Commission for its natural gas operations in Oregon?

A. The Company's currently authorized rate of return for its Oregon operations is 8.21%, effective April 1, 2008.

Q. Including this current request, how many times has the Company requested an increase in base rates since you acquired the Oregon properties in 1991?

A. In 1991, the Company, then known as The Washington Water Power Company, doing business as WP Natural Gas (WPNG), acquired the Oregon and California natural gas service territory of CP National. WPNG implemented a 0.50% decrease in base rates at that time and instituted a four and one-half year rate freeze. Upon the end of this rate

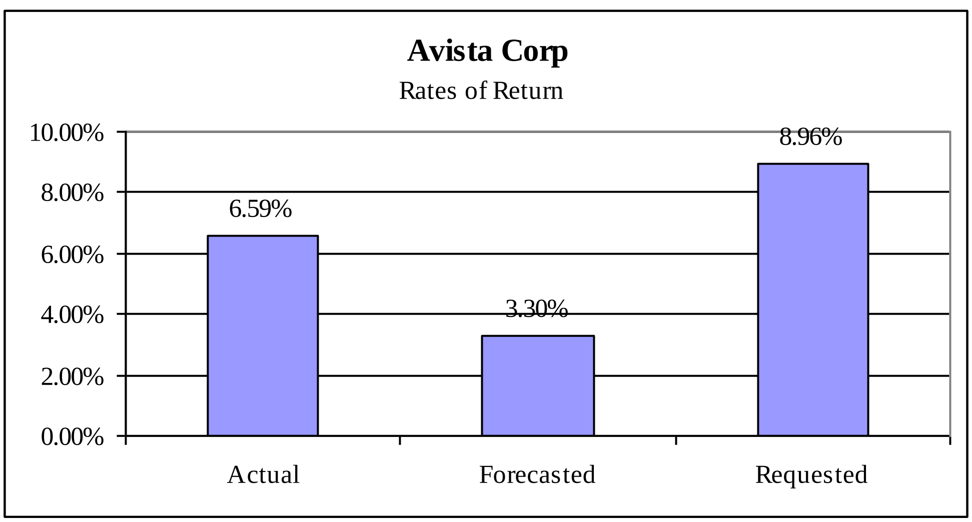
[1] Percentages reflect the proposed increase to base tariff rates. Mr. Hirschkorn describes the effect based on present billing rates.

stability period, a 2.94% general rate decrease was implemented effective December 1, 1995. Thereafter, the Company again implemented a base rate decrease of 2.1% effective December 1, 1997. In October 2003, the Company implemented a 9.9% increase in base rates. In 2008, the Company implemented a general rate increase in two increments totaling 1.8%. Thus, Avista has had only three general rate increases since we acquired the properties eighteen years ago.

Q. By way of summary, could you please explain the different rates of return that you will be presenting in your testimony?

A. Yes. As shown in Illustration No.1 below, there are three different rates of return that will be discussed. The <u>actual</u> ROR earned by the Company during the twelve months ended December 31, 2008, the <u>forecasted</u> ROR determined in my Exhibit No. 501, page 1, and the <u>requested</u> ROR.

Illustration No. 1:



Q. What is the test year the Company is utilizing for this general rate request?

A. The forecasted test period being used by the Company is the twelve months ended December 31, 2010, presented on a forecasted basis. Currently authorized rates are based upon the 2006 test year utilized in Docket No. UG-181 adjusted on a pro forma basis.

Q. Why did the Company use the year ending December 31, 2010 as the test period?

A. The forecasted test period in this case was selected to best reflect the conditions during which time the new rates will be in effect. Rates from this proceeding will be effective in the early part of 2010, which closely matches the forecasted test period used by the Company in the calculation of the revenue requirement.

Q. Please explain how the Company developed the revenue requirement for the test period.

A. Revenue requirement preparation began with the historical accounting information for the twelve months ended December 31, 2008. Each of the revenue requirement components in the historical period was analyzed to determine if a normalizing adjustment was warranted to reflect normal operating conditions. The historical information was then adjusted to include previous Commission–ordered adjustments; next these results were adjusted to recognize known, measurable and anticipated events to determine a forecasted 2010 test period.

Q. Why did the Company begin with historical information?

A. The Company began with historical information and made adjustments to arrive at the forecasted test period revenue requirement because starting with historical information provides a solid foundation and paper trail that is easily auditable.

Q. Please summarize the process used to adjust the historical information to reflect the forecasted test period revenues and costs.

A. Revenues are adjusted for the effect of applying the current Commission approved tariff rates to the forecasted test period projected customer usage. Historical operations and maintenance ("O&M") expenses were separated into labor and non-labor components. Non-labor costs were adjusted using a combination of historical averages, Company forecasted amounts, and the consumer price index (CPI). Historical labor costs were also adjusted for increases through the end of the forecasted test period. Specific adjustments are described in further detail later in my testimony and shown in Exhibit 501.

Q. How has the Company addressed areas where cost increases are different than inflation?

A. The Company analyzed O&M expenses by FERC account to determine the most reasonable and prudent method to forecast these costs. The Company utilized a variety of means to best derive a reasonable forecast, which included the use of a historical average, internal forecast, or CPI.

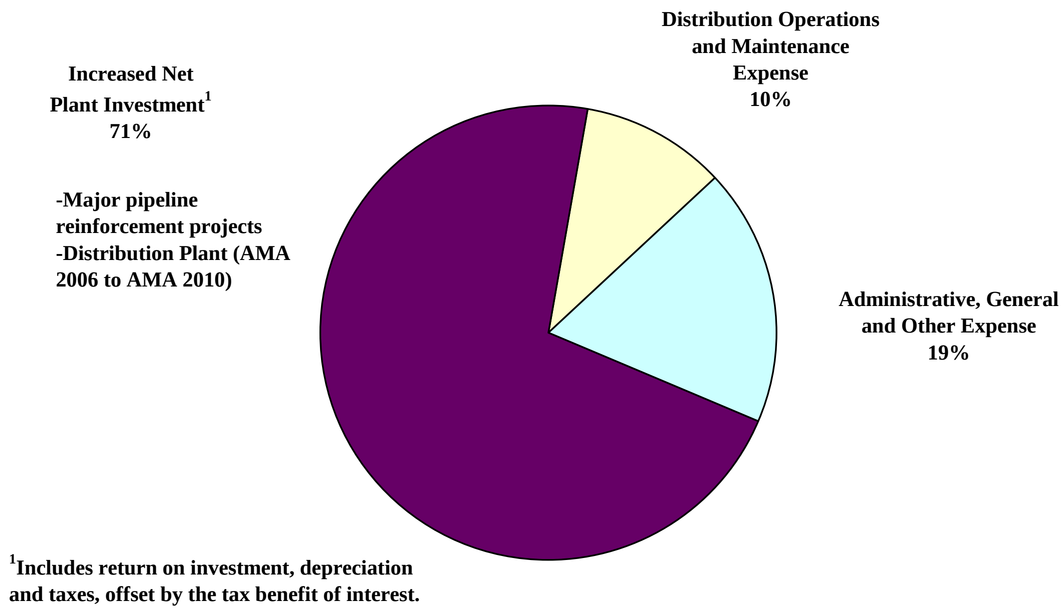
PRIMARY FACTORS

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

A. Illustration No. 2 below, shows the primary factors driving the natural gas revenue requirement in this case. Additional details regarding these items are provided later in my testimony.

Illustration No. 2:

Oregon Primary Components of Revenue Requirement



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

A. As indicated by the Company's forecasted test period results, there are numerous operational factors that have impacted the Company's Oregon jurisdiction results of operations since the 2006 test year of operations used for Avista's last base rate increase in Oregon. By 2010, total rate base is forecasted to increase by approximately $49 million, or 50%, and net operating income is expected to decline by $5.1 million. In comparing the 2010 forecasted test period for this filing to 2006, many operational costs have also increased significantly. At a summary level, increases in O&M and A&G costs are approximately $4 million, and increases in "Taxes Other Than Income" are approximately $1.4 million, between the historical test period of 2006 and the forecasted test period of 2010.

Q. Please explain each of the three components or segments shown in Illustration 2 above.

A. The largest segment, Increase in Net Plant Investment, comprises approximately 71% of the overall request, and includes depreciation recovery, taxes associated with plant, and the return on additional plant investment offset by the tax benefit of interest. Net rate base for Oregon increased by $49 million, as explained in further detail below.

The next largest segment is Administrative and General Expenses along with other expenses that make up 19% of the total request. Administration and general expenses (A&G) have increased $2.6 million, since 2006. The largest part of this increase relates to labor from 2006 through the forecasted test period 2010 of approximately $841,000. The increase in labor is reasonable given that this case spans over a four-year time period from our previous test year for the twelve months ended December 31, 2006 to the twelve months ended December 31, 2010. Other A&G increases are due mainly to rising Company pension and medical costs.

The final segment, representing 10% of the overall revenue requirement increase, is Distribution Operation and Maintenance Expense. Overall, Operation and Maintenance Expense (O&M) increased $1.4 million. Of that total, distribution O&M increased $1.2 million. The main source of this increase is from mains and services expense, measuring and regulator station expense, and customer installation expenses.

Q. Please explain the major components of the $49 million increase in total rate base.

A. Gross plant increased approximately $76.1 million and gas inventory increased approximately $1.2 million, with an offsetting increase in Accumulated Depreciation and amortization of approximately $19.5 million and a Deferred Federal Income Tax increase of approximately $8.8 million. All of these net to $49 million in total rate base.

Q. What were the major components of the $76.1 million of gross plant additions?

A. Gross plant increased approximately $76.1 million, as compared to what is currently included in base rates. This includes the actual plant additions from 2006 AMA through 2008 (net of the 2007 – 2008 plant that had been pro formed in the previous general rate case) of approximately $39.6 million and the 2009 – 2010 forecasted capital additions of approximately $36.3 million. The capital additions were primarily distribution plant ($66 million, or 87% of gross plant) that was necessary to continue to meet the energy and reliability needs of our customers.

The four largest forecasted capital projects included in this filing are the East Medford Reinforcement Project, the Roseburg Reinforcement Project, the Gas ERT Battery Replacement Project, and the Grants Pass Reinforcement Project, all of which are described in more detail in Mr. DeFelice's testimony.

GENERAL REVENUE REQUIREMENT

Q. Would you please explain what is shown in Exhibit 501?

A. Yes. Exhibit 501 shows 2008 actual results and forecasted natural gas operating results and rate base for the 2010 test period for the Company's Oregon jurisdiction.

Column (b) of page 1 of Exhibit 501 shows the twelve months ended December 31, 2008 operating results and components of the end-of-period rate base as recorded; column (c) is the total of all adjustments to net operating income and rate base; and column (d) is forecasted results of operations, all under existing rates. Column (e) shows the revenue increase required which would allow the Company an opportunity to earn its requested 8.96% rate of return. Column (f) reflects forecasted natural gas operating results with the requested general increase of $14,205,000.

Q. Would you please explain page 2 of Exhibit No. 501?

A. Yes. As discussed earlier in my testimony, page 2 shows the calculation of the $14,205,000 revenue requirement using the requested 8.96% rate of return.

Q. Would you now please explain page 3 of Exhibit 501?

A. Yes. Page 3 shows the derivation of the net operating income to gross revenue conversion factor. The conversion factor takes into account uncollectible accounts receivable, Oregon Commission fees, Oregon Energy Resource Supplier Assessment Fees, Franchise Taxes and Oregon Excise Tax, which is the Oregon state income tax. Federal income taxes are reflected at 35%.

Q. Now turning to pages 4 through 6 of your Exhibit 501, would you please explain what those pages show?

A. Yes. Page 4 begins with actual operating results and rate base for the twelve months ended December 31, 2008 in column (b). Individual earnings test adjustments that are standard components of our annual earnings reporting to the Commission begin in column (c) on page 4 and continue through column (k) on page 5. Column (l) on page 5, entitled

Restated Total, is the subtotal of all preceding columns. The eight individual forecast adjustments are presented in column (F1) through column (F8) on pages 5 and 6.

EARNINGS TEST ADJUSTMENTS

Q. Would you please explain each of these adjustments, the reason for the adjustment and its effect on test period state of Oregon net operating income and/or rate base?

A. Yes. The first adjustment, column (c) on page 4, entitled **Memberships and Dues**, classifies expenses by category and specific percentages are applied to determine the recoverable amounts. This calculation is consistent with what was recommended to the Company during Staff review of December 31, 1994 Earnings Report. The effect of this adjustment on state of Oregon net operating income is an increase of $22,000.

Column (d), **Salaries and Wages**, adjusts the 2008 historical year to be consistent with that approved by the Commission in Order No. 03-570, September 25, 2003 and in Order No. 08-185, March 31, 2008. As recommended by Staff in the review of adjusted Results of Operations for 12/31/1994, Staff's approach recommended an adjustment for 1/2 the difference between actual payroll and the annual percent based on the Consumer Price Index. The Union portion of this adjustment annualizes the effect on union labor expense of the union wage adjustments implemented in April of each year. The result of this adjustment on net operating income is a decrease of $10,000 and an increase in rate base of $10,000.

The adjustment in column (e), **Incentive Pay**, adjusts 2008 historical year incentive expense to the actual 2008 incentive expense paid in 2009, removes 100% of the executive incentive payout, removes 30% of non-executive incentive payout, and reflects a 50/50 sharing of merit-based incentive pay between the Company and customers, as agreed to in Docket No. UG-181. In addition, this adjustment forecasts incentive expenses for 2010 by using the Consumer Price Index. The effect of this adjustment on state of Oregon net operating income is an increase of $105,000.

The adjustment in column (f), **Eliminate Revenue Pass-Through**, has no impact on the Company's revenue requirement. This adjustment removes the impact of the collection through revenues of franchise taxes that exceed the general level of 3% and the impact of the collection of Low-Income Rate Assistance Plan (LIRAP) revenues from results of operations. The impact of both of these items nets to zero and facilitates analysis of cost of service and rate design.

Column (g), **Uncollectible Expense**, revises the historical period level of accrued expense to the 2008 actual net customer accounts receivable write-offs. The effect on state of Oregon net operating income is a decrease of $192,000.

The adjustment in column (h), **Miscellaneous**, removes prior period and non-recurring items impacting 2008 historical period operating income. It includes an adjustment for franchise fees that relate to the prior period. The impact of this adjustment on Oregon net operating income is a decrease of $316,000.

Q. Please turn to page 5 and explain the adjustments shown there.

A. Column (i), **Remove Senate Bill 408 Accrual**, removes all accounting transactions recorded in 2008 related to the provisions of Oregon Senate Bill 408. This includes the removal of the revenue and amortization of $479,968 related to the refund or the

2006 tax return period. In addition, this adjustment removes $2,156,743 of true-ups recorded in 2008 for the 2006 and 2007 tax return period accruals. Finally, it removes $1,450,000 that the Company had accrued in 2008 for the 2008 tax return period. The adjustment decreases net operating income by $460,000.

The adjustment in column (j), **SIT-FIT**, adjusts Oregon state income tax expense and federal income tax expense applicable to Oregon gas utility operations. Avista Corporation files a consolidated federal income tax return for an affiliated group that includes electric utility operations in Washington and Idaho, gas utility operations in Oregon, Washington, and Idaho, and non-utility subsidiary operations.

Federal income tax expense is determined for Oregon gas utility operations on a stand-alone basis, or, in other words, based on the income generated by Oregon gas operations. The ($202,000) adjustment to current federal income tax expense relates to the federal income tax impact of the adjustment to Oregon state income tax. The $251,000 adjustment to deferred federal income tax relates to correcting a deferred tax credit item that was correctly assigned to Oregon gas operations, but was inadvertently overstated.

The level of Oregon state income tax was also calculated on a stand-alone basis, since this is the method used to determine taxes paid in Senate Bill 408 filings. Oregon stand-alone taxable income before state income tax was multiplied by the state statutory rate of 6.6% to determine the amount of Oregon state income tax. The adjustment to Oregon state income amounts to an increase of $578,000.

The net impact to Oregon net operating income for federal and state income taxes is a reduction of $627,000.

Column (k), entitled **Restate Debt Interest**, restates debt interest using the Company's forecasted weighted average cost of debt, as outlined in the testimony and exhibits of Company witness Mr. Thies and applied to Oregon's forecasted level of rate base to produce a forecasted level of tax deductible interest expense. The federal income tax effect of the restated level of interest for the test period increases Oregon net operating income by $242,000.

Column (l) entitled **Restated Total**, provides a subtotal of preceding columns (b) through column (k) and represents actual operating results and rate base, plus the standard rate base adjustments that have been included in prior annual earnings reporting to the Oregon Commission.

FORECASTED ADJUSTMENTS

Q. Please explain the significance of the eight columns that begin on page 5 and continue on page 6, in your Exhibit 501.

A. The eight adjustments subsequent to the Restated Total column represent forecasted adjustments that recognize the jurisdictional impacts of items that will affect the forecasted operating period levels. They encompass revenue and expense items as well as additional capital projects and inventory items. These adjustments bring the 2008 operating results and rate base to the final forecasted level for the 2010 forecasted test period.

Q. Why did the Company use a forecasted test period?

A. The Company chose to use a forecasted test period to best reflect the conditions during which new rates will be in effect. Rates as a result of this case will match revenues and expenses for the forecasted test period ending December 31, 2010.

Q. Please continue with your explanation of the forecasted adjustments on page 5.

A. Column (F1), **Forecast Expense Adjustment**, increases non-labor O&M and A&G expenses based on forecasts through 2010 for the various FERC accounts. Workpapers accompanying my testimony and Exhibit in this case provide summary adjustments by FERC account and provide the Company's analysis of each FERC account balance and the methodology which the Company chose to make the adjustment. This adjustment decreases Oregon net operating income by $430,000.

The overall changes in non-labor O&M and A&G expenses from our last rate case that was based on a 2006 historical test period to the twelve months ended December 31, 2010 are detailed out in Illustration 3 below:

Illustration 3:

Description	2006 Non-Labor Expenses	2010 Non-Labor Expenses	Change from 2006 Actual to 2010 Forecasted $
Other Gas Expense	**104,958**	**201,088**	**96,130**
Underground Storage	**-**	**18,943**	**18,943**
Distribution Expenses	**1,391,420**	**2,079,185**	**687,765**
Customer Accounts and Service	**1,141,652**	**1,187,018**	**45,366**
Sales Operating Expenses	**141,839**	**85,504**	**(56,335)**
Admin and General	**3,449,894**	**4,635,406**	**1,185,512**
Total O&M Expenses	**6,229,763**	**8,207,145**	**1,977,382**

As shown above, the largest dollar increases are non-labor distribution expenses as well as the non-labor A&G expenses.

Non-Labor distribution expenses increased roughly $688,000 since 2006. The major components of this change are additional mains and services expense of approximately $400,000. Of the $400,000 most of it relates to atmospheric testing and pressure reads that will occur in 2010. The remaining increases are for distribution expenses and small miscellaneous other expenses.

Non-Labor A&G expenses have increased approximately $1.2 million since 2006. The major components of this are damage claims and insurance premiums of approximately $280,000, maintenance of general plant of $270,000, and miscellaneous and regulatory expenses of $329,000.

Column (F2), **Forecast Revenue Adjustment**, takes into account forecasted normalized usage and customers during 2010. It calculates revenues and purchased gas expense based on rates and associated gas costs approved in the Company's most recent Purchased Gas Adjustment filing. This adjustment was made under the direction of Mr. Hirschkorn and is described further in his testimony. The effect of this adjustment is to increase Oregon net operating income by $246,000.

Column (F3), **Forecast Labor and Benefits Adjustment**, reflects changes to the historical period labor and benefits for union, non-union and executives forward to 2010 levels. Historical period labor and benefits for 2008 were restated to annualize the March 1, 2008 increase, include the 2009 increase, and to include the 2010 increase as of March 1, 2010. This adjustment also includes changes in both the Company's pension and medical insurance expense planned for 2010, for a total decrease in Oregon net operating income of $683,000.

Q. Please turn to page 6 and continue with your explanation of the forecast adjustments.

A. Column (F4), **Forecast Property Tax Adjustment**, forecasts the property tax accrual to the most current forecasted information available and eliminates any adjustments related to the prior year. The effect of this adjustment is to decrease Oregon net operating income by $192,000.

Column (F5), **Forecast 2008 Vintage Plant Adjustment**, forecasts depreciation expense to the 2010 expense level on all plant in service at December 31, 2008. In addition, the associated accumulated depreciation and DFIT were adjusted to reflect the forecasted 2010 balances on an AMA basis for all 2008 vintage plant in service at December 31, 2008. This net effect of the adjustment decreases Oregon net operating income by $37,000 and decreases rate base by $9,268,000.

Column (F6), **Forecast 2009 Capital Additions Adjustment**, forecasts all Oregon capital projects that will become operational and will transfer to plant in service in 2009, and the associated accumulated depreciation and DFIT to December 31, 2009 on an EOP basis. This adjustment also forecasts depreciation expense and property taxes on the 2009 capital projects to the 2010 forecasted test year level. This adjustment was made under the direction of Mr. DeFelice and is described further in his testimony. This adjustment decreases Oregon net operating income by $483,000 and increases rate base by $20,332,000.

Column (F7), **Forecast 2010 Capital Additions Adjustment**, forecasts all Oregon capital projects that will become operational and will transfer to plant in service in 2010, and the associated accumulated depreciation and DFIT to December 31, 2010 on an AMA basis. The 2010 major plant additions described by Mr. DeFelice at pages 9 through 15 of his testimony are reflected at cost. This adjustment also forecasts depreciation expense and property taxes on the 2010 capital projects to the 2010 forecasted test year level. In addition, this adjustment forecasts the 2009 capital projects [forecasted in adjustment (F6)] associated accumulated depreciation and DFIT to December 31, 2010, on an AMA basis. This adjustment was also made under the direction of Mr. DeFelice and is described further in his testimony. This adjustment decreases Oregon net operating income by $549,000 and increases rate base by $14,697,000.

Column (F8), **Forecast Inventory Adjustment**, reflects an adjustment to the twelve months ended December 31, 2008 inventory rate base balance for the gas stored at the Company's Jackson Prairie and Mist underground storage facilities to a forecasted average of monthly average inventory balance expected for the 2010 forecasted test period. The effect on Oregon rate base is a decrease of $2,986,000.

Workpapers for each of the adjustments described above accompany the Company's filed case.

Q. Referring back to page 1, line 23, of Exhibit 501, what was the actual and forecasted gas rate of return realized by the Company during the test period?

A. For the State of Oregon, the actual test period rate of return was 6.59%. The forecasted rate of return is 3.30% under present rates. Thus, the Company does not, on a forecasted basis, realize the 8.96% rate of return requested by the Company in this case.

Q. How much additional net operating income would be required for the State of Oregon gas operations to allow the Company an opportunity to earn its proposed 8.96% rate of return on a forecasted basis?

A. The net operating income deficiency amounts to $8,359,000, as shown on line 5, page 2 of Exhibit 501. The resulting revenue requirement is shown on line 7 and amounts to $14,205,000, or an increase of 11.6% over forecasted revenues.

ALLOCATION PROCEDURES

Q. Have there been any changes to the Company's system and jurisdictional procedures since the Company's last general natural gas case, Docket No. UG-181?

A. No. For ratemaking purposes, the Company allocates revenues, expenses and rate base between electric and gas services and between Oregon, Washington, and Idaho jurisdictions where electric and/or gas service is provided. The current methodology was implemented in 1994 and has not changed. The allocation factors used in this case have been provided with my workpapers.

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

A. Yes, it does.

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON JURISDICTION FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
Line No.	DESCRIPTION	Actual Per Results Report (EOP)	Total Adjustments	Forecasted Total	Proposed Revenues & Related Exp	Forecasted Proposed Total (AMA)
	a	*b*	*c*	*d*	*e*	*f*
	OPERATING REVENUES					
1	Total General Business	$128,123	$ (7,706)	$120,417	$14,205	$134,622
2	Total Transportation	2,391	(5)	2,386		2,386
3	Other Revenues	67,985	(67,836)	149		149
4	Total Operating Revenues	198,499	(75,547)	122,952	14,205	137,157
	OPERATING EXPENSES					
5	Gas Purchased	160,985	(71,958)	89,027		89,027
6	Operation and Maintenance	11,597	(934)	10,663	91	10,754
7	Administration & General	7,006	571	7,577	46	7,623
8	Taxes Other than Income	5,931	(542)	5,389	300	5,689
9	Depreciation & Amortization	3,325	2,174	5,499		5,499
10	Total Operating Expenses	188,844	(70,689)	118,155	437	118,592
11	OPERATING INCOME BEFORE FIT	9,655	(4,858)	4,797	13,768	18,565
	INCOME TAXES					
12	Current Federal Income Taxes	236	(1,765)	(1,529)	4,501	2,972
13	Deferred Federal Income Taxes	1,346	4	1,350		1,350
14	State Income Taxes	(161)	267	106	909	1,015
15	Total Income Taxes	1,421	(1,494)	(73)	5,410	5,337
16	NET OPERATING INCOME	$8,234	($3,364)	$4,870	$8,358	$13,228
	RATE BASE					
17	Utility Plant in Service	230,167	36,321	266,488		266,488
18	Less: Accum Depr and Amort	(88,453)	(7,336)	(95,789)	0	(95,789)
19	Net Utility Plant	141,714	28,985	170,699	0	170,699
20	Accumulated Deferred FIT	(21,987)	(3,214)	(25,201)		(25,201)
21	Inventory and Other	5,137	(2,986)	2,151	0	2,151
22	TOTAL RATE BASE	$124,864	$22,785	$147,649	$0	$147,649
23	RATE OF RETURN	6.59%		3.30%		8.96%

AVISTA UTILITIES
Calculation of General Revenue Requirement
Oregon Natural Gas Jurisdiction
TWELVE MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	(000's of Dollars)
1	Forecasted Rate Base	$147,649
2	Proposed Rate of Return	8.960%
3	Net Operating Income Requirement	$13,229
4	Forecasted Net Operating Income	$4,870
5	Net Operating Income Deficiency	$8,359
6	Conversion Factor	0.58846
7	Revenue Requirement	$14,205
8	Total General Business Revenues	$122,803
9	Percentage Revenue Increase	11.6%

AVISTA UTILITIES
Calculation of Conversion Factor
Oregon Natural Gas Jurisdiction
TWELVE MONTHS ENDED DECEMBER 31, 2010

Line No.	Description		Factor
1	Revenues		1.000000
	Expense:		
2	Uncollectibles		0.006412
3	Commission Fees		0.002500
4	Energy Resource Supplier Assessment		0.000687
5	Franchise Fees		0.021097
6	Oregon Excise Tax		0.063974
6	Total Expense		0.094670
7	Net Operating Income Before FIT		0.905330
8	Federal Income Tax @	35.00%	0.316865
9	REVENUE CONVERSION FACTOR		0.588465

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON FORECASTED RESULTS — Blue = Done
TWELVE MONTHS ENDED DECEMBER 31, 2010 — Red = Not Done
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Per Results of Operations Report	Memberships & Dues Adj.	Salaries and Wages	Incentive Pay Adj.	Eliminate Pass-Thru Revenue	Uncollectible Expense	MISC Adj
	a	b	c	d	e	f	g	h
	REVENUES							
1	Total General Business	$128,123				$ (2,000)		
2	Total Transportation	2,391				(23)		
3	Other Revenues	67,985						
4	Total Gas Revenues	198,499	0	0	0	(2,023)	0	0
	EXPENSES							
5	Exploration and Development	0						
	Production							
6	City Gate Purchases	160,985						
7	Purchased Gas Expense	0						
8	Other Gas Expenses	544						
9	Depreciation	1						
10	Taxes	0						
11	Total Production	161,530	0	0	0	0	0	0
	Transmission							
12	Operating Expenses	0						
13	Depreciation	0						
14	Taxes	0						
15	Total Transmission	0	0	0	0	0	0	0
	Distribution							
16	Operating Expenses	5,328		19				
17	Depreciation	3,231						
18	Taxes	5,931				(2,023)		520
19	Total Distribution	14,490	0	19	0	(2,023)	0	520
20	Customer Accounting	2,865	0		0	0	317	0
21	Customer Service & Information	2,732						
22	Sales Expenses	128						
	Administrative & General							
23	Operating Expenses	7,006	(36)	(2)	(173)			
24	Depreciation & Amortization	93						
25	Taxes	0						
26	Total Admin. & General	7,099	(36)	(2)	(173)	0	0	0
27	Total Gas Expense	188,844	(36)	17	(173)	(2,023)	317	520
28	OPERATING INCOME BEFORE FIT	9,655	36	(17)	173	0	(317)	(520)
	FEDERAL INCOME TAX							
29	Current Accrual	236	12	(6)	57		(104)	(170)
30	Deferred FIT	1,346						
31	State Income Tax	(161)	2	(1)	11		(21)	(34)
32	NET OPERATING INCOME	$8,234	$22	($10)	$105	$0	($192)	($316)
	RATE BASE: PLANT IN SERVICE							
33	Production Plant	8						
34	Underground Storage Plant	5,061						
35	Transmission Plant	0						
36	Distribution Plant	208,465		$10				
37	General Plant	16,633						
38	Total Plant in Service	230,167	0	10	0	0	0	0
	ACCUMULATED DEPRECIATION							
39	Production Plant	0						
40	Underground Storage Plant	28						
41	Transmission Plant	0						
42	Distribution Plant	83,497						
43	General Plant	4,928						
44	Total Accum. Depreciation	88,453	0	0	0	0	0	0
45	DEFERRED FIT	(21,987)						
46	GAS INVENTORY	5,137						
47	TOTAL RATE BASE	$124,864	$0	$10	$0	$0	$0	$0
48	RATE OF RETURN	6.59%						

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Remove SB 408 Accrual	SIT - FIT Adjustment	Restate Debt Interest	Restated Total	Forecast Expense Adjustment	Forecast Revenue Adjustment	Forecast Labor & Benefits Adjustment
	a	i	j	k	-	F1	F2	F3
	REVENUES							
1	Total General Business	$442			$126,565		$ (6,148)	
2	Total Transportation	$38			2,406		(20)	
3	Other Revenues				67,985		(67,836)	
4	Total Gas Revenues	480	0	0	196,956	0	(74,004)	0
	EXPENSES							
5	Exploration and Development				0			
	Production							
6	City Gate Purchases				160,985		(71,958)	
7	Purchased Gas Expense				0			
8	Other Gas Expenses				544	59		42
9	Depreciation				1			
10	Taxes				0			
11	Total Production	0	0	0	161,530	59	(71,958)	42
	Transmission							
12	Operating Expenses				0	19		
13	Depreciation				0			
14	Taxes				0			
15	Total Transmission	0	0	0	0	19	0	0
	Distribution							
16	Operating Expenses				5,347	291		480
17	Depreciation				3,231			
18	Taxes				4,428		(130)	
19	Total Distribution	0	0	0	13,006	291	(130)	480
20	Customer Accounting	0	0	0	3,182		(40)	197
21	Customer Service & Information				2,732	1	(2,262)	7
22	Sales Expenses				128	(64)		
	Administrative & General							
23	Operating Expenses				6,795	403	(20)	399
24	Depreciation & Amortization	1,187			1,280			
25	Taxes				0			
26	Total Admin. & General	1,187	0	0	8,075	403	(20)	399
27	Total Gas Expense	1,187	0	0	188,653	709	(74,410)	1,125
28	OPERATING INCOME BEFORE FIT	(707)	0	0	8,303	(709)	406	(1,125)
	FEDERAL INCOME TAX							
29	Current Accrual		(202)	(206)	(383)	(232)	133	(368)
30	Deferred FIT	(247)	251		1,350			
31	State Income Tax		578	(36)	338	(47)	27	(74)
32	NET OPERATING INCOME	($460)	($627)	$242	$6,998	($430)	$246	($683)
	RATE BASE: PLANT IN SERVICE							
33	Production Plant				8			
34	Underground Storage Plant				5,061			
35	Transmission Plant				0			
36	Distribution Plant				208,475			
37	General Plant				16,633			
38	Total Plant in Service	0	0	0	230,177	0	0	0
	ACCUMULATED DEPRECIATION							
39	Production Plant				0			
40	Underground Storage Plant				28			
41	Transmission Plant				0			
42	Distribution Plant				83,497			
43	General Plant				4,928			
44	Total Accum. Depreciation	0	0	0	88,453	0	0	0
45	DEFERRED FIT				(21,987)			
46	GAS INVENTORY				5,137			
47	TOTAL RATE BASE	$0	$0	$0	$124,874	$0	$0	$0
48	RATE OF RETURN				5.60%			

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Forecast Property Tax Adjustment	Forecast Depreciation Adjustment	Forecast Capital Additions 2009 Adjustment	Forecast Capital Additions 2010 Adjustment	Forecast Inventory Adjustment	Forecasted Total
	a	F4	F5	F6	F7	F8	-
	REVENUES						
1	Total General Business						$120,417
2	Total Transportation						$2,386
3	Other Revenues						$149
4	Total Gas Revenues	0	0	0	0	0	122,952
	EXPENSES						
5	Exploration and Development						0
	Production						
6	City Gate Purchases						89,027
7	Purchased Gas Expense						0
8	Other Gas Expenses						645
9	Depreciation						1
10	Taxes	1					1
11	Total Production	1	0	0	0	0	89,674
	Transmission						
12	Operating Expenses						19
13	Depreciation						0
14	Taxes						0
15	Total Transmission	0	0	0	0	0	19
	Distribution						
16	Operating Expenses						6,118
17	Depreciation		81	263	268		3,843
18	Taxes	297		267	419		5,281
19	Total Distribution	297	81	530	687	0	15,242
20	Customer Accounting	0	0	0	0	0	3,339
21	Customer Service & Information	0				0	478
22	Sales Expenses	0				0	64
	Administrative & General						
23	Operating Expenses	0				0	7,577
24	Depreciation & Amortization	0	(20)	219	176	0	1,655
25	Taxes	19		47	41	0	107
26	Total Admin. & General	19	(20)	266	217	0	9,339
27	Total Gas Expense	317	61	796	904	0	118,155
28	OPERATING INCOME BEFORE FIT	(317)	(61)	(796)	(904)	0	4,797
	FEDERAL INCOME TAX						
29	Current Accrual	(104)	(20)	(260)	(295)		(1,529)
30	Deferred FIT						1,350
31	State Income Tax	(21)	(4)	(53)	(60)		106
32	NET OPERATING INCOME	($192)	($37)	($483)	($549)	$0	$4,870
	RATE BASE: PLANT IN SERVICE						
33	Production Plant						8
34	Underground Storage Plant						5,061
35	Transmission Plant						0
36	Distribution Plant			$17,818	$13,983		240,276
37	General Plant			$3,146	$1,364		21,143
38	Total Plant in Service	0	0	20,964	15,347	0	266,488
	ACCUMULATED DEPRECIATION						
39	Production Plant						0
40	Underground Storage Plant						28
41	Transmission Plant						0
42	Distribution Plant		4,968	117	139		88,721
43	General Plant		1,889	107	116		7,040
44	Total Accum. Depreciation	0	6,857	224	255	0	95,789
45	DEFERRED FIT		(2,411)	(408)	(395)		(25,201)
46	GAS INVENTORY					(2,986)	2,151
47	TOTAL RATE BASE	$0	($9,268)	$20,332	$14,697	($2,986)	$147,649
48	RATE OF RETURN						3.30%

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF TARA L. KNOX
REPRESENTING THE AVISTA CORPORATION

Long-Run Incremental Cost

INTRODUCTION

Q. Would you please state your name, business address and present position with Avista Corporation?

A. My name is Tara L. Knox. My business address is East 1411 Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation department.

Q. Would you briefly describe your responsibilities?

A. I am responsible for preparing data for and maintaining the regulatory cost of service models for the Company as well as providing support in the preparation of pro forma results of operations studies and miscellaneous other duties as required.

Q. Would you please describe your educational background?

A. I graduated from Washington State University with a Bachelor of Arts degree in General Humanities in 1982 and a Master of Accounting degree in 1990. As an employee in the rate department of Avista Corp (and WWP) since 1991, I have attended several rate-making classes, including the EEI Electric Rates Advanced Course which specializes in cost allocation and cost of service issues.

Q. Have you previously sponsored testimony in regulatory proceedings?

A. Yes. I have sponsored testimony before the Oregon, Washington and Idaho Commissions regarding cost of service.

Q. Would you please briefly summarize your testimony?

A. My testimony presents the cost of service study prepared for this filing. The results of the long-run incremental cost study indicate, that at current rates, on a relative margin to cost basis, residential customers are generally in line with relative cost of service, small commercial and seasonal customers are paying less than their relative cost of service, while large general, interruptible, and transportation customer groups exceed their relative cost of service to varying degrees.

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

A. Yes. I am sponsoring Exhibit No. 601, which is the Company's long-run incremental cost (LRIC) study and Exhibit No. 602, which shows the functional component classification of the Company's proposed revenue requirement in this case.

Q. Were these exhibits prepared by you?

A. Yes, they were.

LONG-RUN INCREMENTAL COST STUDY

Q. What is a long-run incremental cost study and what is its purpose?

A. A long-run incremental cost study is an engineering-economic study which estimates the incremental annual cost of providing natural gas service to customers segregated into groups according to their usage characteristics. In the Company's study, customers are grouped by rate schedule. When applied to current results of operations, the study indicates the adequacy of current rates compared to costs. The study results are used as one of the guidelines in determining the appropriate rate spread among rate schedules.

Q. What are the elements of the LRIC study?

A. The elements of the cost study include incremental plant investment, incremental operating and maintenance expenses, and the cost of gas supplied to a customer.

All of the information is accumulated in terms of cost per customer for an average or typical customer on each rate schedule.

Incremental Investment Costs

Q. What is included in incremental plant investment?

A. Plant investment required for a new customer includes a gas main extension to reach the customer, a service line to connect the customer to the main, and metering equipment at the customer's premises. The distribution system must be capable of meeting the combined peak needs of all customers at reliable pressure, so capacity reinforcement investment is required for new customer loads over the long term. Mandated safety and reliability requirements cause incremental costs to the distribution system for the benefit of all customers. Additionally, over the long run, all distribution facilities ultimately require replacement. These facilities provide both capacity and commodity for the benefit of all customers. The appropriate allocation of the Company's recent investment in underground storage (2008 expansion of Jackson Prairie) has also been included in the incremental investment cost analysis.

Q. Are these items identified in the cost study presented in this case?

A. Yes. Exhibit 601 page 3 shows the calculation of the 2010 cost per customer of the various investment costs included in this study. System core main investments have been categorized into capacity or commodity unit costs.

Q. How are new customer investment costs quantified in this study?

A. Typical main extensions are quantified in terms of the size and length of pipe recently provided for customers, multiplied by recent costs for each pipe size. A summary of the last three years of Oregon project work orders were used to identify the average length and typical size of pipe to serve different residential and small commercial customers. Interruptible and transportation customers, that have not had recent installations, were individually examined to determine average current cost of pipe that is dedicated to them. Special contract transportation customers, who have a feasible option to direct-connect to the interstate pipeline, were assigned the estimated bypass cost. For large general service customers on Schedule 424, a random sample comprising approximately 15% of the population was selected. Using the facilities mapping system and the in-service date of the mains, the length and size of apparent line extensions associated with the randomly selected customers were identified and current costs applied to determine the sample line extension cost per customer for this group, the resulting values were also used for the seasonal customers on Schedule 444.

Services were quantified by the size of pipe typically needed for the type of customer. For large general service, interruptible and transportation customers, the sample analysis and identified dedicated pipe was used to determine average current cost, similar to the main extension cost assignment.

Metering equipment was quantified by a weighted average current meter cost per customer. The weighted average captures the actual equipment types in service on each rate schedule priced at the 2008 average installed cost. For transportation customers, $1,000 was added to approximate the additional cost of telemetering equipment required for transportation service.

Q. You stated that system core main costs were simplified into capacity-related and commodity-related investments. Would you please explain what is included in these categories?

A. Yes. First, the Company's Oregon (non-revenue producing) distribution system investment projects were segregated into reinforcement projects versus safety and reliability projects based on the capital project categories described in Mr. DeFelice's testimony. A four-year average (2 years actual and 2 years budget) annual investment total was determined for the two types of projects. The reinforcement projects are considered capacity-related and therefore were divided by estimated Oregon total design day usage in therms. The safety and reliability projects are considered commodity-related and therefore were divided by annual therms. Long-run replacement cost was estimated by computing the current cost of all Oregon mains in service at 12/31/2008 by size and type. The current cost already accounted for by customer main extensions, reinforcement projects, and safety/reliability projects were deducted to determine remaining system replacement investment. The remaining value was segregated into capacity versus commodity by the 2008 peak and average ratio. The capacity portion was then divided by estimated Oregon total design day usage and the commodity portion was divided by annual therms.

Q. How was 2010 incremental capacity-related investment per customer quantified?

A. The sum of the investment per design day therm for reinforcement projects and the capacity-related portion of system replacement was divided by days in the year to arrive at a 100% load factor cost per therm shown on line 13 (Exhibit 601 page 3). This cost per therm has been adjusted for each rate schedule, based on the average estimated design day load factor for customers served under the schedule. Customers' design day load characteristics are the primary criteria associated with system capacity planning. The rate schedule cost per therm is then applied to average annual consumption per customer to get capacity main investment per customer for each schedule.

Q. How was 2010 incremental commodity-related main investment per customer quantified?

A. The investment per therm for safety and reliability projects and the commodity-related portion of system replacement are added together to determine the incremental commodity main investment per therm. This per therm cost is then multiplied by the average annual consumption per customer to get the capacity-related main investment per customer for each schedule.

Q. How was investment in underground storage facilities quantified?

A. The Oregon jurisdiction December 2008 underground storage plant balance was used to represent investment in underground storage facilities. The settlement in Docket No. UG-181 contained provisions for the assignment of costs associated with Oregon's share of the Jackson Prairie Storage expansion recognizing that storage provides benefits to customers both through the mitigation of gas commodity costs and pipeline balancing. The assignment was 86% sales commodity and 14% throughput (balancing). This relationship has been maintained in this cost study by determining the cost per therm based on throughput of 14% of the investment, and the cost per therm based on sales volumes of the remaining 86%

of the investment. These unit costs are then multiplied by the average use per customer to determine the investment per customer for each schedule.

Q. Exhibit 601 page 3 shows a "levelized plant cost factor" for each investment. What is the purpose of this factor?

A. The levelized plant cost factor is an annual carrying charge applied to plant investments. There is a different factor for services, meters, mains and underground storage based on different estimated lives.

Q. How are the levelized plant cost factors determined?

A. A "Revenue Requirement Model" is used to determine the levelized revenue requirement (annual cost) associated with incremental plant over the estimated life of the asset. The model accounts for all costs and expenses associated with owning and maintaining the asset.

<u>Operating Expenses</u>

Q. What is included in gas supply and customer service related incremental operating and maintenance expenses?

A. This category attempts to capture the current costs associated with gas scheduling and planning, meter reading, and billing customers.

Q. Are these items identified in the cost study presented in this case?

A. Yes. Exhibit 601 page 4 itemizes the various operating and maintenance expenses included in this study.

Q. Please explain the items shown on Exhibit 601 page 4.

A. Gas supply schedulers schedule and track all the natural gas being delivered at all delivery points on the system, including the gas owned by transportation customers. The majority of their time is spent for the benefit of core customers, however, transportation customers require individual attention. A proportion of their time devoted to providing services for transportation versus core customers was applied to the scheduler's hours charged to FERC Account 813 "Other Gas Expenses" during 2008, resulting in an estimate of the annual hours necessary for these services. The annual hours were then divided by the number of customers served to arrive at the hours per customer shown on page 4, line 1.

The long run cost of gas management planning was estimated by dividing the hours charged by gas planning staff to FERC Account 813 "Other Gas Expenses" during the test year by the number of gas customers served to arrive at the annual hours per customer shown on page 4, line 4.

Similarly, the hours dedicated to manually billing interruptible and transportation customers were divided by the number of customers billed to get the annual hours per customer for that function. The total hours charged to meter reading in 2008 were divided by the number of customers to determine the annual hours per customer spent on meter reading.

All of these labor hour estimates are then priced at the average direct labor charges per hour during 2008 to estimate the incremental cost per customer.

Finally, billing cost per customer has been estimated from the average annual cost per customer the Company has experienced in the Oregon service territory over the last five years.

<u>Cost of Gas Commodity</u>

Q. What is included in the cost of gas?

A. In this portion of the study, the cost of gas includes all of the items included in the gas cost deferral process. These include all of the commodity, demand, and upstream transportation charges the Company passes through to customers. The per therm rates shown on Exhibit 601, page 1, reflect the rates approved as a result of the most recent purchased gas adjustment (PGA) filing that went into effect November 1, 2008, grossed up for the revenue related expenses shown in Ms. Andrews revenue conversion factor.

Results Analysis

Q. Briefly describe what is shown on Exhibit 601 page 1 entitled "Result Summary Method I".

A. The first three lines present the pro forma rate year usage and customer statistics relevant to the study. The annual per customer and per therm results of all the cost items previously discussed are summarized to obtain total incremental costs, first on a per therm basis, then expanded to reflect the pro forma rate year usage on line 14. All items include revenue related expenses either through an after the fact gross up or embedded in the carrying charge on investment costs. The cost of gas is deducted on line 15 to result in long-run incremental distribution costs on line 16. The distribution cost relationship of the service schedules to the Oregon total is then used to allocate current and proposed total margins to service schedules. These allocated margin levels represent distribution "costs", based on the LRIC results.

Target margin values are shown on line 25 (LRIC Based Target Margin) that represent the margin revenue (including the proposed increase) required from each schedule that would be perfectly aligned with the cost study. A comparison of margin revenue provided by present rates with the LRIC Based Target Margin results in an Oregon Total margin to cost ratio (shown on line 21) of 0.69. These relationships are then restated in relation to one another on line 21A. Mr. Hirschkorn uses this Relative Margin to Cost at Present Rates as a guide to spread the proposed increase by service schedule.

Q. What is shown on Exhibit No. 601, Page 2 entitled "Result Summary Method II"?

A. This is a second result summary in which the Long Run Incremental Costs are applied to the Company revenue requirement by a more complex method. The first three lines are the same as the first summary showing the pro forma rate year usage and customer statistics relevant to the study. The next section shows the pro forma rate year incremental costs for each component in the study. The Long Run Incremental Distribution Cost on Line 17 is the sum of all the components (except gas commodity costs) and is directly comparable with the values on Line 16 of Result Summary Method I.

Q. What is shown in the next section?

A. The next section brings in the Company revenue requirement segregated into components comparable with the LRIC components shown above. Each component cost is then assigned to the rate schedules based on the LRIC results for the equivalent component. Once all of the components have been assigned, the results for each schedule are summed to produce the LRIC Based Target Margin on line 27. Following this are the resulting Present Margin to Target Margin ratios stated both in the absolute (Line 29) and on a relative basis (Line 29A). On line 28, I also included a comparison of Total Present Revenue to Total Proposed Cost which includes the cost of gas in both the numerator and denominator.

Q. Where did the revenue requirement components come from?

A. Exhibit No. 602 shows how the pro forma results of operations, including the requested revenue increase from Ms. Andrews Exhibit No. 501, have been assigned to the functional component classifications used in the cost of service.

Q. Why have you prepared two different sets of results?

A. The first result summary presents the margin assignment by the single allocation method which the Company has utilized in previous cases. During the settlement process in the last general rate case in Oregon (Docket No. UG-181), Commission staff provided alternative presentations of the results where all the components of the long-run incremental cost study were stated at the full pro forma level. This presentation allowed for the relationships among the component parts to be used in their analysis and recommendations. The component assignment result summary I have proposed in Method II takes Staff analysis one step further by weighting the LRIC components by the related components of Company's proposed revenue requirement in developing the target margin revenue. This provides a more refined target margin than the method employed in past cases.

I am presenting both methods so that Mr. Hirschkorn may consider the rate spread implications of both the way it has been done before, and the more complex new method.

Q. What are the results of the Company's LRIC study under both Method I and Method II?

A. The following table shows the relative margin-to-cost ratio at present rates for each rate schedule under Method I (Single Allocation) and Method II (Component Allocation):

Table 1 Long Run Incremental Cost Study

Customer Class	Method I Single Allocation Relative Margin-to-Cost	Method II Component Allocation Relative Margin-to-Cost
	Present Rates	Present Rates
Residential Service Schedule 410	1.06	0.98
General Service Schedule 420	0.82	0.92
Large General Service Schedule 424	1.11	1.25
Interruptible Sales Service Schedule 440	1.39	1.54
Seasonal Sales Service 444	0.74	0.79
Special Contracts Schedule 447	0.94	1.16
Transportation Service Schedule 456	1.22	1.46
Total Oregon Gas	1.00	1.00

The present relative margin-to-cost ratios indicate that, under both methods, general service (primarily commercial) customers on Schedule 420 and seasonal service customers on Schedule 444 are paying somewhat less than their relative cost of service, while large general (Schedule 424), interruptible (Schedule 440), and transportation (Schedule 456) service customers are paying somewhat more than their relative cost of service. Residential service customers on Schedule 410 are not far from parity under either method, but are slightly over relative cost of service using Method 1 and slightly under relative cost of service using Method II. The summary results of this study were provided to Mr. Hirschkorn as an input into development of the proposed rates.

Q. Please summarize your testimony regarding cost of service.

A. I have provided a long-run incremental cost study by service schedule for the Company's Oregon jurisdiction. The study incorporates the essential elements of providing service to customers over the long term. As a guideline for the proposed rate spread, the study indicates that it would be reasonable for small general service customers on Schedule 420 and seasonal customers on Schedule 444 to receive a somewhat larger percentage increase than other customer groups, and large general service, interruptible service, and transportation customers on Schedules 424, 440 and 456 to receive a smaller percentage increase than other customer groups.

Q. Does this conclude your pre-filed, direct testimony?

A. Yes, it does.

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2010

RESULT SUMMARY METHOD I *(Single 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	TOTAL ANNUAL THERM DELIVERIES	116,602,381	49,542,068	27,280,991	4,082,190	5,776,303	184,605	3,135,262	26,600,962
2	2010 AVERAGE CUSTOMERS	95,697	84,314	11,208	98	30	8	5	34
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		588	2,434	41,655	192,543	23,076	627,052	782,381
			49	203	3,471	16,045	1,923	52,254	65,198
	INCREMENTAL NON-COMMODITY COSTS PER CUSTOMER								
4	INVESTMENT COSTS (Levelized rate includes Taxes & Revenue Related Expenses)		$356.85	$1,243.70	$7,383.18	$19,922.59	$5,143.94	$141,504.37	$78,155.38
5	GAS SUPPLY O&M (Grossed up for Revenue Related Expenses)	1.03167	$1.93	$1.93	$1.93	$35.15	$1.93	$741.37	$741.37
6	CUST0MER O&M (Grossed up for Revenue Related Expenses)	1.03167	$21.80	$21.82	$21.82	$96.32	$21.82	$96.32	$96.32
7	TOTAL NON-COMMODITY COST PER CUSTOMER		$380.58	$1,267.46	$7,406.94	$20,054.06	$5,167.70	$142,342.06	$78,993.08
8	TOTAL NON-COMMODITY COST PER THERM		$0.64770	$0.52072	$0.17782	$0.10415	$0.22395	$0.22700	$0.10096
	INCREMENTAL COMMODITY COSTS PER THERM								
9	COMMODITY COST (Grossed up for Revenue Related Expenses)	1.03167	$0.85670	$0.85670	$0.85670	$0.85670	$0.85670		
10	DEMAND COST (Grossed up for Revenue Related Expenses)	1.03167	$0.23085	$0.23085	$0.23085	$0.00000	$0.23085		
11	AMORTIZATION RATE/THERM (Grossed up for Revenue Related Expenses	1.03167	($0.01159)	($0.01278)	($0.01278)	($0.05423)	($0.01278)		
12	TOTAL COMMODITY COSTS PER THERM		$1.07596	$1.07476	$1.07476	$0.80246	$1.07476	$0.00000	$0.00000
13	TOTAL INCREMENTAL COSTS PER THERM		$1.72366	$1.59548	$1.25258	$0.90662	$1.29871	$0.22700	$0.10096
14	LONG-RUN INCREMENTAL COST	$ 142,907,508	$ 85,393,840	$ 43,526,283	$ 5,113,266	$ 5,236,896	$ 239,748	$ 711,710	$ 2,685,765
15	COST OF GAS	$ 91,846,926	$ 53,305,263	$ 29,320,596	$ 4,387,386	$ 4,635,274	$ 198,407	$ -	$ -
16	LONG-RUN INCREMENTAL DISTRIBUTION COST	$ 51,060,582	$ 32,088,577	$ 14,205,687	$ 725,880	$ 601,622	$ 41,341	$ 711,710	$ 2,685,765
	16A CLASS COST AS PERCENT OF TOTAL COST	100.00%	62.84%	27.82%	1.42%	1.18%	0.08%	1.39%	5.26%
17	CURRENT REVENUE	$ 122,802,190	$ 73,836,744	$ 36,342,651	$ 4,876,152	$ 5,143,278	$ 217,070	$ 403,670	$ 1,982,625
18	COST OF GAS	$ 91,846,926	$ 53,305,263	$ 29,320,596	$ 4,387,386	$ 4,635,274	$ 198,407	$ -	$ -
19	CURRENT MARGIN	$ 30,955,264	$ 20,531,481	$ 7,022,055	$ 488,766	$ 508,004	$ 18,663	$ 403,670	$ 1,982,625
	19A CURRENT MARGIN IN $ PER THERM	$ 0.265477	$ 0.414425	$ 0.257397	$ 0.119731	$ 0.087946	$ 0.101097	$ 0.128752	$ 0.074532
20	RELATIVE CURRENT COST (*Current Margin Allocated by Line 16A LRIDC*)	$ 30,955,264	$ 19,453,565	$ 8,612,138	$ 440,062	$ 364,731	$ 25,063	$ 431,471	$ 1,628,234
	20A CURRENT COST IN $ PER THERM	$ 0.265477	$ 0.392668	$ 0.315683	$ 0.107800	$ 0.063143	$ 0.135765	$ 0.137619	$ 0.061210
21	MARGIN TO COST RATIO at PRESENT RATES (Line 19 ÷ Line 25)	**0.69**	**0.72**	**0.56**	**0.76**	**0.95**	**0.51**	**0.64**	**0.83**
	21A **Relative Margin to Cost at Present Rates**	**1.00**	**1.06**	**0.82**	**1.11**	**1.39**	**0.74**	**0.94**	**1.22**
22	MARGIN LESS RELATIVE COST @ PRESENT RATES *(Line 19 - Line 20)*	$ -	$ 1,077,916	$ (1,590,083)	$ 48,704	$ 143,273	$ (6,400)	$ (27,801)	$ 354,391
	22A MARGIN LESS COST @ PRESENT RATES IN $ PER THERM	$ -	$ 0.022	$ (0.058)	$ 0.012	$ 0.025	$ (0.035)	$ (0.009)	$ 0.013
23	TOTAL DISTRIBUTION LRIC TARGET REVENUE INCREASE BY SCHEDULE	$ 14,205,000	$ 7,849,093	$ 5,542,090	$ 153,235	$ 24,097	$ 17,901	$ 225,798	$ 392,786
24	PROPOSED MARGIN at UNITY	$ 45,160,264	$ 28,380,574	$ 12,564,145	$ 642,001	$ 532,101	$ 36,564	$ 629,468	$ 2,375,411
	24A PROPOSED MARGIN IN $ PER THERM	$ 0.387301	$ 0.572858	$ 0.460546	$ 0.157269	$ 0.092118	$ 0.198065	$ 0.200771	$ 0.089298
25	**LRIC BASED TARGET MARGIN (*Proposed Margin Allocated by Line16A LRIDC***	**$ 45,160,264**	**$ 28,380,574**	**$ 12,564,145**	**$ 642,001**	**$ 532,101**	**$ 36,564**	**$ 629,468**	**$ 2,375,411**
	25A PROPOSED COST IN $ PER THERM	$ 0.387301	$ 0.572858	$ 0.460546	$ 0.157269	$ 0.092118	$ 0.198065	$ 0.200771	$ 0.089298
26	PROPOSED MARGIN TO COST RATIO (Line 24 ÷ Line 25) NOT USED	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
27	TARGET INCREASE AS PERCENT OF TOTAL PRESENT REVENUE	11.57%	10.63%	15.25%	3.14%	0.47%	8.25%	55.94%	19.81%
27A	TARGET INCREASE AS PERCENT OF CURRENT MARGIN	45.89%	38.23%	78.92%	31.35%	4.74%	95.92%	55.94%	19.81%

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2010

RESULT SUMMARY METHOD II *(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	2010 ANNUAL THERM DELIVERIES		116,602,381	49,542,068	27,280,991	4,082,190	5,776,303	184,605	3,135,262	26,600,962
2	2010 AVERAGE CUSTOMERS		95,697	84,314	11,208	98	30	8	5	34
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER			588	2,434	41,655	192,543	23,076	627,052	782,381
4	Gas Commodity Costs		91,846,926	53,305,263	29,320,596	4,387,386	4,635,274	198,407	-	-
5	Gas Scheduling	1.03167	80,332	44,491	5,914	52	1,012	4	3,700	25,159
6	Gas Planning		134,554	118,549	15,759	138	42	11	7	48
7	Meter Reading		86,617	74,414	10,100	88	873	7	146	989
8	Billing		2,005,393	1,764,040	234,497	2,050	2,017	167	336	2,286
	Customer Installation Investment Cost									
9	Meters		2,851,075	1,911,720	783,711	46,406	22,287	4,169	22,544	60,238
10	Services		6,564,592	5,658,319	745,532	28,376	33,874	2,316	9,740	86,433
11	Main Extensions		27,339,611	16,878,482	9,423,476	306,172	72,798	24,994	479,807	153,883
12	Total Customer Installation Investment Cost		36,755,279	24,448,521	10,952,719	380,954	128,959	31,479	512,091	300,554
	System Core Main Cost									
13	Capacity		6,181,166	3,040,912	1,557,303	128,704	166,060	-	62,163	1,226,025
14	Commodity		4,817,860	2,047,849	1,126,859	168,622	238,600	7,626	129,507	1,098,798
15	Total Core Main Cost		10,999,027	5,088,760	2,684,161	297,326	404,660	7,626	191,670	2,324,823
16	Underground Storage Cost		999,381	549,801	302,536	45,271	64,059	2,047	3,760	31,905
17	Long Run Incremental Distribution Cost		51,060,582	32,088,577	14,205,687	725,880	601,622	41,342	711,710	2,685,765
18	Revenue at Present Rates		122,803,000	73,837,000	36,343,000	4,876,000	5,143,000	217,000	404,000	1,983,000
19	**Margin Revenue at Present Rates**		**30,956,000**	**20,531,694**	**7,022,380**	**488,610**	**507,722**	**18,593**	**404,000**	**1,983,000**
	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components									
20	Cost of Gas Commodity		91,847,000	53,305,306	29,320,620	4,387,390	4,635,278	198,407	-	-
21	Scheduling and Planning Costs		665,000	504,554	67,071	586	3,263	48	11,471	78,006
22	Meter Reading, Billing, Etc. Costs		3,192,000	2,805,122	373,207	3,263	4,409	266	735	4,997
23	Meters & Services Costs		15,071,000	12,116,832	2,447,753	119,699	89,894	10,380	51,676	234,766
24	System Core Main Costs		25,118,000	14,392,092	7,932,458	395,389	312,812	21,371	439,926	1,623,953
25	Underground Storage Costs		1,115,000	613,409	337,537	50,509	71,470	2,284	4,195	35,596
26	Proposed Cost		137,008,000	83,737,315	40,478,646	4,956,836	5,117,125	232,757	508,003	1,977,319
27	**LRIC Based Target Margin**		**45,161,000**	**30,432,009**	**11,158,026**	**569,446**	**481,847**	**34,349**	**508,003**	**1,977,319**
28	Current Revenue to Proposed Cost (Includes Cost of Gas)		**0.90**	**0.88**	**0.90**	**0.98**	**1.01**	**0.93**	**0.80**	**1.00**
29	Current Margin Revenue to LRIC Based Target Margin		**0.69**	**0.67**	**0.63**	**0.86**	**1.05**	**0.54**	**0.80**	**1.00**
	29A **Relative Margin to Cost at Present Rates**		**1.00**	**0.98**	**0.92**	**1.25**	**1.54**	**0.79**	**1.16**	**1.46**
30	Component LRIC Target Increase by Schedule		$ 14,205,000	$ 9,900,315	$ 4,135,646	$ 80,836	$ (25,875)	$ 15,757	$ 104,003	$ (5,681)
31	Target Increase as Percent of Total Present Revenue		11.57%	13.41%	11.38%	1.66%	-0.50%	7.26%	25.74%	-0.29%
	31A Target Increase as Percent of Present Margin Revenue		45.89%	48.22%	58.89%	16.54%	-5.10%	84.75%	25.74%	-0.29%

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2010

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	50 yr life							
1	TYPICAL SERVICE PIPE SIZE		3/4"	3/4"	1 1/4" - 2"	1/2" - 1.25"	1 1/4" - 2"	1/2" - 1.25"	1/2" - 1.25"
2	AVERAGE SERVICE COST		$ 339.97	$ 336.97	$ 1,466.84	$ 5,720.09	$ 1,466.84	$ 9,868.57	$ 12,878.17
3	LEVELIZED PLANT COST FACTOR		0.1974	0.1974	0.1974	0.1974	0.1974	0.1974	0.1974
4	ANNUAL REVENUE REQUIREMENT		$ 67.11	$ 66.52	$ 289.55	$ 1,129.15	$ 289.55	$ 1,948.06	$ 2,542.15
	METERS & REGULATORS	45 yr life							
5	METERS & REGULATORS		$ 114.63	$ 353.51	$ 2,393.99	$ 3,755.82	$ 2,634.35	$ 22,795.08	$ 8,957.06
6	LEVELIZED PLANT COST FACTOR		0.1978	0.1978	0.1978	0.1978	0.1978	0.1978	0.1978
7	ANNUAL REVENUE REQUIREMENT		$ 22.67	$ 69.92	$ 473.53	$ 742.90	$ 521.07	$ 4,508.87	$ 1,771.71
	MAIN INVESTMENT	70 yr life							
8	AVERAGE MAIN EXTENSION PER CUSTOMER		70	294	1164	619	1164	Estimated	866
9	TYPICAL PIPE SIZE REQUIRED		2 "	2 "	sample	dedicated plt	same as 424	Bypass Cost	dedicated plt
10	AVERAGE COST PER FOOT 2006		14.48	14.48	13.59	$ 19.85	13.59		$ 26.46
11	MAIN EXTENSION INVESTMENT		$ 1,013.60	$ 4,257.12	$ 15,818.76	$ 12,286.51	$ 15,818.76	$ 485,880.00	$ 22,916.35
12	ESTIMATED DESIGN DAY LOAD FACTOR	100%	24.03%	25.82%	46.75%	51.27%	0.00%	74.34%	31.98%
13	INCR CAPACITY MAIN INVESTMENT PER THERM	0.074630	$ 0.310570	$ 0.289040	$ 0.159636	$ 0.145563	$ -	$ 0.100390	$ 0.233365
14	2010 AVERAGE THERMS PER CUSTOMER		588	2,434	41,655	192,543	23,076	627,052	782,381
15	CAPACITY MAIN INVESTMENT		$ 182.62	$ 703.52	$ 6,649.65	$ 28,027.08	$ -	$ 62,949.81	$ 182,580.03
16	INCR COMMODITY MAIN INVESTMENT PER THERM		0.209148	$ 0.209148	$ 0.209148	$ 0.209148	$ 0.209148	$ 0.209148	$ 0.209148
17	2010 AVERAGE THERMS PER CUSTOMER		588	2,434	41,655	192,543	23,076	627,052	782,381
18	SAFETY MAIN INVESTMENT		$ 122.98	$ 509.07	$ 8,712.06	$ 40,269.98	$ 4,826.30	$ 131,146.67	$ 163,633.42
19	TOTAL MAIN INVESTMENT PER CUSTOMER		$ 1,319.19	$ 5,469.71	$ 31,180.47	$ 80,583.57	$ 20,645.06	$ 679,976.48	$ 369,129.80
20	LEVELIZED PLANT COST FACTOR		0.1975	0.1975	0.1975	0.1975	0.1975	0.1975	0.1975
21	ANNUAL REVENUE REQUIREMENT		$ 260.54	$ 1,080.27	$ 6,158.14	$ 15,915.26	$ 4,077.40	$ 134,295.36	$ 72,903.14
	UNDERGROUND STORAGE INVESTMENT								
22	BALANCING INVESTMENT PER THROUGPUT THERM		$ 0.006076	$ 0.006076	$ 0.006076	$ 0.006076	$ 0.006076	$ 0.006076	$ 0.006076
23	STORAGE INVESTMENT PER SALES THERM		$ 0.050104	$ 0.050104	$ 0.050104	$ 0.050104	$ 0.050104		
24	2010 AVERAGE THERMS PER CUSTOMER		588	2,434	41,655	192,543	23,076	627,052	782,381
25	UNDERGROUND STORAGE INVESTMENT		$ 33.03	$ 136.74	$ 2,340.18	$ 10,817.07	$ 1,296.41	$ 3,809.97	$ 4,753.75
26	LEVELIZED PLANT COST FACTOR	50 yr life	0.1974	0.1974	0.1974	0.1974	0.1974	0.1974	0.1974
27	ANNUAL REVENUE REQUIREMENT		$ 6.52	$ 26.99	$ 461.95	$ 2,135.29	$ 255.91	$ 752.09	$ 938.39
28	**TOTAL INCREMENTAL INVESTMENT COST PER CUSTOMER**		**$ 356.85**	**$ 1,243.70**	**$ 7,383.18**	**$ 19,922.59**	**$ 5,143.94**	**$ 141,504.37**	**$ 78,155.38**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2010

INCREMENTAL OPERATING AND MAINTENANCE 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
	GAS MANAGEMENT (SCHEDULING)							
1	ANNUAL HOURS	0.01399	0.01399	0.01399	1.01399	0.01399	17.97727	17.97727
2	AVERAGE RATE PER HOUR	$ 35.86	$ 35.86	$ 35.86	$ 35.86	$ 35.86	$ 35.86	$ 35.86
3	LABOR COST	$ 0.51148	$ 0.51148	$ 0.51148	$ 32.70612	$ 0.51148	$ 717.24772	$ 717.24772
	GAS MANAGEMENT (PLANNING)							
4	ANNUAL HOURS	0.029908	0.029908	0.029908	0.029908	0.029908	0.029908	0.029908
5	AVERAGE RATE PER HOUR	$ 56.97	$ 56.97	$ 56.97	$ 56.97	$ 56.97	$ 56.97	$ 56.97
6	LABOR COST	$ 1.36288	$ 1.36288	$ 1.36288	$ 1.36288	$ 1.36288	$ 1.36288	$ 1.36288
7	**TOTAL GAS SUPPLY O&M**	**$ 1.87**	**$ 1.87**	**$ 1.87**	**$ 34.07**	**$ 1.87**	**$ 718.61**	**$ 718.61**
	METER READING							
8	ANNUAL HOURS	0.04233	0.04322	0.04322	0.96203	0.04322	0.96203	0.96203
9	AVERAGE RATE PER HOUR	$ 20.21	$ 20.21	$ 20.21	$ 29.32	$ 20.21	$ 29.32	$ 29.32
10	LABOR COST	$ 0.85549	$ 0.87348	$ 0.87348	$ 28.20672	$ 0.87348	$ 28.20672	$ 28.20672
	CUSTOMER HANDBILLS							
11	ANNUAL HOURS	0.00000	0.00000	0.00000	2.03354	0.00000	2.03354	2.03354
12	AVERAGE RATE PER HOUR	$ -	$ -	$ -	$ 22.07	$ -	$ 22.07	$ 22.07
13	LABOR COST	$ -	$ -	$ -	$ 44.88	$ -	$ 44.88	$ 44.88
	BILLING							
14	ANNUAL POSTAGE PER CUST	$ 3.39	$ 3.39	$ 3.39	$ 3.39	$ 3.39	$ 3.39	$ 3.39
15	5 YR AVERAGE PER CUST	$ 16.89	$ 16.89	$ 16.89	$ 16.89	$ 16.89	$ 16.89	$ 16.89
16	BILLING COST	$ 20.28	$ 20.28	$ 20.28	$ 20.28	$ 20.28	$ 20.28	$ 20.28
17	**TOTAL CUSTOMER O&M**	**$ 21.14**	**$ 21.15**	**$ 21.15**	**$ 93.37**	**$ 21.15**	**$ 93.37**	**$ 93.37**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2010

RESULT SUMMARY

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 Contrac Service SCH 447	Transportation Service SCH 456
	STATISTICS									
1	2010 ANNUAL THERM DELIVERIES		116,602,381	49,542,068	27,280,991	4,082,190	5,776,303	184,605	3,135,262	26,600,962
2	2010 AVERAGE CUSTOMERS		95,697	84,314	11,208	98	30	8	5	34
3	: ANNUAL THERM DELIVERIES PER CUSTOMER			588	2,434	41,655	192,543	23,076	627,052	782,381
	Gas Scheduling	1.03167	80,332	44,491	5,914	52	1,012	4	3,700	25,159
	Gas Planning		134,554	118,549	15,759	138	42	11	7	48
	Meter Reading		86,617	74,414	10,100	88	873	7	146	989
	Billing		2,005,393	1,764,040	234,497	2,050	2,017	167	336	2,286
	Customer Installation Investment Cost									
	Meters		2,851,075	1,911,720	783,711	46,406	22,287	4,169	22,544	60,238
	Services		6,564,592	5,658,319	745,532	28,376	33,874	2,316	9,740	86,433
	Main Extensions		27,339,611	16,878,482	9,423,476	306,172	72,798	24,994	479,807	153,883
	Total Customer Installation Investment Cost		36,755,279	24,448,521	10,952,719	380,954	128,959	31,479	512,091	300,554
	System Core Main Cost									
	Capacity		6,181,166	3,040,912	1,557,303	128,704	166,060	-	62,163	1,226,025
	Commodity		4,817,860	2,047,849	1,126,859	168,622	238,600	7,626	129,507	1,098,798
	Total Core Main Cost		10,999,027	5,088,760	2,684,161	297,326	404,660	7,626	191,670	2,324,823
	Underground Storage Cost		999,381	549,801	302,536	45,271	64,059	2,047	3,760	31,905
	Long Run Incremental Distribution Cost		51,060,582	32,088,577	14,205,687	725,880	601,622	41,342	711,710	2,685,765
	Monthly LRIC Distribution Cost per Customer		$ 44.46	$ 31.72	$ 105.62	$ 617.24	$ 1,671.17	$ 430.64	$ 11,861.84	$ 6,582.76
	Non-Commodity Revenue at Present Rates		30,955,264	20,531,481	7,022,055	488,766	508,004	18,663	403,670	1,982,625
	Current Non-Commodity Revenue/ Distribution LRIC		0.61	0.64	0.49	0.67	0.84	0.45	0.57	0.74
	Monthly Factor Costs per Customer									
	Gas Scheduling		$ 0.07	$ 0.04	$ 0.04	$ 0.04	$ 2.81	$ 0.04	$ 61.66	$ 61.66
	Gas Planning		$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.12
	Meter Reading		$ 0.08	$ 0.07	$ 0.08	$ 0.08	$ 2.43	$ 0.08	$ 2.43	$ 2.43
	Billing		$ 1.75	$ 1.74	$ 1.74	$ 1.74	$ 5.60	$ 1.74	$ 5.60	$ 5.60
	Meter Installations		$ 2.48	$ 1.89	$ 5.83	$ 39.46	$ 61.91	$ 43.42	$ 375.74	$ 147.64
	Service Installations		$ 5.72	$ 5.59	$ 5.54	$ 24.13	$ 94.10	$ 24.13	$ 162.34	$ 211.85
	Main Extensions		$ 23.81	$ 16.68	$ 70.07	$ 260.35	$ 202.22	$ 260.35	$ 7,996.78	$ 377.16
	System Core Mains		$ 9.58	$ 5.03	$ 19.96	$ 252.83	$ 1,124.06	$ 79.43	$ 3,194.50	$ 5,698.10
	Underground Storage		$ 0.87	$ 0.54	$ 2.25	$ 38.50	$ 177.94	$ 21.33	$ 62.67	$ 78.20
	Total		$ 44.46	$ 31.72	$ 105.62	$ 617.24	$ 1,671.17	$ 430.64	$ 11,861.84	$ 6,582.76
	Monthly Narrow Customer Costs		$ 10.02	$ 9.30	$ 13.19	$ 65.41	$ 164.03	$ 69.37	$ 546.10	$ 367.52
	Monthly Other Distribution Cost per Customer		$ 34.44	$ 22.42	$ 92.43	$ 551.84	$ 1,507.14	$ 361.27	$ 11,315.73	$ 6,215.24

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

Compute Functional Revenue Requirement

FUNCTIONAL CLASSIFICATION

Line No.	DESCRIPTION		Forecasted Total	Cost of Gas Commodity	Scheduling and Planning Costs	Meter Reading Billing, Etc Costs	Meters & Services Costs	System Core Main Costs	Underground Storage Costs
	a		-						
	REVENUES								
1	Revenue From Rates		$122,803	91,847	665	3,192	15,071	25,118	1,115
2	Proposed Increase		14,205						
3	Other Revenues		149				149		
4	Total Gas Revenues		137,157	91,847	665	3,192	15,220	25,118	1,115
	EXPENSES								
5	Exploration and Development		0						
	Production								
6	City Gate Purchases		89,027	89,027					
7	Purchased Gas Expense		0						
8	Other Gas Expenses		645		645				
9	Depreciation		1						1
10	Taxes		1						1
11	Total Production		89,674	89,027	645	0	0	0	2
	Underground Storage								
12	Operating Expenses		19						19
13	Depreciation		0						0
14	Taxes		0						0
15	Total Underground Storage		19	0	0	0	0	0	19
	Distribution								
16	Operating Expenses		6,118				2,352	3,766	
17	Depreciation		3,843				1,843	2,000	
18	Taxes		2,690				1,034	1,656	
19	Total Distribution		12,651	0	0	0	5,229	7,422	0
20	Customer Accounting		2,552			2,552			
21	Customer Service & Information		478			478			
22	Sales Expenses		64			64			
	Administrative & General								
23	Operating Expenses		7,186				2,705	4,333	148
24	Depreciation & Amortization		1,655				623	998	34
25	Taxes		107				40	65	2
26	Total Admin. & General		8,948	0	0	0	3,368	5,396	184
	Reveue Related Expenses								
	20 Uncollectibles	0.006412	878	589	4	20	97	161	7
	23 Commission Fees	0.002500	343	230	2	8	38	63	3
	23 ERSA	0.000687	94	63	0	2	10	17	1
	18 Franchise Fees	0.021097	2,891	1,938	14	67	318	530	24
27	Total Gas Expense	0.030696	118,592	91,847	665	3,192	9,060	13,589	239
28	OPERATING INCOME BEFORE FIT		18,565	0	0	0	6,160	11,529	876
	FEDERAL INCOME TAX								
29	Current and Deferred FIT		(179)	-	-	-	(59)	(111)	(8)
30	FIT on Revenue Increase	0.316865	4,501	-	-	-	1,493	2,795	212
31	State Income Tax		106	-	-	-	35	66	5
	SIT on Revenue Increase	0.063974	909	-	-	-	302	564	43
32	NET OPERATING INCOME		$13,228	$0	$0	$0	$4,389	$8,214	$624
	Interest Expense	3.30%	4,872	0	0	0	1,617	3,026	230
	RATE BASE: PLANT IN SERVICE								
33	Production Plant		8						8
34	Underground Storage Plant		5,061						5,061
35	Transmission Plant		0						
36	Distribution Plant		240,276				92,364	147,912	
37	General Plant		21,143				7,960	12,746	437
38	Total Plant in Service		266,488	0	0	0	100,324	160,658	5,506
	ACCUMULATED DEPRECIATION								
39	Production Plant		0						0
40	Underground Storage Plant		28						28
41	Transmission Plant		0						
42	Distribution Plant		88,721				39,198	49,523	
43	General Plant		7,040				2,650	4,244	145
44	Total Accum. Depreciation		95,789	0	0	0	41,848	53,767	173
45	DEFERRED FIT		(25,201)				(9,487)	(15,193)	(521)
46	GAS INVENTORY		2,151						2,151
47	TOTAL RATE BASE		$147,649	$0	$0	$0	$48,989	$91,698	$6,963
48	RATE OF RETURN		8.96%	#DIV/0!	#DIV/0!	#DIV/0!	8.96%	8.96%	8.96%

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF BRIAN J. HIRSCHKORN
REPRESENTING THE AVISTA CORPORATION

Revenue Adjustment, Rate Spread, and Rate Design

INTRODUCTION

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

A. My name is Brian J. Hirschkorn and my business address is East 1411 Mission Avenue, Spokane, Washington. My present position is Manager of Retail Pricing.

Q. Would you describe your responsibilities in your position as Manager of Retail Pricing?

A. My primary areas of responsibility include electric and gas rate design, special contract pricing, customer usage and revenue analysis, PGA filing oversight, and tariff administration.

Q. Would you briefly describe your educational background?

A. I graduated from Washington State University in 1978 with Bachelor degrees in Business Administration and Accounting.

Q. Have you previously testified before other state commissions?

A. Yes. I have testified before the Washington & Idaho Commissions in numerous rate proceedings as a revenue and rate design witness.

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

A. My testimony in this proceeding will cover the spread of the proposed annual margin/revenue increase among the Company's gas service schedules as well as the application of the increase to the rates within each of the schedules. I will also briefly discuss changes seen in customer natural gas usage since 2006.

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

A. Yes. I am sponsoring Exhibit Nos. 701, 702 and 703, which were prepared under my supervision and direction.

Q. Would you please explain what is contained in Exhibit No. 701 and 702?

A. Exhibit No. 701 contains the present natural gas rates and schedules which are on file with the Commission as a part of our present tariff, PUC OR. No. 5. Exhibit No. 702 contains the proposed natural gas rates and schedules which reflect the proposed annual revenue increase of $14,205,000.

Q. Could you please explain what is contained in Exhibit No. 703?

A. Exhibit No. 703 contains information regarding the proposed rate spread and rate design of the proposed annual revenue increase of $14,205,000. Page 1 shows customer usage information by service schedule for 2006 (Company's last test year/general filing), 2008 and forecasted for 2010. Page 2 shows the application of the overall revenue/margin increase by service schedule and the cost of service results before and after application of the proposed increase. Page 3 shows the proposed revenue and percentage increase by service schedule. Page 4 shows the present billing rates under each of the schedules, the proposed changes to those rates, and the rates after application of the proposed changes. The information contained in these pages will be referred to and discussed later in my testimony.

REVENUE ADJUSTMENT AND CUSTOMER USAGE

Q. Would you please describe the Revenue Adjustment?

A. Yes. The Revenue Adjustment represents the difference between the Company's actual recorded retail revenues during 2008 and forecasted revenue for 2010. Forecasted revenue for 2010 is based on projected customer usage and number of customers from the Company's most recent forecast applied to the present natural gas rates in effect. The Revenue Adjustment also contains an adjustment for purchased gas costs, which represents the difference between actual recorded gas costs during 2008 and “pro forma” gas costs for 2010. Pro forma gas costs for 2010 were determined using forecasted 2010 customer usage applied to the gas costs reflected in present rates, as approved by the Commission in UG 182 (Company's most recent PGA filing).

Q. You mentioned that projected customer usage for 2010 was taken from the Company's most recent financial forecast. Could you please explain?

A. Yes. The Company’s forecast is updated periodically throughout the year to include the most recent actual results and for significant changes in the assumptions included in the forecast. The most recent forecast update was in May (2009) which included actual customer usage through March 2009 and an estimated PGA decrease in the fall of 2009.

Q. Did the Company utilize projected usage from this forecast for all schedules/customer classes?

A. Projected customer usage from the forecast was used for all sales schedules and actual 2008 usage was used for transportation schedules (447 and 456). One adjustment was made for a large customer that switched from transportation to interruptible sales service during 2008.

Q. How does projected 2010 customer usage compare to (weather-normalized) usage since the Company's last general filing?

A. 2006 was the test year used in the company's last general filing (Docket No. UG 181). Page 1 of Exhibit 703 shows actual and weather normalized usage by rate schedule for 2006 and 2008, as well as the forecasted usage for 2010 used in this filing. As shown on lines 16 and 18, total throughput (sales and transportation volumes) is down considerably since 2006. Nearly all of this decrease in throughput is due to a reduction in usage by large transportation customers (Schedules 447 and 456). Many of these customers are wood-product manufacturers whose operations have been severely affected by the current recession.

Q. How does projected 2010 usage for residential and commercial customers compare to 2006 usage for these customer classes?

A. As shown in Exhibit 703, page 1 lines 1 and 3, total forecasted 2010 usage for residential customers is slightly less than total (weather-corrected) residential usage in 2006. As shown on lines 4 and 6, commercial usage shows a more significant drop (4.5%) from 2006 to forecasted 2010. Perhaps more importantly, use-per-customer continues to decline: residential use-per-customer is projected to be down 3.7% from 2006 to 2010, and commercial-use-per customer is projected to be down 7.7% over that same period.

Q. How does this customer usage information affect this filing?

A. The Company's higher level of operating costs must be recovered over a lower level of throughput/volume as compared to 2006, thus creating additional need for rate relief. The majority of the costs associated with operating the Company's gas distribution system are fixed; however, those costs are recovered mostly through volumetric/usage charges. While the long-term interest is best served by customers using energy wisely and efficiently, reduced customer usage results in the Company under-recovering its fixed costs.

Q. Is the Company proposing any changes to the present allocation of gas costs by rate schedule used in its PGA filings?

A. No.

PROPOSED RATE DESIGN AND RATE SPREAD

Q. Would you please describe the Company's present rate schedules and the types of gas service offered under each?

A. Yes. The following table shows the type of customer and the average number of customers served during 2008 under each of the Company's Oregon natural gas schedules:

Schedule	Type of Customer	No. of Customers
Residential Sch. 410	Residential	83,541
General Sch. 420	Commercial	11,026
Lge. General Sch. 424	Lge. Comm. & Industrial	96
Interruptible Sch. 440	Lge. Comm. & Industrial	21
Seasonal Sch. 444	Non-winter Use	8
Transportation Sch. 456	Lge. Industrial	34
Sp. Contract Sch. 447	Lge. Industrial Transportation	5

Q. How does the Company propose to spread the proposed revenue increase of $14,205,000, or 11.6%, among its various service schedules?

A. The Company utilized the cost of service results sponsored by Company witness Knox as a guide to spread the proposed margin/revenue increase by service schedule. As described in Ms. Knox's testimony, she prepared two different studies, and the results were generally consistent between the two studies, i.e., the margin-to-cost ratio for each schedule is either above 1.00 (unity) or below 1.00 in both studies. Generally, if the results of the cost of service studies show that the schedule is below unity (present margin is less than the cost of service), the Company is proposing to apply an increase to the margin that is higher than the overall margin increase. Conversely, if the results of the cost of service studies show that the schedule is above unity (present margin is greater than the cost of service), the Company is proposing to apply an increase to the margin that is less than the overall increase. Below is a table showing the average margin-to-cost ratio for the two studies under present rates and proposed rates. The "Percent of Overall Margin Increase" column reflects the percentage applied to the overall margin increase (45.1%) for each schedule.

Schedule	Margin to Cost at Present Rates	Percent of Overall Margin Increase	Margin to Cost at Proposed Rates
Residential Sch. 410	1.02	98%	1.01
General Sch. 420	0.87	120%	0.93
Lge. General Sch. 424	1.18	95%	1.16
Interruptible Sch. 440	1.47	75%	1.35
Seasonal Sch. 444	0.77	120%	0.82
Transportation Sch. 456	1.34	75%	1.24

As shown above, application of the proposed margin increase by schedule results in the margin-to-cost ratio moving closer to unity for all service schedules. This information is also shown in more detail on page 2 of Exhibit 703.

Q. What are the proposed percentage increase in the margin for each schedule, as well as the proposed percentage increase in total revenue?

A. Below is the proposed percentage increase in present margin, as well as the proposed increase in revenue (including gas costs) for each service schedule:

Schedule	Increase to Present Margin	Increase in Present Revenue
Residential Sch. 410	45.1%	12.5%
General Sch. 420	55.1%	10.6%
Lge. General Sch. 424	43.6%	4.4%
Interruptible Sch. 440	34.4%	3.4%
Seasonal Sch. 444	55.1%	4.7%
Transportation Sch. 456	34.4%	34.4%
Total	45.9%	11.6%

More detailed information related to the revenue increase by schedule is shown on Page 3 of Exhibit 703. One item of note in the above table - the rates and revenue for Transportation Schedule 456 do not include gas (commodity) or pipeline transportation costs, as the Company provides only distribution service to these customers. Assuming a cost of $5.00 per dekatherm (50 cents per therm) for commodity and pipeline transportation for these customers, the proposed increase would represent an average increase of about 5% in transportation customers' total natural gas bill.

Q. Is the company projecting a PGA rate decrease for customers this fall?

A. Yes. The Company is projecting an overall PGA decrease this fall that would more than offset the requested general increase. As of the date of this filing, the Company has hedged (fixed) the price on a significant portion of forecasted customer gas requirements for the 2009-10 PGA year. While the level of the decrease is dependent upon the actual price of volumes not yet purchased, the Company is relatively confident that the PGA will be a significant decrease based on the amount of gas that has been hedged to date and economic conditions continuing to support current wholesale gas prices in the near-term.

Q. Turning now to the proposed changes to the rates <u>within</u> the various service schedules, could you please describe what is shown on Page 4 of Exhibit No. 703?

A. Page 4 of Exhibit No. 703 shows the present rates for each of the various schedules, the proposed increases to those rates, and the resulting proposed rates.

Q. Could you please describe the proposed changes in the rates for Residential Schedule 410 that result in the overall revenue increase of 12.5% for that Schedule?

A. As shown on Page 4 of Exhibit No. 703, the Company is proposing an increase in the present monthly customer charge of $0.75 per month, or 12.5%, from $6.00 to $6.75. The present charge per therm is increased by $0.17155 per therm, from $1.36785 to $1.53940 per therm.

Q. What is the change in the average residential customer's bill as a result of these proposed changes?

A. Based on an average usage level of 49 therms per month, the average residential bill would increase $9.15 per month, or 12.5%, from $73.31 to $82.46.

Q. Could you please describe the changes you propose to the rates of General Service Schedule 420?

A. Yes. As shown on Page 2 of Exhibit No. 703, the present rates for service under Schedule 420 consist of an $8.00 per month customer charge and a usage charge of $1.29272 per therm. The Company is proposing an increase in the customer charge of $0.75

per month, from $8.00 to $8.75, and an increase of $0.13804 per therm in the usage charge. These changes result in the overall proposed increase of 10.6% in the revenue for the Schedule.

Q. Could you please describe the service provided and the proposed rate changes under Large General Service Schedule 424 and Seasonal Service 444?

A. Yes. Large General Service Schedule 424 provides service to customers whose usage is at least 75% for uses other than space-heating, i.e., who have a relatively high load-factor compared to other firm service customers. The Company is proposing an increase of $0.05105 per therm to the present usage rate under the Schedule and an increase of $4.00 per month in the present monthly customer charge, from $46.00 to $50.00 per month, resulting in an overall increase of 4.4% in revenue under the Schedule.

Seasonal Service Schedule 444 is for customers who use no natural gas during December, January and February. There are only eight customers served under the Schedule, most of whom are mint farmers. Customers served under this Schedule are not assessed a monthly customer charge. The Company is proposing an increase in the per therm charge under the Schedule of $0.05567 per therm.

Q. Could you please describe the service provided and the proposed rate changes under Interruptible Schedule 440?

A. Interruptible Service Schedule 440 serves customers that are able to curtail their natural gas usage or switch to an alternate fuel upon relatively short notice by the Company. These customers are not assigned firm pipeline transportation costs through their rates, as they do not create peak service requirements. The Company is proposing that the rate for service under Schedule 440 be increased by $0.03027 per therm, resulting in the proposed revenue increase of 3.4% for the Schedule. There is also an annual minimum charge under the Schedule associated with usage of 50,000 therms per year multiplied by the margin rate; correspondingly, the annual minimum margin rate is also proposed to increase by $0.03027 per therm.

Q. Could you please describe the proposed changes to the present rates for Transportation Service Schedule 456?

A. Yes. Transportation Schedule 456 provides Company distribution service for large customers who use over 225,000 therms per year. These customers purchase natural gas and pipeline transportation from a third party. As shown on Page 4 of Exhibit No. 703, the present rates under the Schedule consist of a monthly customer charge of $187.50 and a five-block rate structure with declining rates for higher usage. The Company is proposing an increase of $62.50 per month, or 33.3% in the customer charge, to $250.00, and a uniform percentage increase of 34.5% to all rate blocks under the Schedule.

Q. Why is the Company proposing such a large increase in the monthly customer charge under Transportation Schedule 456?

A. Prior to March 2004, the monthly customer charge under the Schedule was $250.00. Per Commission Order No. 03-570 in UG-153, approving the stipulation among the parties in that Case, the rates for Schedule 456 (including the customer charge) were reduced by 25% over the period March 2004 – October 2005. The proposed increase to $250 per month matches the Commission approved level prior to March 2004, is consistent with the overall proposed increase in the rates under the Schedule and is more reflective of the cost of providing service to these customers. In addition to monthly meter reading and billing, the Company executes individual contracts with these customers and installs special telemetering equipment at their premise in order to receive daily meter readings to assist in daily pipeline nomination and balancing.

Q. Is the Company proposing any other changes to its natural gas service tariffs in this filing?

A. No.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

BRIAN J. HIRSCHKORN
Exhibit No. 701

Present Natural Gas Service Tariffs

SCHEDULE 410

GENERAL RESIDENTIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:
Applicable to residential natural gas service for all purposes.

TERRITORY:
This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:
The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:	Per Meter Per Month
Customer Charge:	$6.00
Commodity Charge Per Therm:	$1.36785

Minimum Charge:
The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408 and Margin Reduction Surcharge Schedule 496.
2. A reconnection charge shall be made for restoration of service where service has been turned off for seasonal turnoff, or for other reasons arising through the action or for the convenience of the customer. (See Rule No. 20)
3. Service under this schedule is subject to adjustments as specified under Schedule 451 as well as any other applicable adjustments approved by the Public Utility Commission.
4. The above Commodity Charge includes a $.00438 per therm for the Residential Low Income Rate Assistance Program, as set forth under Schedule 493.
5. When service has been discontinued at the Customer's request and then reestablished within a twelve-month period, the Customer shall be required to pay the monthly minimum charges that would have been billed had service not been discontinued.

Advice No. 08-08-G Effective For Service On & After
Issued October 27, 2008 November 1, 2008

Issued by Avista Utilities
By Kelly O. Norwood, V.P. State & Federal Regulation

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 420
GENERAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to commercial and small industrial natural gas service for all purposes.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Customer Charge:	$8.00
Commodity Charge Per Therm:	$1.29272

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408 and Margin Reduction Surcharge Schedule 496.

2. A reconnection charge shall be made for restoration of service when service has been turned off for reasons arising through action of or for the convenience of the customer. (See Rule No. 20)

3. Service for the sole purpose of supplying a fireplace, log lighter, gas log, barbecue or any multiple or combination thereof, will be rendered only under this schedule. Where service for such purpose is requested, an advance-in-aid of construction in the amount of the Company's estimated total additional investment in the facilities required to provide such service shall be made prior to the commencement of construction. If the advance is for facilities to serve more than one customer location, an appropriate portion thereof will be assigned to each customer location. The advance will be refunded by the Company to the person or entity who made the

(continued)

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 424

LARGE GENERAL AND INDUSTRIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to large commercial and industrial use customers where at least 75% of the natural gas requirements are for uses other than space heating and where adequate capacity exists in the Company's system. Customers served under this schedule must use a minimum of 29,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Customer Charge:	$46.00
Commodity Charge Per Therm:	$1.18131

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.
2. This service is available only where adequate capacity exists in the Company's system.
3. As a condition precedent to service under this schedule an executed Agreement with the Company is required specifying quantity requirements and other terms and conditions as hereinafter provided.

(continued)

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 440

INTERRUPTIBLE NATURAL GAS SERVICE
FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must use a minimum of 50,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:	Per Meter Per Month
Commodity Charge Per Therm:	$.89041

Annual Minimum Charge:

Each Customer shall be subject to an Annual Minimum Charge if their gas usage during the prior year does not equal or exceed 50,000 therms. Such Annual Minimum Charge shall be determined by subtracting their actual usage for a twelve-month period from 50,000 therms multiplied by 11.285 cents per therm.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.

2. This service is available only where capacity in excess of firm sales and firm transportation requirements exists in the Company's system.

3. Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in Section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-

(continued)

SCHEDULE 444

SEASONAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable for natural gas service to customers whose entire natural gas requirements for any calendar year are supplied during the period from and after March 1, and continuing through November 30, of each year.

Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-261). An "essential agricultural" or "high-priority" user receiving service under this schedule can obtain protection from curtailment by requesting transfer to the appropriate firm rate schedule of the Company.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Commodity Charge Per Therm:	$1.17586

Minimum Charge:
$7,836.80 per season.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.

2. A contract will be required for a period of one (1) year when service is first rendered and year by year thereafter. Service will be subject to termination at the end of any contract year in the event the supply of gas may become limited to other firm gas customers.

3. The Company, when operating its propane-air peak shaving facilities, falls under the jurisdiction of the Federal Energy Agency with respect to the Company's

(continued)

SCHEDULE 456

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for the transportation of customer-owned natural gas for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must transport over the Company's system a minimum of 225,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Customer Charge:	$187.50
Volumetric Charge Per Therm:	
First 10,000	$.13148
Next 20,000	$.07906
Next 20,000	$.06496
Next 200,000	$.05080
All Additional	$.02568

Minimum Charge:
The minimum monthly charge shall be $1,354.30 per month, accumulative annually.

Gross Revenue Fee Reimbursement:

The total of all charges invoiced by the Company shall be subject to a Gross Revenue Fee reimbursement charge of 2.6371 percent to cover governmental fees and levies imposed upon the Company, as those fees and levies may be in effect from time to time.

(continued)

AVISTA/702
Hirschkorn

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

BRIAN J. HIRSCHKORN
Exhibit No. 702

Proposed Natural Gas Service Tariffs

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 410

GENERAL RESIDENTIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to residential natural gas service for all purposes.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	$6.75	(I)
Commodity Charge Per Therm:	$1.53940	(I)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408 and Margin Reduction Surcharge Schedule 496.
2. A reconnection charge shall be made for restoration of service where service has been turned off for seasonal turnoff, or for other reasons arising through the action or for the convenience of the customer. (See Rule No. 20)
3. Service under this schedule is subject to adjustments as specified under Schedule 451 as well as any other applicable adjustments approved by the Public Utility Commission.
4. The above Commodity Charge includes a $.00438 per therm for the Residential Low Income Rate Assistance Program, as set forth under Schedule 493.
5. When service has been discontinued at the Customer's request and then reestablished within a twelve-month period, the Customer shall be required to pay the monthly minimum charges that would have been billed had service not been discontinued.

Advice No. 09-03-G Effective For Service On & After
Issued June 25, 2009 July 27, 2009

Issued by Avista Utilities
By Kelly O. Norwood, V.P. State & Federal Regulation

SCHEDULE 420
GENERAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to commercial and small industrial natural gas service for all purposes.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	$8.75	(I)
Commodity Charge Per Therm:	$1.43076	(I)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408 and Margin Reduction Surcharge Schedule 496.

2. A reconnection charge shall be made for restoration of service when service has been turned off for reasons arising through action of or for the convenience of the customer. (See Rule No. 20)

3. Service for the sole purpose of supplying a fireplace, log lighter, gas log, barbecue or any multiple or combination thereof, will be rendered only under this schedule. Where service for such purpose is requested, an advance-in-aid of construction in the amount of the Company's estimated total additional investment in the facilities required to provide such service shall be made prior to the commencement of construction. If the advance is for facilities to serve more than one customer location, an appropriate portion thereof will be assigned to each customer location. The advance will be refunded by the Company to the person or entity who made the

(continued)

SCHEDULE 424

LARGE GENERAL AND INDUSTRIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to large commercial and industrial use customers where at least 75% of the natural gas requirements are for uses other than space heating and where adequate capacity exists in the Company's system. Customers served under this schedule must use a minimum of 29,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	$50.00	(I)
Commodity Charge Per Therm:	$1.23236	(I)

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.
2. This service is available only where adequate capacity exists in the Company's system.
3. As a condition precedent to service under this schedule an executed Agreement with the Company is required specifying quantity requirements and other terms and conditions as hereinafter provided.

(continued)

SCHEDULE 440

INTERRUPTIBLE NATURAL GAS SERVICE
FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must use a minimum of 50,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Commodity Charge Per Therm:	$.92068	(I)

Annual Minimum Charge:

Each Customer shall be subject to an Annual Minimum Charge if their gas usage during the prior year does not equal or exceed 50,000 therms. Such Annual Minimum Charge shall be determined by subtracting their actual usage for a twelve-month period from 50,000 therms multiplied by 14.312 cents per therm. (I)

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.

2. This service is available only where capacity in excess of firm sales and firm transportation requirements exists in the Company's system.

3. Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in Section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-

(continued)

SCHEDULE 444

SEASONAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable for natural gas service to customers whose entire natural gas requirements for any calendar year are supplied during the period from and after March 1, and continuing through November 30, of each year.

Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-261). An "essential agricultural" or "high-priority" user receiving service under this schedule can obtain protection from curtailment by requesting transfer to the appropriate firm rate schedule of the Company.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Commodity Charge Per Therm:	$1.23153	(I)

Minimum Charge:
$7,836.80 per season.

SPECIAL CONDITIONS:

1. The above Commodity Charge Per Therm is subject to the provisions of Income Tax Adjustment Schedule 408.

2. A contract will be required for a period of one (1) year when service is first rendered and year by year thereafter. Service will be subject to termination at the end of any contract year in the event the supply of gas may become limited to other firm gas customers.

3. The Company, when operating its propane-air peak shaving facilities, falls under the jurisdiction of the Federal Energy Agency with respect to the Company's

(continued)

SCHEDULE 456

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for the transportation of customer-owned natural gas for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must transport over the Company's system a minimum of 225,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	$250.00	(I)
Volumetric Charge Per Therm:		
First 10,000	$.17679	(I)
Next 20,000	$.10630	(I)
Next 20,000	$.08735	(I)
Next 200,000	$.06831	(I)
All Additional	$.03453	(I)

Minimum Charge:
The minimum monthly charge shall be $1,354.30 per month, accumulative annually.

Gross Revenue Fee Reimbursement:

The total of all charges invoiced by the Company shall be subject to a Gross Revenue Fee reimbursement charge of 2.6371 percent to cover governmental fees and levies imposed upon the Company, as those fees and levies may be in effect from time to time.

(continued)

Avista Utilities
Oregon - Gas
Pro Forma Revenue Under Present and Proposed Base Tariff Rates
Year Ended 12/31/08

WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PRESENT BILL DETERMINANTS								
	THERMS								
BJH-5	BLOCK 1		49,542,068	27,280,991	4,082,190	5,776,303	184,605	3,897,200	
BJH-5	BLOCK 2							6,486,906	1,184,555
BJH-5	BLOCK 3							4,415,618	
BJH-5	BLOCK 4							11,583,266	1,500,000
BJH-5	BLOCK 5							217,972	450,707
	SUBTOTAL	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	ADJUSTMENT TO ACTUAL								
	TOTAL BEFORE ADJUSTMENT	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	WEATHER & UNBILLED REV. ADJ.								
	TOTAL PROFORMA THERMS	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
BJH-5	TOTAL BILLS		1,011,771	134,496	1,170	478	37	408	60
	TOTAL MINIMUM BILLS								
	PROPOSED BILL DETERMINANTS								
	THERMS								
	BLOCK 1		49,542,068	27,280,991	4,082,190	5,776,303	184,605	3,897,200	
	BLOCK 2							6,486,906	1,184,555
	BLOCK 3							4,415,618	
	BLOCK 4							11,583,266	1,500,000
	BLOCK 5							217,972	450,707
	SUBTOTAL	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	ADJUSTMENT TO ACTUAL								
	TOTAL BEFORE ADJUSTMENT	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	WEATHER & UNBILLED REV. ADJ.								
	TOTAL PROFORMA THERMS	116,602,382	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962	3,135,262
	TOTAL BILLS		1,011,771	134,496	1,170	478	37	408	60
	TOTAL MINIMUM BILLS								

Avista Utilities
Oregon - Gas
Pro Forma Revenue Under Present and Proposed Base Tariff Rates
Year Ended 12/31/08

WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PRESENT RATES								
Exh 701	BASIC CHARGE		$6.00	$8.00	$46.00			$187.50	
BJH-7	ANNUAL MINIMUM								$317,482
Exh 701	BLOCK 1 PER THERM		$1.36785	$1.29272	$1.18131	$0.89041	$1.17586	$0.13148	$0.02700
Exh 701	BLOCK 2 PER THERM							$0.07906	$0.02500
Exh 701	BLOCK 3 PER THERM							$0.06496	$0.04694
Exh 701	BLOCK 4 PER THERM							$0.05080	$0.02750
Exh 701	BLOCK 5 PER THERM							$0.02568	$0.03400
	PROPOSED RATES								
	BASIC CHARGE		$6.75	$8.75	$50.00			$250.00	
	ANNUAL MINIMUM								$317,482
	BLOCK 1 PER THERM		$1.53940	$1.43076	$1.23236	$0.92068	$1.23153	$0.17679	$0.02700
	BLOCK 2 PER THERM							$0.10630	$0.02500
	BLOCK 3 PER THERM							$0.08735	$0.04694
	BLOCK 4 PER THERM							$0.06831	$0.02750
	BLOCK 5 PER THERM							$0.03453	$0.03400

Avista Utilities
Oregon - Gas
Pro Forma Revenue Under Present and Proposed Base Tariff Rates
Year Ended 12/31/08

WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PRESENT REVENUE								
	BASE TARIFF REVENUE								
	BASIC CHARGE	$7,276,914	$6,070,626	$1,075,968	$53,820			$76,500	
	ANNUAL MINIMUM	$317,482							$317,482
	BLOCK 1	$113,727,885	$67,766,118	$35,266,683	$4,822,332	$5,143,278	$217,070	$512,404	
	BLOCK 2	$542,469						$512,855	$29,614
	BLOCK 3	$286,839						$286,839	
	BLOCK 4	$629,680						$588,430	$41,250
	BLOCK 5	$20,922						$5,598	$15,324
	ANNUAL MINIMUM	$0							
	SUBTOTAL	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670
	ADJUST TO ACTUAL	$0							
	TOTAL BASE TARIFF REVENUE	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670
	ADJUSTMENT REVENUE								
	UNBILLED REVENUE ADJUSTMENT								
	UNBILLED THERMS	0							
Exh 701	UNBILLED RATE		$1.36785	$1.29272	$1.18131		$1.17586		
	UNBILLED REVENUE	$0	$0	$0	$0		$0		
	WEATHER NORMALIZATION ADJ								
	WEATHER-SENSITIVE THERMS	0	0	0					
Exh 701	WEATHER-SENSITIVE RATE		$1.36785	$1.29272					
	WEATHER-SENSITIVE REVENUE	$0	$0	$0					
	OTHER ADJUSTMENTS								
	TOTAL ADJUSTMENT REVENUE	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL BASE TARIFF REVENUE	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670
	TOTAL PRESENT REVENUE	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670

Avista Utilities
Oregon - Gas
Pro Forma Revenue Under Present and Proposed Base Tariff Rates
Year Ended 12/31/08

WORK PAPER REFERENCE		TOTAL	RESIDENTIAL SCHED. 410	GEN SVC SCHED. 420	LG GEN SVC SCHED. 424	INTERRUPT SCHED. 440	SEASONAL SCHED. 444	TRANSPORT SCHED. 456	SP CONTRACT SCHED. 447
	PROPOSED REVENUE								
	BASE TARIFF REVENUE								
	BASIC CHARGE	$8,166,794	$6,829,454	$1,176,840	$58,500			$102,000	
	ANNUAL MINIMUM	$317,482							$317,482
	BLOCK 1	$126,562,791	$76,265,060	$39,032,551	$5,030,728	$5,318,127	$227,347	$688,979	
	BLOCK 2	$719,199						$689,585	$29,614
	BLOCK 3	$385,683						$385,683	
	BLOCK 4	$832,453						$791,203	$41,250
	BLOCK 5	$22,850						$7,526	$15,324
	ANNUAL MINIMUM	$0							
	SUBTOTAL	$137,007,254	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977	$403,670
	NET SHIFTING ADJUSTMENT								
	SUBTOTAL	$137,007,254	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977	$403,670
	ADJUST TO ACTUAL	$0							
	TOTAL BASE TARIFF REVENUE	$137,007,254	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977	$403,670
	ADJUSTMENT REVENUE								
	UNBILLED REVENUE ADJUSTMENT								
	UNBILLED THERMS	0	0	0	0		0		
BJH-2	UNBILLED RATE		$1.53940	$1.43076	$1.23236		$1.23153		
	UNBILLED REVENUE	$0	$0	$0	$0		$0		
	WEATHER NORMALIZATION ADJ								
	WEATHER-SENSITIVE THERMS	0	0	0					
BJH-2	WEATHER-SENSITIVE RATE		$1.53940	$1.43076					
	WEATHER-SENSITIVE REVENUE	$0	$0	$0					
	OTHER ADJUSTMENTS								
	TOTAL ADJUSTMENT REVENUE	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL BASE TARIFF REVENUE	$137,007,254	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977	$403,670
	TOTAL PROPOSED REVENUE	$137,007,254	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977	$403,670
	TOTAL PRESENT REVENUE	$122,802,190	$73,836,744	$36,342,651	$4,876,152	$5,143,278	$217,070	$1,982,625	$403,670
	TOTAL INCREASED REVENUE	**$14,205,064**	**$9,257,770**	**$3,866,740**	**$213,076**	**$174,849**	**$10,277**	**$682,353**	**$0**
	PERCENT REVENUE INCREASE	**11.57%**	**12.54%**	**10.64%**	**4.37%**	**3.40%**	**4.73%**	**34.42%**	**0.00%**

	TOTAL	**SCHED. 410**	**SCHED. 420**	**SCHED. 424**	**SCHED. 440**	**SCHED. 444**	**SCHED. 456**
Proposed Rate Workup - from Pres & Prop Rev tab							
THERMS							
BLOCK 1	90,763,358	49,542,068	27,280,991	4,082,190	5,776,303	184,605	3,897,200
BLOCK 2	6,486,906						6,486,906
BLOCK 3	4,415,618						4,415,618
BLOCK 4	11,583,266						11,583,266
BLOCK 5	217,972						217,972
ADJ. TO ACTUAL							
WEATHER & U/B THERMS							
TOTAL PROFORMA THERMS	113,467,120	49,542,068	27,280,991	4,082,190	5,776,303	184,605	26,600,962
TOTAL BILLS		1,011,771	134,496	1,170	478	37	408
		84,314	11,208	98	40	3	34
Proposed Revenue	$136,603,520	$83,094,398	$40,209,455	$5,089,226	$5,318,116	$227,347	$2,664,977
Targeted Rate Increase							
Present Basic/Min Charge		$6.00	$8.00	$46.00			$187.50
BASIC/MIN CHARGE		$6.75	$8.75	$50.00			$250.00
% Δ in Basic Charge		12.5%	9.4%	8.7%			33.3%
Basic Charge Revenue	$8,166,794	$6,829,454	$1,176,840	$58,500			$102,000
Present Block 1 Rate		$1.36785	$1.29272	$1.18131	$0.89041	$1.17586	$0.13148
Present Block 2 Rate							$0.07906
Present Block 3 Rate							$0.06496
Present Block 4 Rate							$0.05080
Present Block 5 Rate							$0.02568
1) Flat Rate Increase		$1.00000	$1.00000	$1.00000	$1.00000	$1.00000	-$0.13689
2) % Rate Increase		12.54%	10.68%	4.32%	3.40%	4.73%	34.46%
Method --->		**2**	**2**	**2**	**2**	**2**	**2**
BLOCK 1 PER THERM		$1.53940	$1.43076	$1.23236	$0.92068	$1.23153	$0.17679
BLOCK 2 PER THERM							$0.10630
BLOCK 3 PER THERM							$0.08735
BLOCK 4 PER THERM							$0.06831
BLOCK 5 PER THERM							$0.03453
BLOCK 1 PER THERM		$1.53940	$1.43076	$1.23236	$0.92068	$1.23153	$0.17679
BLOCK 2 PER THERM							$0.10630
BLOCK 3 PER THERM							$0.08735
BLOCK 4 PER THERM							$0.06831
BLOCK 5 PER THERM							$0.03453
Blocks 1-5 Revenue	$128,436,726	$76,264,944	$39,032,615	$5,030,726	$5,318,116	$227,347	$2,562,977
Adj. to Actual Revenue		$0	$0	$0	$0	$0	$0
Weather & U/B Revenue		$0	$0	$0	$0	$0	$0
Revenue Remaining	$0	$0	$0	$0	$0	$0	$0
Revenue Remaining - ¢/Th	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
check - < $4k is rounding	-$63	-$116	$64	-$1	-$11	$0	$0
Proposed Target	**$136,603,520**	$83,094,398	$40,209,455	$5,089,226	$5,318,116	$227,347	$2,664,977
Proposed Actual	**$136,603,583**	$83,094,514	$40,209,391	$5,089,228	$5,318,127	$227,347	$2,664,977
	$63	$116	-$64	$1	$11	$0	$0
Rate Δ Check							
Basic/Min Charge	11.7%	12.5%	9.4%	8.7%	#DIV/0!	#DIV/0!	33.3%
Adj. to Actual Revenue	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Weather & U/B Revenue	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Block Therm Charges	11.6%	12.5%	10.7%	4.3%	3.4%	4.7%	34.5%
Overall Revenue	**11.6%**	**12.5%**	**10.6%**	**4.4%**	**3.4%**	**4.7%**	**34.4%**
Avg. Usage		49	203	3,489	12,084	4,989	65,198

Avista Utilities
Docket No. UG-___
Rate Spread Summary
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2010

Type of Service	Schedule Number	Avg. No. of Customers	Annual Therms	Avg. Use per Customer per Month	Revenue at Pres. Rates ($000's)	Avg. Bill Under Pres. Rates	Revenue Percentage Increase	Revenue Increase ($000's)	Avg. Increase per Customer per Month	Revenue at Prop. Rates ($000's)	Avg. Bill Under Prop. Rates
Residential	410	84,314	49,542,068	49	$73,837	$73.31	12.5%	$9,258	$9.15	$83,095	$82.46
General Service	420	11,208	27,280,991	203	36,343	$270.42	10.6%	3,867	$28.77	40,209	$299.19
Large General Service	424	98	4,082,190	3,489	4,876	$4,168	4.4%	213	$182	5,089	$4,350
Interruptible Service	440	40	5,776,303	12,084	5,143	$10,760	3.4%	175	$366	5,318	$11,126
Seasonal Service	444	3	184,605	4,989	217	$5,866	4.7%	10	$278	227	$6,144
Transportation Service	456	34	26,600,962	65,198	1,983	$4,859	34.4%	682	$1,672	2,665	$6,532
Special Contract	447	5	3,135,262	52,254	404	$6,728	0.0%	0	$0	404	$6,728
Total		95,702	116,602,382		$122,802		11.6%	$14,205		$137,007	

EXHIBIT C

Avista Utilities
State of Oregon
Comparison of Natural Gas Usage
2006 & 2008 Weather-Normalized & 2010 Forecast

Line No.		Actual Usage	Weather & Unbilled Adj.	Normalized Usage	Avg. Customers	Annual Use/ Customer	Monthly Use/ Customer
	Residential Sch 410						
1	2006	49,257,514	525,049	**49,782,563**	81,424	611.4	**50.9**
2	2008	50,560,635	(3,921,539)	46,639,096	83,541	558.3	46.5
3	2010			**49,542,068**	84,314	587.6	**49.0**
	Commercial Sch 420						
4	2006	28,301,835	252,099	**28,553,934**	10,808	2,642	220
5	2008	28,271,134	(1,993,020)	26,278,114	11,026	2,383	199
6	2010			**27,280,991**	11,208	2,434	203
	Industrial Sales Schs. 424, 440 & 444						
7	2006			7,251,357	134	54,115	4,510
8	2008			9,935,547	137	72,522	6,044
9	2010			10,043,098	140	71,736	5,978
	Total Sales Volumes						
10	2006			85,587,854	92,366		
11	2008			82,852,757	94,704		
12	2010			86,866,157	95,662		
	Transport Schs. 447 & 456						
13	2006			**40,985,407**	41	999,644	83,304
14	2008			29,736,224	39	762,467	63,539
15	2010			**29,736,224**	39	762,467	63,539
	Total Throughput						
16	2006			**126,573,261**			
17	2008			112,588,981			
18	2010			**116,602,381**			

Avista Utilities
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2010

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	CURRENT REVENUE	$ 122,802,190	$ 73,836,744	$ 36,342,651	$ 4,876,152	$ 5,143,278	$ 217,070	$ 403,670	$ 1,982,625
2	COST OF GAS	$ 91,846,926	$ 53,305,263	$ 29,320,596	$ 4,387,386	$ 4,635,274	$ 198,407	$ -	$ -
3	CURRENT MARGIN	$ 30,955,264	$ 20,531,481	$ 7,022,055	$ 488,766	$ 508,004	$ 18,663	$ 403,670	$ 1,982,625
4	% of Current Margin excl Sch 447	100.00%	67.20%	22.98%	1.60%	1.66%	0.06%		6.49%
5	Total Revenue Requirement	$ 14,205,000							
6	Revenue Requirement as a Percent of Margin Revenue	45.89%							
7	Percentage Applied to Overall Margin Increase		98.26%	120.00%	95.00%	75.00%	120.00%		75.00%
8	Increase as a Percent of Total Current Margin		45.09%	55.07%	43.59%	34.42%	55.07%		34.42%
9	**PROPOSED MARGIN REVENUE INCREASE**	**$ 14,205,000**	**$ 9,257,654**	**$ 3,866,804**	**$ 213,074**	**$ 174,838**	**$ 10,277**		**$ 682,352**
10	**Proposed Revenue Increase**	**11.57%**	**12.54%**	**10.64%**	**4.37%**	**3.40%**	**4.73%**		**34.42%**
	Cost of Service Method I								
10	Proposed Margin	$ 45,160,264	$ 29,789,135	$ 10,888,859	$ 701,840	$ 682,842	$ 28,940	$ 403,670	$ 2,664,977
11	LRIC Based Target Margin (Line 25 of Knox Exhibit 601 Page 1 of 4)	$ 45,160,264	$ 28,380,574	$ 12,564,145	$ 642,001	$ 532,101	$ 36,564	$ 629,468	$ 2,375,411
12	**Relative Margin to Cost at Present Rates (Method I - Line 21A of Knox Exhibit 601 Page 1 of 4)**	**1.00**	**1.06**	**0.82**	**1.11**	**1.39**	**0.74**		**1.22**
13	**Relative Margin to Cost at Proposed Rates**	**1.00**	**1.05**	**0.87**	**1.09**	**1.28**	**0.79**		**1.12**
	Cost of Service Method II								
14	Proposed Margin	$ 45,160,264	$ 29,789,135	$ 10,888,859	$ 701,840	$ 682,842	$ 28,940	$ 403,670	$ 2,664,977
15	LRIDC Based Target Margin (Line 27 of Knox Exhibit 601 Page 2 of 4)	$ 45,161,000	$ 30,432,009	$ 11,158,026	$ 569,446	$ 481,847	$ 34,349	$ 508,003	$ 1,977,319
16	**Relative Margin to Cost at Present Rates (Method II - Line 29A of Knox Exhibit 601 Page 2 of 4)**	**1.00**	**0.98**	**0.92**	**1.25**	**1.54**	**0.79**		**1.46**
17	**Relative Margin to Cost at Proposed Rates**	**1.00**	**0.98**	**0.98**	**1.23**	**1.42**	**0.84**		**1.35**
18	**Average of Two Methods - Present Rates**	**1.00**	**1.02**	**0.87**	**1.18**	**1.47**	**0.77**		**1.34**
19	**Average of Two Methods - Proposed Rates**	**1.00**	**1.01**	**0.93**	**1.16**	**1.35**	**0.82**		**1.24**

Avista Utilities
Proposed Revenue Increase by Schedule
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2010
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Revenue Under Present Rates	Increase/ (Decrease)	Revenue Under Proposed Rates	Therms (000s)	Increase/ (Decrease) Per Therm	**Revenue Percentage Increase**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	410	$73,837	$9,258	$83,095	49,542	18.69¢	**12.5%**
2	General Service	420	36,343	3,867	40,209	27,281	14.17¢	**10.6%**
3	Large General Service	424	4,876	213	5,089	4,082	5.22¢	**4.4%**
4	Interruptible Service	440	5,143	175	5,318	5,776	3.03¢	**3.4%**
5	Seasonal Service	444	217	10	227	185	5.57¢	**4.7%**
6	Transportation Service	456	1,983	682	2,665	26,601	2.57¢	**34.4%**
7	Special Contract	447	404	0	404	3,135	0.00¢	**0.0%**
8	Total		$122,802	$14,205	$137,007	116,602	12.18¢	**11.6%**

Avista Utilities
Comparison of Present & Proposed Gas Rates
Oregon - Gas

Present Rates	Change	Proposed Rates
Residential Service Schedule 410		
$6.00 Customer Charge	$0.75/month	$6.75 Customer Charge
All Therms - $1.36785/Therm	$0.17155/therm	All Therms - $1.53940/Therm
General Service Schedule 420		
$8.00 Customer Charge	$0.75/month	$8.75 Customer Charge
All Therms - $1.29272/Therm	$0.13804/therm	All Therms - $1.43076/Therm
Large General Service Schedule 424		
$46.00 Customer Charge	$4.00/month	$50.00 Customer Charge
All Therms - $1.18131/Therm	$0.05105/therm	All Therms - $1.23236/Therm
Interruptible Service Schedule 440		
All Therms - $0.89041/Therm	$0.03027/therm	All Therms - $0.92068/Therm
Seasonal Service Schedule 444		
All Therms - $1.17586/Therm	$0.05567/therm	All Therms - $1.23153/Therm
Transportation Service Schedule 456		
$187.50 Customer Charge	$62.50/month	$250.00 Customer Charge
1st 10,000 Therms - $0.13148/Therm	$0.04531/therm	1st 10,000 Therms - $0.17679/Therm
Next 20,000 Therms - $0.07906/Therm	$0.02724/therm	Next 20,000 Therms - $0.10630/Therm
Next 20,000 Therms - $0.06496/Therm	$0.02239/therm	Next 20,000 Therms - $0.08735/Therm
Next 200,000 Therms - $0.05080/Therm	$0.01751/therm	Next 200,000 Therms - $0.06831/Therm
Over 250,000 Therms - $0.02568/Therm	$0.00885/therm	Over 250,000 Therms - $0.03453/Therm

Avista Utilities
Oregon - Gas
Usage & Billings by Rate Schedule
Pro Forma Year Ended 12/31/10

	Total therms (1)	Billings
Schedule 410	49,542,068	1,011,771
Schedule 420	27,280,991	134,496
Schedule 424	4,082,190	1,170
Schedule 440	5,776,303	478
Schedule 444	184,605	37
Schedule 447		
Biomass One	0	12
Collins Products	1,184,555	12
Douglas Forest Products	0	12
Murphy Plywood	1,500,000	12
Roseburg Forest Products	450,707	12
Total Sch. 447	3,135,262	60

	First 10000 thms	Next 20000 thms	Next 20000 thms	Next 200000 thms	>250000 thms	Total therms	Billings
Schedule 456	3,897,200	6,486,906	4,415,618	11,583,266	217,972	26,600,962	408

(1) from Company load forecast for 2010, 4/16/09;
Sch. 447 & Sch. 456 from normalized 2008
(2) shown on workpapers BJH-10
(3) shown on workpaper BJH-7
(4) shown on workpaper BJH-8
(5) shown on workpaper BJH-9

	Total therms	Billings
This worksheet	116,602,382	95,702
Load Forecast		
Schs. 410 - 444	85,843,372	95,662
Schs. 447 & 456	29,137,694	41
	114,981,066	95,703
ignore 2010 447 & 456	-29,137,694	-41
use 2008 447 & 456	29,736,224	39
	115,579,596	95,701
Add Sabroso to load forecast	1,022,786	1
	116,602,382	95,702

Avista Utilities
Oregon - Gas
Year Ended December 31, 2008

Alcan	226563	10,248	10,809	9,653	8,682	10,018	11,646	10,506	12,763	12,727	13,257	14,317	6,971	131,597	
BH Mint	450116435									50,021	2,756			52,777	
Boise Cascade LLC Inland Region	730084103	2,752	4,024	2,339	1,967	1,526	360	103	21	19	21	707	1,575	15,414	
Boise Cascade LLC Medford 4003	180268	1,529	1,833	1,632	1,483	1,733	1,552	1,535	1,500	1,463	1,524	1,431	1,306	18,521	
Borden Chemical Co	109631	13,733	16,803	13,178	10,777	14,024	11,453	7,825	10,434	7,892	9,107	12,190	11,140	138,556	
Dancer Lumber Company	130102623	9,312	15,218	12,167	8,474	15,053	13,445	12,983	12,091	10,308	11,012	14,277	12,063	146,403	
Department of Veterans Affairs	129504	100,784	99,722	94,961	76,774	90,590	58,109	37,771	30,348	25,755	32,088	59,174	77,170	783,246	
Department of Veterans Affairs	217907	59,471	59,724	59,005	54,597	62,719	44,930	41,955	34,990	32,695	40,557	47,073	43,509	581,225	
Grande Ronde Hospital	100086	24,538	33,588	28,056	24,581	24,963	15,408	13,682	13,359	11,831	14,287	17,406	23,612	245,311	
Hamann Angus Ranch	570046355									39,575	25,004			64,579	
Knife River Materials	173985					153						733	1,013	1,899	
Knife River Materials	570117080	2,230									4,772	12,133	2,830	21,965	
Knife River Materials - Roseburg	225016	3,700	4,186	3,710	3,825	4,774	4,472	13,737	7,037	4,472	6,418	4,589	3,208	64,128	
Lagrande School District	101277	29,636	40,475	27,055	21,078	23,082	8,880	3,252	85		476	13,216	17,429	184,664	
Lagrande School District	101870	215	201	217	213	235	220	189	121	138	318	2,542	3,421	8,030	
Medford School Dist 549C	129490	15,389	18,709	18,084	11,186	11,907	4,218	256	5	60	677	6,162	15,966	102,619	
Medford School Dist 549C	133731	9,662	11,219	12,554	7,218	9,151	3,500	1,289	191	190	741	2,414	5,123	63,252	
Medford School Dist 549C	135016	17,489	21,120	18,890	8,259	11,875	3,680	1,379	359	248	645	7,910	12,345	104,199	
Medford School Dist 549C	151901	9,500	10,729	8,965	6,584	8,474	2,472	655	189	172	572	3,584	7,363	59,259	
Orcutt;Dave	770106925									83	26,259			26,342	
Oregon Linen Inc	212741	7,862	7,534	7,786	5,608	6,584	5,812	5,657	6,406	6,349	7,505	8,083	6,615	81,801	
Pinnacle Health Care	290074125	4,938	5,594	4,461	3,939	3,923	3,237	3,286	2,855	2,746	3,584	3,840	3,553	45,956	
Premier Mint Oils, Inc.	690046355									41,866	28,686			70,552	
Sabroso Co 5710-110	157503	94,006	51,872	81,664	53,632	30,427	114,996	297,274	298,915	236,206	217,199	205,073	160,822	1,842,086	
Sky Lakes Medical Center	243178	8,330	8,988	8,204	8,275	9,074	8,533	8,510	8,502	16,654	15,629	13,501	9,429	123,629	
Umpqua Community College	221337	15,610	21,218	16,395	13,213	18,265	8,703	6,948	3,280	2,734	4,557	8,691	9,607	129,221	
Umpqua Dairy	213236	16,769	18,817	17,670	15,989	18,138	14,575	13,211	13,192	11,641	14,738	16,910	14,855	186,505	
VSS Emultech	157430	7,513	13,924	24,147	16,169	13,648	11,802	16,427	15,981	14,758	14,739	11,045	6,595	166,748	
Weishaar Brothers	410046355									28,622	30,091	62		58,775	
Westfarm Foods	129772	10,083	9,413	10,157	6,754	10,405	8,859	7,543	7,586	6,481	8,430	8,537	7,861	102,109	
Total OR Sch 440 therms		475,299	485,720	480,950	369,277	400,741	360,862	505,973	480,210	565,706	535,649	495,600	465,381	5,621,368	
Total Billings		38	37	37	37	38	37	37	36	41	42	40	39	459	
Revenue Runs		382,730	433,647	399,069	315,432	370,079	245,646	208,510	180,546	565,568	535,331	517,908	465,381	4,619,847	
plus Adjustments															From / To
Lagrande School District	101870	215	201	217	213	235	220	189	121	138	318			2,067	420 Oct '08 only
Rogue Valley Manor	157502											-24,850		-24,850	didn't switch to 440 fr 456
Sabroso Co 5710-110	157503	94,006	51,872	81,664	53,632	30,427	114,996	297,274	298,915					1,022,786	Sch 456 / 440
other unknown		-1,652							628			2,542		1,518	
Subtotal Adjustments		92,569	52,073	81,881	53,845	30,662	115,216	297,463	299,664	138	318	-22,308		1,001,521	
Revenue Run therms after adjustments		475,299	485,720	480,950	369,277	400,741	360,862	505,973	480,210	565,706	535,649	495,600	465,381	5,621,368	

ANNUAL USAGE, Sch 444	**Cust No**	**JAN08**	**FEB08**	**MAR08**	**APR08**	**MAY08**	**JUN08**	**JUL08**	**AUG08**	**SEP08**	**OCT08**	**NOV08**	**DEC08**	**Total**
Agri Star Inc	114300								1	3	2,753	172		2,929
City of Grants Pass	189716						3,433	776	934	1,394				6,537
Ferguson Ranch	410101104								5,028	2,745				7,773
N Valley Mint Distillers	112799									13,620	8,171			21,791

Avista Utilities
Oregon - Gas
Year Ended December 31, 2008

Oregon Trail Mint	112009									14,089	30,588			44,677
Rogers Asphalt & Paving	103914		14	20	11	2,369	2,722	6,054	5,722	692	9,012	2,914	3,960	33,490
Rovey Farms	770097678									29,310	8,116			37,426
Willow Creek Mint	113309									22,772	7,413			30,185
Total OR Sch 444 therms			14	20	11	2,369	6,155	6,830	11,685	84,625	66,053	3,086	3,960	184,808
Total Billings		0	1	1	1	1	2	2	4	8	6	2	1	29
Revenue Runs			14	20	11	2,369	6,155	6,830	6,656	86,909	68,798	2,914	3,960	184,636
unknown adjustments												172		172
Revenue Run therms after adjustments			14	20	11	2,369	6,155	6,830	6,656	86,909	68,798	3,086	3,960	184,808

ANNUAL USAGE, Sch 447	**Cust No**	**JAN08**	**FEB08**	**MAR08**	**APR08**	**MAY08**	**JUN08**	**JUL08**	**AUG08**	**SEP08**	**OCT08**	**NOV08**	**DEC08**	**Total**
Bio Mass One LP	164412													
Collins Products	243184	90,844	156,516	129,035	104,200	124,841	97,425	124,405	86,500	49,942	110,712	66,292	43,843	1,184,555
Douglas Co Forest Products	219268													
Murphy Plywood Co	450109789	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	1,500,000
Roseburg Forest Products LVL	490049120	24,200	55,721	46,050	33,728	40,325	31,409	26,186	36,921	37,792	46,140	42,742	29,493	450,707
Total OR Sch 447 therms		240,044	337,237	300,085	262,928	290,166	253,834	275,591	248,421	212,734	281,852	234,034	198,336	3,135,262
Total Billings		5	5	5	5	5	5	5	5	5	5	5	5	60
Revenue Runs		121,415	230,911	257,691	277,394	332,915	278,842	310,880	260,258	231,475	249,178	229,637	133,463	2,914,059
normalize Murphy for test period		118,629	106,326	42,394	-14,466	-42,749	-25,008	-35,289	-11,837	-18,741	32,674	4,397	64,873	221,203
Revenue Run therms after adjustments		240,044	337,237	300,085	262,928	290,166	253,834	275,591	248,421	212,734	281,852	234,034	198,336	3,135,262

Sch. 447 Revenue														
Bio Mass One LP	$0.02700	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Collins Products	$0.04694	4,264	7,347	6,057	4,891	5,860	4,573	5,840	4,060	2,344	5,197	3,112	2,058	55,603
Douglas Co Forest Products	$0.03400													
Murphy Plywood	$0.02750	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	41,250
Roseburg Forest Products LVL	$0.02500	605	1,393	1,151	843	1,008	785	655	923	945	1,154	1,069	737	11,268
Total OR Sch 447 usage revenue		$8,307	$12,177	$10,646	$9,172	$10,306	$8,796	$9,932	$8,421	$6,727	$9,788	$7,618	$6,233	$108,121

Sch. 447 Annual Min. Charge calc.			Total
Bio Mass One LP	$38,000	$38,000	$38,000
Collins Products	$0		55,603
Douglas Co Forest Products	$157,000	157,000	157,000
Murphy Plywood	$75,000	33,750	75,000
Roseburg Forest Products LVL	$100,000	88,732	100,000
Total OR Sch 447 annual min. rev.		$317,482	$425,603

Avista Utilities
Oregon - Gas
Year Ended December 31, 2008

ANNUAL USAGE, Sch 456	Cust No	JAN08	FEB08	MAR08	APR08	MAY08	JUN08	JUL08	AUG08	SEP08	OCT08	NOV08	DEC08	Total	1st 10,000 thms/mo
Albina Asphalt	243182	60,095	52,312	36,073	39,540	67,902	113,292	75,921	82,139	84,838	75,723	66,365	40,851	795,051	120,000
American Linen	144478	26,495	27,580	24,586	25,641	26,268	24,013	25,239	26,355	24,840	24,837	25,231	22,694	303,779	120,000
Amy's Kitchen	650100771	67,332	96,547	87,704	90,641	85,352	71,529	54,734	42,942	49,939	57,596	87,747	92,776	884,839	120,000
Aqua Glass West Inc	257144	33,528	39,749	32,103	26,866	24,317	17,921	8,583	2,463	2,267	6,663	13,758	18,294	226,512	99,976
Asante Health System	130040311	35,186	35,596	32,132	31,954	28,710	25,461	21,113	19,200	19,383	20,556	25,798	28,121	323,210	120,000
Bear Creek Operations	157185	57,728	60,639	49,636	50,622	46,181	34,935	32,019	31,044	27,751	33,706	45,602	55,271	525,134	120,000
Boise Cascade LLC Inland Region	109632	161,408	170,480	151,085	110,053	107,496	83,054	83,378	96,770	119,377	114,226	86,131	72,682	1,356,140	120,000
Boise Cascade LLC Inland Region	110939	119,275	108,721	101,926	117,605	26,834	157							474,518	50,157
Boise Cascade LLC Inland Region	730084103	31,842	29,138	24,825	20,634	16,348	14,546	14,768	11,447	12,277	11,911	15,284	18,606	221,626	120,000
Boise Cascade LLC Medford 4003	129502	26,278	36,265	23,176	12,697	20,906	23,425	47,199	43,081	30,471	34,961	34,405	22,235	355,099	120,000
Boise Cascade LLC Medford 4003	156840	52,644	79,714	74,147	61,963	64,302	52,093	30,682	35,342	29,277	39,343	44,645	34,333	598,485	120,000
Boise Cascade LLC Medford 4003	180268	23,242	27,468	25,020	34,214	37,264	38,329	32,955	37,249	32,100	33,499	37,264	32,093	390,697	120,000
C&D Lumber Co	268178	7,316	17,416	19,354	26,168	9,860	3,088		1,231	4,698	2,956	3,827	20,639	116,553	72,976
Carestream Health Inc	130105718	197,670	237,909	217,221	200,308	196,046	184,969	166,604	162,543	157,393	177,772	195,921	172,997	2,267,353	120,000
Certainteed	188444	54,782	95,158	89,752	99,303	102,899	67,857	68,703	75,828	66,587	82,453	75,302	81,583	960,207	120,000
Columbia Forest Products	243187	97,216	184,850	192,465	175,283	192,509	169,683	171,409	155,753	129,625	131,040	85,850	84,854	1,770,537	120,000
E O U	109630	75,365	93,513	70,855	66,534	51,751	35,281	16,420	259	97	10,388	43,405	51,071	514,939	100,356
Green Diamond Sand Products	266363	27,323	49,848	36,974	48,813	41,490	34,301	46,084	46,668	36,458	44,344	52,867	22,964	488,134	120,000
Jeld Wen Inc	256941	136,201	176,435	142,077	125,106	91,820	71,833	82,575	86,418	64,128	17,070	54,492	35,704	1,083,859	120,000
Knife River Materials	173985	5,910	5,670	4,879	6,452	5,479	5,345	95,983	129,591	60,413	61,348	58,076	15,942	455,088	93,735
Master Brand Cabinets	199303	46,731	66,019	58,697	55,265	51,995	33,445	22,202	11,461	10,056	19,735	45,313	42,720	463,639	120,000
Medite Div Sierrapine Ltd	157182	97,846	159,687	187,312	194,279	191,776	163,399	149,600	119,809	103,713	119,687	134,024	183,171	1,804,303	120,000
Mercy Healthcare Inc	224950	36,185	35,618	31,012	31,908	28,733	25,598	25,088	23,897	23,839	25,556	28,150	28,645	344,229	120,000
Murphy Plywood Co	530067699	136,171	158,869	157,988	163,871	138,612	120,535	125,492	119,587	107,919	118,398	133,288	94,209	1,574,939	120,000
Nordic Veneer Inc	226144	67,393	87,188	96,462	90,103	77,787	68,154	62,205	59,292	64,147	77,147	76,296	52,310	878,484	120,000
Providence Medical Center	157183	66,399	66,315	58,867	61,305	54,423	49,845	44,960	40,659	40,600	43,969	54,200	60,323	641,865	120,000
Rogue Valley Manor	157502	47,960	48,472	37,991	37,773	30,392	21,814	17,377	11,036	12,884	15,707	25,464	36,055	342,925	120,000
Rogue Valley Medical Ctr	157030	102,079	103,253	91,878	95,527	88,483	83,900	69,557	65,152	69,692	73,017	85,206	90,750	1,018,494	120,000
Roseburg Forest Products Plant 4	370117415	14,730	14,730	14,730	14,730	14,730	14,730	14,730	14,730	16,415	16,179	16,575	11,435	178,441	120,000
Southern Oregon University	122751	89,616	113,191	94,781	91,858	79,975	50,817	30,227	25,212	24,863	25,379	54,864	80,348	761,131	120,000
Timber Products	157180	205,285	303,407	296,854	279,692	282,728	263,785	261,569	262,508	229,542	243,009	267,429	224,763	3,120,571	120,000
Timber Products	50077265	26,968	34,161	28,309	25,311	24,796	25,762	18,741	20,785	20,713	27,582	28,139	17,930	299,197	120,000
Western Veneer & Slicing	157327	18,899	20,442	13,897	17,291	10,162	13,571	15,990	17,215	19,281	16,364	17,100	12,657	192,869	120,000
White City Plywood	157188	99,257	141,505	102,190	105,216	106,782	93,595	93,780	72,980	12,582	13,681	15,151	11,396	868,115	120,000
Total OR Sch 456		2,352,355	2,977,865	2,706,958	2,634,526	2,425,108	2,100,062	2,025,887	1,950,646	1,708,165	1,815,802	2,033,169	1,870,422	26,600,962	3,897,200
Total Billings		34	34	34	34	34	34	34	34	34	34	34	34	408	
Revenue Runs		2,505,685	3,094,864	2,842,025	2,736,504	2,440,805	2,200,328	2,308,431	2,234,831	1,693,435	1,815,802	2,008,319	1,870,422	27,751,451	
plus Adjustments															From / To
Panel Products	730095677	-74,054	-79,857	-68,133	-63,076									-285,120	closed
Rogue Valley Manor	157502											24,850		24,850	Sch 440 / 456
Roseburg Forest Products Plant 4	370117415	14,730	14,730	14,730	14,730	14,730	14,730	14,730	14,730	14,730				132,567	new; full yr est.
Sabroso Co 5710-110	157503	-94,006	-51,872	-81,664	-53,632	-30,427	-114,996	-297,274	-298,915					-1,022,786	Sch 456 / 440
Subtotal Adjustments		-153,330	-116,999	-135,067	-101,978	-15,697	-100,266	-282,544	-284,185	14,730		24,850		-1,150,489	
Revenue Runs after adjustments		2,352,355	2,977,865	2,706,958	2,634,526	2,425,108	2,100,062	2,025,887	1,950,646	1,708,165	1,815,802	2,033,169	1,870,422	26,600,962	

Revenue Meters Report by Location Twelve Months Ended for Report Date : '09/30/2008'

Service	State C	Rate S	Rate Schedule Desc	RevClsDesc	200812 Meters	Usage	Revenue	TME Avg Meters	Usage	Revenue				
Gas	OR	410	410 RESIDENTIAL NATURAL G	01 RESIDENTIAL	84,077	6,159,374	8,846,115	83,541	50,560,635	76,927,287	G	OR	410	01
				21 FIRM COMMERCIAL	0	0	0	0	0	0	G	OR	410	21
				Sum	84,077	6,159,374	8,846,115	0	50,560,635	76,927,287	G	OR	410	
		420	420 GENERAL NATURAL GAS S	01 RESIDENTIAL	37	4,527	6,113	35	37,537	52,892	G	OR	420	01
				21 FIRM COMMERCIAL	11,003	3,270,330	4,296,152	10,962	28,138,915	38,494,301	G	OR	420	21
				31 FIRM- INDUSTRIAL	15	6,840	8,920	15	80,601	109,041	G	OR	420	31
				80 INTERDEPARTMENT REVEN	15	1,440	1,972	15	16,148	22,840	G	OR	420	80
				Sum	11,070	3,283,137	4,313,157	0	28,273,201	38,679,074	G	OR	420	
		424	424 LARGE GENERAL AND IND	21 FIRM COMMERCIAL	94	375,654	445,573	94	3,915,612	4,883,470	G	OR	424	21
				31 FIRM- INDUSTRIAL	2	6,703	7,957	2	118,536	147,059	G	OR	424	31
				Sum	96	382,357	453,530	0	4,034,148	5,030,530	G	OR	424	
		440	440 INTERRUPTIBLE NATURAL	22 INTERRUPTIBLE COMMERC	26	389,349	344,465	25	3,269,524	3,040,414	G	OR	440	22
				41 INTERRUPTIBLE-INDUSTRI	12	76,032	67,267	13	1,350,323	1,256,369	G	OR	440	41
				Sum	38	465,381	411,732	0	4,619,847	4,296,783	G	OR	440	
		444	444 SEASONAL NATURAL GAS	21 FIRM COMMERCIAL	0	0	0	1	6,537	7,984	G	OR	444	21
				31 FIRM- INDUSTRIAL	1	3,960	4,628	3	178,099	217,377	G	OR	444	31
				Sum	1	3,960	4,628	0	184,636	225,361	G	OR	444	
		447B	447B SPECIAL CONTRACT - BI	92 INDUSTIAL-TRANS OF GAS	1	0	0	1	0	38,000	G	OR	447B	92
				Sum	1	0	0	0	0	38,000	G	OR	447B	
		447D	447D SPECIAL CONTRACT - D	92 INDUSTIAL-TRANS OF GAS	1	0	0	1	0	156,998	G	OR	447D	92
				Sum	1	0	0	0	0	156,998	G	OR	447D	
		447M	447M SPECIAL CONTRACT - M	92 INDUSTIAL-TRANS OF GAS	1	60,127	1,653	1	1,278,797	35,167	G	OR	447M	92
				Sum	1	60,127	1,653	0	1,278,797	35,167	G	OR	447M	
		447R	447R SPECIAL CONTRACT - R	92 INDUSTIAL-TRANS OF GAS	1	29,493	737	1	450,707	76,817	G	OR	447R	92
				Sum	1	29,493	737	0	450,707	76,817	G	OR	447R	
		447W	447W SPECIAL CONTRACT - C	92 INDUSTIAL-TRANS OF GAS	1	43,843	2,058	1	1,184,555	55,614	G	OR	447W	92
				Sum	1	43,843	2,058	0	1,184,555	55,614	G	OR	447W	
		456	456 TRANSPORTATION SERVI	22 INTERRUPTIBLE COMMERC	0	0	0	0	0	0	G	OR	456	22
				91 COMMERCIAL-TRANS OF G	8	398,277	33,220	8	4,566,909	370,413	G	OR	456	91
				92 INDUSTIAL-TRANS OF GAS	28	1,472,145	112,238	28	23,184,542	1,635,131	G	OR	456	92
				Sum	36	1,870,422	145,458	0	27,751,451	2,005,544	G	OR	456	
		460	TAX ADJUSTMENT IN TERRIT	01 RESIDENTIAL	0	0	142,569	0	0	1,244,601	G	OR	460	01
				21 FIRM COMMERCIAL	0	0	76,131	0	0	699,284	G	OR	460	21
				22 INTERRUPTIBLE COMMERC	0	0	5,999	0	0	40,221	G	OR	460	22
				31 FIRM- INDUSTRIAL	0	0	228	0	0	2,334	G	OR	460	31
				41 INTERRUPTIBLE-INDUSTRI	0	0	1,062	0	0	13,984	G	OR	460	41
				80 INTERDEPARTMENT REVEN	0	0	0	0	0	3	G	OR	460	80
				91 COMMERCIAL-TRANS OF G	0	0	741	0	0	7,868	G	OR	460	91
				92 INDUSTIAL-TRANS OF GAS	0	0	1,056	0	0	15,042	G	OR	460	92
				Sum	0	0	227,785	0	0	2,023,337	G	OR	460	
		499	499 REPORTING SCHED NUMB	19 THEFT OF SERVICE-GAS	0	0	1,167	0	0	12,534	G	OR	499	19
				88 MISC-SERVICING CUSTOME	0	0	9,975	0	0	122,645	G	OR	499	88
				Sum	0	0	11,142	0	0	135,179	G	OR	499	
		Sum			95,323	12,298,094	14,417,997	0	118,337,977	129,685,690	G	OR	Sum	

Summary by Rate Schedule

Total 410 RESIDENTIAL NATURAL GAS SERVICE	GOR410		84,077	6,159,374	8,846,115	83,541	50,560,635	76,927,287
Total 420 GENERAL NATURAL GAS SERVICE	GOR420		11,070	3,283,137	4,313,157	11,027	28,273,201	38,679,074
Total 424 LARGE GENERAL AND INDUSTRIAL SERVIC	GOR424		96	382,357	453,530	96	4,034,148	5,030,530
Total 424J LARGE GENERAL SERVICE - JACKSON CO	GOR424J		0	0	0	0	0	0
Total 440 INTERRUPTIBLE NATURAL GAS SERVICE	GOR440		38	465,381	411,732	38	4,619,847	4,296,783
Total 444 SEASONAL NATURAL GAS SERVICE	GOR444		1	3,960	4,628	3	184,636	225,361
Total 447B SPECIAL CONTRACT - BIOMAS	GOR447B		1	0	0	1	0	38,000
Total 447D SPECIAL CONTRACT - DOUGLAS COUNTY	GOR447D		1	0	0	1	0	156,998
Total 447M SPECIAL CONTRACT - MURPHY PLYWOO	GOR447M		1	60,127	1,653	1	1,278,797	35,167
Total 447R SPECIAL CONTRACT - ROSEBURG FOREST	GOR447R		1	29,493	737	1	450,707	76,817
Total 447W SPECIAL CONTRACT - COLLINS	GOR447W		1	43,843	2,058	1	1,184,555	55,614
Total 456 TRANSPORTATION SERVICE - INTERRUPTI	GOR456		36	1,870,422	145,458	36	27,751,451	2,005,544
Total 460 TAX ADJUSTMENT IN TERRITORY SERVED	GOR460		0	0	227,785	0	0	2,023,337
Total 499 REPORTING SCHED NUMBER FOR MISC GA	GOR499		0	0	11,142	0	0	135,179
		Total	95,323	12,298,094	14,417,997	94,746	118,337,977	129,685,690
		GORSum	95,323	12,298,094	14,417,997	94,746	118,337,977	129,685,690
		Diff	0	0	0	0	0	0

Summary by Rate Class - 12 Mos.

		Meters	Usage
Res	OR01	83,576	50,598,172
Theft	OR19	0	0
Comm	OR21	11,056	32,061,064
Comm-Int	OR22	25	3,269,524
Ind	OR31	20	377,236
Ind-Int	OR41	13	1,350,323
Intdpt	OR80	15	16,148
Misc Svc	OR88	0	0
Comm-Tra	OR91	8	4,566,909
Ind-Tra	OR92	33	26,098,601
Total OR		94,746	118,337,977
Other Rev (493)			
Total OR excl Unbi		94,746	118,337,977
		0	0
Retail		94,746	118,337,977
Unbilled			782,702
Total OR		94,746	119,120,679