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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO.	**CASE NO. AVU-E-04-1/ AVU-G-04-1**

DIRECT TESTIMONY OF MICHAEL FUSS

IDAHO PUBLIC UTILITIES COMMISSION

JUNE 21, 2004

Q. Please state your name and business address for the record.

A. My name is Michael Fuss. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as a Staff engineer.

Q. What is your educational and professional background?

A. I have a Bachelor of Science Degree in Civil Engineering from Washington State University and a Master of Business Administration Degree from Boise State University. I am a licensed Civil Engineer in the states of Idaho, Oregon, and Washington. I am a past president of the Southern Idaho Section of the American Society of Civil Engineers and have been a member of various professional affiliations and service organizations.

I have over 15 years of Civil Engineering Experience in the areas of Municipal, Utility, Regulatory, and Development Civil Engineering and consulting.

While at the Idaho Public Utility Commission I have attended the National Association of Regulatory Utility Commissioners (NARUC) Basic Training Program, Risk Management Techniques for the Natural Gas Industry at New Mexico State University and the Northwest Public Power Association's course on Unbundled Cost of Service & Rate Design.

Q. What is the purpose of your testimony?

A. My testimony pertains only to Avista's Natural Gas (Gas) rate case. In my testimony I review the Company's Natural Gas Jurisdictional Separation Study (Separation Study). This separation study is used by Avista to develop the Idaho gas unadjusted results of operation.

I review the Company's Gas Cost of Service (COS) Study, its method of incorporating the results of operation adjustments, and the development of the Class Revenue Requirement.

I also review the Cost of Gas in base rates, Gas Special Contracts, and recommend an additional natural gas tariff sheet.

Q. How is your testimony structured?

A. My testimony is structured as follows:

Summary

Gas Jurisdictional Separation

Methodology

Adjustments

Cost of Service

Methodology

Other Studies

Adjustments

Adjustment Summary

Cost of Gas in Base Rates

Special Contracts

Tariff Summary Sheet Recommendation

Q. Would you please summarize your testimony?

A. I have reviewed and recommend acceptance of the Company's Gas Jurisdictional Separation Study using the Four-Factor methodology with one minor adjustment.

I have also reviewed and recommend acceptance of the Company's Gas Cost of Service Study known as the Washington Accepted Methodology with exception of two adjustments. I recommend an adjustment in usage within the pro forma revenue calculation that results in an increase of $23,000 to current revenues. I also recommend allocating storage expenses and credits based on winter therm usage as opposed to the annual usage proposed by the Company.

I recommend that the Company's request to move the cost of gas in base rates to $0.44989/therm be considered reasonable. I believe increasing the cost of gas in base rates will reduce the overall magnitude of future PGA adjustments. If actual gas costs increase, the PGA adjustment will be lower; and if actual gas costs decrease, a PGA credit is more likely.

I recommend acceptance of the Company's treatment of Idaho gas special contracts within the Gas COS Study. I believe the Gas COS Study appropriately allocates gas special contract revenues and expenses.

I recommend that the Company be directed to add a tariff summary sheet to its gas tariff schedules. I believe the additional tariff sheet will not be administratively burdensome for the Company and it will provide clarity for Customers.

GAS JURISDICTIONAL SEPARATION STUDY

Q. Have you reviewed the Company's Gas Jurisdictional Separation Study and do you have any recommendations regarding the study?

A. Yes, I have reviewed the Company's Gas Jurisdictional Separation Study and recommend that the Commission accept the Separation Study with a minor adjustment. The Separation Study uses the Four-Factor methodology, a methodology first reviewed by Staff when initiated by the Company in 1993. The Separation Study is also consistent with the methodology used in Case No. WWP-E-98-11, the last Avista Idaho Electric General Rate Case. Furthermore, the general methodology of the Separation Study has been approved for the Company in all of its other operating jurisdictions.

Methodology

Q. Please give a brief description of the Company's Gas Jurisdictional Separation Study methodology.

A. Jurisdictional separation is performed in the following steps.

<u>Direct Assignment</u>

All expenses, revenues, and rate base investments that can be directly assigned are allotted to the Idaho gas jurisdiction.

<u>Utility Codes</u>

For items not directly assigned, six utility codes are used to assign expenses, revenues and rate base to common cost categories. The categories are Avista Electric, Avista Gas, WPNG (Avista Gas OR/CA), Common to Avista Electric and Avista Gas, Common to Avista Gas and WPNG, and Common to Avista Electric, Avista Gas and WPNG.

<u>Four-Factor</u>

For common items the Company uses an allocator composed of four factors to allocate these items to the Idaho natural gas utility. The four factors are: Direct O&M Expense excluding labor and resource costs, Direct Labor, Number of Customers, and Net Direct Plant.

<u>Other Allocators</u>

The Company uses a number of other allocators such as five-day firm peak demand, distribution operating expense and number of customers to allocate the appropriate Avista Gas costs to the Idaho gas jurisdiction.

Adjustments

Q. Do you recommend that the methodology from the Company's Gas Jurisdictional Separation Study be accepted without change?

A. No. I believe that one minor adjustment is necessary.

Q. Would you please explain your minor adjustment?

A. I believe the Separation Study is inconsistent in the allocation of plant investment, expenses, and revenues in the following tax adjusting (Schedule "m") accounts in report G-SCM-12A: 1999.09 Hardware/Software/Furniture Lease Payments, 1999.13 Airplane Lease Payments, and 1999.14 Sale Leaseback of General Office Building. In the Separation Study as filed, the Company uses allocator 5-Actual Therms Purchased for these accounts. I believe this is incorrect.

In all other areas within the Separation Study where I reviewed the natural gas accounts 1999.09, 1999.13, and 1999.14, the revenue and expenses were allocated using the four-factor allocator. The same

Schedule "m" accounts are also allocated using the four-factor methodology in the Electric Jurisdictional Separation Study. Therefore, I recommend that the appropriate four-factor allocator be used to distribute costs in the stated gas accounts.

Q. What is the net affect of this adjustment?

A. Using the four-factor allocator on the listed accounts reduces Idaho's share of taxes and the Idaho gas net operating income by $1,888. The Company in answer to Staff Production Request No. 179 confirmed the amount of the adjustment.

GAS COST OF SERVICE STUDY

Methodology

Q. Would you please describe the Company's Gas Cost of Service (COS) Study?

A. Certainly, the Company's Gas COS Study is a complex operation using three main Excel spreadsheets to incorporate the results of operation, make adjustments, functionalize, classify, and allocate expenses to develop the revenue requirement for the various customer classes. Output from the Gas COS Study is then used to help design rates. The Company uses the spreadsheet "Proform" to incorporate the results of operation and make adjustments. It uses the spreadsheet "Assign" to functionalize, classify, and assign costs. "Assign" contains various parameters used to develop allocation factors and facilitate cost assignment. The final spreadsheet "Sumcost" organizes the results and provides a revenue requirement estimate for each customer class.

The Company's Gas Cost of Service Study also incorporates a number of "other studies" used to normalize the results and create allocation factors. Some of the other studies worth mentioning are the weather normalization study, the Pro Forma Gas Revenue Calculation, the Labor Dollars study, and the Weighted Meter and Service Cost Analysis.

Other Studies

Q. Would you please explain the significance of these other studies and why these particular studies are most important?

A. Certainly. The weather normalization study is important because natural gas usage is highly weather dependant for most customer classes. The weather normalization study uses regression analysis to determine the amount of gas consumption that is weather dependant for each customer class. It also relates the test year weather pattern to a 30-year normal weather pattern and adjusts the test year usage to reflect normal weather conditions. Staff witness Sterling's direct testimony includes additional discussion on weather normalization.

The Pro Forma Revenue Calculation develops normalized billing determinants (therms and customers) adjusting the test year to reflect expected conditions on average. This includes but is not limited to known customer changes, weather normalization, and period adjustments. The Pro Forma Calculation uses rates in place during the test year to reflect the appropriate normalized revenue generation by the various customer classes.

The Labor Dollars Study is a study that is embedded within the Gas COS Study that determines labor cost allocation. This study is important because it is used to develop labor allocators used in the four-factor allocator within the Jurisdictional Separation Study. The labor allocators are also used to allocate costs for some labor related accounts.

The Weighted Meter and Service Cost Analysis is an engineering/economic study that calculates metering and service costs for the various customer classes. This study is important because it creates weighting factors and cost relationships used to allocate a number of meter and customer cost categories.

Q. What is the purpose of the Gas Cost of Service Study?

A. The Gas Cost of Service Study is an engineering economic analysis that allocates expenses to establish the revenue requirement based on cost causation. The account-by-account study apportions each expense to the various customer classes or rate schedules. The Gas Cost of Service Study is the starting point in ultimately establishing rates for each customer class. The results of the study provide an indication of the amount of revenue that should be generated from rates for each customer class or rate schedule.

Q. Do you agree with the Company's Gas Cost of Service Study?

A. Not entirely; there are any number of ways to perform a cost of service study and any number of items that can be used to allocate costs among customer classes. Any individual or interest group could reasonably argue for changes that would cause costs to shift from one customer class to another. After a detailed review of the Company's Gas COS Study, I believe several small adjustments are required.

Adjustments

Q. What changes to the Company's Gas Cost of Service Study do you recommend?

A. I recommend changes to the Company's Pro Forma Gas Revenue calculation. The Company adjusts for known and measurable changes in usage by adding or subtracting revenue in the Pro Forma Revenue Calculation. In Brian Hirschkorn's workpapers GA1-GA5 adjustments are made in gas consumption to reflect actual conditions, weather normalization, and unbilled usage. The consumption reduction in Mr. Hirschkorn's calculation of revenue associated with Schedules 111 and 112 double counts gas revenue included in the monthly minimum charge. Double counting the reduction causes an understatement of approximately $23,000 in the Idaho Gas Pro Forma Revenue Calculation. I recommend that additional revenue be included in the Company's Gas COS Study to properly reflect normalized revenues.

I further recommend adding consumption to the normalized billing determinants used to determine proposed rates.

Q. What is the net affect of your recommended adjustments?

A. The net affect of my adjustments is a decrease in Idaho Gas Revenue Requirement of $23,414 when tax effects are included.

Q. Does Staff agree with the methodology the Company uses to allocate storage costs and storage capacity release credits to the various Idaho customer classes?

A. No. Staff has reviewed the Company's

methodology and believes that adjustment is necessary. The Company allocates storage costs and credits among the Idaho classes based on annual consumption. While this methodology will allocate costs and credits, it does not reflect the true value each class receives when using the Company's storage facilities.

The primary purpose of the Company's storage facilities is for winter peak supply. The use of the storage facilities is very limited throughout the rest of the year. In fact stored gas is currently distributed to Idaho on a systematic schedule. Storage is used in the months of November, December, January, February, and March. Staff believes that allocating storage costs based on individual customer class usage over these months is more appropriate because it better reflects values received by each class. Consequently, I have included this allocation methodology in the Company's Gas Cost of Service Study.

Furthermore, Staff believes that the storage capacity release credits should also be allocated based on the monthly storage withdrawal cycle. Staff has made two adjustments to the Company's Gas Cost of Service Study to reflect this change. Staff first allocates the credit over the Company's fixed storage withdrawal schedule on the basis of volume to determine the amount of credit attributable to each month. Staff then allocates the monthly storage credit to each customer class based on the class's contribution to the monthly throughput. I have included this allocation methodology in Staff's adjustment to the Gas Cost of Service Study. The storage allocator calculation is attached as Exhibit No. 136. All natural gas rates and Gas Cost of Service results presented in my testimony include these allocations. While the changes to the storage allocations do not change the Gas Jurisdictional Revenue Requirement, Staff believes it provides a more appropriate revenue requirement by customer class. Staff recommends that the Commission approve allocation of storage costs and credits based on the Company's actual use of storage.

Adjustment Summary

Q. What is the net affect on the Gas Jurisdictional Revenue Requirement from the recommended adjustments included in your testimony?

A. The net affect to the Idaho Gas Revenue Requirement is a decrease of $26,367. The decrease is shown as adjustment G13 & G14 on Staff Exhibit No. 107.

Q. Have you provided a summary of the Staff adjusted Gas Cost of Service results?

A. Yes, attached as Exhibit No. 137 are the results of the Staff adjusted Gas Cost of Service Study.

COST OF GAS IN BASE RATES

Q. Has the Company requested a change in the cost of gas included in base rates?

A. Yes, the Company has requested to increase gas costs in base rates to $0.44989/therm.

Q. Do you believe an adjustment of gas cost in base rates is necessary?

A. Yes, over the past several years the Company has requested and received several fairly large Purchase Gas Cost Adjustments (PGA). These rate adjustments were intended to reflect the Company's actual cost of gas purchased for customers above the price of gas included in base rates. The Company is proposing to add the current PGA WACOG adjustment of $0.27186/therm to base rates to produce a total base rate gas cost of $0.44989/therm.

I believe this change in gas cost is appropriate. Base rates should reflect the best estimate of what gas costs would be in the future. The more accurately base rates reflect gas costs, the less extreme PGA adjustments will be.

Q. Is a gas cost of $0.44989/therm the appropriate price level to be included in base rates today?

A. While Staff cannot predict the magnitude of future natural gas prices with certainty, we believe that the $0.44989/therm proposed by the Company is a reasonable price level for natural gas in base rates going forward. Natural gas prices are considerably higher today than in 1988 when the current base rate gas price of $0.17803/therm was established. However, Staff notes that increasing gas costs included in base rates will not eliminate the need for a PGA in the future. To the extent actual gas costs increase, the PGA will simply be lower than it otherwise would have been. If actual gas costs decrease, then larger PGA credits will result.

That being said, natural gas is in a period of extreme volatility. Staff believes that natural gas prices will likely vary between $0.300 and $0.600 over the next five to seven years. The Company's proposed cost of gas in base rates falls at approximately the mid-point of Staff's estimated range of future gas prices. Therefore, Staff recommends that the Company's proposal be accepted.

SPECIAL CONTRACTS (NATURAL GAS)

Q. How are Idaho Gas Special Contract customers like Potlatch, IMCO, and Lignetics treated in the rate case?

A. The Company has included all expenses associated with serving Idaho's Gas Special Contract customers in the general rate filing. These expenses are allocated among all customer classes using the same methodology used for allocating other service costs. In order to offset the rate effect of allocating special contract expenses to other customer classes, special contract revenue is also credited to the classes. The result is the inclusion of costs and benefits to all other customer classes.

Staff believes that the revenue credit continues to provide an adequate offset to Company expenses as approved by the Commission during the contract approval process. Based on Staff's review of the Company's Gas Cost of Service Study, the credits are appropriately applied.

Q. Are Idaho Gas Special Contract Customers rates changed as a result of this case?

A. No. All Gas Special Contract Customers in Idaho are served under existing long-term contracts at fixed rates. All current Idaho contracts were in place before the test year used by the Company in this case. While Special Contract rates are not changed as a result of this case, the Commission has previously reviewed the contract conditions and revenue contribution from these customers and found them prudent. However, when the current contracts expire, the terms and contribution of each contract should be reevaluated and updated to reflect the appropriate cost of service or appropriate level of contribution to margin. Staff does not believe that any change is necessary at this time.

TARIFF ISSUE

Q. Do you have any natural gas general tariff recommendations?

A. Yes, Staff recommends that the Company add a tariff summary sheet, denoted as sheet D, which summarizes all natural gas rate schedules and all natural gas adjustment clauses with the exception of local franchise fees. Currently the Company uses a number of tariff sheets such as Schedules 150, 155, and 191 to identify various periodic rate adjustments such as Purchase Gas Adjustments (PGAs) and Demand Side Management (DSM) tariff riders. While the use of the various tariff schedules minimizes the number of sheets that must be updated, the practice increases the likelihood for rate calculation errors and is somewhat confusing to customers. Staff believes adding a tariff sheet will benefit customers and will not be overly burdensome on the Company.

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

A. Yes, it does.

Staff Calculation
Allocate Storage Costs Based on Storage Withdrawal Schedule

Withdrawal from Schedule 163 paragraph 4
5/28/2004

Storage Capacity Release Credit to Idaho $647,000

Spread of Credit based on the Storage Withdrawal Schedule		
From Schedule 163 Para 4		
	Withdrawal Dth	Credit Spread
November	65179	$61,579
December	170748	$161,316
January	213435	$201,645
February	192780	$182,131
March	42687	$40,329
Total	684829	$647,000

Rate Schedule Allocator Based on Winter Usage							
Data From Production Request 290							
	Sch 101	Sch 111	Sch 121	Sch 131	Sch 146	Total	
November	5148821	1269795	222157	60150	381259	7082182	
December	6649173	1535662	225555	62009	374138	8846537	
January	8669247	1939247	204488	60327	378706	11252015	
February	7606192	1728687	197331	50236	322536	9904982	
March	7340150	1692575	212566	47471	288421	9581183	
Total	35413583	8165966	1062097	280193	1745060	46666899	**New Allocator E08**
						46666899	Check

Summed Allocator for Storage Capacity Credit							
Credit Allocated To Schedule Based on Therm Usage							
	Sch 101	Sch 111	Sch 121	Sch 131	Sch 146	Total	
November	$44,768	$11,041	$1,932	$523	$3,315	$61,579	
December	$121,247	$28,003	$4,113	$1,131	$6,822	$161,316	
January	$155,360	$34,753	$3,665	$1,081	$6,787	$201,645	
February	$139,861	$31,787	$3,628	$924	$5,931	$182,131	
March	$30,896	$7,124	$895	$200	$1,214	$40,329	
Total	$492,133	$112,707	$14,232	$3,858	$24,069	$647,000	**New Allocator S22**
						$647,000	Check

Exhibit No. 136
Case No. AVU-E-04-1/
AVU-G-04-1
M. Fuss, Staff
6/21/04

Sumcost	AVISTA UTILITIES AS ADJUSTED BY PUC STAFF	Natural Gas Utility	
Company Base Case	Cost of Service General Summary	Idaho Jurisdiction	6/18/04
WA Accepted Methodology	For The Twelve Months Ended December 31, 2002		4:37 PM

	(b) Description	(c) (d) (e)	(f) System Total	(g) Residential Service Sch 101	(h) Small Firm Service Sch 111	(i) Large Firm Service Sch 121	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Plant In Service							
1	Production Plant							
2	Underground Storage Plant		5,041,000	3,825,407	882,095	114,729	30,267	188,503
3	Distribution Plant		87,598,000	75,115,371	10,131,341	937,240	199,847	1,214,201
4	Intangible Plant		766,000	652,766	91,047	8,694	1,902	11,591
5	General Plant		5,943,000	5,064,228	706,537	67,486	14,762	89,987
6	Total Plant In Service		99,348,000	84,657,773	11,811,019	1,128,149	246,778	1,504,281
	Accum Depreciation							
7	Production Plant							
8	Underground Storage Plant		(2,294,000)	(1,740,822)	(401,414)	(52,209)	(13,773)	(85,782)
9	Distribution Plant		(26,397,000)	(22,793,740)	(2,880,654)	(299,560)	(63,624)	(359,421)
10	Intangible Plant		(626,000)	(533,435)	(74,422)	(7,109)	(1,555)	(9,479)
11	General Plant		(2,076,000)	(1,769,029)	(246,806)	(23,574)	(5,157)	(31,434)
12	Total Accumulated Depreciation		(31,393,000)	(26,837,027)	(3,603,296)	(382,452)	(84,110)	(486,115)
13	Net Plant		67,955,000	57,820,746	8,207,723	745,696	162,668	1,018,166
14	Accumlulated Deferred FIT		(9,831,160)	(8,377,462)	(1,168,781)	(111,638)	(24,420)	(148,859)
15	Miscellaneous Rate Base		743,000	515,867	138,081	32,620	6,839	49,592
16	Total Rate Base		58,866,840	49,959,152	7,177,023	666,679	145,087	918,899
17	Revenue From Retail Rates		51,419,278	40,113,651	8,954,774	1,521,691	385,070	444,092
18	Other Operating Revenues		1,156,000	925,383	173,755	19,897	5,091	31,875
19	Total Revenues		52,575,278	41,039,034	9,128,529	1,541,588	390,161	475,967
	Operating Expenses							
20	Purchased Gas Costs		35,797,892	27,296,587	6,923,227	1,262,238	312,505	3,334
21	Underground Storage Expenses		133,805	101,539	23,414	3,045	803	5,003
22	Distribution Expenses		2,123,435	1,822,953	214,313	39,047	8,452	38,669
23	Customer Accounting Expenses		1,918,196	1,863,897	46,106	5,235	1,309	1,649
24	Customer Information Expenses		257,116	220,236	23,672	4,865	1,023	7,321
25	Sales Expenses		216,129	213,954	2,105	37	7	26
26	Admin & General Expenses		3,593,160	2,950,686	436,794	74,663	20,296	110,721
27	Total O&M Expenses		44,039,733	34,469,853	7,669,631	1,389,130	344,396	166,723
28	Taxes Other Than Income Taxes		876,000	746,673	104,021	9,923	2,168	13,215
29	Depreciation Expense							
30	Underground Storage Plant Depr		104,968	79,656	18,368	2,389	630	3,925
31	Distribution Plant Depreciation		2,125,000	1,841,640	226,067	23,626	5,013	28,653
32	General Plant Depreciation		321,016	273,548	38,164	3,645	797	4,861
33	Amortization of Intangible Plant		260,000	221,555	30,910	2,952	646	3,937
34	Total Depr & Amort Expense		2,810,984	2,416,399	313,509	32,613	7,087	41,376
35	Income Tax		1,389,744	707,601	469,169	52,362	19,775	140,837
36	Total Operating Expenses		49,116,461	38,340,526	8,556,330	1,484,027	373,426	362,151
37	Net Income		3,458,817	2,698,508	572,199	57,561	16,734	113,815
38	Rate of Return		5.88%	5.40%	7.97%	8.63%	11.53%	12.39%
39	Return Ratio		1.00	0.92	1.36	1.47	1.96	2.11
40	Interest Expense		2,761,000	2,343,207	336,620	31,269	6,805	43,099

Exhibit No. 137
Case No. AVU-E-04-1/
AVU-G-04-1
M. Fuss, Staff

Sumcost
Company Base Case
WA Accepted Methodology

AVISTA UTILITIES AS ADJUSTED BY PUC STAFF
Cost of Service General Summary
For The Twelve Months Ended December 31, 2002

Natural Gas Utility
Idaho Jurisdiction

6/18/04
4:37 PM

(b) Description	(c) (d) (e)	(f) System Total	(g) Residential Service Sch 101	(h) Small Firm Service Sch 111	(i) Large Firm Service Sch 121	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
STAFF REVENUE REQUIREMENT CALCULATION							
Total Rate Base		$58,866,840	$49,959,152	$7,177,023	$666,679	$145,087	$918,899
Total Current Revenues		$52,575,278	$41,039,034	$9,128,529	$1,541,588	$390,161	$475,967
Total Current Operating Expenses AT		$49,116,461	$38,340,526	$8,556,330	$1,484,027	$373,426	$362,151
Net Income AT		$3,458,817	$2,698,508	$572,199	$57,561	$16,734	$113,815
Current Rate of Return		5.88%	5.40%	7.97%	8.63%	11.53%	12.39%
Percent of Current Return		100.00%	91.93%	135.69%	146.94%	196.30%	210.80%
Recommended Rate of Return		9.25%	9.25%	9.25%	9.25%	9.25%	9.25%
Net Income Required At Rec. ROR		$5,445,183	$4,621,222	$663,875	$61,668	$13,421	$84,998
Income Deficiency BT		$1,986,366	$1,922,714	$91,676	$4,107	($3,314)	($28,817)
Tax Gross Up Factor		0.639261	0.639261	0.639261	0.639261	0.639261	0.639261
Increase in Rev. Rqmt. AT		$3,107,284	$3,007,713	$143,409	$6,425	($5,184)	($45,079)
Total Recommended Revenue Requirement		$55,682,562	$44,046,747	$9,271,938	$1,548,013	$384,977	$430,888
Other Operating Revenues (Staff Alloc)		($1,156,000)	($925,383)	($173,755)	($19,897)	($5,091)	($31,875)
Rev. Req. From Rates @ COS & ROR		$54,526,562	$43,121,364	$9,098,183	$1,528,116	$379,886	$399,013
Staff Adjustment		$0	($213,745)	$105,251	$21,840	$10,759	$75,895
Staff Recommended Rate Revenue Requirement		$54,526,562	$42,907,619	$9,203,435	$1,549,956	$390,644	$474,908
Cost of Service Index		100.00%	99.50%	101.16%	101.43%	102.83%	119.02%
Recommended Increase		$3,107,284	$2,793,968	$248,660	$28,265	$5,575	$30,816
Recommended Increase (%)		5.98%	6.97%	2.78%	1.86%	1.45%	6.94%

AVISTA UTILITIES
STAFF PROPOSED COST OF SERVICE BY SCHEDULE
IDAHO - GAS
12 MONTHS ENDED DECEMBER 31, 2002
(000s of Dollars)

Line No	Type of Service	Schedule Number	Revenue Under Present Rates (1)	Move to COS	Cost of Service Revenue Requirement	Therms (000s)	Cost of Service Per Therm	Cost of Gas
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	General Service	101	$40,114	$3,008	$43,121	50978	84.588¢	$27,297
2	Large General Service	111	$8,955	$143	$9,098	12930	70.368¢	$6,923
3	High Annual Load Factor LGS	121	$1,522	$6	$1,528	2357	64.825¢	$1,262
4	Interruptible Service	131	$385	($5)	$380	691	54.974¢	$313
5	Transportation Service	146	$444	($45)	$399	4200	9.501¢	$3
6	Special Contracts		$500	$0	$500	58852	0.850¢	$0
7	Total		$51,919	$3,107	$55,027	130007	42.326¢	$35,798

(1) Includes Purchase Adjustment Schedule 150 / Excludes other rate adjustments

AVISTA UTILITIES AS ADJUSTED BY PUC STAFF
Summary by Function with Margin Analysis
For The Twelve Months Ended December 31, 2002

Natural Gas Utility
Idaho Jurisdiction

6/18/04
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	(b) Description	(c) (d) (e)	(f) System Total	(g) Residential Service Sch 101	(h) Small Firm Service Sch 111	(i) Large Firm Service Sch 121	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Functional Cost Components at Current Rates							
1	Production		36,008,084	27,456,863	6,963,878	1,269,650	314,340	3,353
2	Underground Storage		(174,818)	(175,993)	(9,368)	229	1,134	9,179
3	Distribution		11,422,937	9,444,718	1,463,583	168,334	46,803	299,499
4	Common		4,163,193	3,388,156	536,701	83,482	22,794	132,061
5	**Total Current Rate Revenue**		**51,419,396**	**40,113,743**	**8,954,795**	**1,521,695**	**385,070**	**444,093**
6	Exclude Cost of Gas w / Revenue Exp.		35,847,253	27,336,965	6,933,468	1,264,105	312,715	0
7	**Total Margin Revenue at Current Rates**		**15,572,143**	**12,776,778**	**2,021,327**	**257,590**	**72,355**	**444,093**
	Margin per Therm at Current Rates							
8	Production		$0.002260	$0.002352	$0.002352	$0.002352	$0.002352	$0.000798
9	Underground Storage		($0.002457)	($0.003452)	($0.000725)	$0.000097	$0.001641	$0.002186
10	Distribution		$0.160534	$0.185271	$0.113197	$0.071410	$0.067729	$0.071312
11	Common		$0.058508	$0.066463	$0.041510	$0.035414	$0.032985	$0.031444
12	Total Current Margin Melded Rate per Therm		**$0.218846**	**$0.250633**	**$0.156334**	**$0.109273**	**$0.104707**	**$0.105740**
	Functional Cost Components at Uniform Current Return							
13	Production		36,008,084	27,456,863	6,963,878	1,269,650	314,340	3,353
14	Underground Storage		(198,311)	(151,648)	(34,191)	(4,018)	(1,164)	(7,290)
15	Distribution		11,445,404	10,095,121	1,059,087	120,206	25,725	145,265
16	Common		4,164,219	3,426,340	513,145	80,523	21,465	122,746
17	Total Uniform Current Cost		**51,419,396**	**40,826,676**	**8,501,918**	**1,466,360**	**360,367**	**264,075**
18	Exclude Cost of Gas w / Revenue Exp.		35,847,253	27,336,965	6,933,468	1,264,105	312,715	0
19	Total Uniform Current Margin		**15,572,143**	**13,489,711**	**1,568,450**	**202,255**	**47,652**	**264,075**
	Margin per Therm at Uniform Current Return							
20	Production		$0.002260	$0.002352	$0.002352	$0.002352	$0.002352	$0.000798
21	Underground Storage		($0.002787)	($0.002975)	($0.002644)	($0.001704)	($0.001685)	($0.001736)
22	Distribution		$0.160850	$0.198029	$0.081912	$0.050993	$0.037228	$0.034588
23	Common		$0.058523	$0.067212	$0.039688	$0.034159	$0.031063	$0.029226
24	Total Current Uniform Margin Melded Rate per Therm		**$0.218846**	**$0.264619**	**$0.121308**	**$0.085799**	**$0.068958**	**$0.062877**
25	**Margin to Cost Ratio at Current Rates**		**1.00**	**0.95**	**1.29**	**1.27**	**1.52**	**1.68**
	Functional Cost Components at Proposed Rates							
26	Production		36,007,890	27,456,689	6,963,859	1,269,647	314,340	3,353
27	Underground Storage		(60,260)	(80,574)	4,264	2,399	1,653	11,999
28	Distribution		14,249,882	11,993,804	1,685,697	192,920	51,559	325,902
29	Common		4,329,168	3,537,791	549,635	84,994	23,093	133,655
30	**Total Proposed Rate Revenue**		**54,526,680**	**42,907,711**	**9,203,455**	**1,549,960**	**390,645**	**474,909**
31	Exclude Cost of Gas w / Revenue Exp.		35,847,060	27,336,792	6,933,450	1,264,103	312,715	0
32	**Total Margin Revenue at Proposed Rates**		**18,679,621**	**15,570,919**	**2,270,005**	**285,856**	**77,931**	**474,909**
	Margin per Therm at Proposed Rates							
33	Production		$0.002260	$0.002352	$0.002352	$0.002352	$0.002352	$0.000798
34	Underground Storage		($0.000847)	($0.001581)	$0.000330	$0.001017	$0.002392	$0.002857
35	Distribution		$0.200264	$0.235274	$0.130376	$0.081839	$0.074612	$0.077598
36	Common		$0.060841	$0.069398	$0.042510	$0.036056	$0.033419	$0.031824
37	Total Proposed Margin Melded Rate per Therm		**$0.262518**	**$0.305444**	**$0.175568**	**$0.121264**	**$0.112775**	**$0.113078**
	Functional Cost Components at Uniform Proposed Return							
38	Production		36,007,992	27,456,793	6,963,860	1,269,646	314,340	3,353
39	Underground Storage		(79,636)	(61,591)	(13,425)	(1,317)	(452)	(2,852)
40	Distribution		14,268,359	12,500,995	1,397,466	150,814	32,260	186,824
41	Common		4,329,965	3,567,578	532,850	82,405	21,877	125,256
42	Total Uniform Proposed Cost		**54,526,680**	**43,463,775**	**8,880,751**	**1,501,549**	**368,025**	**312,581**
43	Exclude Cost of Gas w / Revenue Exp.		35,847,161	27,336,895	6,933,450	1,264,102	312,714	0
44	Total Uniform Proposed Margin		**18,679,519**	**16,126,880**	**1,947,301**	**237,447**	**55,311**	**312,581**
	Margin per Therm at Uniform Proposed Return							
45	Production		$0.002260	$0.002352	$0.002352	$0.002352	$0.002352	$0.000798
46	Underground Storage		($0.001119)	($0.001208)	($0.001038)	($0.000559)	($0.000654)	($0.000679)
47	Distribution		$0.200523	$0.245224	$0.108083	$0.063978	$0.046684	$0.044483
48	Common		$0.060852	$0.069983	$0.041212	$0.034957	$0.031659	$0.029824
49	Total Proposed Uniform Margin Melded Rate per Therm		**$0.262516**	**$0.316350**	**$0.150609**	**$0.100728**	**$0.080041**	**$0.074427**
50	**Margin to Cost Ratio at Proposed Rates**		**1.00**	**0.97**	**1.17**	**1.20**	**1.41**	**1.52**

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Sumcost
Company Base Case
WA Accepted Methodology

AVISTA UTILITIES AS ADJUSTED BY PUC STAFF
Summary by Classification with Unit Cost Analysis
For The Twelve Months Ended December 31, 2002

Natural Gas Utility
Idaho Jurisdiction

6/18/04
4:37 PM

	(b) Description	(c) (d) (e)	(f) System Total	(g) Residential Service Sch 101	(h) Small Firm Service Sch 111	(i) Large Firm Service Sch 121	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Cost by Classification at Current Return by Schedule							
1	Commodity		35,426,653	26,598,445	7,008,647	1,195,444	356,422	267,694
2	Demand		8,590,440	6,390,267	1,782,268	269,550	14,220	134,135
3	Customer		8,049,185	7,617,071	276,567	70,930	18,286	66,331
4	Total Current Rate Revenue		52,066,278	40,605,784	9,067,482	1,535,924	388,928	468,161
	Revenue per Therm at Current Rates							
5	Commodity		$0.497875	$0.521764	$0.542065	$0.507123	$0.515784	$0.063739
6	Demand		$0.120727	$0.125354	$0.137845	$0.114347	$0.020578	$0.031938
7	Customer		$0.113121	$0.149419	$0.021390	$0.030090	$0.026462	$0.015794
8	Total Revenue per Therm at Current Rates		$0.731724	$0.796536	$0.701300	$0.651560	$0.562824	$0.111471
	Cost per Unit at Current Rates							
9	Commodity Cost per Therm		$0.497875	$0.521764	$0.542065	$0.507123	$0.515784	$0.063739
10	Demand Cost per Peak Day Therms		$21.07	$21.24	$26.92	$16.27	$5.79	$6.21
11	Customer Cost per Customer per Month		$11.42	$10.91	$40.27	$591.09	$761.90	$789.66
	Cost by Classification at Uniform Current Return							
12	Commodity		35,281,826	26,798,312	6,787,102	1,173,898	343,750	178,764
13	Demand		8,496,290	6,585,267	1,592,513	246,857	7,317	64,337
14	Customer		8,288,162	7,935,699	234,580	59,752	13,128	45,003
15	Total Uniform Current Cost		52,066,278	41,319,277	8,614,195	1,480,507	364,196	288,104
	Cost per Therm at Current Return							
16	Commodity		$0.495840	$0.525684	$0.524931	$0.497984	$0.497446	$0.042564
17	Demand		$0.119404	$0.129179	$0.123169	$0.104720	$0.010588	$0.015319
18	Customer		$0.116479	$0.155669	$0.018143	$0.025348	$0.018998	$0.010715
19	Total Cost per Therm at Current Return		$0.731724	$0.810532	$0.666242	$0.628051	$0.527033	$0.068599
	Cost per Unit at Uniform Current Return							
20	Commodity Cost per Therm		$0.495840	$0.525684	$0.524931	$0.497984	$0.497446	$0.042564
21	Demand Cost per Peak Day Therms		$20.84	$21.89	$24.05	$14.90	$2.98	$2.98
22	Customer Cost per Customer per Month		$11.75	$11.37	$34.16	$497.93	$547.02	$535.76
23	**Revenue to Cost Ratio at Current Rates**		**1.00**	**0.98**	**1.05**	**1.04**	**1.07**	**1.62**
	Cost by Classification at Proposed Return by Schedule							
24	Commodity		36,358,960	27,380,243	7,130,111	1,206,415	359,276	282,915
25	Demand		9,483,541	7,154,132	1,886,416	281,135	15,778	146,081
26	Customer		9,331,061	8,865,377	299,615	76,639	19,449	69,981
27	Total Proposed Rate Revenue		55,173,562	43,399,752	9,316,142	1,564,188	394,503	498,977
	Revenue per Therm at Proposed Rates							
28	Commodity		$0.510978	$0.537100	$0.551460	$0.511778	$0.519913	$0.067363
29	Demand		$0.133279	$0.140338	$0.145900	$0.119261	$0.022832	$0.034782
30	Customer		$0.131136	$0.173906	$0.023173	$0.032511	$0.028145	$0.016663
31	Total Revenue per Therm at Proposed Rates		$0.775393	$0.851344	$0.720532	$0.663550	$0.570891	$0.118808
	Cost per Unit at Proposed Rates							
32	Commodity Cost per Therm		$0.510978	$0.537100	$0.551460	$0.511778	$0.519913	$0.067363
33	Demand Cost per Peak Day Therms		$23.26	$23.78	$28.49	$16.97	$6.42	$6.76
34	Customer Cost per Customer per Month		$13.23	$12.70	$43.63	$638.66	$810.39	$833.11
	Cost by Classification at Uniform Proposed Return							
35	Commodity		36,246,348	27,536,372	6,972,062	1,187,521	347,658	202,735
36	Demand		9,411,285	7,306,248	1,751,159	261,271	9,456	83,149
37	Customer		9,515,929	9,113,904	269,690	66,857	14,726	50,752
38	Total Uniform Proposed Cost		55,173,562	43,956,525	8,992,911	1,515,649	371,841	336,636
	Cost per Therm at Proposed Return							
39	Commodity		$0.509395	$0.540162	$0.539236	$0.503762	$0.503102	$0.048272
40	Demand		$0.132263	$0.143322	$0.135439	$0.110835	$0.013685	$0.019798
41	Customer		$0.133734	$0.178781	$0.020858	$0.028362	$0.021311	$0.012084
42	Total Cost per Therm at Proposed Return		$0.775393	$0.862266	$0.695533	$0.642959	$0.538097	$0.080154
	Cost per Unit at Uniform Proposed Return							
43	Commodity Cost per Therm		$0.509395	$0.540162	$0.539236	$0.503762	$0.503102	$0.048272
44	Demand Cost per Peak Day Therms		$23.08	$24.28	$26.45	$15.77	$3.85	$3.85
45	Customer Cost per Customer per Month		$13.50	$13.06	$39.27	$557.14	$613.60	$604.19
46	**Revenue to Cost Ratio at Proposed Rates**		**1.00**	**0.99**	**1.04**	**1.03**	**1.06**	**1.48**

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 21ST DAY OF JUNE 2004, SERVED THE FOREGOING **DIRECT TESTIMONY OF MICHAEL FUSS,** IN CASE NO. AVU-E-04-1/AVU-G-04-1, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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