BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant,	)	DOCKET UE-080416
v.	)	and
AVISTA CORPORATION d/b/a AVISTA UTILITIES	)	DOCKET UG-080417
Respondent.	)	MULTIPARTY SETTLEMENT STIPULATION

I. PARTIES

1. This Multiparty Settlement Stipulation is entered into by Avista Corporation ("Avista" or the "Company"), the Staff of the Washington Utilities and Transportation Commission ("Staff"), Northwest Industrial Gas Users ("NWIGU"), and The Energy Project, jointly referred to herein as the "Stipulating Parties." The Industrial Customers of Northwest Utilities ("ICNU"), while a signatory, only joins in those portions of the Stipulation identified below. The Public Counsel Section of the Washington Office of Attorney General ("Public Counsel") does not join in. The Stipulating Parties agree that this Multiparty Settlement Stipulation is in the public interest and should be accepted as a full resolution of all issues in these Dockets. ICNU agrees to resolve the issues identified below, but opposes the position that this Multiparty Settlement should resolve all

issues in these Dockets. The Stipulating Parties understand this Multiparty Settlement Stipulation is subject to Commission approval.

II. INTRODUCTION

2. On March 4, 2008, Avista filed with the Commission certain tariff revisions designed to effect general rate increases for electric service (Docket UE-080416) and natural gas service (Docket UG-080417) in the State of Washington. Avista requests an increase in electric rates of $36.6 million, or 10.3 percent, and an increase in natural gas rates of $6.6 million or 3.3 percent. On March 6, 2008, the Commission entered Order 01 suspending the tariff revisions and consolidating Dockets UE-080416 and UG-080417 for hearing and determination pursuant to WAC 480-07-320. A Prehearing Conference Order (Order 02) issued on April 3, 2008, which, inter alia, established a procedural schedule. On July 25, 2008, the Company filed supplemental pre-filed direct testimony and exhibits to reflect a revised electric service revenue requirement of $47.4 million; the Company, however, did not otherwise revise its tariff filing to reflect these changes. Representatives of all parties appeared at the August 20, 2008 Settlement Conference, which was held for the purpose of narrowing the contested issues in this proceeding. Subsequently, the parties participated in telephonic Settlement Conferences on August 29, 2008, September 4, 2008, September 8, 2008, and September 9, 2008.

3. The Stipulating Parties have reached a Multiparty Settlement Stipulation on all issues in this proceeding and wish to present their agreement for the Commission's consideration. The Stipulating Parties therefore adopt the following Multiparty Settlement Stipulation in the interest of expediting the disposition of this proceeding.

4. ICNU joins with the following identified portions of the Stipulation: Power Supply-Related Adjustments (Section III. A. (a.)); Cost of Capital (Section III. A. (m.)); Rate Spread/Rate Design (Section III. B.); Low Income Bill Assistance Funding (Section III. C.); Demand Side Management (DSM) Expenditures (Section III. D.); and Prudency of Energy Efficiency Expenditures (Section III. E.). ICNU expressly reserves the right to contest other issues that have been resolved among the Stipulating Parties and shall not be foreclosed from raising such additional issues as may be properly within the scope of this proceeding.

III. AGREEMENT

A. <u>Revised Revenue Requirement</u>

5. The Stipulating Parties have agreed to a number of revenue requirement adjustments to both the filed electric and natural gas cases. These are described in the tables set forth immediately below:

SUMMARY TABLE OF ADJUSTMENTS TO ELECTRIC REVENUE REQUIREMENT 000s of Dollars		Revenue Requirement	Rate Base
Amount As Filed		**$ 36,617**	**$ 950,944**
Adjustments:			
* Power Supply-Related Adjustments			
	Hydro filtering	(1,597)	0
	WNP-3 Contract (Use of 5-year average availability)	(136)	0
	Fuel (Natural Gas) (Use of $8.30/Dth and include actual short-term transaction through August 25, 2008)	8,486	0
	Colstrip (Correct Colstrip fuel price)	(877)	0
	Noxon Generation Upgrade (Pro Form 2009 capital upgrade project)	1,557	8,714
* Cost of Capital			
	Adjust return on equity to 10.20%	(4,229)	0
	Adjust cost of debt to 6.51%	1,017	0
Relicensing/Litigation[1]			
	Relicensing and confidential litigation costs deferred for later recovery, with carrying charge (5.0%); Include amortization of Montana riverbed litigation costs with accrued interest	(8,053)	(37,044)
Capital Additions			
	Pro form in the capital cost and expenses associated with the major generation and transmission project upgrades	60	14,299
Customer Deposits			
	Remove customer deposits from Rate Base; include interest as operating expense	(189)	(2,155)
Federal/Deferred Income Tax Expense			
	Adjust federal and deferred federal income tax expense	405	0
Incentives			
	Adjust incentives to actual	(415)	0
Officers' Salaries			
	Adjust officers' salaries for correction of error	(140)	0
Union and Non-Executives' Salaries			
	Remove union and non-executive 2009 wage increase	(1,188)	0
Colstrip Generation O&M Expenses			
	Reduce mercury emissions O&M costs	(699)	0
Administrative and General Expenses			
	Remove sponsorship costs	(109)	0
Production Property			
	Flow through impact of Production & Transmission adjustments	2,174	4,549
Restate Debt Interest			
	Flow through impact of Rate Base adjustments	(146)	0
Total Adjustments		**(4,079)**	**(11,637)**
Adjusted Amounts		**$ 32,538**	**$ 939,307**
[1] Please see Andrews' (EMA-1T) unredacted testimony at Pages 23-24.			

[*] Denotes concurrence of ICNU

SUMMARY TABLE OF ADJUSTMENTS TO NATURAL GAS REVENUE REQUIREMENT 000s of Dollars		Revenue Requirement	Rate Base
Amount As Filed		$ 6,587	$ 172,957
Adjustments:			
Cost of Capital			
	Adjust return on equity to 10.20%	(778)	0
	Adjust cost of debt to 6.51%	194	0
Natural Gas Inventory			
	Natural gas inventory included in Rate Base as originally filed	0	0
Capital Additions			
	Remove pro forma capital additions	(666)	(2,506)
Customer Deposits			
	Remove customer deposits from Rate Base; include interest as operating expense	(109)	(1,248)
Federal Income Tax Expense			
	Remove tax deduction	48	0
Incentives			
	Adjust incentives to actual	(109)	0
Officers' Salaries			
	Adjust officers' salaries for correction of error	(37)	0
Union and Non-Executives' Salaries			
	Remove union and non-executive 2009 wage increase	(320)	0
Restate Debt Interest			
	Flow through impact of Rate Base adjustments	(42)	0
Total Adjustments		**(1,819)**	**(3,754)**
Adjusted Amounts		**$ 4,768**	**$ 169,203**

Attached as Appendix 1 are the electric and natural gas Summary of Revenue Requirement Adjustments schedules showing adjusted pro forma results incorporating these agreed-upon adjustments.

a.) <u>Power Supply-Related Adjustments:</u>

(i) <u>Hydro filtering</u> –This adjustment removes the power supply expense from the 50-year average for months when the hydro generation was either higher or lower by more than one standard deviation from the average generation for that month.

(ii) WNP-3 Contract – This adjustment increases the amount of energy purchased under the WNP-3 contract by including 2007 energy purchased in the 5-year average. Increasing the amount of WNP-3 power purchased lowers power supply expense because the WNP-3 price is lower than market power prices in the AURORA model.

(iii) Adjust (Natural Gas) Fuel Costs – This adjustment reflects a pro forma period natural gas price of $8.30/Dth for natural gas-fired generation for the unhedged portion of the 2009 generation. This adjustment also includes the actual 2009 calendar-year wholesale electric and natural gas transactions entered into through August 25, 2008.

(iv) Correct Colstrip Fuel Cost Error – This adjustment corrects a mathematical error in the calculation of the Colstrip coal cost. The correction is designed to properly reflect the 2009 pro forma period fuel price.

(v) Noxon Generation Upgrade – The Noxon upgrade, scheduled for completion in March of 2009, is designed to increase that unit's efficiency by 5%, and provide additional capacity of 7.5 MW. The Company's original filing included the additional generation expected from the upgrade (2.33 average megawatts of additional energy in an average water year) within the Company's Dispatch Model for the rate year, but inadvertently excluded the capital investment for this project from its revenue requirement. The Stipulating Parties agree, for settlement purposes, to include the capital investment and increased generation for ratemaking purposes.

(vi) Modification to Energy Recovery Mechanism (ERM) – This adjustment incorporates an element of asymmetry in the ERM by giving customers a greater share of the benefits when power expenses are lower than the authorized level. The adjustment changes the sharing level in the second ERM band ($4 million to $10 million) to 75% customer/25% Company when power supply expenses are lower (rebate direction), while maintaining the 50%/50% sharing in the second band when power supply expenses are higher (surcharge direction). This adjustment does not affect the pro forma power supply expense.

b.) **Capital Additions:**

Capital additions for electric operations shall include capital costs and expenses associated with the major generation and transmission project upgrades. Capital additions for natural gas operations shall include capital costs and expenses associated with the Jackson Prairie expansion project. These capital additions include projects completed during 2007, and projects expected to be completed and transferred to plant-in-service by December 31, 2008, in time for new rates to be in effect. The capital costs have been averaged for their appropriate pro forma period with the associated depreciation expense and property tax, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets.

c.) **Customer Deposits:**

Customer deposits shall be removed from rate base, and interest on the customer deposits will be included as an operating expense for electric and natural gas operations.

d.) Federal/Deferred Income Tax Expense:

The Company's Schedule M tax computation deduction that was incorrectly included in the Company's calculation of taxable income in determining federal income tax expense shall be removed. Also, the proper level of deferred tax expense (DFIT) based on the proper allocation percentage used to calculate allocated DFIT for the test period has been reflected.

e.) Incentives:

The incentive calculation shall reflect the actual expenses for the test period instead of the six-year average proposed by the Company.

f.) Officers' Salaries:

This adjustment corrects the Company's pro forma adjustment of officers' salaries for an error identified by the Company.

g.) Union and Non-Executives' Salaries:

The pro formed 2009 wage increase for union and non-executives shall be removed.

h.) Colstrip Mercury Emission O&M:

This adjustment reduces the pro formed 2009 O&M costs associated with the mercury control abatement project at Colstrip. The original system expense amount of the mercury control O&M costs was estimated to be approximately $3 million annually or $250,000 monthly, and this process had been anticipated to start in July 2009. The plan was revised to start this mercury abatement process in November 2009, for a total cost of approximately $465,000 for two months.

i.) **Administrative and General Expenses:**

This adjustment removes non-utility expenses that should have been excluded from utility results within the Company's test period, in its original filing. These expenses are related to costs expended by the Company for sponsorship agreements in support of community affairs.

j.) **Production Property:**

This adjustment corrects an erroneous value in the calculation of the production property adjustment contained within the Company's original filing, representing approximately $2.1 million of this adjustment. The remaining portion of the adjustment is directly linked to all other adjustments in this Multiparty Settlement Stipulation that affect production and transmission related revenues, expenses, and rate base.

k.) **Weather Normalization:**

The Stipulating Parties agree that the use of a rolling 25-year average of normal heating and cooling degree days in the calculation of the weather adjustment is for settlement purposes only, and shall not be deemed as precedent for any other proceeding.

l.) **Natural Gas Inventory:**

The pro formed Jackson Prairie working gas inventory (AMA balance for 2009 pro forma period) shall be included in rate base.

m.) **<u>Cost of Capital:</u>**

The Stipulating Parties agree to a 10.2% return on equity, and adopt the capital structure as filed by the Company. The cost of debt has been adjusted from 6.38% to 6.51% to reflect actual cost of debt through July 2008 with pro forma adjustments to update the debt cost through December 31, 2008.

Agreed-upon Cost of Capital	Percent of Total Capital	Cost	Component
Total Debt	53.70%	6.51%	3.50%
Common Equity	46.30%	10.20%	4.72%
TOTAL	100.00%		8.22%

n.) **<u>Accounting Treatment for Certain Costs:</u>**

(i.) <u>Spokane River Relicensing</u> – The Company included in its filing the processing costs associated with its Spokane River relicensing efforts, which expenditures included actual life-to-date costs from April 2001 through December 31, 2007, and 2008 pro forma expenditures through December 31, 2008. (<u>See</u> Andrews' Direct Testimony at page 23.) Although the Company anticipates receiving a final license from the Federal Energy Regulatory Commission ("FERC") in the near future, that has yet to occur. The relicensing costs will remain in CWIP (Construction Work in Progress), and the Company will continue to accrue AFUDC until issuance of the license, at which time the relicensing costs will be transferred to plant in service and depreciation will begin to be recorded. The Stipulating Parties have agreed that the costs were prudently incurred and have agreed, that once the Company receives the license, to defer as a regulatory asset (in Account 182.3 – Other Regulatory Assets) Washington's share of the depreciation/amortization associated with the aforementioned relicensing costs and related protection, mitigation, or enhancement expenditures, together with a carrying charge on the deferral, as well as a carrying charge on the amount of relicensing costs not yet included in rate base. The annual carrying charge for deferrals and rate base not yet included in establishing rates shall be 5.0%. Any costs that exceed the pro formed costs in this case would be addressed in a separate filing.

(ii.) Confidential Litigation – Company witness Andrews describes the confidential litigation at pages 23 and 24 of her pre-filed direct testimony (unredacted). Although the matter is still pending and has yet to be finally resolved, it is expected to reach resolution in the near future. The Stipulating Parties have agreed that the pro forma costs in this case are prudent and have agreed to defer as a regulatory asset (in Account 182.3 – Other Regulatory Assets) Washington's share of the depreciation/amortization associated with the aforementioned costs with a carrying charge on the deferral as well as a carrying charge on the amount of costs not yet included in rate base for subsequent recovery in rates. The annual carrying charge shall be 5.0%. Any costs that exceed the pro formed costs in this case would be addressed in a separate filing.

(iii.) Montana Riverbed Litigation – On November 11, 2007, Avista filed an Application with the Commission (Docket No.UE-072131) requesting an accounting order authorizing deferral of settlement lease payments and interest accruals relating to the recent settlement of a lawsuit in the State of Montana over the use of the riverbed related to the Company's ownership of the Noxon Rapids and Cabinet Gorge hydroelectric projects located on the Clark Fork River. The Commission, in its Order No. 01, authorized the deferral of settlement lease payments together with interest, at the weighted cost of debt, until the matter was addressed in this general rate filing. The Stipulating Parties have agreed to the Company's requested amortization of costs, together with recovery of accrued interest on the Washington share of deferrals at the weighted cost of debt, net of related deferred tax benefit.

6. ERM Authorized Level of Expense. Appendix 2 sets forth the agreed-upon level of power supply expense, retail load and revenue credit resulting from this Stipulation, that will be used in the monthly Energy Recovery Mechanism ("ERM") calculations.

7. Decoupling Baseline. Pursuant to the Commission's order adopting the Avista decoupling pilot, In Re Petition of Avista Corp., Order 04, Docket UG-060518, para. 49, the baseline for the decoupling mechanism has been updated so as to use the test year employed in this rate case proceeding. (See Settlement Agreement, Docket UG-060518, supra, section III. C. (6.)). The update of the baseline is reflected in Appendix 3.

B. Rate Spread/Rate Design:

8. The Stipulating Parties agree to apply a uniform percentage increase across the electric

service schedules for purposes of recovering Avista's revenue requirement. Appendix 4 shows the impact on each electric and natural gas service schedule of the spread of the proposed increase. The residential basic charge for electric and natural gas residential customers would be increased from $5.50 to $5.75 per month.

9. For Extra Large General Service Schedule 25 Rate Design, the Stipulating Parties agree with the following rate design recommendations for Schedule 25: The Company's proposed Schedule 25 demand charges should be adopted. The first and second energy block rates shall be increased by a uniform percentage. The increase applied to the third energy block rate shall be 2.0 percent less than the percentage increase applied to the first and second block rates as shown on Page 2 of Appendix 4. This Schedule 25 rate design formula shall apply to the final revenue requirement in this case, regardless of whether it is different from the revenue requirement in Appendix 4.

10. For natural gas, the Stipulating Parties agree that the final revenue requirement shall be spread across natural gas service schedules in the same proportion to the Company's filed rate spread proposal as set forth in column (d), Page 1 of 3, Exhibit (BJH-7). (See Appendix 4, Page 3)

C. <u>Low Income Bill Assistance Funding:</u>

11. The Stipulating Parties agree to adjust the LIRAP portion of the tariff riders (Schedules 91 and 191) to provide an increase in annual funding of $500,000. With this increase, the annual funding level for electric low income customers will be $2,864,000, and for natural gas customers will be $1,580,000. Appendix 5 identifies the tariff rider adjustments to schedule 91 and 191 (in ¢/kwh or ¢/therm) to reflect increased levels of funding for LIRAP and DSM (as discussed below).

D. Demand Side Management (DSM) Expenditures:

12. The Stipulating Parties agree to increase low income DSM by $350,000 over and above existing funding level of $1,132,000, and to adjust the Tariff Rider Adjustment Schedules (91 and 191) accordingly. For purposes of program administration, the total funding level of $1,482,000 for low income DSM includes amounts that may be dedicated to energy-related health and safety measures, the expenditures for which shall not exceed fifteen (15%) percent of overall actual low-income DSM expenditures. The Company and The Energy Project agree to work with participating low income agencies on the development of contract provisions to assure that the combined portfolio of electric and natural gas low-income DSM expenditures remain cost-effective. The Company will provide the External Energy Efficiency ("Triple-E") board with enhanced reporting on the status of the limited income portfolio on a quarterly basis and as part of the biannual meetings of the board.

E. Prudency of Energy Efficiency Expenditures:

13. The Stipulating Parties agree that Avista's expenditures for electric and natural gas efficiency programs for the period January 1, 2007 through December 31, 2007 have been prudently incurred.

F. Effective Date:

14. As an integral part of this settlement, the Stipulating Parties have agreed that the new rates shall be implemented on January 1, 2009, and will support a modification of the procedural schedule to accommodate such a date. ICNU is not in agreement with the proposed effective date for new rates.

IV. EFFECT OF THE MULTIPARTY SETTLEMENT STIPULATION

15. Binding on Parties. The Stipulating Parties agree to support the terms of the Multiparty

Settlement Stipulation throughout this proceeding, including any appeal, and recommend that the Commission issue an order adopting the Multiparty Settlement Stipulation contained herein. The Stipulating Parties understand that this Multiparty Settlement Stipulation is subject to Commission approval. The Stipulating Parties agree that this Multiparty Settlement Stipulation represents a compromise in the positions of the Stipulating Parties. As such, conduct, statements and documents disclosed in the negotiation of this Multiparty Settlement Stipulation shall not be admissible evidence in this or any other proceeding.

16. Integrated Terms of Multiparty Settlement. The Stipulating Parties have negotiated this Multiparty Settlement Stipulation as an integrated document. Accordingly, the Stipulating Parties recommend that the Commission adopt this Multiparty Settlement Stipulation in its entirety. Each Stipulating Party has participated in the drafting of this Multiparty Settlement Stipulation, so it should not be construed in favor of, or against, any particular Party.

17. Procedure. The Stipulating Parties shall cooperate in submitting this Multiparty Settlement Stipulation promptly to the Commission for acceptance. The Stipulating Parties shall make available a witness or representative in support of this Multiparty Settlement Stipulation. The Stipulating Parties agree to cooperate, in good faith, in the development of such other information as may be necessary to support and explain the basis of this Multiparty Settlement Stipulation and to supplement the record accordingly.

The Stipulating Parties agree to stipulate into evidence the prefiled direct testimony and exhibits of the Company as they relate to the stipulated issues, together with such evidence in support of the Stipulation as may be offered at the time of the hearing on the Multiparty Settlement.

If the Commission rejects all or any material portion of this Multiparty Settlement Stipulation, or adds additional material conditions, each Stipulating Party reserves the right, upon written notice to the Commission and all parties to this proceeding within seven (7) days of the date of the Commission's Order, to withdraw from the Multiparty Settlement Stipulation. If any Stipulating Party exercises its right of withdrawal, this Multiparty Settlement Stipulation shall be void and of no effect, and the Stipulating Parties will support a joint motion for an expedited procedural schedule to address the issues that would otherwise have been settled herein.

18. Advance Review of News Releases. All Stipulating Parties agree:

(i.) to provide all other Stipulating Parties the right to review in advance of publication any and all announcements or news releases that any other Stipulating Party intends to make about the Multiparty Settlement Stipulation. This right of advance review includes a reasonable opportunity for a Stipulating Party to request changes to the text of such announcements. However, no Stipulating Party is required to make any change requested by another Stipulating Party; and

(ii.) to include in any news release or announcement a statement that Staff's recommendation to approve the settlement is not binding on the Commission itself. This subsection does not apply to any news release or announcement that otherwise makes no reference to Staff.

19. No Precedent. The Stipulating Parties enter into this Multiparty Settlement Stipulation to avoid further expense, uncertainty, and delay. By executing this Multiparty Settlement Stipulation, no Stipulating Party shall be deemed to have accepted or consented to the facts, principles, methods

or theories employed in arriving at the Multiparty Settlement Stipulation, and, except to the extent expressly set forth in the Multiparty Settlement Stipulation, no Stipulating Party shall be deemed to have agreed that such a Multiparty Settlement Stipulation is appropriate for resolving any issues in any other proceeding.

20. Public Interest. The Stipulating Parties agree that this Multiparty Settlement Stipulation is in the public interest.

21. Execution. This Multiparty Settlement Stipulation may be executed by the Stipulating Parties in several counterparts and as executed shall constitute one Multiparty Settlement Stipulation.

Entered into this 15th day of September, 2008

Company: By: ______________________

David J. Meyer
VP, Chief Counsel for Regulatory and
Governmental Affairs

Staff: By: ______________________

Gregory J. Trautman
Assistant Attorney General

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Chad M. Stokes
Cable Huston Benedict
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Ronald Roseman
Attorney at Law

APPENDIX 1
AVISTA UTILITIES
Summary of Revenue Requirement Adjustments
Restatement Summary Washington Electric

		FILED CASE		FINAL SETTLEMENT		IMPACT ON DIFFERENCE		REVENUE REQUIREMENT	
		Washington Electric		Washington Electric		Washington Electric		NOI	Rate Base
Item	Description	NOI	Rate Base	NOI	Rate Base	NOI	Rate Base	0.62190134	8.22%
b	Per Results Report	$63,798	$1,009,868	$63,798	$1,009,868	$0	$0		
c	Deferred FIT Rate Base	0	(139,033)	0	(139,033)	0	0		
d	Deferred Gain on Office Building	0	(210)	0	(210)	0	0		
e	Colstrip 3 AFUDC Elimination	225	(2,342)	225	(2,342)	0	0		
f	Colstrip Common AFUDC	0	460	0	460	0	0		
g	Kettle Falls Disallow.	(56)	(913)	(56)	(913)	0	0		
h	Customer Advances	0	(258)	0	(258)	0	0		
i	Depreciation True-up	212	0	212	0	0	0		
j	Settlement Exchange Power	0	20,432	0	20,432	0	0		
	Actual	64,179	888,004	64,179	888,004	0	0	0	0
k	Eliminate B & O Taxes	(19)	0	(19)	0	0	0		
l	Property Tax	831	0	831	0	0	0		
m	Uncollect. Expense	70	0	70	0	0	0		
n	Regulatory Expense	(12)	0	(12)	0	0	0		
o	Injuries and Damages	8	0	8	0	0	0		
p	FIT	149	0	(103)	0	252	0	($405)	$0
q	Eliminate WA Power Cost Defer	(10,623)	0	(10,623)	0	0	0		
r	Nez Perce Settlement Adjustment	(6)	0	(6)	0	0	0		
s	Eliminate A/R Expenses	593	0	593	0	0	0		
t	Office Space Charges to Subsidiaries	6	0	6	0	0	0		
u	Restate Excise Taxes	32	0	32	0	0	0		
v	Net Gains/losses	68	0	68	0	0	0		
w	Revenue Normalization	18,145	0	18,145	0	0	0		
x	Restate Debt Interest	(2,612)	0	(2,521)	0	(91)	0	$146	$0
	Restated Total	$70,809	$888,004	$70,648	$888,004	$161	$0	($260)	$0
PF1	Pro Forma Power Supply	(6,408)	0	(10,062)	0	$3,654	$0	($5,876)	$0
PF2	Pro Forma Prod Property Adj	3,776	(17,504)	2,798	(12,955)	$978	($4,549)	($1,573)	($601)
PF3	Pro Forma Labor Non-Exec	(1,522)	0	(783)	0	($739)	$0	$1,188	$0
PF4	Pro Forma Labor Exec	(160)	0	(73)	0	($87)	$0	$140	$0
PF5	Pro Forma Transmission Rev/Exp	(487)	0	(487)	0	$0	$0	$0	$0
PF6	Pro Forma Capital Add 2007	(346)	32,809	(818)	36,386	$472	($3,577)	($759)	($473)
PF7	Pro Forma Capital Add 2008	(2,044)	7,292	(434)	18,014	($1,610)	($10,722)	$2,589	($1,417)
PF8	Pro Forma Asset Management	(1,152)	0	(1,152)	0	$0	$0	$0	$0
PF09	Pro Forma Spokane Rvr Relicensing	(1,464)	21,960	0	0	($1,464)	$21,960	$2,354	$2,903
PF10	Pro Forma CDA Tribe Settlement	(499)	15,084	0	0	($499)	$15,084	$802	$1,994
PF11	Pro Forma Montana Lease	(2,222)	3,299	(2,222)	3,299	$0	$0	$0	$0
PF12	Pro Forma Colstrip Mercury Emiss. O&M	(630)	0	(195)	0	($435)	$0	$699	$0
PF13	Pro Forma Incentives	(258)	0	0	0	($258)	$0	$415	$0
PF14	Pro Forma 2009 Noxon Upgrade	0	0	(252)	8,714	$252	($8,714)	($405)	($1,152)
PF15	Pro Forma Misc. Adj.	0	0	8	(2,155)	($8)	$2,155	$13	$285
	Pro Forma Total	$57,393	$950,944	$57,506	$939,307	($113)	$11,637	($671)	$1,538
									$867
	Impact of ROE reduced to 10.2% & Cost of Debt changed to 6.51%								*$3,212*
	Total Revenue Requirement Difference								*$4,079*

APPENDIX 1
AVISTA UTILITIES
Summary of Revenue Requirement Adjustments
Restatement Summary Washington Gas

		FILED CASE Washington Gas		FINAL SETTLEMENT Washington Gas		IMPACT ON DIFFERENCE Washington Gas		REVENUE REQUIREMENT	
								NOI	Rate Base
Item	Description	NOI	Rate Base	NOI	Rate Base	NOI	Rate Base	0.622038	8.22%
b	Per Results Report	$11,064	$172,323	$11,064	$172,323	$0	$0		
c	Deferred FIT Rate Base	0	(26,823)	0	(26,823)	0	0		
d	Deferred Gain on Office Building	0	(71)	0	(71)	0	0		
e	Gas Inventory	0	5,607	0	5,607	0	0	$0	$0
f	Weatherization and DSM Investment	0	784	0	784	0	0		
g	Customer Advances	0	(64)	0	(64)	0	0		
h	Depreciation True-up	214	0	214	0				
	Actual	11,278	151,756	11,278	151,756	0	0	$0	$0
i	Revenue Normalization & Gas Cost Adju	1,149	0	1,149	0	0	0		
j	Eliminate B & O Taxes	(4)	0	(4)	0	0	0		
k	Property Tax	341	0	341	0	0	0		
l	Uncollectible Expense	68	0	68	0	0	0		
m	Regulatory Expense Adjustment	(8)	0	(8)	0	0	0		
n	Injuries and Damages	(73)	0	(73)	0	0	0		
o	FIT	(9)	0	(39)	0	30	0	($48)	$0.00
p	Net Gains/losses	8	0	8	0	0	0		
q	Eliminate A/R Expenses	99	0	99	0	0	0		
r	Office Space Charges to Subs	2	0	2	0	0	0		
s	Restate Excise Taxes	(15)	0	(15)	0	0	0		
t	O&M Savings	94	0	94	0	0	0		
u	Restate Debt Interest	(342)	0	(316)	0	(26)	0	$42	$0.00
	Restated Total	$12,588	$151,756	$12,584	$151,756	$4	$0	($6)	$0.00
PF1	Pro Forma Labor Non-Exec	(412)	0	(213)	0	($199)	$0	$320	$0.00
PF2	Pro Forma Labor Exec	(43)	0	(20)	0	($23)	$0	$37	$0.00
PF3	Pro Forma JP Storage	(1,374)	18,695	(1,374)	18,695	$0	$0	$0	$0.00
PF4	Pro Forma Capital Add 2007	170	549	0	0	$170	$549	($273)	$72
PF5	Pro Forma Capital Add 2008	(378)	1,957	0	0	($378)	$1,957	$608	$259
PF6	Pro Forma Incentives	(68)	0	0	0	($68)	$0	$109	$0
PF7	Pro Forma Misc	0	0	(35)	(1,248)	$35	$1,248	($56)	$165
	Pro Forma Total	$10,483	$172,957	$10,942	$169,203	($459)	$3,754	$739	$496
									$1,235
	Impact of ROE reduced to 10.2% & Cost of Debt changed to 6.51%								$584
	Total Revenue Requirement Difference								$1,819

APPENDIX 2
Avista Corp
Pro forma January 2009 - December 2009
ERM Authorized Power Supply Expense and Retail Sales

ERM Authorized Power Supply Expense

	Total	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Account 555 - Purchased Power	194,348,832	30,091,785	22,838,518	23,370,878	9,605,989	6,523,940	6,747,211	12,561,581	15,241,179	15,797,591	16,243,566	17,128,779	18,197,814
Account 501 - Thermal Fuel	30,176,320	2,784,264	2,615,186	2,820,159	2,479,357	1,179,683	1,251,113	2,770,889	2,904,140	2,790,501	2,894,130	2,820,427	2,866,470
Account 547 - Natrual Gas Fuel	75,784,442	5,862,807	6,719,121	5,504,797	3,069,202	2,408,166	2,641,706	7,709,107	10,588,078	8,899,202	6,509,120	8,117,247	7,755,891
Account 447 - Sale for Resale	113,278,918	14,937,371	14,121,956	15,684,802	8,406,398	11,757,106	10,396,756	12,129,479	7,731,761	6,792,199	2,907,426	4,434,046	3,979,618
Power Supply Expense	187,030,675	23,801,485	18,050,868	16,011,033	6,748,151	-1,645,317	243,274	10,912,098	21,001,635	20,695,095	22,739,390	23,632,407	24,840,557
Transmission Expense	14,331,973	1,193,417	1,193,417	1,193,417	1,193,417	1,193,417	1,193,417	1,193,417	1,193,417	1,204,390	1,193,417	1,193,417	1,193,417
Transmission Revenue	-9,252,389	(672,566)	(656,246)	(730,202)	(696,692)	(790,645)	(1,121,595)	(1,014,918)	(861,786)	(653,241)	(718,736)	(703,074)	(632,690)
Broker Fees	52,000	4,333	4,333	4,333	4,333	4,333	4,333	4,333	4,333	4,333	4,333	4,333	4,333
Hydro Filter	-2,366,272	185,666	-148,933	380,009	-858,376	-1,808,982	-1,512,667	-2,132,021	-621,536	554,068	1,180,546	593,361	1,822,593
Total Power Supply Expense	189,795,987	24,512,335	18,443,439	16,858,591	6,390,833	-3,047,193	-1,193,238	8,962,909	20,716,063	21,804,645	24,398,950	24,720,443	27,228,210

ERM Authorized Washington Retail Sales

	Total	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Total Retail Sales, MWh	5,580,783	557,363	482,600	468,215	413,065	417,489	417,458	475,799	458,544	425,385	456,640	475,820	532,406

The Retail Revenue Credit Rate is $46.62/MWh per Andrews' Production Property Adjustment workpapers.

APPENDIX 3

Avista Utilities
Washington - Gas - Test Year Calculations for Decoupling
2007 - Docket No. UG-080417

Schedule 101	Per BJH(1)	Annual Total	January	February	March	April	May	June	July	August	September	October	November	December
Therms														
Usage from Revenue Run(2)	115,583,967	115,583,967	21,292,599	21,234,566	14,472,322	9,724,124	6,113,562	3,664,833	2,462,636	2,010,203	2,332,936	4,484,817	9,398,517	18,392,852
Ded: Prior Mo. Unbilled(2)	(12,030,752)	(73,860,142)	(12,031,121)	(13,080,128)	(9,183,384)	(6,818,622)	(5,528,289)	(3,344,977)	(1,756,030)	(1,252,074)	(1,306,999)	(2,341,020)	(6,393,005)	(10,824,493)
Add: Current Mo. Unbilled(2)	12,425,609	74,254,377	13,080,128	9,183,384	6,818,622	5,528,289	3,344,977	1,756,030	1,252,074	1,306,999	2,341,020	6,393,005	10,824,493	12,425,356
Add: Weather Adjustment(2)	612,353	612,353	(2,152,492)	751,774	1,312,963	(642,747)	722,661	40,108	-	-	-	(134,804)	-	714,890
Test Year Monthly Therms	116,591,177	116,590,555	20,189,114	18,089,596	13,420,523	7,791,044	4,652,911	2,115,994	1,958,680	2,065,128	3,366,957	8,401,998	13,830,005	20,708,605
Adjust to Annual Pro Forma		622	369	-	-	-	-	-	-	-	-	-	-	253
Monthly Pro Forma Therms		116,591,177	20,189,483	18,089,596	13,420,523	7,791,044	4,652,911	2,115,994	1,958,680	2,065,128	3,366,957	8,401,998	13,830,005	20,708,858
Customers / Billings														
Test Yr Customers/Billings(2)	1,673,784	1,673,784	138,804	139,210	139,055	139,113	139,012	138,838	138,877	139,096	139,568	140,039	140,930	141,242
Test Year Average Use/Cust		70	145	130	97	56	33	15	14	15	24	60	98	147

Sch 101 Base Rate/therm(3)	$1.13793
Times: 1 minus Revenue Related Items (4).	0.956981
Revenue prior to gross up	$1.08898
Less: Weighted Average Gas Cost/therm(5)	($0.84697)
Margin Rate/therm	**$0.24201**

(1) From Hirschkorn workpapers in Docket No. UG-080417 BJH -17, BJH -14, BJH - 22, and BJH - 1
(2) From 2007 Monthly Data (calculated from data in Hirschkorn workpapers BJH-22, BJH-23, BJH-25 and BJH-15)
(3) From Appendix 4 Settlement Proposed Schedule 101 per therm base rate
(4) From Andrews Exhibit No.___(EMA-3), page 3, line 7
(5) From Andrews workpaper I14, cost of gas included in base rates.

APPENDIX 4

AVISTA UTILITIES
PROPOSED INCREASE BY SERVICE SCHEDULE
WASHINGTON - ELECTRIC
12 MONTHS ENDED DECEMBER 31, 2007
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Base Tariff Revenue Under Present Rates(1)	General Increase	Base Tariff Revenue Under Proposed Rates(2)	**Base Tariff Percent Increase**	Total Billed Revenue at Present Rates	Total GRC & Sch. 91 Increase	**Percent Increase on Billed Revenue**
	(a)	(b)	(c)	(d)	(e)	**(f)**	(g)	(h)	**(i)**
1	Residential	1	$155,272	$14,198	$169,470	**9.1%**	$168,032	$14,434	**8.6%**
2	General Service	11	$37,753	$3,451	$41,204	**9.1%**	$42,597	$3,505	**8.2%**
3	Large General Service	21	$107,361	$9,811	$117,172	**9.1%**	$120,575	$9,969	**8.3%**
4	Extra Large General Service	25	$42,477	$3,878	$46,355	**9.1%**	$47,600	$3,934	**8.3%**
5	Pumping Service	31	$7,944	$726	$8,670	**9.1%**	$8,909	$739	**8.3%**
6	Street & Area Lights	41-48	$5,192	$475	$5,666	**9.1%**	$5,888	$483	**8.2%**
7	Total		$355,999	$32,538	$388,537	**9.1%**	$393,602	$33,064	**8.4%**

(1) Excludes all present rate adjustments: Sch. 59 - BPA Residential Exchange, Sch. 91 - DSM Rider, and Sch. 93 - Power Cost Surcharge

(2) Includes all present rate adjustments: Sch. 59 - BPA Residential Exchange, Sch. 91 - DSM Rider, and Sch. 93 - Power Cost Surcharge

APPENDIX 4

AVISTA UTILITIES
WASHINGTON - ELECTRIC
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

(a)	Base Tariff Sch. Rate (b)	Present ERM & Other Adj.(1) (c)	Present Billing Rate (d)	General Rate Increase (e)	Sch. 91 LIRAP/DSM Increase (f)	Proposed Billing Rate (g)	Proposed Base Tariff Rate (h)
Residential Service - Schedule 1							
Basic Charge	$5.50		$5.50	**$0.25**		**$5.75**	**$5.75**
Energy Charge:							
First 600 kWhs	$0.05409	$0.00385	$0.05794	**$0.00517**	**$0.00010**	**$0.06321**	**$0.05926**
600 - 1,300 kWhs	$0.06293	$0.00607	$0.06900	**$0.00602**	**$0.00010**	**$0.07512**	**$0.06895**
All over 1,300 kWhs	$0.07377	$0.00877	$0.08254	**$0.00706**	**$0.00010**	**$0.08970**	**$0.08083**
General Services - Schedule 11							
Basic Charge	$6.00		$6.00	**$0.25**		**$6.25**	**$6.25**
Energy Charge:							
First 3,650 kWhs	$0.08579	$0.01191	$0.09770	**$0.00806**	**$0.00013**	**$0.10589**	**$0.09385**
All over 3,650 kWhs	$0.08032	$0.01191	$0.09223	**$0.00755**	**$0.00013**	**$0.09991**	**$0.08787**
Demand Charge:							
20 kW or less	no charge		no charge	**no charge**			**no charge**
Over 20 kW	$3.50/kW		$3.50/kW	$0.35/kW		$3.85/kW	$3.85/kW
Large General Service - Schedule 21							
Energy Charge:							
First 250,000 kWhs	$0.05720	$0.00843	$0.06563	**$0.00513**	**$0.00010**	**$0.07086**	**$0.06233**
All over 250,000 kWhs	$0.05110	$0.00843	$0.05953	**$0.00460**	**$0.00010**	**$0.06423**	**$0.05570**
Demand Charge:							
50 kW or less	$250.00		$250.00	**$25.00**		**$275.00**	**$275.00**
Over 50 kW	$3.00/kW		$3.00/kW	$0.30/kW		$3.30/kW	$3.30/kW
Primary Voltage Discount	$0.20/kW		$0.20/kW			$0.20/kW	$0.20/kW
Extra Large General Service - Schedule 25							
Energy Charge:							
First 500,000 kWhs	$0.04416	$0.00544	$0.04960	**$0.00417**	**$0.00006**	**$0.05383**	**$0.04833**
500,000 - 6,000,000 kWhs	$0.03973	$0.00544	$0.04517	**$0.00375**	**$0.00006**	**$0.04898**	**$0.04348**
All over 6,000,000 kWhs	$0.03832	$0.00544	$0.04376	**$0.00285**	**$0.00006**	**$0.04667**	**$0.04117**
Demand Charge:							
3,000 kva or less	$9,000		$9,000	**$1,000**		**$10,000**	**$10,000**
Over 3,000 kva	$2.75/kva		$2.75/kva	$0.25/kva		$3.00/kva	$3.00/kva
Primary Volt. Discount							
11 - 60 kv	$0.20/kW		$0.20/kW			$0.20/kW	$0.20/kW
60 - 115 kv	$0.80/kW		$0.80/kW			$0.80/kW	$0.80/kW
115 or higher kv	$1.00/kW		$1.00/kW			$1.00/kW	$1.00/kW
Annual Minimum	Present:	$571,610			Proposed:	**$627,380**	
Pumping Service - Schedule 31							
Basic Charge	$6.00		$6.00	**$0.25**		**$6.25**	**$6.25**
Energy Charge:							
First 165 kW/kWh	$0.07206	$0.00745	$0.07951	**$0.00666**	**$0.00010**	**$0.08627**	**$0.07872**
All additional kWhs	$0.05147	$0.00745	$0.05892	**$0.00476**	**$0.00010**	**$0.06378**	**$0.05623**

(1) Includes all present rate adjustments: Sch. 59 - BPA Residential Exchange (Sch. 1 only), Sch. 91 - DSM Rider, and Sch. 93 - ERM Surcharge.

APPENDIX 4

AVISTA UTILITIES
PROPOSED INCREASE BY SERVICE SCHEDULE
WASHINGTON - GAS
12 MONTHS ENDED DECEMBER 31, 2007
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Base Tariff Revenue Under Present Rates(1)	Proposed General Increase(2)	Base Tariff Revenue Under Proposed Rates	**Base Tariff Percent Increase**	Total Billed Revenue at Present Rates	Total GRC & Sch. 191 Increase	**Percent Increase on Billed Revenue**
	(a)	(b)	(c)	(d)	(e)	**(f)**	(g)	(h)	**(i)**
1	General Service	101	$138,898	$3,399	$142,297	**2.4%**	$141,883	$3,627	**2.6%**
2	Large General Service	111	$50,255	$1,091	$51,345	**2.2%**	$51,355	$1,173	**2.3%**
3	Large General Svc.-High Annual Load Factor	121	$6,568	$199	$6,766	**3.0%**	$6,785	$209	**3.1%**
4	Interruptible Service	131	$602	$8	$610	**1.4%**	$619	$9	**1.5%**
5	Transportation Service	146	$1,623	$72	$1,695	**4.4%**	$1,625	$72	**4.4%**
6	Special Contracts	148	$1,722	$0	$1,722	**0.0%**	$1,722	$0	**0.0%**
7	Total		$199,668	$4,768	$204,436	**2.4%**	$203,990	$5,091	**2.5%**

(1) Includes Purchase Adjustment Schedule 150; excludes other rate adjustments.

APPENDIX 4

AVISTA UTILITIES
WASHINGTON - GAS
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

(a)	Base Rate(1) (b)	Present Rate Adj.(2) (c)	Present Billing Rate (d)	General Rate Increase (e)	Sch. 191 LIRAP/DSM Increase (f)	Proposed Billing Rate(2) (g)	Proposed Base Rate(1) (h)
General Service - Schedule 101							
Basic Charge	$5.50		$5.50	**$0.25**		**$5.75**	**$5.75**
Usage Charge:							
All therms	$1.11237	$0.02560	$1.13797	**$0.02556**	**$0.00196**	**$1.16549**	**$1.13793**
Large General Service - Schedule 111							
Usage Charge:							
First 200 therms	$1.13862	$0.02278	$1.16140	**$0.02803**	**$0.00170**	**$1.19113**	**$1.16665**
200 - 1,000 therms	$1.06705	$0.02278	$1.08983	**$0.02262**	**$0.00170**	**$1.11415**	**$1.08967**
All over 1,000 therms	$1.00057	$0.02278	$1.02335	**$0.02120**	**$0.00170**	**$1.04625**	**$1.02177**
Minimum Charge:							
per month	$135.07		$135.07	**$5.36**		**$140.43**	**$140.43**
per therm	$0.46327	$0.02278	$0.48605	**$0.00123**	**$0.00170**	**$0.48898**	**$0.46450**
High Annual Load Factor Large General Service - Schedule 121							
Usage Charge:							
First 500 therms	$1.10892	$0.03211	$1.14103	**$0.02606**	**$0.00158**	**$1.16867**	**$1.13498**
500 - 1,000 therms	$1.05402	$0.03211	$1.08613	**$0.03210**	**$0.00158**	**$1.11981**	**$1.08612**
1,000 - 10,000 therms	$0.98698	$0.03211	$1.01909	**$0.03006**	**$0.00158**	**$1.05073**	**$1.01704**
10,000 - 25,000 therms	$0.94487	$0.03211	$0.97698	**$0.02878**	**$0.00158**	**$1.00734**	**$0.97365**
All over 25,000 therms	$0.93336	$0.03211	$0.96547	**$0.02843**	**$0.00158**	**$0.99548**	**$0.96179**
Minimum Charge:							
per month	$329.43		$329.43	**$13.03**		**$342.46**	**$342.46**
per therm	$0.45006	$0.03211	$0.48217		**$0.00158**	**$0.48375**	**$0.45006**
Interruptible Service - Schedule 131							
Usage Charge:							
First 10,000 therms	$0.97509	$0.02717	$1.00226	**$0.01373**	**$0.00153**	**$1.01752**	**$0.98882**
10,000 - 25,000 therms	$0.93377	$0.02717	$0.96094	**$0.01315**	**$0.00153**	**$0.97562**	**$0.94692**
25,000 - 50,000 therms	$0.92363	$0.02717	$0.95080	**$0.01301**	**$0.00153**	**$0.96534**	**$0.93664**
All over 50,000 therms	$0.92028	$0.02717	$0.94745	**$0.01296**	**$0.00153**	**$0.96194**	**$0.93324**
Annual Minimum per therm	Present:	$0.14471				Proposed:	$0.15786
Transportation Service - Schedule 146							
Basic Charge	$200.00		$200.00	**$0.00**		**$200.00**	**$200.00**
Usage Charge:							
First 20,000 therms	$0.07134	$0.00008	$0.07142	**$0.00331**		**$0.07473**	**$0.07465**
20,000 - 50,000 therms	$0.06352	$0.00008	$0.06360	**$0.00294**		**$0.06654**	**$0.06646**
50,000 - 300,000 therms	$0.05730	$0.00008	$0.05738	**$0.00266**		**$0.06004**	**$0.05996**
300,000 - 500,000 therms	$0.05302	$0.00008	$0.05310	**$0.00246**		**$0.05556**	**$0.05548**
All over 500,000 therms	$0.03995	$0.00008	$0.04003	**$0.00185**		**$0.04188**	**$0.04180**
Annual Minimum per therm	Present:	$0.06352				Proposed:	$0.06646

(1) Includes Schedules 150 - Purchased Gas Cost Adj.

(2) Includes Schedule 155 - Gas Rate Adj., Schedule 159 - Gas Decoupling Rate Adj. (Sch. 101 only), and Schedule 191 - Public Purpose Rider Adj.

APPENDIX 5
Avista Corporation
Rate Adjustments to Schedules 91 and 191
to Reflect Increased Levels of Funding for LIRAP/DSM

A. Schedule 91 (Electric) Tariff Rider Adjustment:
The Schedule 91 (electric) rates are revised to reflect the provisions in Section C, Paragraph 11 and Section D, Paragraph 12 of the Multiparty Settlement Stipulation related to LIRAP and DSM funding.

	DSM Rate (¢/kWh) [(1)]		LIRAP Rate (¢/kWh) [(1)]	
Schedule	Current	Proposed	Current	Proposed
1	$0.00181	$0.00186	$0.00048	$0.00053
11 & 12	$0.00256	$0.00263	$0.00068	$0.00074
21 & 22	$0.00189	$0.00194	$0.00050	$0.00055
25	$0.00124	$0.00127	$0.00033	$0.00036
31 & 32	$0.00167	$0.00173	$0.00044	$0.00048
*41-48	--	--	--	--

B. Schedule 191 (Natural Gas) Tariff Rider Adjustment:
The Schedule 191 (natural gas) rates are revised to reflect the provisions in Section C, Paragraph 11 and Section D, Paragraph 12 of the Multiparty Settlement Stipulation related to LIRAP and DSM funding.

	DSM Rate ($/Therm) [(2)]		LIRAP Rate ($/Therm) [(2)]	
Schedule	Current	Proposed	Current	Proposed
101	$0.01795	$0.01837	$0.00808	$0.00962
111 & 112	$0.01580	$0.01617	$0.00698	$0.00831
121 & 122	$0.01479	$0.01514	$0.00645	$0.00768
131 & 132	$0.01429	$0.01463	$0.00624	$0.00743

* The rates for street and area lights (Schedules 41-48) will also increase to correspond with the overall percentage increase in ¢/kWh for other schedules reflected in the table above.

(1) These energy charges are designed to provide an additional $280,000 of annual DSM funding and an additional $247,000 of annual LIRAP funding.

(2) These therm charges are designed to provide an additional $70,000 of annual DSM funding and an additional $253,000 of annual LIRAP funding.