**BEFORE THE**
**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

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|---|---|---|
| WASHINGTON UTILITIES AND | ) | |
| TRANSPORTATION COMMISSION | ) | DOCKET UE-100467 |
| | ) | |
| Complainant, | ) | and |
| | ) | |
| v. | ) | DOCKET UG-100468 |
| | ) | |
| AVISTA CORPORATION d/b/a | ) | |
| AVISTA UTILITIES | ) | SETTLEMENT STIPULATION |
| | ) | |
| Respondent. | ) | |
| ……………………………………..……… | ) | |

## I. PARTIES

1. This Settlement Stipulation is entered into by Avista Corporation ("Avista" or the "Company"), the Staff of Washington Utilities and Transportation Commission ("Staff"), the Public Counsel Section of the Washington Office of Attorney General ("Public Counsel"), Northwest Industrial Gas Users ("NWIGU"), Industrial Customers of Northwest Utilities ("ICNU"), and The Energy Project, jointly referred to herein as the "Parties." As such, the Parties represent all parties to this proceeding. The Parties agree that this Settlement Stipulation is in the public interest and should be accepted as a full resolution of all issues in these dockets. The Parties understand this Settlement Stipulation is subject to approval of the Washington Utilities and Transportation Commission (the "Commission").

## II. INTRODUCTION

2. On March 23, 2010, Avista filed with the Commission certain tariff revisions designed to increase general rates for electric service (Docket UE-100467) and natural gas service (Docket UG-100468) in the State of Washington. Avista requested an increase in electric rates of $55.3 million, or 13.8 percent, and an increase in natural gas rates of $8.5 million, or 5.4 percent. On April 5, 2010, the Commission entered Order 01 suspending the tariff revisions and consolidating Dockets UE-100467 and UG-100468 for hearing and determination pursuant to WAC 480-07-320. A Prehearing Conference Order (Order 04) issued on April 5, 2010, established a procedural schedule, among other things. Representatives of all Parties appeared at an August 4, 2010 Settlement Conference, which was held for the purpose of narrowing the contested issues in this proceeding, followed by subsequent settlement discussions on August 10-11, 2010.

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

## III. AGREEMENT

### A. Revised Increase and Rate Effective Date

4. The Parties agree that Avista shall be authorized to implement rate changes designed to increase its annual revenues from Washington electric customers by $29.50 million (or 7.4 percent), and Washington natural gas customers by $4.55 million (or 2.9 percent). The Parties agree that the rate changes identified herein should be effective with service on and after December 1, 2010.

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

| TABLE 1<br>SUMMARY TABLE OF ADJUSTMENTS TO ELECTRIC REVENUE REQUIREMENT<br>000s of Dollars | | Revenue Requirement | Rate Base |
|---|---|---|---|
| **Amount As Filed** | | **$ 55,298** | **$ 1,075,665** |
| | **Adjustments:** | | |
| **a)** | **Cost of Capital** | | |
| | Adjust return on equity to 10.2%; common equity to 46.5%; includes a Rate of Return of 7.91% | (7,273) | 0 |
| **b)** | **Power Supply-Related Adjustments** | | |
| | i Lower Gas/Electric Prices | (14,970) | 0 |
| | iii Include short-term contracts through 7/22/2010 | 3,267 | 0 |
| | iii Include lower colstrip outage | (880) | 0 |
| | iv Include higher Colstrip fuel cost | 1,498 | 0 |
| | v Include lower Stimson rates | (126) | 0 |
| | vi Include lower WNP-3 rates | (351) | 0 |
| | vii Include higher Wells cost | 167 | 0 |
| | viii Adjust for hydro shape change | (165) | 0 |
| | ix Include test year loads | (11,230) | 0 |
| **c)** | **Production Property Adj** | | |
| | Remove the Pro Forma Production Property Adjustment due to use of historical loads used for power supply | 18,957 | 37,643 |
| **d)** | **Lancaster** | | |
| | Recover $6.8 million of Lancaster deferral over 5 years | (1,526) | (3,149) |
| **e)** | **Capital Additions** | | |
| | Include the full effect of the 2009 Noxon upgrade and major (7) generation projects though April 30, 2010 | (7,761) | (48,783) |
| **f)** | **Noxon 2010/2011** | | |
| | Remove pro forma property taxes on the 2010/2011 Noxon upgrade projects | (126) | 0 |
| **g)** | **Executive Labor** | | |
| | Reduce executive labor charged to the Utility | (563) | 0 |
| **h)** | **Incentives** | | |
| | Remove test period executives' incentives | (309) | 0 |
| **i)** | **Spokane River / CDA Tribe Settlement Deferrals** | | |
| | Revise the Spokane River and CDA Tribe Settlement deferrals previously approved to a 10 year amortization | (661) | 214 |
| **j)** | **Pro Forma Vegetation Management** | | |
| | Increase vegetation management expense by $1.025 million; Increase the Company's Washington annual required spend for vegetation management to $4.025 million | (1,073) | 0 |
| **k)** | **Information Services** | | |
| | Based on the actual spend to June 30, 2010, and remove pro forma 2011 costs | (1,162) | 0 |
| **l)** | **Colstrip - Mercury Emission** | | |
| | Revise for known changes to Colstrip mercury emission costs | (33) | 0 |
| **m)** | **Employee Pension** | | |
| | Revise for known changes to pension costs | (35) | 0 |
| **n)** | **Administrative and General Expenses** | | |
| | Reduce administrative and general expenses | (444) | 0 |
| **o)** | **Working Capital** | | |
| | Reduce proposed working capital adjustment | (701) | (5,507) |
| **p)** | **Optional Renewable Power Rate (Buck-a-Block) Program** | | |
| | Remove the effect of the Company's Buck-A-Block (renewable) program from base rates | 19 | 0 |
| **q)** | **Restate Debt** | | |
| | Flow through impact of Rate Base adjustments | (316) | 0 |
| | **Total Adjustments** | **$ (25,797)** | **$ (19,582)** |
| | **Adjusted Revenue Requirement** | **$ 29,501** | **$ 1,056,083** |

| TABLE 2<br>SUMMARY TABLE OF ADJUSTMENTS TO NATURAL GAS REVENUE REQUIREMENT<br>000s of Dollars | | Revenue Requirement | Rate Base |
|---|---|---|---|
| **Amount As Filed** | | **$ 8,489** | **$ 199,233** |
| | **Adjustments:** | | |
| **a)** | **Cost of Capital**<br>Adjust return on equity to 10.2%; common equity to 46.5%; includes a Rate of Return of 7.91% | (1,346) | 0 |
| **e)** | **Capital Additions**<br>Eliminate natural gas capital additions | (231) | (1,525) |
| **g)** | **Executive Labor**<br>Reduce executive labor charged to the Utility | (63) | 0 |
| **h)** | **Incentives**<br>Remove test period executive incentives | (87) | 0 |
| **k)** | **Information Services**<br>Based on the actual spend to June 30, 2010, and remove pro forma 2011 costs | (324) | 0 |
| **m)** | **Employee Pension**<br>Revise for known changes to pension costs | (8) | 0 |
| **n)** | **Administrative and General Expenses**<br>Reduce administrative and general expenses | (235) | 0 |
| **o)** | **Working Capital**<br>Remove the natural gas working capital adjustment | (516) | (4,053) |
| **p)** | **Optional Renewable Power Rate (Buck-a-Block) Program**<br>Remove the effect of the Company's Renewable (Buck-a-Block) program from base rates | (8) | 0 |
| **q)** | **Restate Debt**<br>Flow through impact of Rate Base adjustments | 131 | 0 |
| **r)** | **Jackson Prairie**<br>Use revised plant and cushion gas accounting in base rates; defer revenue requirement of additional actual 2011 working gas inventory balance to be recovered through PGA | (1,248) | (8,692) |
| | **Total Adjustments** | **$ (3,935)** | **$ (14,270)** |
| | **Adjusted Revenue Requirement** | **$ 4,554** | **$ 184,963** |

Accordingly, the revenue requirement adjustments for the Company's electric operations show a reduction of $25,797,000 to the Company's filed-for revenue requirement increase. The revenue requirement adjustments for the Company's natural gas operations show a reduction of $3,935,000 to the Company's filed-for revenue requirement increase. 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. These adjustments are described in further detail below. The letter references correspond to the line items in the table of adjustments for both electric (Table 1) and natural gas (Table 2) above.

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

The Parties agree to a 10.2 percent return on equity, with a 46.5 percent common equity ratio, and adopt the capital structure and resulting rate of return as set forth below:

**Agreed-upon Cost of Capital**

| | Percent of Total Capital | Cost | Component |
|---|---|---|---|
| Total Debt | 53.50% | 5.93% | 3.17% |
| Common Equity | 46.50% | 10.20%[1] | 4.74% |
| Total | 100.00% | | 7.91% |

[1]The Parties reserve the right to argue for a direct reduction in return on equity due to natural gas decoupling in a future general rate case.

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

(i) <u>Natural Gas/Electric Prices</u> – This adjustment reduces the annual average natural gas price, as included in the Company's direct filing, from $6.38/dth to $5.13/dth. This price is based on a 3-month average through July 21, 2010 of 2011 forward prices. The average Mid C flat electric price correspondingly dropped from $49.73/MWh to $41.32/MWh.

(ii) <u>Short-Term Contracts</u> – This adjustment includes all 2011 wholesale electric and natural gas short-term transactions entered into through July 22, 2010.

(iii) <u>Colstrip Outage</u> – The Parties agree to decrease the forced outage rate at Colstrip Units 3 and 4 from 9.36 percent to 6.71 percent.

(iv) Colstrip Fuel Cost – This adjustment reflects an increase in the 2011 Colstrip coal cost from $19.72/ton to $21.92/ton based on updated information from Western Energy Company (Colstrip coal provider).

(v) Stimson Rates – This adjustment reflects a lower purchase price for the Stimson purchase for October 2011 through December 2011 from $84.28/MWh to $65.15/MWh to reflect new Idaho avoided costs.

(vi) WNP-3 Contract Adjustment – The Parties agree to lower the WNP-3 purchase price to reflect no increase in the midpoint rate from the 2009-10 contract year to the 2011 pro forma period.

(vii) Wells Cost – This adjustment increases the Wells purchase cost based on the updated information provided by Douglas County PUD on April 30, 2010.

(viii) Hydro Shape Change – This adjustment reflects changes in the heavy-load/light-load hour hydro production splits to be within 2 percent each month of the actual five-year average.

(ix) Test Year Loads – This adjustment reflects the decrease in load for the use of weather- adjusted 2009 test-year load from a forecasted 2011 pro forma load. System load decreased by 48.3 aMW.

**c.) Production Property Adjustment:**

The production property adjustment was removed from the revenue requirement due to the use of historical loads for determining power supply costs, as described above.

**d.) Lancaster:**

Avista will recover $6.8 million of the 2010 Lancaster deferral, amortized over a five-year period. (See discussion, below, in Section III.B.)

**e.)** **Capital Additions:**

Capital additions for electric operations shall include capital costs and expenses associated with certain major generation project upgrades. This adjustment includes the full effect of the Noxon Unit No. 1 generation upgrade project included in the settlement approved in Dockets UE-090134 and UG-090135 and completed during 2009, and certain major projects expected to be completed and transferred to plant-in-service by November 30, 2010, 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, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets. Pro formed capital additions for natural gas operations were removed.

**f.)** **2010 and 2011 Noxon Generation Upgrades:**

The Noxon Unit No. 3 generation upgrade completed in May 2010 (designed to increase that unit's efficiency by 4.15 percent and provide additional capacity of 7.5 MW) and the Noxon Unit No. 2 generation upgrade scheduled for completion in March of 2011 (designed to increase that unit's efficiency by 2.42 percent and provide additional capacity of 7.5 MW) were included. The capital costs have been averaged for their appropriate pro forma period with the associated depreciation expense, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets. Pro forma property taxes have been excluded from this adjustment.

**g.)** **Executive Labor:**

This adjustment consists of three individual components: (1) it reduces the amount of executive salaries and benefits charged to the utility and allocates a greater portion of both to subsidiary/non-utility operations; (2) it reduces executive base salaries so that executive salary costs included in rates reflect increases in closer proportion to those for non-executive employee salaries; and, (3) it removes costs of executive supplemental deferred compensation and long-term disability benefits, which are available only to executive employees.

**h.)** **<u>Incentives:</u>**

The incentives for executives were removed from the revenue requirement. The Company will review its non-executive incentive compensation programs and provide testimony in its next general rate case: (1) identifying, explaining, and to the extent possible, quantifying the programs' benefit(s) to ratepayers; and, (2) explaining how the programs comply with the Commission's Final Orders in previous Avista general rate cases, specifically Dockets UE-991606[1] and UE-090134[2].

**i.)** **<u>Coeur d'Alene (CDA) Tribe Settlement and Spokane River Relicensing (SRR) Deferrals:</u>**

The Parties agree to a ten-year amortization of the remaining balances beginning December 1, 2010 of the CDA Settlement Deferral, the CDA/SRR - CDR (Coeur d'Alene Reservation Trust Restoration Fund) deferral, the Spokane River Deferral, and the Spokane River PM&E Deferral.

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[1] *WUTC v. Avista Corporation, d/b/a Avista Utilities*, Third Supplemental Order, Docket Nos. UE-991606 and UG-991607 (consolidated), ¶¶ 268-73.

[2] *WUTC v. Avista Corporation, d/b/a Avista Utilities*, Final Order (Order No. 10), Docket Nos. UE-090134 and UG-090135 (consolidated), ¶¶ 128-29.

**j.) <u>Vegetation Management Expenses:</u>**

This adjustment reflects an increase to the electric vegetation management costs. The Company is currently required, by Commission Order in Docket UE-050482, to spend approximately $2.8 million per year for electric vegetation management (includes electric distribution and transmission expenses). Avista reports this to the Commission annually within the Company's Commission Basis Report, and maintains a one-way balancing account to track any funds under-spent (below the $2.8 million). In the event there are unspent funds for vegetation management in any given year, those unspent funds will be accounted for and spent in the subsequent year or credited back to customers. This adjustment increases the electric expense $1.025 million above the test period amount of $3.0 million, and increases the required annual spend level from the current $2.8 million to $4.025 million.

**k.) <u>Information Services Expenses:</u>**

This adjustment reflects an increase in ongoing information service requirements based on actual expenditures through June 30, 2010.

**l.) <u>Colstrip Mercury Emissions Expenses:</u>**

This adjustment reflects the revised amount for the Company's mercury abatement expenses required for its Colstrip Units #3 and #4 production plant.

**m.) <u>Employee Pension:</u>**

This adjustment reflects the decrease in employee pension related expenses based on updated information received by the Company.

**n.) <u>Administrative and General Expenses:</u>**

This adjustment removes all or a portion of various administrative and general costs, including certain dues, 50 percent of Board of Director fees and expenses (as ordered in Docket UE-090134/UG-090135), certain advertising costs, and certain non-recurring expenses. The costs addressed by this adjustment include and/or are related to:

i. Board of Directors' fees
ii. Board of Director meeting costs
iii. Other Director Costs (gifts, non-meeting travel, professional portraits)
iv. Employee retirement party
v. Employee entertainment/sporting event
vi. Executive charity-related travel
vii. Reimbursement of executive relocation expenses
viii. Charitable donations
ix. Dues and fees to civic organizations (Rotaries, Chambers of Commerce, etc.)
x. Corporate aircraft travel (non-cost-effective or non-utility flights)
xi. Promotional/image advertising
xii. Employee gifts
xiii. Customer give-away items and gifts
xiv. Corporate logo apparel and items
xv. Various other costs improperly charged to utility accounts as identified by non-company parties through discovery in this proceeding.

The Company, for its part, has agreed to remove all or a portion of the expenses related to the above items, for settlement purposes only, and as part of an overall adjustment for administrative and general expenses, including the removal of all expenses that are prohibited by law. The Company reserves the right to address the appropriateness of expenses set forth above in any future proceeding, except where recovery is prohibited by law.

**o.)** **Working Capital:**

This adjustment reduces the Company's proposed electric working capital pro forma adjustment, and removes the natural gas working capital adjustment proposed by the Company.

**p.)** **Optional Renewable Power Rate (Buck-a-Block) Program:**

This adjustment removes the effect of the Company's Optional Renewable Power Rate Program, also referred to as "Buck-A-Block," from base rates. See additional details regarding agreed-upon measures included in Paragraph 21 below. Going forward, the Company will maintain separate accounts for all Buck-a-Block program costs and revenues to ensure compliance with WAC 19.29A.090(5) (specifying that "[a]ll costs…associated with any option . . . must be allocated to the customers who voluntarily choose that option and may not be shifted to any customers who have not chosen such option").

**q.)** **Restate Debt Interest:**

Reflects the income tax effect of the change in interest expense related to all other adjustments in the Stipulation that affect rate base. This adjustment restates debt interest using the agreed-upon pro forma weighted average cost of debt of 3.17 percent.

**r.)** **Jackson Prairie (JP) Storage:**

The Parties agree to the revised accounting treatment proposed by the Company for its existing cushion gas using the net book value of the utility assets at February 2010 to record the transfer of the cushion gas from non-recoverable (FERC Account No. 352.3), which is a depreciable asset, to recoverable (FERC Account No. 117.1), which is a non-depreciable asset. The JP assets that will be added on May 1, 2011 will include plant assets as well as cushion gas that will be recorded in both recoverable and non-recoverable FERC accounts using a similar allocation method. The pro formed Jackson Prairie working gas inventory for the additional storage effective May 1, 2011, and associated additional operations and maintenance costs, were removed from the revenue requirement and rate base. The revenue requirement associated with Avista's rate of return applied to the actual balance of the additional JP working gas inventory applicable to Washington gas operations shall be calculated as a deferred cost beginning May 1, 2011 to be recovered in the Company's future PGA filings starting with Avista's fall 2011 PGA filing, until recovered in base rates in a subsequent general rate case. In addition, the additional operations and maintenance costs shall be recorded in the Company's PGA deferrals for later recovery in rates until those costs are included in base retail rates.

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

7. Decoupling Baseline and Application. Pursuant to the Commission's order initially adopting the Avista decoupling pilot, In Re Petition of Avista Corp., Order 04, Docket UG-060518, paragraph 49, the baseline for the decoupling mechanism has been updated so as to use the test year employed in this rate case proceeding. The update of the baseline is reflected in Appendix 3. In addition, the Company will address in its next general rate case "whether the program should recover DSM-

related lost margin from all rate schedules,"[3] an issue which the Parties agree is not resolved at this time.

## B. Recovery of Lancaster in Rates

8. In its Order 10, in Docket UE-090134, the Commission allowed Avista to defer costs incurred by Avista associated with its purchase of power from the Lancaster Generating Facility[4] until such time as the prudence of such costs and compliance with certain other requirements could be addressed in a subsequent general rate case – i.e., in this Docket ( UE-100467). The Parties have agreed that the costs of Lancaster for 2011 and going forward are reasonable and should be reflected in rates. For settlement purposes, Avista agrees to recover only $6.8 million of the amounts deferred in 2010, which would be recoverable in rates over a five (5) year amortization period, with a rate of return on the unamortized balance. Avista agrees to waive recovery of all other Lancaster-related deferred amounts for 2010.[5] As part of the settlement related to the 2010 Lancaster deferrals, the Parties agree that there will be no deferrals under the ERM for 2010 in either the rebate or surcharge direction.[6] Avista will take the risk on any changes in ERM-related power supply costs for 2010.[7] The Company will continue to file Monthly Power Cost Deferral Reports, per Docket UE-011595, which will specifically account for the deferral for Lancaster-related contracts until that deferral is no longer in place.

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[3] *WUTC v. Avista Corporation, d/b/a Avista Utilities*, Final Order (Order No. 10), Docket Nos. UE-090134 and UG-090135 (consolidated), ¶ 303.

[4] The Lancaster Generating Facility is a 275 MW combined-cycle combustion turbine located near Rathdrum, Idaho. Avista is a party to a power purchase agreement (PPA) whereby the output of the facility was transferred to Avista on January 1, 2010, for a period ending October 31, 2026.

[5] The year-to-date cumulative account balance of the Lancaster deferral was $7,570,233 through July 2010, and Avista estimates that the amount deferred for the entire year (2010) will be approximately $12 million.

[6] Through July 2010, the year-to-date difference between actual net power costs and authorized costs is $3,846,404 in the surcharge direction (within the deadband). Avista estimates that the amount of the deferral for the entire year (2010) will be in the range of $0 to $5 million.

[7] The current balance in the ERM of approximately $526,400 at July 31, 2010 shall also be reduced to zero such that the ERM balance at December 31, 2010 will be zero.

9. The Parties agree that the Lancaster PPA complies with the Greenhouse Gases Emissions Performance Standard (EPS) established in RCW 80.80.

**C. Rate Spread/Rate Design**

10. Electric Rate Spread/Rate Design:

a) Electric Cost of Service/Rate Spread – The Parties agree to use a pro-rata allocation of the Company's electric rate spread percentages from its original filing for purposes of spreading the revised revenue requirement, as shown on Page 1 of Appendix 4.

b) Electric Rate Design –

(i.) The Residential Basic Charge would remain at the current level of $6.00 per month.

(ii.) For the rate design of Schedule 25, the basic charge would increase from $11,000 to $12,500, and there would be a uniform percentage increase in the first two blocks, and an increase of 70 percent of the increase in Blocks 1 & 2 for Block 3. In addition, the demand charge would increase from $3.50 to $4.00, the Primary Voltage Discount for 60 kV would increase from $1.00 to $1.10, and the Primary Voltage Discount for 115 kV would increase from $1.20 to $1.30.

(iii.) The Rate Design for other Schedules would be as proposed by Avista in its original filing:

- Schedule 1 would have a uniform percentage increase for the blocks.
- Schedule 11 would have an increase in the Basic Charge from $6.75 to $10.00 per month, and a uniform percentage increase to blocks. In addition, the demand charge would increase from $4.25 to $5.00 per kilowatt.

- Schedule 21 would have an increase in the Basic Charge from $300 to $350 per month, and a uniform percentage increase to blocks. In addition, the demand charge would increase from $4.00 to $4.75 per kilowatt.
- Schedule 31 would have an increase in the Basic charge from $6.75 to $7.75 per month, and there would be a uniform percentage increase to blocks.
- Lighting would see a uniform percentage increase.

11. <u>Natural Gas Rate Spread/Rate Design</u>:

a) Natural Gas Cost of Service/Rate Spread – The Parties agree to use a pro-rata allocation of the Company's natural gas rate spread percentages from its original filing, modified as described in part b. below, for purposes of spreading the revised revenue requirement as shown on Page 1 of Appendix 4.

b) The Parties agree that the assignment of underground storage costs by throughput for balancing purposes will be reduced from 20 percent to 13 percent, with the additional Jackson Prairie capacity. The Company agrees to provide further information with respect to this issue in its next general rate case.

c) Natural Gas Rate Design

(i.) The Residential Basic Charge will remain at the current level of $6.00 per month.

(ii.) The Rate Design for other Schedules would be as proposed by Avista in its original filing:

- Schedule 111 would have an increase in the monthly Minimum Charge based on Schedule 101 rates (breakeven at 200 therms), and a uniform percentage increase to blocks 2 and 3.

- Schedule 121 would have an increase in the monthly Minimum Charge based on 101 rates (breakeven at 500 therms), and a uniform percentage increase to blocks 2-4, with no change to block 5.
- Schedule 131 would have a uniform percentage increase to blocks.
- Schedule 146 would have an increase in the Basic Charge from $201.30 to $225 per month, and a uniform percentage increase to all blocks.

**D. <u>Low Income Rate Assistance Program (LIRAP) Funding:</u>**

12. The Parties agree to adjust the LIRAP portion of the tariff riders (Schedules 91 and 191) to provide an increase in annual funding that reflects the same percentage increase as the overall percentage increase in revenue requirement in this case – i.e., 7.4 percent for electric and 2.9 percent for natural gas. With this increase, the annual funding level for electric low income customers will be approximately $3.3 million, and for natural gas low income customers will be approximately $1.7 million. Appendix 5 identifies the tariff rider adjustments to Schedule 91 and 191 (in ¢/kwh or ¢/therm) to reflect increased levels of funding for LIRAP. As a part of its compliance filing, the Company will file revised Schedule 91 and 191 tariffs consistent with the changes identified in Appendix 5.

**E. <u>Demand Side Management (DSM) Expenditures:</u>**

13. The Parties agree to reallocate existing levels of DSM funding under Schedules 91 and 191 in order to increase low income DSM by $500,000 over and above the existing funding level of $1.5 million. For purposes of program administration, the total funding level of $2 million for low income DSM includes amounts that may be dedicated to energy-related health and human safety measures, the expenditures for which shall not exceed fifteen (15) percent of overall actual low income DSM expenditures. In addition, Avista shall remove $15,000 (related to incorrect customer

rebates) from its Washington natural gas DSM account, and shall also remove $56,733 (electric) and $6,500 (natural gas) (reflecting improperly charged dues and memberships) from its DSM tariff rider accounts.

**F. Prudence of Energy Efficiency Expenditures:**

14. Avista, Staff, NWIGU, ICNU, and The Energy Project agree that Avista's expenditures for electric and natural gas energy efficiency programs in 2008 and 2009 were prudently incurred. Public Counsel does not take a position on the prudence of these expenditures, but does not oppose the settlement of this issue due to the conditions related to DSM set forth herein.

**G. DSM Accounting Review and Evaluation:**

15. Rebate Processing Procedures for DSM Programs Avista will conduct, either internally or by an independent, third-party, a comprehensive review of its customer rebate processing system for all rebate programs, including process analysis/best practices review of rebate processing to ensure accuracy. As part of this review there will be a thorough examination of the Company's procedures for prescriptive rebate programs where the amount of the rebate varies and is calculated individually for each customer (e.g., residential insulation and window replacement). The review is expected to culminate in a final report with recommendations regarding any new systems and/or controls the Company should implement to improve and enhance its rebate processing, including but not limited to controls to ensure that rebates do not exceed the program maximum, currently set at fifty percent of project cost for most programs. Avista shall furnish the final report resulting from this review in a report to be provided to all parties, and the Triple E Board, upon completion and prior to the Company's next general rate case.

16. In addition, the Company agrees that an independent, third-party will conduct Evaluation, Measurement, and Verification ("EM&V") of Avista's Limited Income Weatherization program as

part of the conditions approved by the Commission in Docket UE-100176.[8] The Company also agrees that an independent, third-party will conduct an impact evaluation and cost-effectiveness analysis of Avista's residential windows program (natural gas and electric), using program participant data from 2008 and/or 2009, with a final report completed no later than May 30, 2011. Avista and the selected evaluator will work in good faith to ensure all program participant data is as accurate as possible. If necessary, the selected evaluator may conduct an audit of all participant data for this program.

17. Independent, External Review of Data Management Strategy. Avista agrees that an independent, third-party will conduct an evaluation of Avista's data tracking systems and data strategy for its DSM programs. The review will examine Avista's internal operations for data entry, tracking, and reporting, and its systems for ongoing review, oversight and controls to ensure data accuracy. As part of this review, the selected external evaluator will share industry best practices regarding data management strategies. The review will also examine whether the documentation required from participating customers is appropriate. The review is expected to culminate in a final report with findings, as well as recommendations regarding any new systems and/or controls the company should implement to improve and enhance its DSM data management. In addition, the final report will include recommendations regarding effective and accurate procedures that should be followed to correct DSM data, when errors are discovered particularly in filings with the Commission. Avista shall furnish the final report resulting from this review in a report to be provided to all Parties, and the Triple E Board, upon completion and prior to Avista's next general rate case.

[8] *See* Docket UE-100176, Order 01, "Order Approving Avista's Ten-Year Achievable Conservation Potential And Biennial Conservation Target Subject To Conditions".

**H.** **<u>Effective Date:</u>**

18. As an integral part of this settlement, the Parties have agreed that the new rates shall be implemented on December 1, 2010, and support a modification of the procedural schedule to accommodate such a date.

**I.** **<u>Next General Rate Case:</u>**

19. The Company will not file a general rate case in the Washington jurisdiction before April 1, 2011.

**J.** **<u>Accounting Procedures</u>:**

20. <u>Policies/Procedures Regarding Cost Allocations.</u>

Prior to its next Washington general rate case filing, Avista will review its existing policies and procedures regarding the Company's allocation of costs between utility, LIRAP, and non-utility accounts, and produce a report with a detailed description of these policies and procedures. This report will include an explanation of safeguards in place so that subsidiary or non-utility expenses remain separate from and are not being charged to utility accounts. The report will also include the prescribed methods identified for proper allocation of shared/common costs between utility and non-utility accounts. The policies and procedures and related report shall be served on all Parties to the current rate case. Parties reserve the right to challenge or propose amendments to Avista's allocation policies and methodologies in any future rate case. The Company will maintain records of the cost of performing the review and preparing the report (including labor overhead/time spent) and Parties reserve the right to challenge Avista's recovery of all or part of these costs at such time as Avista may seek recovery (i.e., its next general rate case).

21. <u>Internal Audit of Certain Accounting Policies Regarding Allocations.</u>

Avista's Internal Audit Department will perform an annual audit of current accounting practices (including accounting for LIRAP programs) relating to: compliance with regulatory treatment of utility expenditures; accuracy of jurisdictional allocations; and allocations between utility and non-utility accounts for subsidiary and corporate-wide (shared) expenses. Following this audit, Avista will make any necessary revisions to its training materials (see Paragraph 23, below) and put in place measures so that inappropriate subsidiary, or shared, costs are correctly accounted for and not recorded to utility operating accounts. The Internal Audit Department will prepare a report regarding the results of its audit, including a list of all concerns, incorrect treatment of costs, and steps for improving the accuracy and propriety of accounting practices.

22. Avista will commit to performing the annual internal audit as described above and provide a copy of the same to all parties for three (3) years following its initial audit and report. Parties reserve the right to challenge any inappropriately recorded costs. In addition, the Company shall maintain records of the cost of performing the audits and preparing the reports (including labor overhead/time spent) and Parties reserve the right to challenge Avista's recovery of all or part of these costs at such time as Avista may seek recovery (i.e., its next general rate case).

23. Employee Training.

Avista will provide ongoing training for Avista employees to comply with required accounting and allocation practices as discussed in Paragraphs 20 and 21 above. This will include meeting with departments to explain proper labeling of expenses, accounting treatment, and allocations. Training materials will include guidelines regarding the proper use of various FERC accounts and proper expense labeling systems, so that costs are accurately identified for ratemaking purposes. Avista will distribute a semi-annual written reminder to employees to properly label and record expenditures (including appropriate utility/non-utility and jurisdictional allocations). The training described above and the first semi-annual reminder will be provided by Avista before the

Company files its next general rate case. In addition, the Company will maintain records of the cost of performing the preparing and providing trainings and training materials/written reminders (including labor overhead/time spent) and Parties reserve the right to challenge Avista's recovery of all or part of these costs at such time as Avista may seek recovery (i.e., its next general rate case).

24. <u>Review of Accounting Procedures Relating to Optional Renewable Power Rate Program.</u>

Avista shall perform an internal review of its Optional Renewable Power Rate Program ("Buck-a-Block") and prepare a report to be provided to all parties before its next Washington general rate case that describes the accounting for all costs associated with the program. These costs will include shared and overhead costs, such as labor, information services, and supplies that are used in the administration of the program. The report will provide a narrative explanation of how shared costs are allocated to the program. The report will also provide a breakdown of the 2010 actual costs allocable to Washington for each program component (costs of RECs, advertising/administration, internal labor-related overhead, and all other costs). Going forward, Avista will account for all Buck-a-Block program costs separate from other utility operations. The Company will maintain records of the cost of performing this internal review and preparing the subsequent reports (including labor overhead/time spent) and Parties reserve the right to challenge Avista's recovery of all or part of these costs at such time as Avista may seek recovery (i.e., its next general rate case).

## IV. EFFECT OF THE SETTLEMENT STIPULATION

25. <u>Binding on Parties</u>. The Parties agree to support the terms of the Settlement Stipulation throughout this proceeding, including any appeal, and recommend that the Commission issue an order adopting the Settlement Stipulation contained herein. The Parties understand that this

Settlement Stipulation is subject to Commission approval. The Parties agree that this Settlement Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements and documents disclosed in the negotiation of this Settlement Stipulation shall not be admissible evidence in this or any other proceeding.

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

27. Procedure. The Parties shall cooperate in submitting this Settlement Stipulation promptly to the Commission for acceptance. The Parties shall make available a witness or representative in support of this Settlement Stipulation. The 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 Settlement Stipulation and to supplement the record accordingly.

28. Reservation of Rights. The 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 Settlement. If the Commission rejects all or any material portion of this Settlement Stipulation, or adds additional material conditions, each 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 Settlement Stipulation. If any Party exercises its right of withdrawal, this Settlement Stipulation shall be void and of no effect, and the Parties will support a joint motion for a procedural schedule to address the issues that would otherwise have been settled herein.

29. Advance Review of News Releases. All Parties agree:

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

30. No Precedent. The Parties enter into this Settlement Stipulation to avoid further expense, uncertainty, and delay. By executing this Settlement Stipulation, no Party shall be deemed to have accepted or consented to the facts, principles, methods or theories employed in arriving at the Settlement Stipulation, and, except to the extent expressly set forth in the Settlement Stipulation, no Party shall be deemed to have agreed that such a Settlement Stipulation is appropriate for resolving any issues in any other proceeding.

31. Public Interest. The Parties agree that this Settlement Stipulation is in the public interest.

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

Entered into this 24th day of August, 2010.

Company: By: ______________________
David J. Meyer
VP, Chief Counsel for Regulatory and Governmental Affairs

Staff: By: ______________________
Gregory J. Trautman
Assistant Attorney General

Public Counsel: By: ______________________
Sarah A. Shifley
Assistant Attorney General

NWIGU: By: ______________________
Chad M. Stokes
Cable Huston Benedict Haagensen & Lloyd LLP

ICNU: By: ______________________
S. Bradley Van Cleve
Davison Van Cleve, P.C.

The Energy Project: By: ______________________
Ronald Roseman
Attorney at Law

Entered into this 24th day of August, 2010.

| | |
|---|---|
| Company: | By: ________________<br>David J. Meyer<br>VP, Chief Counsel for Regulatory and Governmental Affairs |
| Staff: | By: Gregory J. Trautman<br>Gregory J. Trautman<br>Assistant Attorney General |
| Public Counsel: | By: ________________<br>Sarah A. Shifley<br>Assistant Attorney General |
| NWIGU: | By: ________________<br>Chad M. Stokes<br>Cable Huston Benedict<br>Haagensen & Lloyd LLP |
| ICNU: | By: ________________<br>S. Bradley Van Cleve<br>Davison Van Cleve, P.C. |
| The Energy Project: | By: ________________<br>Ronald Roseman<br>Attorney at Law |

Entered into this 24th day of August, 2010.

| | |
|---|---|
| Company: | By: ____________________<br>David J. Meyer<br>VP, Chief Counsel for Regulatory and Governmental Affairs |
| Staff: | By: ____________________<br>Gregory J. Trautman<br>Assistant Attorney General |
| Public Counsel: | By: ____________________<br>Sarah A. Shifley<br>Assistant Attorney General |
| NWIGU: | By: ____________________<br>Chad M. Stokes<br>Cable Huston Benedict<br>Haagensen & Lloyd LLP |
| ICNU: | By: ____________________<br>S. Bradley Van Cleve<br>Davison Van Cleve, P.C. |
| The Energy Project: | By: ____________________<br>Ronald Roseman<br>Attorney at Law |

Entered into this ______day of August, 2010.

| | |
|---|---|
| Company: | By: ______________________________<br>David J. Meyer<br>VP, Chief Counsel for Regulatory and<br>Governmental Affairs |
| Staff: | By: ______________________________<br>Gregory J. Trautman<br>Assistant Attorney General |
| Public Counsel: | By: ______________________________<br>Sarah A. Shifley<br>Assistant Attorney General |
| NWIGU: | By: ______________________________<br>Chad M. Stokes<br>Cable Huston Benedict<br>Haagensen & Lloyd LLP |
| ICNU: | By: ______________________________<br>S. Bradley Van Cleve<br>Davison Van Cleve, P.C. |
| The Energy Project: | By: ______________________________<br>Ronald Roseman<br>Attorney at Law |

Entered into this 24th day of August, 2010.

| | |
|---|---|
| Company: | By: ______________________<br>David J. Meyer<br>VP, Chief Counsel for Regulatory and Governmental Affairs |
| Staff: | By: ______________________<br>Gregory J. Trautman<br>Assistant Attorney General |
| Public Counsel: | By: ______________________<br>Sarah A. Shifley<br>Assistant Attorney General |
| NWIGU: | By: ______________________<br>Chad M. Stokes<br>Cable Huston Benedict<br>Haagensen & Lloyd LLP |
| ICNU: | By: S Bradley Van Cleve<br>S. Bradley Van Cleve<br>Davison Van Cleve, P.C. |
| The Energy Project: | By: ______________________<br>Ronald Roseman<br>Attorney at Law |

Entered into this 24th day of August, 2010.

Company: By: ______________________
David J. Meyer
VP, Chief Counsel for Regulatory and
Governmental Affairs

Staff: By: ______________________
Gregory J. Trautman
Assistant Attorney General

Public Counsel: By: ______________________
Sarah A. Shifley
Assistant Attorney General

NWIGU: By: ______________________
Chad M. Stokes
Cable Huston Benedict
Haagensen & Lloyd LLP

ICNU: By: ______________________
S. Bradley Van Cleve
Davison Van Cleve, P.C.

The Energy Project: By: for Ronald Roseman by Charlotte [illegible]
Ronald Roseman
Attorney at Law

# APPENDIX 1

# AVISTA UTILITIES

**APPENDIX 1**

## Summary of Revenue Requirement Adjustments - Electric

| Column | Description | NOI | Rate Base | NOI | Rate Base | NOI | Rate Base | NOI | Rate Base |
|---|---|---|---|---|---|---|---|---|---|
| | **(000's Of Dollars)** | **FILED CASE** | | **FILED SETTLEMENT** | | **DIFFERENCE** | | **REVENUE REQUIREMENT** | |
| | | **Washington Electric** | | **Washington Electric** | | **Washington Electric** | | **NOI** | **Rate Base** |
| **Column** | **Description** | **NOI** | **Rate Base** | **NOI** | **Rate Base** | **NOI** | **Rate Base** | **0.62116** | **7.91%** |
| b | Per Results Report | $73,374 | $1,150,959 | $73,374 | $1,150,959 | $0 | $0 | $0 | $0 |
| c | Deferred FIT Rate Base | 0 | (163,716) | 0 | (163,716) | 0 | 0 | 0 | 0 |
| d | Deferred Gain on Office Building | 0 | (41) | 0 | (41) | 0 | 0 | 0 | 0 |
| e | Colstrip 3 AFUDC Elimination | 193 | (1,700) | 193 | (1,700) | 0 | 0 | 0 | 0 |
| f | Colstrip Common AFUDC | 0 | 426 | 0 | 426 | 0 | 0 | 0 | 0 |
| g | Kettle Falls Disallow. | (56) | (756) | (56) | (756) | 0 | 0 | 0 | 0 |
| h | Customer Advances | 0 | (257) | 0 | (257) | 0 | 0 | 0 | 0 |
| i | Customer Deposits | (6) | (3,060) | (6) | (3,060) | 0 | 0 | 0 | 0 |
| j | Settlement Exchange Power | 0 | 16,412 | 0 | 16,412 | 0 | 0 | 0 | 0 |
| k | Restating CDA Settlement | (558) | 4,676 | (558) | 4,676 | 0 | 0 | 0 | 0 |
| l | Restating CDA Settlement Deferral | (329) | 822 | (99) | 938 | 230 | 116 | (370) | 15 |
| m | Restating CDA/SRR CDR | (951) | 3,746 | (935) | 3,754 | 16 | 8 | (26) | 1 |
| n | Restating Spokane River Relicensing | (242) | 7,271 | (242) | 7,271 | 0 | 0 | 0 | 0 |
| o | Restating Spokane River Deferral | (158) | 395 | (47) | 450 | 111 | 55 | (179) | 7 |
| p | Restating Spokane River PM&E Deferral | (100) | 250 | (30) | 285 | 70 | 35 | (113) | 4 |
| q | Restating Montana Lease | (53) | 2,419 | (53) | 2,419 | 0 | 0 | 0 | 0 |
| | Actual | 71,114 | 1,017,846 | 71,541 | 1,018,060 | 427 | 214 | (687) | 27 |
| r | Eliminate B & O Taxes | (36) | 0 | (36) | 0 | 0 | 0 | 0 | 0 |
| s | Property Tax | (1,194) | 0 | (1,194) | 0 | 0 | 0 | 0 | 0 |
| t | Uncollect. Expense | 42 | 0 | 42 | 0 | 0 | 0 | 0 | 0 |
| u | Regulatory Expense | (47) | 0 | (47) | 0 | 0 | 0 | 0 | 0 |
| v | Injuries and Damages | 35 | 0 | 35 | 0 | 0 | 0 | 0 | 0 |
| w | FIT | (890) | 0 | (890) | 0 | 0 | 0 | 0 | 0 |
| x | Eliminate WA Power Cost Defer | 153 | 0 | 153 | 0 | 0 | 0 | 0 | 0 |
| y | Nez Perce Settlement Adjustment | (7) | 0 | (7) | 0 | 0 | 0 | 0 | 0 |
| z | Eliminate A/R Expenses | 181 | 0 | 181 | 0 | 0 | 0 | 0 | 0 |
| aa | Office Space Charges to Subsidiaries | 5 | 0 | 5 | 0 | 0 | 0 | 0 | 0 |
| ab | Restate Excise Taxes | 7 | 0 | 7 | 0 | 0 | 0 | 0 | 0 |
| ac | Net Gains/losses | 53 | 0 | 53 | 0 | 0 | 0 | 0 | 0 |
| ad | Revenue Normalization | 3,882 | 0 | 3,882 | 0 | 0 | 0 | 0 | 0 |
| ae | Misc Restating | 161 | 0 | 437 | 0 | 276 | 0 | (444) | 0 |
| af | Colstrip Mercury Emiss. O&M | (577) | 0 | (556) | 0 | 21 | 0 | (34) | 0 |
| ag | Working Capital | 0 | 23,695 | 0 | 18,188 | 0 | (5,507) | 0 | (701) |
| ah | Restate Debt Interest | (962) | 0 | (766) | 0 | 196 | 0 | (316) | 0 |
| R1 | Revised Buck-A Block | 0 | 0 | (12) | 0 | (12) | 0 | 19 | 0 |
| R2 | Officer Incentives Adj | 0 | 0 | 192 | 0 | 192 | 0 | (309) | 0 |
| | Restated Total | $71,920 | $1,041,541 | $73,020 | $1,036,248 | $1,100 | ($5,293) | ($1,771) | ($674) |
| PF1 | Pro Forma Power Supply | (18,288) | 0 | (4,132) | 0 | 14,156 | 0 | (22,790) | 0 |
| PF2 | Pro Forma Production Property | 8,798 | (37,643) | 0 | 0 | (8,798) | 37,643 | 14,164 | 4,794 |
| PF3 | Pro Forma Lancaster Amortization | (1,583) | 7,127 | (884) | 3,978 | 699 | (3,149) | (1,125) | (401) |
| PF4 | Pro Forma Labor Non-Exec | (1,269) | 0 | (1,269) | 0 | 0 | 0 | 0 | 0 |
| PF5 | Pro Forma Labor Exec | (102) | 0 | 248 | 0 | 350 | 0 | (563) | 0 |
| PF6 | Pro Forma Transmission Rev/Exp | 1,167 | 0 | 1,167 | 0 | 0 | 0 | 0 | 0 |
| PF7 | Pro Forma Capital Add 2010 | (1,067) | 55,984 | (105) | 7,201 | 962 | (48,783) | (1,549) | (6,212) |
| PF8 | Pro Forma Noxon Gen 2010/2011 | (191) | 8,656 | (113) | 8,656 | 78 | 0 | (126) | 0 |
| PF9 | Pro Forma Vegetation Management | (1,332) | 0 | (666) | 0 | 667 | 0 | (1,073) | 0 |
| PF10 | Pro Forma Information Services | (1,555) | 0 | (833) | 0 | 722 | 0 | (1,162) | 0 |
| PF11 | Pro Forma Employee Benefits | 417 | 0 | 439 | 0 | 22 | 0 | (35) | 0 |
| PF12 | Pro Forma Insurance | (42) | 0 | (42) | 0 | 0 | 0 | 0 | 0 |
| PF13 | Pro Forma Clark Fork/Spokane Rel PM&E | (1,619) | 0 | (1,619) | 0 | 0 | 0 | 0 | 0 |
| | **Pro Forma Total** | **$55,254** | **$1,075,665** | **$65,212** | **$1,056,083** | **$9,958** | **($19,582)** | **($16,030)** | **($2,494)** |

| | |
|---|---|
| | ($18,524) |
| **Impact of ROE reduced to 10.2% & Common Equity to 46.5%** | ($7,273) |
| **Total Adjustments to Proposed Revenue Requirement** | **($25,797)** |
| **Originally Filed Revenue Requirement** | $55,298 |
| **Revenue Increase Per Settlement** | **$29,501** |

# AVISTA UTILITIES

**APPENDIX 1**

## Summary of Revenue Requirement Adjustments - Natural Gas

| | (000's Of Dollars) | FILED CASE Washington Gas | | FILED SETTLEMENT Washington Gas | | DIFFERENCE Washington Gas | | REVENUE REQUIREMENT | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | NOI | Rate Base |
| **Item** | **Description** | **NOI** | **Rate Base** | **NOI** | **Rate Base** | **NOI** | **Rate Base** | **0.62130** | **7.91%** |
| b | Per Results Report | $12,148 | $204,811 | $12,148 | $204,811 | $0 | $0 | $0 | $0 |
| c | Deferred FIT Rate Base | 0 | (31,005) | 0 | (31,005) | 0 | 0 | 0 | 0 |
| d | Deferred Gain on Office Building | 0 | (14) | 0 | (14) | 0 | 0 | 0 | 0 |
| e | Gas Inventory | 0 | 8,440 | 0 | 8,440 | 0 | 0 | 0 | 0 |
| f | Customer Advances | 0 | (38) | 0 | (38) | 0 | 0 | 0 | 0 |
| g | Customer Deposits | (3) | (1,359) | (3) | (1,359) | 0 | 0 | 0 | 0 |
| | Actual | 12,145 | 180,835 | 12,145 | 180,835 | 0 | 0 | 0 | 0 |
| h | Revenue Normalization & Gas Cost Adjust | (395) | 0 | (395) | 0 | 0 | 0 | 0 | 0 |
| i | Eliminate B & O Taxes | (6) | 0 | (6) | 0 | 0 | 0 | 0 | 0 |
| j | Property Tax | (124) | 0 | (124) | 0 | 0 | 0 | 0 | 0 |
| k | Uncollectible Expense | 229 | 0 | 229 | 0 | 0 | 0 | 0 | 0 |
| l | Regulatory Expense Adjustment | 24 | 0 | 24 | 0 | 0 | 0 | 0 | 0 |
| m | Injuries and Damages | 123 | 0 | 123 | 0 | 0 | 0 | 0 | 0 |
| n | FIT | (7) | 0 | (7) | 0 | 0 | 0 | 0 | 0 |
| o | Net Gains/losses | 3 | 0 | 3 | 0 | 0 | 0 | 0 | 0 |
| p | Eliminate A/R Expenses | 32 | 0 | 32 | 0 | 0 | 0 | 0 | 0 |
| q | Office Space Charges to Subs | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| r | Restate Excise Taxes | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| s | Weatherization & DSM Investment Amort Removal | 200 | 0 | 200 | 0 | 0 | 0 | 0 | 0 |
| t | Misc Restating Adjustments | 48 | 0 | 194 | 0 | 146 | 0 | (235) | 0 |
| u | Working Capital | 0 | 4,053 | 0 | 0 | 0 | (4,053) | 0 | (516) |
| v | Restate Debt Interest | (111) | 0 | (192) | 0 | (82) | 0 | 131 | 0 |
| R1 | Remove Buck-a-Block Program | 0 | 0 | 5 | 0 | 5 | 0 | (8) | 0 |
| R2 | Remove Officer Incentives | 0 | 0 | 54 | 0 | 54 | 0 | (87) | 0 |
| | Restated Total | $12,163 | $184,888 | $12,287 | $180,835 | $123 | ($4,053) | ($199) | ($516) |
| PF1 | Pro Forma Labor Non-Exec | (367) | 0 | (367) | 0 | 0 | 0 | 0 | 0 |
| PF2 | Pro Forma Labor Exec | (29) | 0 | 10 | 0 | 39 | 0 | (63) | 0 |
| PF3 | Pro Forma Capital Add 2010 | (23) | 1,525 | 0 | 0 | 23 | (1,525) | (37) | (194) |
| PF4 | Pro Forma JP Storage 2011 | (101) | 12,820 | (13) | 4,128 | 88 | (8,692) | (142) | (1,107) |
| PF5 | Pro Forma Information Services | (430) | 0 | (229) | 0 | 201 | 0 | (324) | 0 |
| PF6 | Pro Forma Employee Benefits | 120 | 0 | 125 | 0 | 5 | 0 | (8) | 0 |
| PF7 | Pro Forma Insurance | (12) | 0 | (12) | 0 | 0 | 0 | 0 | 0 |
| | **Pro Forma Total** | **$11,321** | **$199,233** | **$11,801** | **$184,963** | **$479** | **($14,270)** | **($773)** | **($1,817)** |

| | |
|---|---|
| | **($2,589)** |
| **Impact of ROE reduced to 10.2% & Common Equity to 46.5%** | **($1,346)** |
| **Total Adjustments to Proposed Revenue Requirement** | **($3,935)** |
| **Originally Filed Revenue Requirement** | $8,489 |
| **Revenue Increase Per Settlement** | **$4,554** |

# APPENDIX 2

**APPENDIX 2**

# AVISTA UTILITIES

**Pro forma Januray 2011 - December 2011**

**ERM Authorized Expense and Retail Sales**

**ERM Authorized Power Supply Expense**

| | Total | January | February | March | April | May | June | July | August | September | October | November | December |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Account 555 - Purchased Power | $94,057,336 | $11,944,984 | $9,846,565 | $10,853,067 | $6,732,714 | $4,712,966 | $4,927,815 | $7,041,743 | $7,484,808 | $6,620,235 | $6,005,442 | $8,349,912 | $9,537,086 |
| Account 501 - Thermal Fuel | $34,270,177 | $3,348,316 | $3,062,689 | $3,327,639 | $1,902,982 | $1,556,472 | $1,454,724 | $3,034,374 | $3,367,673 | $3,234,240 | $3,355,439 | $3,270,601 | $3,355,029 |
| Account 547 - Natrual Gas Fuel | $114,574,309 | $10,313,555 | $9,965,514 | $8,687,285 | $3,518,933 | $2,675,756 | $3,294,621 | $11,094,720 | $13,127,806 | $12,566,735 | $11,569,604 | $13,114,461 | $14,645,319 |
| Account 447 - Sale for Resale | $61,906,487 | $3,563,619 | $4,040,473 | $3,415,529 | $4,350,662 | $5,618,561 | $5,671,884 | $10,007,193 | $7,148,106 | $6,784,137 | $2,871,260 | $4,145,606 | $4,289,456 |
| **Power Supply Expense** | $180,995,334 | $22,043,235 | $18,834,295 | $19,452,461 | $7,803,967 | $3,326,633 | $4,005,275 | $11,163,644 | $16,832,181 | $15,637,073 | $18,059,225 | $20,589,368 | $23,247,978 |
| **Transmission Expense** | $17,646,080 | $1,583,916 | $1,428,384 | $1,489,847 | $1,545,721 | $1,353,126 | $1,434,184 | $1,446,414 | $1,475,811 | $1,441,885 | $1,464,318 | $1,464,565 | $1,517,909 |
| **Transmission Revenue** | $12,346,484 | $901,304 | $825,004 | $1,002,240 | $898,432 | $1,029,104 | $1,371,347 | $1,379,878 | $1,150,203 | $1,025,629 | $1,027,312 | $925,342 | $810,690 |
| **Broker Fees** | $124,311 | $10,359 | $10,359 | $10,359 | $10,359 | $10,359 | $10,359 | $10,359 | $10,359 | $10,359 | $10,359 | $10,359 | $10,359 |

**ERM Authorized Washington Retail Sales**

| | Total | January | February | March | April | May | June | July | August | September | October | November | December |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total Retail Sales, MWh** | 5,407,533 | 527,099 | 488,794 | 481,286 | 395,019 | 410,896 | 405,797 | 418,600 | 445,346 | 406,550 | 415,472 | 473,455 | 539,219 |
| **Retail Revenue Credit Rate** | $50.31 /MWh | | | | | | | | | | | | |

# APPENDIX 3

**Avista Utilities**
**Washington - Gas - Test Year Calculations for Decoupling**
**12 Months Ended December 2009 - Docket No. UG-100468**

# 12 MONTHS ENDED DECEMBER 2009 TEST YEAR BASE

## Settlement Docket No. UG-100468

| **Schedule 101** | Per PDE(1) | **Annual Total** | **January** | **February** | **March** | **April** | **May** | **June** | **July** | **August** | **September** | **October** | **November** | **December** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Therms** | | | | | | | | | | | | | | |
| Usage from Revenue Run(2) | 124,216,208 | 124,216,208 | 24,885,757 | 21,106,338 | 17,754,612 | 12,666,299 | 7,615,545 | 3,714,717 | 2,373,945 | 2,111,270 | 2,274,191 | 4,129,665 | 9,700,573 | 15,883,296 |
| Ded: Prior Mo. Unbilled(2) | (15,919,236) | (80,466,703) | (15,919,236) | (13,556,027) | (9,801,943) | (9,117,730) | (5,222,312) | (2,486,077) | (1,639,848) | (1,405,084) | (1,544,210) | (1,964,249) | (7,223,636) | (10,586,351) |
| Add: Current Mo. Unbilled(2) | 17,648,827 | 82,196,294 | 13,556,027 | 9,801,943 | 9,117,730 | 5,222,312 | 2,486,077 | 1,639,848 | 1,405,084 | 1,544,210 | 1,964,249 | 7,223,636 | 10,586,351 | 17,648,827 |
| Add: Weather Adjustment(2) | (6,829,575) | (6,829,575) | (1,357,367) | (710,932) | (2,583,342) | (595,333) | 270,319 | 674,950 | - | - | - | (1,734,191) | 747,742 | (1,541,421) |
| Test Year Monthly Therms | 119,116,224 | 119,116,224 | 21,165,181 | 16,641,322 | 14,487,057 | 8,175,548 | 5,149,629 | 3,543,438 | 2,139,181 | 2,250,396 | 2,694,230 | 7,654,861 | 13,811,030 | 21,404,351 |
| | | | | | | | | | | | | | | |
| **Customers / Billings** | | | | | | | | | | | | | | |
| Test Yr Customers/Billings(2) | 1,722,614 | 1,722,614 | 143,747 | 143,734 | 143,649 | 143,462 | 143,299 | 143,101 | 143,012 | 143,096 | 143,401 | 143,630 | 144,120 | 144,363 |
| Test Year Average Use/Cust | | 69 | 147 | 116 | 101 | 57 | 36 | 25 | 15 | 16 | 19 | 53 | 96 | 148 |

| | Schedule 101 |
|---|---|
| Sch 101 Base Rate/therm(3) | $0.89276 |
| Times: 1 minus Revenue Related Items (4) | 0.955843 |
| Revenue prior to gross up | $0.85334 |
| Less: Weighted Average Gas Cost/therm(5) | $0.58246 |
| **Margin Rate/therm** | **$0.27088** |

(1) From Ehrbar workpapers in Docket No. UG-100468 PDE-G -1, PDE-G-16, and PDE-G-17
(2) From Monthly Data below
(3) From Docket No. UG-100468 Settlement Stipulation Appendix 4, page 5
(4) From Docket No. UG-100468 Andrews Exhibit EMA-3, page 4, line 7
(5) From Schedule 156 purchased gas cost per therm rate (15th revision sheet effective 11/1/2009)

**Avista Utilities**
**Washington - Gas - Test Year Calculations for Decoupling**
**12 Months Ended December 2009 - Docket No. UG-100468**

# 12 MONTHS ENDED DECEMBER 2009 TEST YEAR BASE

## UG-100468 Weather Normalization and Unbilled Calculation

**12 Months Ended December 2009 Monthly Data**

| **Revenue Run Therms** | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total 101 (6) | 24,885,757 | 21,106,338 | 17,754,612 | 12,666,299 | 7,615,545 | 3,714,717 | 2,373,945 | 2,111,270 | 2,274,191 | 4,129,665 | 9,700,573 | 15,883,296 | 124,216,208 |

**Weather Normalization**

| | | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Normal Degree Days (30 Year Average 1980 - 2009) | | 1,120 | 913 | 776 | 542 | 323 | 143 | 35 | 34 | 185 | 540 | 889 | 1,157 | 6,657 |
| Actual Degree Days | | 1,204 | 957 | 936 | 586 | 303 | 93 | 17 | 23 | 103 | 668 | 834 | 1,252 | 6,976 |
| **Degree Day Adjustment (1,7)** | | (84) | (44) | (160) | (44) | 20 | 50 | 18 | 11 | 82 | (128) | 55 | (95) | (319) |
| | Monthly | | | | | | | | | | | | | |
| Res 101 | Use/DD/Cust(7) | 0.1002 | 0.1002 | 0.1002 | 0.0877 | 0.0877 | 0.0877 | 0.0000 | 0.0000 | 0.0000 | 0.0877 | 0.0877 | 0.1002 | |
| Com 101 | Use/DD/Cust(7) | 0.2467 | 0.2467 | 0.2467 | 0.1670 | 0.1670 | 0.1670 | 0.0000 | 0.0000 | 0.0000 | 0.1670 | 0.1670 | 0.2467 | |
| Ind 101 | Use/DD/Cust(7) | 0.4266 | 0.4266 | 0.4266 | 0.2961 | 0.2961 | 0.2961 | 0.0000 | 0.0000 | 0.0000 | 0.2961 | 0.2961 | 0.4266 | |

**Sch. 101**

| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Res 101 | (1,109,528) | (581,150) | (2,112,216) | (507,737) | 230,511 | 575,387 | - | - | - | (1,478,524) | 637,401 | (1,260,401) | (5,606,257) |
| Com 101 | (244,757) | (128,130) | (465,256) | (86,515) | 39,305 | 98,305 | - | - | - | (252,408) | 108,989 | (277,535) | (1,208,002) |
| Ind 101 | (3,082) | (1,652) | (5,870) | (1,081) | 503 | 1,258 | - | - | - | (3,259) | 1,352 | (3,485) | (15,316) |
| Total 101 | (1,357,367) | (710,932) | (2,583,342) | (595,333) | 270,319 | 674,950 | - | - | - | (1,734,191) | 747,742 | (1,541,421) | (6,829,575) |

**Revenue Run Customers (Meters Billed)**

| | Class | | Jan-09 | Feb-09 | Mar-09 | Apr-09 | May-09 | Jun-09 | Jul-09 | Aug-09 | Sep-09 | Oct-09 | Nov-09 | Dec-09 | Annual Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential 101 | 01 | (8) | 131,823 | 131,816 | 131,750 | 131,579 | 131,420 | 131,217 | 131,144 | 131,208 | 131,483 | 131,710 | 132,145 | 132,409 | 1,579,704 |
| Commercial 101 | 21 | (8) | 11,811 | 11,804 | 11,787 | 11,774 | 11,768 | 11,773 | 11,757 | 11,776 | 11,805 | 11,808 | 11,866 | 11,842 | 141,571 |
| Industrial 101 | 31 | (8) | 86 | 88 | 86 | 83 | 85 | 85 | 85 | 86 | 87 | 86 | 83 | 86 | 1,026 |
| Interdepartmental 101 | 80 | (8) | 27 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 313 |
| Total | | | 143,747 | 143,734 | 143,649 | 143,462 | 143,299 | 143,101 | 143,012 | 143,096 | 143,401 | 143,630 | 144,120 | 144,363 | 1,722,614 |

**Monthly Unbilled Calculation**

| | Dec-08 | Jan-09 | Feb-09 | Mar-09 | Apr-09 | May-09 | Jun-09 | Jul-09 | Aug-09 | Sep-09 | Oct-09 | Nov-09 | Dec-09 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| WA101 (9) | 15,919,236 | 13,556,027 | 9,801,943 | 9,117,730 | 5,222,312 | 2,486,077 | 1,639,848 | 1,405,084 | 1,544,210 | 1,964,249 | 7,223,636 | 10,586,351 | 17,648,827 |

(6) From Knox workpapers in Docket No. UG-100468, TLK-R-120
(7) From Knox workpapers in Docket No. UG-100468, TLK-R-53
(8) From Knox workpapers in Docket No. UG-100468, TLK-R-23
(9) From Knox workpapers in Docket No. UG-100468, TLK-R-6 with monthly columns expanded

# APPENDIX 4

## Proposed Rate Spread (Electric)

**Revenue Requirement** **$29,501,000**

| Rate Schedule | | Base Revenues | | Proposed Increase | % of Overall Increase | Pro Rata Share | Overall Increase |
|---|---|---|---|---|---|---|---|
| 1 | $ | 177,103,000 | $ | 26,160,000 | 47.31% | $13,956,000 | 7.9% |
| 11 | $ | 42,070,000 | $ | 5,230,000 | 9.46% | $2,790,000 | 6.6% |
| 21 | $ | 120,869,000 | $ | 16,105,000 | 29.12% | $8,591,000 | 7.1% |
| 25 | $ | 44,938,000 | $ | 5,645,000 | 10.21% | $3,012,000 | 6.7% |
| 31 | $ | 9,096,000 | $ | 1,347,000 | 2.44% | $719,000 | 7.9% |
| 4x | $ | 5,867,000 | $ | 811,000 | 1.47% | $433,000 | 7.4% |
| | **$** | **399,943,000** | **$** | **55,298,000** | **100%** | **$29,501,000** | **7.4%** |

## Proposed Rate Spread (Natural Gas)

**Revenue Requirement** **$4,553,000**

| Rate Schedule | | Base Revenues | | As Filed Proposed Increase | | UG Storage 87/13 Proposed Increase | % of Overall Increase | Pro Rata Share | Overall Increase |
|---|---|---|---|---|---|---|---|---|---|
| 101 | $ | 112,965,000 | $ | 6,890,000 | $ | 6,924,000 | 81.56% | $3,713,000 | 3.3% |
| 111 | $ | 38,484,000 | $ | 1,254,000 | $ | 1,268,000 | 14.94% | $680,000 | 1.8% |
| 121 | $ | 4,342,000 | $ | 142,000 | $ | 143,000 | 1.68% | $77,000 | 1.8% |
| 131 | $ | 441,000 | $ | 12,000 | $ | 13,000 | 0.15% | $7,000 | 1.6% |
| 146 | $ | 1,662,000 | $ | 191,000 | $ | 141,000 | 1.66% | $76,000 | 4.6% |
| | **$** | **157,894,000** | **$** | **8,489,000** | **$** | **8,489,000** | **100.00%** | **$4,553,000** | **2.9%** |

**AVISTA UTILITIES**
**WASHINGTON ELECTRIC**
**PROPOSED INCREASE BY SERVICE SCHEDULE**
**12 MONTHS ENDED DECEMBER 31, 2009**
**(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(1) | **Base Tariff Percent Increase** | Total Billed Revenue at Present Rates (2) | Gen. Incr. as a % of Billed Revenue | Sch. 91 LIRAP Increase | Total General & Sch. 91 Increase | **Percent Increase on Billed Revenue** |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | **(f)** | (g) | (h) | (i) | (j) | **(k)** |
| 1 | Residential | 1 | $177,103 | $13,956 | $191,059 | **7.9%** | $178,941 | **7.8%** | $96 | $14,052 | **7.9%** |
| 2 | General Service | 11 | $42,070 | $2,790 | $44,860 | **6.6%** | $44,249 | **6.3%** | $25 | $2,815 | **6.4%** |
| 3 | Large General Service | 21 | $120,869 | $8,591 | $129,460 | **7.1%** | $126,995 | **6.8%** | $63 | $8,654 | **6.8%** |
| 4 | Extra Large General Service | 25 | $44,938 | $3,012 | $47,950 | **6.7%** | $47,189 | **6.4%** | $26 | $3,038 | **6.4%** |
| 5 | Pumping Service | 31 | $9,096 | $719 | $9,815 | **7.9%** | $9,570 | **7.5%** | $6 | $725 | **7.6%** |
| 6 | Street & Area Lights | 41-48 | $5,867 | $433 | $6,300 | **7.4%** | $6,178 | **7.0%** | $3 | $436 | **7.1%** |
| 7 | Total | | $399,943 | $29,501 | $429,444 | **7.4%** | $413,122 | **7.1%** | $219 | $29,720 | **7.2%** |

(1) Excludes all present rate adjustments: Sch. 59 - BPA Residential Exchange, and Sch. 91 - Public Purpose Rider.

(2) Includes all present rate adjustments: Sch. 59 - BPA Residential Exchange and Sch. 91 - Public Purpose Rider.

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

| (a) | Base Tariff Sch. Rate (b) | Present Rate Adjustments(1) (c) | Present Billing Rate (d) | **General Rate Increase (e)** | **Sch. 91 LIRAP Increase(2) (f)** | **Proposed Billing Rate (g)** | **Proposed Base Tariff Rate (h)** |
|---|---|---|---|---|---|---|---|
| **Residential Service - Schedule 1** | | | | | | | |
| Basic Charge | $6.00 | | $6.00 | **$0.00** | | **$6.00** | **$6.00** |
| Energy Charge: | | | | | | | |
| First 600 kWhs | $0.06103 | $0.00077 | $0.06180 | **$0.00524** | **$0.00004** | **$0.06708** | **$0.06627** |
| 600 - 1,300 kWhs | $0.07101 | $0.00077 | $0.07178 | **$0.00609** | **$0.00004** | **$0.07791** | **$0.07710** |
| All over 1,300 kWhs | $0.08324 | $0.00077 | $0.08401 | **$0.00713** | **$0.00004** | **$0.09118** | **$0.09037** |
| **General Services - Schedule 11** | | | | | | | |
| Basic Charge | $6.75 | | $6.75 | **$3.25** | | **$10.00** | **$10.00** |
| Energy Charge: | | | | | | | |
| First 3,650 kWhs | $0.09638 | $0.00530 | $0.10168 | **$0.00399** | **$0.00006** | **$0.10573** | **$0.10037** |
| All over 3,650 kWhs | $0.09023 | $0.00530 | $0.09553 | **$0.00370** | **$0.00006** | **$0.09929** | **$0.09393** |
| Demand Charge: | | | | | | | |
| 20 kW or less | no charge | | no charge | **no charge** | | | **no charge** |
| Over 20 kW | $4.25/kW | | $4.25/kW | $0.75/kW | | $5.00/kW | $5.00/kW |
| **Large General Service - Schedule 21** | | | | | | | |
| Energy Charge: | | | | | | | |
| First 250,000 kWhs | $0.06284 | $0.00391 | $0.06675 | **$0.00288** | **$0.00004** | **$0.06967** | **$0.06572** |
| All over 250,000 kWhs | $0.05614 | $0.00391 | $0.06005 | **$0.00262** | **$0.00004** | **$0.06271** | **$0.05876** |
| Demand Charge: | | | | | | | |
| 50 kW or less | $300.00 | | $300.00 | **$50.00** | | **$350.00** | **$350.00** |
| Over 50 kW | $4.00/kW | | $4.00/kW | $0.75/kW | | $4.75/kW | $4.75/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 | $0.04928 | $0.00256 | $0.05184 | **$0.00290** | **$0.00003** | **$0.05477** | **$0.05218** |
| 500,000 - 6,000,000 kWhs | $0.04433 | $0.00256 | $0.04689 | **$0.00262** | **$0.00003** | **$0.04954** | **$0.04695** |
| All over 6,000,000 kWhs | $0.04156 | $0.00256 | $0.04412 | **$0.00171** | **$0.00003** | **$0.04586** | **$0.04327** |
| Demand Charge: | | | | | | | |
| 3,000 kva or less | $11,000 | | $11,000 | **$1,500** | | **$12,500** | **$12,500** |
| Over 3,000 kva | $3.50/kva | | $3.50/kva | $0.50/kva | | $4.00/kva | $4.00/kva |
| Primary Volt. Discount | | | | | | | |
| 11 - 60 kv | $0.20/kW | | $0.20/kW | | | $0.20/kW | $0.20/kW |
| 60 - 115 kv | $1.00/kW | | $1.00/kW | $0.10/kW | | $1.10/kW | $1.10/kW |
| 115 or higher kv | $1.20/kW | | $1.20/kW | $0.10/kW | | $1.30/kW | $1.30/kW |
| Annual Minimum | Present: | $649,330 | | | Proposed: | **$697,830** | |
| **Pumping Service - Schedule 31** | | | | | | | |
| Basic Charge | $6.75 | | $6.75 | **$1.00** | | **$7.75** | **$7.75** |
| Energy Charge: | | | | | | | |
| First 165 kW/kWh | $0.08109 | $0.00347 | $0.08456 | **$0.00630** | **$0.00004** | **$0.09090** | **$0.08739** |
| All additional kWhs | $0.05792 | $0.00347 | $0.06139 | **$0.00450** | **$0.00004** | **$0.06593** | **$0.06242** |

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

**AVISTA UTILITIES**
**WASHINGTON GAS**
**PROPOSED INCREASE BY SERVICE SCHEDULE**
**12 MONTHS ENDED DECEMBER 31, 2009**
**(000s of Dollars)**

| Line No. | Type of Service | Schedule Number | Base Tariff Revenue Under Present Rates(1) | Proposed General Increase | Base Tariff Revenue Under Proposed Rates (1) | **Base Tariff Percent Increase** | Total Billed Revenue at Present Rates | Sch. 191 LIRAP Increase | Total General & LIRAP Increase | **Percent Increase on Billed Revenue** |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | **(f)** | (g) | (h) | (i) | **(j)** |
| 1 | General Service | 101 | $112,965 | $3,713 | $116,678 | **3.3%** | $103,604 | $33 | $3,746 | **3.6%** |
| 2 | Large General Service | 111 | $38,484 | $680 | $39,164 | **1.8%** | $34,347 | $12 | $692 | **2.0%** |
| 3 | Large General Svc.-High Annual Load Factor | 121 | $4,342 | $77 | $4,419 | **1.8%** | $3,878 | $1 | $78 | **2.0%** |
| 4 | Interruptible Service | 131 | $441 | $7 | $448 | **1.5%** | $387 | $1 | $8 | **2.0%** |
| 5 | Transportation Service | 146 | $1,662 | $76 | $1,738 | **4.6%** | $1,662 | $0 | $76 | **4.6%** |
| 6 | Special Contracts | 148 | $1,449 | $0 | $1,449 | **0.0%** | $1,449 | $0 | $0 | **0.0%** |
| 7 | Total | | $159,343 | $4,553 | $163,896 | **2.9%** | $145,327 | $47 | $4,600 | **3.2%** |

(1) Includes Purchase Adjustment Schedule 150/156; excludes other rate adjustments.

**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 Increase (f)** | **Proposed Billing Rate(2) (g)** | **Proposed Base Rate(1) (h)** |
|---|---|---|---|---|---|---|---|
| **General Service - Schedule 101** | | | | | | | |
| Basic Charge | $6.00 | | $6.00 | **$0.00** | | **$6.00** | **$6.00** |
| Usage Charge: | | | | | | | |
| All therms | $0.86159 | ($0.07859) | $0.78300 | **$0.03117** | **$0.00028** | **$0.81445** | **$0.89276** |
| **Large General Service - Schedule 111** | | | | | | | |
| Usage Charge: | | | | | | | |
| First 200 therms | $0.89142 | ($0.08484) | $0.80658 | **$0.03135** | **$0.00024** | **$0.83817** | **$0.92277** |
| 200 - 1,000 therms | $0.81545 | ($0.08484) | $0.73061 | **$0.01227** | **$0.00024** | **$0.74312** | **$0.82772** |
| All over 1,000 therms | $0.74742 | ($0.08484) | $0.66258 | **$0.01124** | **$0.00024** | **$0.67406** | **$0.75866** |
| Minimum Charge: | | | | | | | |
| per month | $140.68 | | $140.68 | **$6.27** | | **$146.95** | **$146.95** |
| per therm | $0.18802 | ($0.08484) | $0.10318 | **($0.00000)** | **$0.00024** | **$0.10342** | **$0.18802** |
| **High Annual Load Factor Large General Service - Schedule 121** | | | | | | | |
| Usage Charge: | | | | | | | |
| First 500 therms | $0.85841 | ($0.07761) | $0.78080 | **$0.04636** | **$0.00022** | **$0.82738** | **$0.90477** |
| 500 - 1,000 therms | $0.81137 | ($0.07761) | $0.73376 | **$0.01548** | **$0.00022** | **$0.74946** | **$0.82685** |
| 1,000 - 10,000 therms | $0.74218 | ($0.07761) | $0.66457 | **$0.01416** | **$0.00022** | **$0.67895** | **$0.75634** |
| 10,000 - 25,000 therms | $0.69872 | ($0.07761) | $0.62111 | **$0.01333** | **$0.00022** | **$0.63466** | **$0.71205** |
| All over 25,000 therms | $0.68684 | ($0.07761) | $0.60923 | | **$0.00022** | **$0.60945** | **$0.68684** |
| Minimum Charge: | | | | | | | |
| per month | $342.46 | | $342.46 | **$23.18** | | **$365.64** | **$365.64** |
| per therm | $0.17349 | ($0.07761) | $0.09588 | | **$0.00022** | **$0.09610** | **$0.17349** |
| Annual Minimum per therm | Present: | $0.23144 | | | | Proposed: | $0.24560 |
| **Interruptible Service - Schedule 131** | | | | | | | |
| Usage Charge: | | | | | | | |
| First 10,000 therms | $0.71369 | ($0.08203) | $0.63166 | **$0.01132** | **$0.00022** | **$0.64320** | **$0.72501** |
| 10,000 - 25,000 therms | $0.67174 | ($0.08203) | $0.58971 | **$0.01066** | **$0.00022** | **$0.60059** | **$0.68240** |
| 25,000 - 50,000 therms | $0.66145 | ($0.08203) | $0.57942 | **$0.01050** | **$0.00022** | **$0.59014** | **$0.67195** |
| All over 50,000 therms | $0.65805 | ($0.08203) | $0.57602 | **$0.01044** | **$0.00022** | **$0.58668** | **$0.66849** |
| Annual Minimum per therm | Present: | $0.16100 | | | | Proposed: | $0.17166 |
| **Transportation Service - Schedule 146** | | | | | | | |
| Basic Charge | $201.30 | | $201.30 | **$23.70** | | **$225.00** | **$225.00** |
| Usage Charge: | | | | | | | |
| First 20,000 therms | $0.07512 | | $0.07512 | **$0.00317** | | **$0.07829** | **$0.07829** |
| 20,000 - 50,000 therms | $0.06688 | | $0.06688 | **$0.00282** | | **$0.06970** | **$0.06970** |
| 50,000 - 300,000 therms | $0.06034 | | $0.06034 | **$0.00255** | | **$0.06289** | **$0.06289** |
| 300,000 - 500,000 therms | $0.05583 | | $0.05583 | **$0.00236** | | **$0.05819** | **$0.05819** |
| All over 500,000 therms | $0.04206 | | $0.04206 | **$0.00178** | | **$0.04384** | **$0.04384** |
| Annual Minimum per therm | Present: | $0.06688 | | | | Proposed: | $0.06970 |

(1) Includes Schedules 150/156 - 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 UTILITIES



## SCHEDULE 91 - Electric Public Purpose Rider

| | Current DSM Rate | Current LIRAP Rate | LIRAP Increase | New DSM Rate | New LIRAP Rate | Total DSM & LIRAP Rate | Change |
|---|---|---|---|---|---|---|---|
| Schedule 1 | $0.00317 | $0.00058 | 7.38% | $0.00317 | 0.00062 | $0.00379 | $0.00004 |
| Schedule 11 & 12 | $0.00449 | $0.00081 | 7.38% | $0.00449 | 0.00087 | $0.00536 | $0.00006 |
| Schedule 21 & 22 | $0.00331 | $0.00060 | 7.38% | $0.00331 | 0.00064 | $0.00395 | $0.00004 |
| Schedule 25 | $0.00217 | $0.00039 | 7.38% | $0.00217 | 0.00042 | $0.00259 | $0.00003 |
| Schedule 31 & 32 | $0.00295 | $0.00052 | 7.38% | $0.00295 | 0.00056 | $0.00351 | $0.00004 |
| Schedule 41 - 48 | 4.65% | 0.84% | 7.38% | 4.33% | 0.84% | 5.16% | |

## SCHEDULE 191 - Natural Gas Public Purpose Rider

| | Current DSM Rate | Current LIRAP Rate | LIRAP Increase | New LIRAP Rate | Total DSM & LIRAP Rate | Change |
|---|---|---|---|---|---|---|
| Schedule 101 | $0.05135 | $0.00979 | 2.88% | $0.01007 | $0.06142 | $0.00028 |
| Schedule 111 & 112 | $0.04939 | $0.00846 | 2.88% | $0.00870 | $0.05809 | $0.00024 |
| Schedule 121 & 122 | $0.04675 | $0.00781 | 2.88% | $0.00803 | $0.05478 | $0.00022 |
| Schedule 131 & 132 | $0.04298 | $0.00756 | 2.88% | $0.00778 | $0.05076 | $0.00022 |