Office of the Secretary
Service Date
October 8, 2004

# BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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| **IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO.** | ) | **CASE NO. AVU-E-04-1 AVU-G-04-1** <br> <br> **ORDER NO. 29602** |

**ISSUED OCTOBER 8, 2004**

**BOISE, IDAHO**

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## SUMMARY

On February 6, 2004, Avista Corporation dba Avista Utilities (Avista; Company) filed an Application with the Idaho Public Utilities Commission (Commission) for authority to increase its rates and charges for electric and natural gas service in the State of Idaho. The Company serves approximately 109,315 electric customers and 61,799 natural gas customers in northern Idaho. A change in the Company's current Power Cost Adjustment (PCA) surcharge was also requested. On September 9, 2004, the Commission issued Amended Interlocutory Order No. 29588 that contained our initial findings in these cases and authorized changes in the Company's electric and natural gas rates. In this final Order we reaffirm the rate changes set out in Order No. 29588 and provide our detailed findings.

By this final Order the Commission affirms the change in electric rates authorized in Amended Interlocutory Order No. 29588 and authorizes the Company to increase its Idaho electric base revenue requirement by $24,716,195 or approximately 16.90%. This increase is offset by disallowances in the Power Cost Adjustment (PCA) coupled with an adjustment in the PCA recovery period and a reduction in the Energy Efficiency Rider. These offsetting adjustments reduce the authorized net revenue increase to $3,182,000 or 1.9% of current annual revenue. The electric rates we approve as just and reasonable are set out in attached Appendix A. *Idaho Code* § 61-502. The net amount of actual increase varies by class of customer and usage. The resultant increase for an electric residential customer using an average of 941 kWh per month is $4.01, or a 7.1% increase in the customer's electric bill.

The Commission also affirms the change in natural gas rates authorized in Amended Interlocutory Order No. 29588 and authorizes the Company to increase its Idaho natural gas revenues by $3,311,000 or approximately 6.38%. The natural gas rates we approve as just and reasonable are those set forth in attached Appendix B. *Idaho Code* § 61-502. The base rates we approve are the embedded fixed base rates used in the updated weighted average cost of gas (WACOG) calculation of $0.44989 per therm and incorporated in the Company's PGA adjustment authorized in Order No. 29590, Case No. AVU-G-04-2. The net amount of actual increase varies by class of customer and usage. The resultant increase for a natural gas residential customer using an average of 73 therms of gas per month is $12.84 per month, or 21.39%.

In this Order the Commission approves a pro forma electric rate base of $424,114,000; a pro forma natural gas rate base of $59,653,000; a return on equity of 10.4%; and an overall rate of return of 9.25%.

## APPLICATION

Avista is a public utility engaged in the generation, transmission and distribution of electric power and the distribution of natural gas. The Company in its Application requested a Commission Order approving revised electric and natural gas rates and charges effective March 10, 2004. The proposed effective date was suspended pending hearing on the Application and further Order of the Commission. Order No. 29432; *Idaho Code* § 61-622.

Avista's last electric general rate case in Idaho was completed in 1999. (Case No. WWP-E-98-11, Order No. 28097.) Since that time, Avista's overall electric rates in Idaho have been modified under the Company's Power Cost Adjustment (PCA) mechanism to reflect changes in power costs related to streamflow and wholesale market conditions. Avista contends that an electric rate increase is necessitated by new generating projects, reduced wholesale revenue and increased fuel costs. The Company's original Application request of $35.2 million or a 24.1% increase in electric revenue was revised at hearing to $31.1 million or 21.2%.

Avista's last natural gas general rate case in Idaho was completed in 1989. (Case No. WWP-G-88-5, Order No. 22749.) Since that time, Avista's overall natural gas rates in Idaho have been modified under the Company's Purchased Gas Cost Adjustment (PGA) mechanism to reflect changes in variable gas-related costs. Avista contends that a natural gas rate increase is necessitated by decreased therm usage and increased general business expenses. The Company's original request of $4.754 million or a 9.16% increase in natural gas revenue costs was revised at hearing to $4.06 million or 7.8%.

The Company's requested revenue increase in its Application is predicated on a proposed 9.82% rate of return, including an 11.5% return on equity. Tr. at 98; 104. Avista alleges that the rates in its present tariffs are no longer reasonable or adequate and do not allow it to earn a fair and reasonable return on investment.

***Appearances***

A technical hearing in Case Nos. AVU-E-04-1 and AVU-G-04-1 was held in Boise, Idaho the week of July 19, 2004. The following parties appeared by and through their respective counsel of record:

| | |
|---|---|
| Avista Corporation | David S. Meyer, Esq. |
| Potlatch Corporation | Conley E. Ward, Esq. |
| Coeur Silver Valley, Inc. | Charles L. A. Cox, Esq. |
| Community Action Partnership Association of Idaho (CAPAI) | Brad M. Purdy, Esq. |
| Commission Staff | Scott D. Woodbury, Esq.<br>Lisa Nordstrom, Esq. |

A continued technical hearing was held in Boise on August 16, 2004.

***Public Workshops, Hearings and Comments***

Prior to the technical hearings in this case, the Commission Staff in May 2004 conducted public workshops in Coeur d'Alene and Moscow to discuss the Company's Application and to answer customer questions. Public testimony hearings conducted by the Commission were held in Kellogg and Sandpoint on July 26, 2004 and in Lewiston on July 27, 2004. Six customers attended the workshops and about 100 people attended the three public hearings. Of those who attended, 25 people testified at the hearings. Among those testifying were Idaho State Senator Shawn Keough and Representative Bonnie Douglas. The Commission also solicited public written comments regarding the Company's Application. By August 6, 2004, the Commission had received written comments from 81 residential customers and 15 non-residential customers. The Commission also received written comments from area taxing authorities – four school districts, Shoshone and Clearwater County Commissioners, and a sewer district, all concerned about the impact of a rate increase. Additionally, more than 1,500 signatures were attached to four separate petitions from the Company's customers. All those who commented and signed petitions opposed any rate increase.

The Commission greatly appreciates the efforts customers made to express their opinions regarding their electric and natural gas rates. Approximately one-half of the comments were from low and fixed income customers concerned about being able to afford any increases in their utility bills. More than one-half of the residential customer comments also asked that the Commission consider the poor economy in northern Idaho before granting any rate increases.

We have reviewed and considered the record in Case Nos. AVU-E-04-1 and AVU-G-04-1 including: the Prehearing Memorandum filed by Potlatch; the transcript of technical proceedings; the transcript of public testimony and filed public comments; and the Petition for Intervenor Funding filed by CAPAI. Although this Order grants an increase, our decisions on Low Income Weatherization Assistance, DSM programs and the Winter Payment Program can help customers manage their bills. With this background in mind we now discuss the test year, capital structure and rate of return issues presented in this case and common to both the Company's electric and natural gas operations.

**Avista Utilities – Electric and Gas**

As set out in greater detail below, the Commission approves a normalized 12-month test year ending December 31, 2002 for net operating income and an average of monthly averages 2002 test year for rate base for Avista Utilities. We approve an embedded capital structure for Avista at December 31, 2003 consisting of 50.08% debt, 5.57% trust preferred securities, 1.76% preferred stock and 42.59% common equity. We accept an embedded cost of debt of 8.68%, embedded cost for trust preferred securities of 6.15% and embedded preferred stock cost of 7.35%. We approve a return on common equity of 10.4% and an overall weighted cost of capital and rate of return of 9.25%.

***Test Year***

Avista proposed a 2002 test year presented on a pro forma basis for net operating income and an average of monthly average 2002 test year for rate base items. Tr. at 147. Staff accepted the 2002 test year proposed by the Company. Tr. at 1117. Potlatch witness Peseau argues that use of a 2002 test year, adjusted for allegedly known and measurable changes, produces a mismatch of revenues from 2002 and year-end expenses and rate base from 2004. This mismatch, Potlatch contends, should be corrected by: (1) reversing the pro forma entries and properly matching test year averages for both sides of the ledger, (2) updating revenues to the 2004 level in the same manner as rate base and expenses (preferred method), or (3) employing the rate base adjustments adopted in the Idaho Power rate case. Tr. at 922-926.

Addressing Potlatch's contention that there is a mismatch between revenues and expenses, Avista witness Falkner contends that each of the Company's test year adjustments fall into an accepted category of adjustment. Revenues, the Company maintains, cannot be annualized to 2004 year-end levels to correct a Potlatch-perceived mismatch because: (1) the 2004 year-end levels of revenues would not be "known and measurable" for another six months, (2) expenses would also need to be adjusted to year-end, and (3) additional revenue from load growth caused by new customers would be offset by additional costs. Tr. at 214-217.

The Commission finds that the timing of the Company's rate case filing was dictated by Company commitment and Commission direction in the Company's 2003 PCA filing, Case No. AVU-E-03-6, Order No. 29377. Avista had a deadline of March 31, 2004 to file its electric general rate case. The timing of the rate case influenced the Company's selection of the test year. The Commission finds use of a 12-month test year ending December 31, 2002 for net operating income and an average of 2004 monthly averages for rate base to be reasonable and appropriate. The matching of test year adjustments will be discussed later with other revenue, expense and rate base adjustments.

## CAPITAL STRUCTURE AND RATE OF RETURN

### *1. Capital Structure*

In its initial filing, Avista witness Malquist recommended a pro forma capital structure consisting of 48.19% long-term debt, 5.79% trust preferred securities, 1.72% preferred stock, and 44.30% common equity, that included adjustments to reflect known and projected changes in long-term debt issuances/redemptions and associated costs through September 30, 2004. Tr. at 97-100; 105; 421-426.

Potlatch witness Thornton recommended no changes to Avista's pro forma capital structure. Tr. at 975. Staff witness Carlock, however, contended that the pro forma changes proposed by Avista were not adequately known and measurable. Staff recommended instead using the embedded capital structure at December 31, 2003 consisting of 50.08% debt, 5.57% trust preferred securities, 1.76% preferred stock and 42.59% common equity. Tr. at 1474. Avista in rebuttal agreed with Staff to use the capital structure at the embedded December 31, 2003 actual levels. Tr. at 193.

The Commission finds Avista's actual embedded capital structure at December 31, 2003 as proposed by Staff and agreed to by the Company, to be appropriate for calculating the Company's overall rate of return.

*2. Cost of Debt*

Avista testified that its embedded cost of long-term debt on December 31, 2003 was 8.68%. Exh. 2, p. 2. The Company proposed making certain pro forma adjustments to update the debt cost through September 30, 2004 to 8.70%. Tr. at 101; Exh. 2, p. 2. Staff accepted and recommended use of the Company's average actual cost of long-term debt outstanding on December 31, 2003, i.e., 8.68%. Tr. at 1475.

The Commission finds it reasonable based on the evidence of the record to reject the pro forma adjustments to be consistent with the capital structure adopted and to use the Company's year-end 2003 embedded cost of debt calculation, 8.68%.

*3. Cost of Trust Preferred Securities*

Avista testified that its embedded cost of trust preferred securities on December 31, 2003 was 6.15%. Exh. 2, p. 2. The Company proposed making certain pro forma adjustments to update the debt cost through September 30, 2004 to 7.01%. Tr. at 102-103; Exh. 2, p. 2. Staff accepted and recommended use of the Company's embedded cost of trust preferred securities on December 31, 2003, 6.15%. Tr. at 1475.

The Commission finds it reasonable based on the evidence of the record to reject the pro forma adjustments to be consistent with the capital structure adopted and to adopt the Company's 6.15% year-end 2003 embedded cost for trust preferred securities as the appropriate cost rate.

*4. Cost of Preferred Stock*

Avista witness Malquist testified that the Company's embedded cost of preferred stock on December 31, 2003 was 7.35%. Exh. 2, p. 2. The Company proposed making certain pro forma adjustments to update the preferred stock cost through September 30, 2004 to 7.34%. Tr. at 102-103; Exh. 2, p. 2. Staff witness Carlock accepted and recommended use of the Company's embedded cost of preferred stock on December 31, 2003, 7.35%. Tr. at 1475.

The Commission finds it reasonable based on the evidence of the record to reject the pro forma adjustments to be consistent with the capital structure adopted and to adopt the Company's 7.35% year-end 2003 embedded cost for preferred stock as the appropriate cost rate.

*5. Cost of Common Equity Capital*

Avista, Staff and Potlatch disagree as to the appropriate cost of common equity capital. The cost of common equity capital, stated as a rate of return on common equity, is a function of several variables. It is primarily an attempt to quantify a rate of return required by investors for that particular investment that is equal to returns earned at the same time by entities of similar risk and uncertainty. The return should also be reasonably sufficient to allow the utility to support its credit and attract new capital needed for utility operations. Avista's electric operation was previously authorized to earn an 8.979% overall return and a 10.75% return on common equity. Case No. WWP-E-98-11, Order No. 28097. For its gas operation the Company was authorized to earn an 11.02% overall return and a 12.75% return on equity. Case No. WWP-G-88-5, Order No. 22749.

Avista in this case requests a rate of return of 11.5% on the common equity portion of its capital structure. Tr. at 98; 104. The Company's cost of capital witness, Dr. Avera, proposes a range for equity return of 10.4-11.9% (eight Western Electric Utilities Benchmark Group) and advocates a higher return within that range. Tr. at 372. Avista witness Malquist believes that the requested 11.5% return will support a bond upgrade and will minimize customer impacts. Tr. at 103-105. Dr. Avera contends that Avista's unique investment risks are significantly greater than the benchmark group. The 11.5% return requested by Avista, Avera contends, is too low given expectations for higher utility bonds going forward, unsettled power markets, below investment-grade credit rating, and hydro uncertainties. Tr. at 372-373.

Staff witness Carlock proposes a range for equity return of 9.5-10.9% and recommends a return on equity of 10.4%. Tr. at 1475. Staff uses the results of discounted cash flow (8.8-11.3%) analysis and the comparable earnings method for industrials and utilities (10-11%) in its computation. Tr. at 1471, 1473.

Potlatch witness Thornton proposes a much lower range for equity return based on a capital asset pricing model (7.70%- 9.90%) and discounted cash flow model analysis (7.5%-9.20%) and recommends a return on equity of 8.5%. Tr. at 1001. Thornton contends that Company witness Malquist bases his return on equity recommendation on personal belief and provides no financial analysis or cost of equity calculations. Tr. at 1003. Thornton believes Company witness Avera's results are upwardly biased and that the eight-company benchmark sampling is too small to impart sufficient confidence. Tr. at 1004-1005. Potlatch witness

Peseau offers simple updates to Avera's data (i.e., growth rate, dividend yields, interest rates) that lowers Avera's ROE estimate by 140 basis points (1.4%). Tr. at 941-952.

**Commission Findings**

In this case, as in Avista's most recent electric rate case (WWP-E-98-11), the parties have advanced different methodologies to analyze and ascertain a fair rate of return on common equity capital, including discounted cash flow (DCF) method, risk premium analysis, and comparable earnings method. Each method attempts to establish a rate of return on common equity at a point sufficiently attractive that free market investors will consider purchasing common equity shares in the company. As with other analytical tools used in the ratemaking process, the methods to evaluate a common equity rate of return are imperfect predictors of future performance. Additionally, the rate of return on equity specified by a regulatory agency is but one factor considered by prudent investors when evaluating a utility's stock. A utility's stock performance in the marketplace is determined by many variables, including management decisions, weather, streamflow conditions, and a host of separate economic factors. Also considered in the instance of Avista Utilities is the corporate structure of Avista Corporation and the Company's unregulated activities.

This Commission has found it reasonable in the past to primarily rely on DCF and comparable earnings methods to determine an appropriate rate of return on common equity. We have confidence in those approaches and primarily rely on them again in this case. The DCF analysis utilizes the dividend rate, stock price and expected growth rate of a company to quantify the return required by the investor. Flotation costs have also been reflected with the DCF method. The comparable earnings method evaluates returns earned by other companies, including utilities, to quantify an investors expected return, taking into account the risks associated with a particular investment. A third methodology to determine a required rate of return on common equity is the risk premium analysis. The risk premium method starts with the rate of return for a low-risk investment, such as government or utility bonds, and adds a premium based on the relative risk associated with a utility's stock. A fourth method, the capital asset pricing model (CAPM) measures risks using the Beta coefficient. The return on equity is measured in relation to the market as a whole. As markets change, new concerns develop in various financial circles related to the calculations used to determine the cost of equity. One such concern continues to be the measurement and proper use of Beta. This Commission has not focused on Beta or CAPM for determining the cost of equity; therefore any new concerns or methods are not at issue in this case and will not be specifically addressed.

The Commission has considered all methodologies and rationale in the cost of capital testimony of the witnesses and finds the middle ground position advanced by Staff witness Carlock to be reasonable. The evidence in this case supports a rate of return on common equity for Avista ranging from 9.5-10.9%. This range encompasses the lower end of Avista's recommended range from 10.4-10.9%, and the upper range of 9.5-9.9% from Potlatch's recommendations. We find Avista's reasonable required rate of return on common equity to be 10.4%. This return on equity with the December 31, 2003 capital structure and cost results in an overall rate of return of 9.25%. In authorizing a 10.4% return on common equity, this Commission acknowledges its desire to maintain Avista as a financially viable utility with credit ratings at or above the current level. The Staff proposal, adopted by this Order, results in a pre-tax interest coverage ratio of 2.71 times. Tr. at 453. This is at the bottom of S&P's BBB- rating. *Id.* A rating of BBB would be an increase for Avista. As Avista continues to strengthen its capital structure, refinance high cost debt and address other rating agency concerns, the pre-tax interest coverage ratio will also improve. This is a move in the right direction to improve Avista's utility bond rating. We anticipate that non-utility operations/affiliates will also be making similar efforts to reduce risk and improve earnings contributions to improve ratings. We encourage Avista to investigate with the Staff reasonable ring fencing efforts to further reduce utility risk and improve ratings. The use of this cost of common equity, together with the cost of debt, cost of trust preferred securities, cost of preferred stock and capital structure previously found, yields the following overall return for rate base:

| **Component** | **Percentage of Capital Structure** | **Cost** | **Weighted Cost** |
|---|---|---|---|
| Debt | 50.08% | 8.68% | 4.35% |
| Trust Preferred Securities | 5.57 | 6.15 | .34 |
| Preferred Stock | 1.76 | 7.35 | .13 |
| Common Equity | 42.59 | 10.40 | 4.43 |
| TOTAL | 100.00% | | 9.25% |

## AVISTA'S ELECTRIC CASE

### ADJUSTMENTS TO ELECTRIC TEST YEAR REVENUES, EXPENSES AND RATE BASE

Once a test year is selected, adjustments are made to test year accounts and rate base to reflect known and measurable changes so that test year totals accurately reflect anticipated amounts for the future period when rates will be in effect. The Idaho Supreme Court has described "rate base" as "the utility's capital investment amount." *Industrial Customers of Idaho Power v. Idaho PUC*, 134 Idaho 285, 291, 1 P.3d 786, 792 (2000). Adjustments to test year accounts generally fall into three categories: 1) normalizing adjustments made for unusual occurrences, like one-time events or extreme weather conditions, so they do not unduly affect the test year; 2) annualizing adjustments made for events that occurred at some point in the test year to average their effect as if they had been in existence during the entire year; and 3) known and measurable adjustments made to include events that occur outside the test year but will continue in the future to affect Company income and expenses.

Staff witnesses Stockton and Harms accepted Avista's proposed Standard Commission Basis Adjustments (Falkner Exh. 14, pp. 4-7, columns c through x), Pro Forma Insurance Adjustment that decreases net operating income by $649,000 (Falkner Exh. 14, p. 8, column ad) and Pro Forma Power Supply Adjustment (Falkner Exh. 14, p. 8, column ab) that decreases net operating income by $7,832,000. Tr. at 1118-1119, 1075.

The Company on rebuttal agreed to and incorporated into its Rebuttal Exhibit 26, pages 10-12 the following Staff proposed adjustments to net operating income and/or rate base:

| Adjustment | Reason | Net Operating Income after Taxes | Rate Base |
|---|---|---|---|
| Cabinet Gorge | Update estimates to actuals | $1,000 | ($110,000) |
| Boulder Park Depreciation | Synchronize depreciation between states | 57,000 | 13,000 |
| Skookumchuck | Sale of plant approved by the Commission, plant and related operating items no longer to be recovered through rates | 8,000 | (104,000) |
| Deferred Federal Income Tax | Appropriate deferred tax accounting treatment | | (9,966,000) |
| Coyote Springs 2 | Update estimates to actuals | 172,000 | (1,621,000) |
| | | | |

| | | | |
|---|---|---|---|
| Small Gen. Options | Remove capital costs, treatment similar to other unfinished plant | | (539,000) |
| Labor (Non-Exec.) | Update estimates to actuals | 26,000 | |
| Labor (Exec.) | Update estimates to actuals | 9,000 | |
| Depreciation | Synchronize depreciation between states | 432,000 | |
| Corp. Fees | Similar treatment for Idaho utilities – split 50%/50% | 74,000 | |
| Miscellaneous Expense | Similar to prior Commission treatment, exclude contributions, dues, and expenses benefiting affiliates | 250,000 | |
| Western Electricity Coordinating Council | Remove expense to reflect Company's non-member status | 10,000 | |
| Advertising Expense | Similar to prior Commission treatment, exclude charitable contributions, image advertising and non-electric ads | 36,000 | |
| Avista Foundation | Correctly assigns expenses to affiliate | 5,000 | |

By accepting these uncontested adjustments the Company revises its requested electric revenue increase to $31,070,000 or 21.24%. Avista Reb. Exh. 26, at 2; Tr. at 195-196, 217.

### *A. Agreed Upon Adjustments*

*1. Accounts Receivable Program Fees*

Avista's Accounts Receivable Sale Program was initiated in 1988 when the Company entered into a five-year agreement to sell $30 million of its accounts receivable. At that time, the effect of the program was to reduce the Company's need for financing and provide the Company with a source of funds at a much lower effective cost. Since 1988, the Company has expanded the limit to sell up to $125 million of the Company's accounts receivable. Staff witness Stockton recommends removing the fees associated with the Company's Accounts Receivable Sale Program because it is analogous to (or a substitute for) a working capital addition to rate base. Avista, Stockton states, has a negative working capital requirement, indicating that shareholders were not the source of working capital and thus no return to shareholders should be allowed on working capital. Staff's adjustment increases net income by $357,000 and decreases total revenue requirement by $558,000. Tr. at 1116; 1127-1131; Tr. at 1087-1088.

On rebuttal Avista witness Falkner states that the Commission has previously allowed the fees as recoverable expense. The Account Receivable Program, he states, is a cost effective method of carrying customer receivables on the Company's balance sheet. The alternative to selling the accounts receivable, he contends, would be a working capital addition to rate base at the Company's authorized rate of return. The Company has not included a working capital adjustment in the past due to the complexity of doing such a study. Falkner contends Staff misinterpreted the results of its working capital study, that actually, he states, shows that working capital is, in fact positive, not negative. Falkner contends that Staff's study supports including the fees associated with the accounts receivable sale as an operating expense. Tr. at 201-202.

As reflected in Stockton's rejoinder testimony, Staff and Avista agreed to reduce Staff's proposed adjustment by 50%. This amended adjustment increases Idaho net operating income after taxes by $179,000 and decreases total revenue requirement by $280,000. Tr. at 1141-1142. The Commission has considered the merits of both Staff and Company positions. The Commission finds the compromise adjustment reached by the Company and Staff to be a reasonable resolution of this issue.

*2. Debt Interest Restatement Adjustment*

Avista restates debt interest using the Company's pro forma weighted average cost of debt and pro forma rate base to produce a pro forma level of tax-deductible interest expense. Tr. at 163. Staff's adjustment restates debt interest using the Staff-proposed embedded weighted average cost of debt to Staff's pro forma rate base. Tr. at 1093-1094. Avista witness Falkner in his rebuttal testimony listed Staff's Debt Interest Adjustment amongst the Company's contested adjustments. Tr. at 196. At hearing, however, Mr. Falkner explained that he agreed with Staff' s calculation methodology to restate debt interest and the only difference between his calculation and Staff's calculation was the level of rate base that is utilized in the calculation. Tr. at 224-225.

As noted below, Avista contests two adjustments (transmission projects and Boulder Park project costs disallowance) that affect the rate base used in Staff's debt interest restatement calculation. The Commission finds that the calculation methodology is not contested and should be applied to the rate base amount we ultimately approve.

*3. Low Income Weatherization Assistance (LIWA) Funding*

The Community Action Partnership Association of Idaho (CAPAI) in the direct testimony of its witness Stamper recommended: 1) elimination of the "R" number requirement that is the total kilowatt usage per year so that all households with electricity as the primary heat source can automatically qualify for weatherization; 2) a change in the current contract between Avista and Community Action Partnership (CAP) to add windows, doors, and base load measures as allowable weatherization measures funded by Avista toward meeting the 1.0 savings to investment ratio; and 3) an increase in low-income weatherization funding from the current 2004 level of $108,208 (Idaho only) to $490,000 to fund the weatherization of 123 Avista units in North Idaho. Tr. at 1061-1064. CAPAI estimates that there are approximately 21,000 households currently eligible for Avista's weatherization program. At current funding levels and program design, it would take nearly 50 years to meet all the needs in north Idaho. Tr. at 1038, 1039.

To be equivalent to Idaho Power on a per customer basis, Staff witness Anderson noted that Avista would have to increase electricity Demand Side Management (DSM) funding for LIWA to $320,000 per year. Staff did not take a position on this issue. Tr. at 849-850.

Avista in rebuttal notes that the Company reached separate agreement with CAPAI. Avista agreed to increase annual limited income electric and gas DSM and BPA Conservation and Renewable Discount (C&RD) funding to $350,000 commencing in 2006. This is slightly higher than the $320,000 calculation appearing in Staff's testimony, but less than the $490,000 originally proposed by CAPAI. The funding will come from the Company's gas and electric DSM tariff riders. The Company also agrees to extend funding eligibility to include doors, windows, and customers who use permanently installed electric or natural gas heating appliances regardless of historic electric usage, and agrees that customers that qualify under U.S. Department of Energy financial standards would be eligible for any measure meeting a savings to investment ratio of 1.0 or above. Tr. at 747-749.

The Commission believes that funds devoted to LIWA are a wise investment that will benefit all Avista ratepayers not just those who experience reduced power bills. Increased LIWA funding can provide significant benefits in terms of lowering uncollectibles and creating permanent load reduction. The Commission commends CAPAI and Avista for the compromise agreement that they presented. As part of the agreement, the Company agreed to increase annual low income weatherization funding from current levels to $350,000 for qualifying electric and gas customers for 2006 and beyond. We find the terms and Company commitments to be both reasonable and acceptable. We note further that the Company's agreement will provide considerable flexibility to the community action agencies in leveraging the funds available so they can do their best job in weatherizing homes. CAPAI estimates that Avista has approximately 17,500 customers below 150% of the federal poverty guidelines in its Idaho service area. Exh. 403; Tr. at 1038; 1048. CAPAI's participation in this case we find was a great benefit to the many small communities and low-income customers served by Avista in northern Idaho.

*4. Demand Side Management (DSM) Funding Levels*

Avista at its May 19, 2004 meeting of its External Energy Efficiency (EEE) Advisory Board proposed reducing the Company's electricity DSM surcharge from the current 1.95% to about 1.25% of base revenues or approximately a $1 million annual reduction. Exh. 132, p. 10. The Company also proposed that the DSM surcharge be set as a cents-per-kWh rate rather than a percentage of base revenues. Tr. at 845, 846. Staff witness Anderson testifies that in light of anticipated DSM expenditures and the need for relief from a likely base rate increase in this case, he agrees to a reduction to the DSM tariff rider with the following conditions: (1) assurance that a reduction in DSM revenues will not negatively impact Avista's pursuit of cost-effective energy measures, regardless of whether such measures result in Avista's DSM fund balance being negative, and (2) an increase in Avista's LIWA contribution to a level determined reasonable by the Commission. Even with the reduction, Anderson notes that Avista's DSM revenue will still be higher than Idaho Power's. Staff supports a surcharge change from a percentage of base revenues to a cents-per-kWh base charge. Tr. at 845-849; 851.

On rebuttal, Avista witness Powell states that a tariff rider equal to 1.25% of current base revenues should be sufficient to meet the Company's forecasted funding needs for year 2005. The Company commits to incur a negative tariff rider balance if cost-effective DSM resource acquisitions require more funds than are available from DSM tariff rider resources. The Company proposes to correct any negative or positive balances in the electric or gas DSM tariff rider through annual revisions. The Company also proposes to revise its DSM surcharge from a percent of revenues to an amount equal to a percent of the current retail rate. Tr. at 745-749. The Company's proposal is not a flat cents per kilowatt hour across all rates, Powell explains, it is a reduction from an amount equal to 1.95% of current base revenues to an amount equal to 1.25% of current base rates. Tr. at 750-751; also at 753.

The Commission finds Avista's proposal to reduce the DSM surcharge from 1.95% to 1.25% of base revenues to be both justified and acceptable. We also find it reasonable to apply the surcharge on a cents/kWh basis. In doing so we commend the Company for its continued commitment to cost-effective DSM resource acquisitions and we expect the Company to continue to pursue cost effective DSM regardless of DSM funding balances.

*5. Coyote Springs 2 (CS2) Deferred Return*

Coyote Springs 2 (CS2) is a 280 MW natural gas combined cycle combustion turbine (CCCT) located near Boardman, Oregon. It was selected by Avista as a supply side resource in the Company's 2000 Request for Proposal (RFP) process. Avista owns 50% of the plant and is requesting a ratebasing of its investment as part of this rate case. Staff witness Harms proposed reducing the Company's revenue requirement by deferring the Company's return on the Coyote Springs 2 project. A return on the project would not be denied, but full recovery of this return deferral would take 10 years to be completed. The Company's annual revenue requirement is reduced by $13,054 per million dollars of Coyote Springs 2 gross plant. Tr. at 1094. While Avista witness Falkner in his rebuttal testimony and schedules did not reduce the revenue requested by the Company for this deferral, during the hearing he stated that the Company agreed with this proposal. Tr. at 225. The Commission accepts Staff's CS2 deferred return proposal as reasonable. Deferring the return serves to mitigate the associated rate increase. The Company will receive the same net present value over 10 years because the deferred balance accrues a carrying charge at the return authorized in this case.

***B. Disputed Adjustments***

*1. Transmission Projects*

To reflect project estimated costs, depreciation, property taxes and income taxes of three transmission projects, i.e., Pine Creek 2003 kV substation, the Beacon-Rathdrum 230 kV line and the Beacon-Bell #4 230 kV line, Avista proposed a pro forma adjustment increasing rate base by $8,849,000 and decreasing net operating income by $249,000. Tr. at 172-173; Tr. at 247.

Staff witness Harms recommends removal of the Beacon to Bell line ($438,000), a project that was suspended until 2005; recommends that the estimated costs for Beacon to Rathdrum line and Pine Creek Substation Rebuild be updated from estimates to lower actual amounts resulting in a rate base reduction of $615,000; and contends that Avista did not reflect proper matching of revenues and expenses as if projects had been in service the full year. To include the plant investment as if the plant had been in operation the full year without corresponding revenue and expense adjustments, Staff contends, is unreasonable and creates a mismatch between test year revenues and expenses. The Commission could disallow the entire adjustment because of this mismatch. One alternative to denying the plant adjustment, Staff suggests, is to remove annualization and show reduced costs for only one month of the test year. Harms stated that the effect of this adjustment reduces rate base by $8,518,000, operating expenses by $358,000, and revenue requirement by $1,592,000. A second alternative is to annualize the projects' costs using a proxy for imputed revenues and expense reductions, producing approximately $270,000 of imputed Idaho revenue and $30,000 of reduced Idaho electric expense. The corrected annualized costs increase rate base by $7,801,000. Tr. at 1076-1080; Exh. 103.

Potlatch witness Peseau contends that Avista pro formed into rate base $26.3 million in transmission projects but made no similar revenue adjustment. This mismatch, Peseau contends, should be corrected by: (1) reversing the pro forma entries and properly matching test year averages on both sides of the ledger, or (2) updating revenues to the 2004 level in the same manner as rate base and expenses, his preferred method, or (3) employing the rate base adjustments adopted in the Idaho Power rate case (5% of the rate base additions). Tr. at 925-926.

Avista witness Falkner on rebuttal contends that the multi-year transmission upgrades included in the Company's filing are complete, known and measurable. The financial benefits of import/export energy revenue, he states, are captured in the power supply model. Should the Commission determine, however, than an adjustment to revenues and/or expenses in conjunction with the full rate base treatment of the new transmission adjustment was necessary, Falkner contends that Staff's proposed proxy alternative of including approximately $270,000 in additional revenues and a $30,000 expense reduction would be reasonable. Tr. at 197-199.

**Commission Findings**

The Commission has reviewed the testimony and recommendations of the parties. It is reasonable as Potlatch surmises that there is an offset or savings related to transmission investment. When significant plant improvements are completed late in the test year or after the test year, the challenge is to reasonably include the investments in the test year in a way that fairly compensates the Company for its investment, but also fairly treats ratepayers by matching investment revenues with investment expenses. We encourage the Company to develop means of computing the expense savings and revenue enhancements associated with transmission investment. We accept as reasonable Staff's proposed Beacon-Bell adjustment and the proposal to update the Beacon-Rathdrum and Pine Creek construction estimates to actuals. Rather than deny the Company's annualizing plant rate base adjustment outright or require the Company to wait for its next rate case to include the plant in rates, we accept Staff's proxy proposal for calculating imputed revenues and expense reductions. We do so reluctantly, however, because the Company has not adequately attempted to calculate expense savings and revenue producing effects. We put the Company on notice that this is not a method we want to use in the future. Henceforth, if the Company seeks full recovery of plant investment as if the plant had been in operation a full year, it must present a corresponding adjustment to revenues and expenses.

*2. Boulder Park Small Generation Project*

Avista witness Lafferty contends that the 25 MW Boulder Park natural gas-fired reciprocating engine generation project was a reasonable addition to Avista's energy resource portfolio and was economic compared to market alternatives at the time the decision to build was made during the "energy crisis." The project was fast-tracked, Lafferty states, in order to mitigate the high prices and volatility in the electric power market in the 2000-2001 energy crisis. Lafferty contends that the Company reasonably managed Boulder Park project costs under the circumstances even though costs were higher than projected due to the fast-track design and construction approach. The May 2001 construction cost estimate was $21 million; the total actual cost was approximately $31.9 million. Contractor costs were approximately $4.7 million over budget due to such factors as the additional design scope, change orders, overall project complexity and project management costs due to the extra time required to complete the project. Avista construction costs were over budget by approximately $2.2. million due to changes in project scope and complexity. Tr. at 541; 592-598.

Staff witness Sterling believes the Company's decision to pursue the Boulder Park project during the 2000-2001 energy crisis was a reasonable response to extremely low water conditions and high market prices. Completion of "fast-track" construction, however, was delayed by eight months, from September 2001 until May 2002. There were also considerable cost overruns. The final cost of Boulder Park was $32.1 million, $11 million over the $21 million construction cost estimate, a greater than 50% cost overrun. Although not new technology for the power industry, the natural gas fuel reciprocating engine generators were the first project of its kind for Avista, a factor which Avista states contributed in part to actual construction costs being higher than original estimates. Tr. at 1220; Avista summary of cost variations, Exh. 129. It is common, Sterling contends, to include a contingency amount in the cost estimate for large construction projects to insure that funds are available in the event of unplanned problems, circumstances or conditions. Contingency amounts for projects similar to this one, Sterling estimates, are typically in the range of 5-15%. Sterling believes ratepayers should be able to expect a utility to have the ability to construct projects at least cost. Staff recommends 10% of the final project cost be disallowed, that equates to a $205,000 reduction in annual Idaho revenue requirement and a $1,085,000 reduction in rate base. Tr. at 1082-1083; Tr. at 1218-1224; Exh. 129.

On rebuttal Avista contends that Staff's recommended 10% Boulder Park disallowance is not appropriate given the challenges presented by the market conditions and the project's unique characteristics. Avista also contends that the slow down of the project was justified by a change in circumstances, lower market energy prices in the summer of 2001 and a financial need to preserve cash. Tr. at 632-633.

**Commission Findings**

The Commission has considered the testimony regarding Boulder Park and finds that a 53% construction cost overrun is unreasonable. We expect a utility such as Avista to have the expertise and experience to plan, construct and manage any project it undertakes at a reasonable cost. This project was planned as a "fast track" response to poor water and a volatile energy market. It was not completed on time and was 53% over budget. The Company must assume some responsibility for the excessive cost. Staff recommends a 10% disallowance and identifies specific cost category overruns. We believe that the Company should be held to a higher standard. Ratepayers will not be asked to pay for what we find to be a Company learning experience. Staff notes that the CS2 and Kettle Falls overruns totaled 16% and 8%, respectively. We find it reasonable to limit the authorized rate base amount for Boulder Park to the project construction estimate plus a 15% contingency. The original construction estimate for Boulder Park was $21,000,000 (Exh. 8, Sch. 35; Exh. 129). An additional 15% increases the total rate base allowed to $24,150,000. The final cost of Boulder Park was approximately $32 million. The total disallowed amount is $7.62 million on a system basis. The Idaho jurisdictional share of the disallowance is $2.6 million.

*3. Prudency of Coyote Springs 2 (CS2)*

Company witness Lafferty testifies that Avista in a spring 2000 update to its 1997 Integrated Resource Plan (IRP) identified a need for new resources. The Company issued an all-resource 2000 Request for Proposal (RFP) for 300 MW of capacity and energy. The Company received 32 proposals from 23 bidders for a total of 2700 MW of supply-side and demand-side resources. The RFP process included third-party review and critique. Resource alternatives were ranked in an evaluation matrix. The Company selected the 280 MW CS2 combined cycle combustion turbine as the preferred supply-side option. CS2 is a project acquired by Avista Power from Enron and was included in the RFP process at an "at cost" price. In addition to overall cost effectiveness, a key factor cited by the Company in selecting the CS2 project was that it included a fully licensed site. The major equipment had already been ordered and an Engineering, Procurement and Construction Contractor (NEPCO) an Enron affiliate, had already been selected.

Due to financial challenges facing the Company because of low water conditions and high market prices in the first half of 2001 and difficulty encountered in finding project financing, Avista sold 50% of the CS2 project to Mirant on December 12, 2001. As part of the transaction, Mirant pays one-half of all capital costs and one-half of all operation and maintenance costs for the project. Mirant is responsible for securing its own natural gas supply and transportation and for making its own arrangements for transmission to move power from the plant. Avista maintains it took reasonable steps to bring the CS2 project to commercial completion as quickly as practicable, and to manage the failure of and damage to CS2's transformers. The project start-up delays, the Company contends, were unforeseeable and uncontrollable. Avista's management of the cost overruns caused by the bankruptcies of Enron and NEPCO, the Company contends, was reasonable. Avista's share of CS2's construction costs as of 9/30/03 was approximately $109 million rather than the $94 million originally projected. Tr. at 540; 542-563.

Staff witness Sterling contends that the CS2 resource was needed by Avista to address projected generation deficits identified in the Company's IRP. One of the primary reasons for the deficit identified in the Company's IRP was the sale of the Company's 201 MW share of the 1340 MW Centralia coal-fired generating plant. Sterling believes that the

Company's RFP process was fair and Staff confirms that CS2 was transferred by Avista Power to Avista Utilities "at cost." It is Staff's position that Avista should not be denied recovery of $15 million in cost overruns, overruns which, Sterling contends, were neither foreseeable nor within the Company's control. Tr. at 1210-1217.

Potlatch witness Peseau notes that in the Company's corporate structure (Exh. 1, p. 5), Avista Utilities is not a separate business entity, only an operating division of Avista Corp. This organizational relationship, he contends, blurs the distinction between regulated and unregulated activities. Tr. at 899. In Avista's last rate case, Peseau reminds the Commission that Potlatch expressed concern that Avista's corporate structure, and its practice of not contemporaneously making trades to its regulated or non-regulated arm, left it with the latitude to subsequently allocate trades based on their profitability. Tr. at 899-900. The transactional facts surrounding CS2, Peseau contends, presents a case that is far worse. Tr. at 900.

As Potlatch recounts events, CS2 was originally a Portland General Electric (PGE) project to be built as a companion to PGE's Coyote Springs 1 generating station located near Boardman, Oregon. At that time PGE was a regulated Enron subsidiary. In mid-1999, Enron and PGE decided to sell CS2. On October 4, 1999, Avista Power, an unregulated Avista Corp. subsidiary, entered into an "evaluation agreement" with PGE that allowed it to begin a due diligence investigation of the plant. On March, 4, 2000, Avista Power signed a Letter of Intent with Enron to buy both CS2 and a turbine purchased by Enron for CS2. The total purchase price when the deal was finally concluded was approximately $59.5 million. Tr. at 900-903.

In December 2000 Avista Corp. announced it would acquire CS2 from Avista Power. Tr. at 553; 606-607. But Potlatch contends that Avista did not in fact immediately follow through on this announcement. Tr. at 905. Avista responds that the Company chose to keep ownership of the plant with the CS2, LLC until construction was completed citing the benefit of forming LLCs to separate costs and liabilities during construction and the Company's initial intent to obtain separate construction financing. Tr. at 607. Potlatch contends that Avista Power was never under a legal obligation to sell to Avista Corp. Avista discovery responses to Potlatch revealed no contract, memorandum of understanding, or any other document that would evidence an intention to proceed with the sale. Tr. at 907. Once Avista began experiencing cash flow problems, Company memos indicate that Avista Power was trying to sell the entire plant to third parties in the summer and fall of 2001, months after the announcement that Avista Utilities would acquire CS2 from Avista Power. Tr. at 905. Ultimately Avista Power sold a 50 percent share of CS2 to Mirant on December 12, 2001. Tr. at 552. The remaining 50 percent of CS2 was not transferred to Avista Corp. until January 1, 2003, after construction was substantially complete. The project began commercial operation for the utility in July 2003. Tr. at 607.

In April 2002, CS2's prime contractor, NEPCO, an Enron affiliate, filed for bankruptcy and CS2 lost the benefit of its fixed price construction contract, while at the same time incurring the cost of replacing the prime contractor and settling with subcontractors. Tr. at 553. The history of CS2, as characterized by Potlatch, has been and continues to be an economic and operational nightmare. The construction problems caused the estimated cost of Avista's half of the plant to increase from approximately $94 million to $109 million. Tr. at 903-904.

Potlatch contends that CS2 should not be recovered in rates until it is proven "used and useful." Peseau contends that is not currently used and useful, and there is no indication it will ever be after the three failures experienced thus far. If CS2 is included in rate base, Peseau recommends that costs be limited to the plant's fair market value as of the January 1, 2003 transfer date, $84,560,000 by his calculations, to prevent an unregulated affiliate from profiting at ratepayer expense. Tr. at 906-908. The basis for Potlatch's fair market value number was a $604/kW construction cost estimate advanced by Avista in rebuttal testimony in a 2002 generic PURPA Surrogate Avoided Resource (SAR) case (GNR-E-02-1). On cross, Potlatch conceded that the Commission did not accept Avista's avoided capital cost in that case, but instead in Order No. 29124 adopted a Northwest Power Planning Council (NWPPC) generating resource advisory committee number ($679/kW), a year 2000 number that when escalated forward two years to provide a comparable comparison to CS2 results in a $99,094,000 value. Tr. at 968.

On rebuttal Avista notes that between July 1, 2003 and January 15, 2004, CS2 performed with a 92% availability factor, generating approximately 85 aMW. The Company at hearing expected CS2 to return to service in mid- to late-August 2004. Tr. at 602; 604-608.

**Commission Findings**

Despite a rather involved history of resource acquisition and construction and the Company's unfortunate entanglement in the Enron bankruptcy, the Commission finds that CS2 was a needed resource and that the acquisition of CS2 by Avista Utilities was reasonable and prudent. We find the purchase cost was reasonable in the context of other resource alternatives offered in the Company's 2000 RFP. The question of whether there was a legal obligation to transfer CS2 following a simple Company announcement of resource selection and the timing of the transfer from Avista Power to Avista Corporation (Avista Utilities) raise questions of opportunistic gamesmanship between regulated and unregulated entities in the Avista Corp. family. The transactional history of the CS2 acquisition suggests that a ring fencing mechanism needs to be put in place to insulate the regulated utility from risks undertaken by non-regulated affiliates. Techniques to be explored include pro-active regulatory oversight, financial restrictions, structural separations, and operational controls.

The "used and useful" issue raised by Potlatch as an argument against ratebasing is perceived by this Commission on the facts of this case to be one of operational and regulatory timing. If the project rate base question had been considered prior to the January 15, 2004 transformer failure, the Company would have been able to demonstrate that CS2 was used and useful and no party would have challenged the Company's assertion. CS2 was indeed operational from July 2003 to January 2004. It performed with a 92% availability factor, generating approximately 85 aMW. It was economically dispatched for two weeks and was ostensibly available for the remainder of that period. We also cannot ignore the fact as stated above that the CS2 project was the low cost resource selected in the Company's 2000 RFP, and that there was a need for the resource.

Applying the reasoning advanced in our discussion above of Boulder Park, we find that Company self-build projects should be subject to a cost overrun cap. We find it reasonable to limit the authorized rate base amount for CS2 to the project construction estimate plus a 15% contingency. The original construction estimate of CS2 was $93,933,400. Rev. Exh. 6, Sch. 15, p. 3. An additional 15%, $14,090,010, increases the total rate base authorized to $108,023,410 (system). The resultant Idaho Commission authorized gross plant is $37,172,000. This compares to the Company and Staff agreed CS2 gross plant (Idaho) number of $37,291,000. Exh. 109. The calculated amount of rate base disallowance is $119,000.

*4. Vegetation Management (Tree Trimming)*

To reflect planned increases in vegetation management, Avista witness Kopczynski proposes a $1.2 million Idaho jurisdictional adjustment using a 2004-2007 four-year average of scheduled Company vegetation management projects. Company witness Falkner contends that the proposed expenditure level is necessary for the proper management of vegetation around both transmission and distribution lines to most effectively ensure reliability levels, improve safety and reduce customer outages. The effect of this adjustment reduces Idaho electric net operating income by $785,000. Tr. at 256; Tr. at 172.

Staff witness Stockton proposes to replace the Company's requested vegetation management expense adjustment with an average of the actual amounts expended during the six-year period of 1998-2003 to reflect variability of expenses and an abnormally low 2002 test year expense. Staff's proposed adjustment increases net income by $288,000 and decreases total revenue requirement by $451,000. Tr. at 1116; 1125-1127; Tr. at 1086-1087.

In response to Staff concerns, Avista witness Falkner recommends use of a "one-way" balancing account. If the Commission were to authorize the Company-requested level of expenses ($1.8 million Idaho), the Company would commit that level of resources annually to vegetation management going forward. If less is spent, the difference would be recorded as a liability and either spent in a future period or returned to customers through an appropriate tracking mechanism. If the Commission were to adopt a six-year historical average as suggested by Staff, Falkner recommends that the Commission exclude the 2002 level of $550,255 as abnormally low. Tr. at 199-200; Tr. at 264-265.

The Commission appreciates the importance of the Company's tree trimming program for system reliability. A good vegetation management program reduces customer outages and maintains system integrity. We also note the level of vegetation management expense approved by the Commission in the Company's last general rate case and recognize the need to enhance expenditures as time passes. This is particularly true in light of the Company's limited expenditures on vegetation management in 2002. Consequently, we find it reasonable to fund the $1.8 million level of expense recommended by Avista for Idaho tree trimming.

*5. Pension Expense*

Avista included in its test year expenses $14,000,000 on a total system-wide basis for employee pension expenses, including an expense adjustment of $900,153 to reduce pension expense from the 2003 Net Periodic Pension Cost of $14,900,153 to the 2004 estimated Net Periodic Pension Cost. Tr. at 168. This pension expense equates to an Idaho electric jurisdictional expense of $2.1 million. Staff witness English disagreed with using 2004 pension expense on the premise that the expense proposed by the Company is simply an estimate and not known and measurable. Tr. at 1155. Staff witness English also disagreed with the use of Net

Periodic Pension Cost and proposed the use of the Required Minimum Contribution under the Employee Retirement Income Securities Act of 1974 (ERISA). Tr. at 1162.

Staff proposed reducing system-wide test year pension expense of $14,000,000 by $5,305,315, bringing the test year pension expense to $8,694,685, thus, increasing Idaho operating income by $554,000 and reducing the Company's revenue requirement by $867,000. Tr. at 1088; Tr. at 1158. Staff witness English explained that the adjustment is a reconciliation between cash and accrual accounting. In other words, although the Company accrues a pension contribution on its books for financial reporting purposes, Avista is only required to contribute to the plan the amount calculated under the ERISA calculations. The recovery of pension expense, English contends, should be based on the actual amount of cash a company is required to contribute to the plan to meet its minimum funding liability. Any funding over the Required Minimum Contribution under ERISA, English contends, penalizes ratepayers. Tr. at 1158-1163.

Company witness Falkner responded in rebuttal that FAS 87 has been the standard for pension expense since its adoption in 1987 and has been previously accepted in Idaho. The reduction of the return on asset assumption, he contends, is supported by actual fund return history, as well as consistency with return reductions by other northwest utilities. Actual contributions to the pension fund have exceeded the level included in Idaho general rates by $29 million since 1999. Absent a larger than minimum contribution in 2002, the minimum 2003 contribution level would have been approximately $14 million, that is the FAS 87 accrual level proposed in this case. Had the Company not contributed additional money to the plan in 2002, Falkner contends, the Required Minimum Contribution for 2003 would be greater than Staff's proposal and by accepting Staff's proposal, the Commission would penalize the Company for attempting to achieve a fully funded pension plan. Tr. at 202-210.

On the evidence presented in this case, the Commission finds the adjustment proposed by the Staff for the pension plan expenses to reconcile cash and accrual accounting to be fair and reasonable. However, the Commission does not wish to unduly impose a penalty upon the Company for its additional contributions in 2002. Therefore, the Commission accepts the amortization of the additional $4.5 million contribution in 2002 over a two year period. Avista will be allowed to recover in rates a total pension expense of $10,347,343 on a system basis or $1,549,386 from the Idaho electric jurisdiction. This results in an adjustment increasing Idaho net operating income by $381,000.

*6. Legal Expenses*

Staff witness English proposes removing expenses from the test year for legal costs that should have been directly assigned to unregulated affiliates (Avista Labs; Avista Communications) or that were for extraordinary events that will not recur (i.e., Enron bankruptcy; or the now closed 2002 FERC investigation into electricity trading practices). This adjustment increases net operating income by $366,000 and reduces Avista's revenue requirement by $73,000. Tr. at 1168-1170; Tr. at 1090.

In response, Avista witness Falkner agrees that legal expenses related to Avista Labs and Avista Communications should be removed. Tr. at 211. Falkner argues, however, that legal fees related to the Enron bankruptcy and FERC investigation are representative of ongoing legal expense, that has remained constant at $3.8 million over the last six years. Such a level, the Company contends, should be reflected in rates absent a showing of imprudence. Alternatively the Company proposes use of a six-year average of legal expense charged to operational accounts to "smooth out" extraordinary items. Such an average would reduce Idaho legal expense allocations to the electric system by $32,500. Tr. at 210-214.

The Commission finds Staff's adjustments removing non-recurring extraordinary legal expense to be reasonable and appropriate. Avista contends that some extraordinary expense always comes up and should not be a reason for excluding the level of expense requested. Our view is that the level of legal expense incurred by the Company is somewhat within its control. Further, we note that the regulatory accounting system does not permit inclusion of unusual expenses in a test year for ratemaking purposes. The Commission has confidence that Avista Corp. will continue to act in good faith to protect the interests of its utility customers and its shareholders.

Incorporating the foregoing adjustments, the Commission approves the following for rate base and revenue requirement.

***Rate Base***

Avista proposed a pro forma electric rate base of $440,270,000 for the Idaho jurisdiction. Exh. 14, p.2. As we indicated in our prior Amended Interlocutory Order No. 29588 the Commission approves as just and reasonable an electric pro forma rate base of $424,114,000. See attached Appendix C.

*Revenue Requirement*

Current revenue recovered in Idaho's electric base rates is $146,248,000. The Commission in this case approves a base revenue requirement of $170,964,195, an increase in electric base rates of $24,716,195 or 16.90%. The resultant average cents per kilowatt hour for base rates is 5.47 cents.

***Summary of Adjustments to Electric Test Year Revenues, Expenses and Rate Base***

Considering all the evidence presented, and including all adjustments, the Commission finds just and reasonable Idaho jurisdictional expenses for the 2002 test year in the amount of $140,696,000, and Idaho jurisdictional operating revenues in the amount of $168,191,000 for an operating income before federal income tax of $27,495,000. The after tax Idaho operating income is $23,121,000. After all adjustments, we find a 2002 total Idaho jurisdictional rate base amount of $424,114,000 to be just and reasonable. Appendix C to this Order summarizes the Commission's findings on rate base and operating results for the test year.

***Calculation of Revenue Deficiency***

Based on ultimate decisions determining the Idaho rate base, net operating income requirement, and return on common equity, we proceed to determine the Idaho revenue deficiency with the following calculation:

| | |
|---|---|
| Rate Base | $424,114,000 |
| Rate of Return | 9.250% |
| Net Operating Income Requirement | $39,231,000 |
| Operating Income | $23,121,000 |
| Income Deficiency | $16,110,000 |
| Conversion Factor | .63926135 |
| Revenue Requirement Deficiency | $25,201,000 |
| Levelized Deferred Return on Coyote Springs 2 | (485,000) |
| Revised Revenue Requirement Deficiency | $24,716,000 |

## JURISDICTIONAL SEPARATIONS, COST OF SERVICE AND RATE DESIGN

The Commission, for the purposes of electric rate design maintains existing customer/service charges, approves a separate rate schedule for Potlatch, approves a two-block energy rate and declining tail-block for electric general service Schedules 11, 21 and 25, and moves all customer classes to within 10% of full Cost of Service.

The Commission also accepts the Company Cost of Service study methodology and allocation factors including the four factor allocation adjustment proposed by Potlatch witness Peseau and accepted by Avista in rebuttal testimony and the Avista rebuttal compromise to the Schedule 25 primary plant distribution adjustment proposed by Coeur Silver witness Yankel. The accepted Cost of Service results were used as the starting point for revenue allocation to customer classes.

### *1. Jurisdictional Separations*

The jurisdictional separations methodology is used by Avista to allocate total electric system costs to its Idaho, Washington or Federal Energy Regulatory Commission (FERC) jurisdictions. The FERC jurisdiction is comprised of Avista's wholesale sales of energy to other utilities. Avista witness Falkner uses the same jurisdictional separation methodology approved by the Commission in the Company's last general rate case, WWP-E-98-4. The methodology directly assigns revenues, costs and investments to jurisdictions where appropriate and allocates the remaining amounts. The methodology uses 2002 test year booked amounts without adjustment. All adjustments are included on an Idaho system basis at the beginning of the cost of service process.

Staff witness Hessing, noting the value of consistency from case to case, accepts the Company's jurisdictional separation methodology. Tr. at 1259-1260.

The record in this case supports a Commission finding that the methodology the Company used to separate costs between the Idaho, Washington and FERC jurisdictions is reasonable and appropriate. The jurisdictional separations study results in an Idaho system revenue requirement allocation of $169.3 million.

### *2. Class Cost of Service Methodology*

Once Idaho jurisdictional test year costs are determined with the jurisdictional separations study, the next step is to allocate the adjusted costs or the revenue requirement to a series of functional costs and then to the different customer classes served by Avista in accordance with recognized principles and generally accepted procedures in order to obtain an indication of relative cost responsibilities of each class of customer. This allocation is done in two parts. First, a class cost of service (COS) study is conducted that identifies what the revenue allocation for each class would be at full COS. Finally, if some increases are considered to be too large, a maximum increase cap is established and unrecovered revenue is spread to other classes.

Avista witness Knox uses the "Peak Credit" Cost of Service methodology approved by the Commission in the Company's last two general rate cases. The Peak Credit method for COS separates the Company's generation costs into demand and energy components. It then allocates demand on a 12 coincident peak basis and energy on a class consumption basis. Avista in this case, however, departs from its standard 60 percent (customer)/40 percent (energy) allocation and proposes to allocate "common costs" on the basis of four factors: direct O&M expenses, direct labor, net direct plant and number of customers. Common costs are typically defined as those costs necessary for the utility to function, but which are left over after most directly assignable costs have been identified and "functionalized" to production, transmission, distribution or customer accounts. Knox provides an alternative scenario to illustrate the impact of different allocations. Under either scenario, residential and extra large general service customers still provide less revenue than the cost to serve them. Tr. at 320-328. Starting with the COS result, Avista witness Hirschkorn proposed a rate spread moving the relative rate of return for each schedule approximately one-half way toward cost of service, with the exception of the lighting schedules. Tr. at 777.

As in the case of Jurisdictional Separations, Staff witness Hessing states that there is value in applying a consistent class cost of service methodology from case to case. Use of a consistent methodology, he states, allows usage, and customer characteristics and the accounting data to drive the results. Hessing accepts the Company's proposed cost of service methodology which he states is the same methodology with minor modifications that the Commission accepted as the starting point for revenue allocation in the Company's last general rate case. Tr. at 1259-1260.

Changes to cost-of-service methodology shift costs among classes and affect revenue requirement responsibility. Staff witness Schunke also proposes an incremental move

(20%) toward full cost of service in recognition that cost of service results are not precise and unacceptably large increases to some classes would occur. If a second step adjustment in cost of service is needed, Schunke recommends reviewing cost of service after the Power Cost Adjustment (PCA) balance drops to zero. Tr. at 1321-1325; Tr. at 1318; Exh. 143.

Coeur Silver Valley witness Yankel contends that if data is utilized that is more reflective of cost causation, the rate of return for the Schedule 25 class comes out to be above the jurisdictional average. Mr. Yankel recommends that Schedule 25 customers be given the average jurisdictional increase. Yankel notes that Avista did not directly assign identifiable primary plant (i.e., lines, towers, and overhead conductors in Accounts 364-367) to corresponding Schedule 25 customers, as it did for Potlatch. Yankel proposes that certain Schedule 25 Primary Distribution costs be directly assigned. Yankel contends that rates should be established that better reflect load factor differences and cost causation. Tr. at 515-523.

Potlatch witness Peseau contends that the change proposed by Avista witness Knox to move to a four-factor allocator for common costs is a significant change that improperly shifts costs to higher load factor customers. Tr. at 957-959. Peseau contends that Knox in her cost of service analysis has improperly defined direct O&M expenses as one of the four-factors to allocate common costs. Peseau contends that this can be corrected by removing the fuel and purchased power expenses.

Avista, Peseau notes, has historically allocated common costs to customer groups with a 60% customer/40% energy allocation factor. Peseau recommends that the Commission continue to use its previously adopted 60%/40% method for common cost allocation or adopt the four-factor method with his corrections. Tr. at 926-933; 958-959.

If the overall approved increase is less than 10%, Peseau recommends that all customer classes be moved to full cost of service. If the increase is greater than 10%, residential and large general service rate customers, he states, should be moved at least halfway toward rate of return parity, with two annual automatic adjustments thereafter to close the remaining gap. Tr. at 938. Peseau contends that Staff's proposal to move various rate schedules only 20% toward cost of service will perpetuate the longstanding subsidies among customer classes. The PCA reduction proposed by the Company in this case, he states, provides an opportunity to make a bold move toward cost of service. Tr. at 959-962. Peseau proposes to allocate transmission costs strictly on a demand basis as, he states, was done in the recent Idaho Power rate case, Case No. IPC-E-03-13. Peseau contends that Avista's cost of service study overstates the annual cost of serving Potlatch by approximately $1.4 million per year. Tr. at 926-938.

Avista witness Knox on rebuttal agreed with Potlatch that resource costs should be excluded from the O&M portion of the four-factor allocator used for common costs in cost of service. She revised her COS study accordingly. Tr. at 338. Knox contends that the 100% demand allocation advocated by Peseau for all transmission costs represents a material change from the peak credit methodology the Company has historically applied and opposes its use. Tr. at 339-341. Regarding Couer Silver's proposal, Knox contends that the cost of primary distribution plant Yankel proposes to assign to Schedule 25 customers is understated and cannot be reasonably estimated without further investigation. Knox proposes an intermediate cost assignment between the Company's allocation and Yankel's estimated assignment, a change which materially increases the rate of return for Schedule 25 customers (including Potlatch's Lewiston Facility) and shifts cost responsibility to other customer classes. Tr. at 341-344.

Hirschkorn recommends that the Commission use the ratio of the revenue increase it proposes for each schedule as a guideline to move halfway toward COS regardless of the overall approved increase. Tr. at 815-817.

Recommended Spread of Revenue Increase

| | |
|---|---|
| Residential Schedule 1 | .401 |
| General Service Schedule 11 | .101 |
| Large General Service Schedule 21 | .236 |
| Extra Large General Service Schedule 25 | .076 |
| Potlatch (Schedule 25) | .155 |
| Pumping Service Schedule 31 | .017 |
| Street and Area Lighting Schedules 41-49 | .014 |
| TOTAL | 1.00 |

Hirschkorn disagrees with Peseau's recommendation that all schedules be moved to full COS over the next 2 years based on the current COS study if the rate increase is greater than 10%. Hirschkorn contends that the cost of service study should only be used as a guide in establishing rates. The testimony has shown, he states, that one or two adjustments in cost allocation can significantly change the results of a study. Tr. at 822.

The Commission has reviewed and considered the Company's cost-of-service allocation study, Potlatch and Coeur Silver's critique of same and Staff's support of the study.

The Commission finds Avista's Peak Credit Cost of Service methodology with the Company proposed revisions to allocation of common costs suggested by Potlatch and allocations of primary distribution costs as suggested by Coeur Silver to be an appropriate starting point to allocate costs to customer classes. Recognizing cost-of-service studies are a balance of art and economic principles, we find that the COS study methodology proposed by the Company reflect a reasonable approximation of class revenue responsibility.

*A. Weather Normalization*

An adjustment is used to calculate the change in kWh usage required to adjust loads experienced to the amount expected given "normal" weather. Avista witness Knox proposes a change in the prior weather normalization methodology to include the effect of weather sensitive cooling and reflect exactly five heating seasons rather than five and a half. The change is reflective of increased saturation of the air conditioning market in the region. It also reflects that although normally a winter peaking utility, in recent years the Company has experienced summer peaks near the same level as the winter peaks. Without incorporating cooling sensitivity, the prior method would add usage during an abnormally hot summer due to fewer than normal heating degree days. Tr. at 319-320. Staff witness Sterling accepts Avista's electric weather normalization performed as accurate and reasonable. Tr. at 1190; 1192-1194.

The Commission has reviewed the record and approves the change in the weather normalization method as reasonable and comporting with changes in the Company's heating degree days and customer usage.

*B. Power Supply Adjustments*

Avista witness Johnson states that the Company's power supply expense has increased by approximately $11 million (Idaho) from the prior general rate case. The increase is primarily driven by reduced wholesale net revenues and an increase in fuel expense. The Company proposed 67 pro forma adjustments to 2002 test year power supply revenue and expenses, the majority of which are associated with contracts, the expiration of an existing contract or the initiation of an existing contract, or due to specific, projected or estimated changes in contract rates or charges. The remaining charges result from the AURORA dispatch simulation model, and projected fuel expenses. Expenses have been reduced by $85.9 million and revenues have been reduced by $55.4 million for a net $30.5 million decrease in the system revenue requirement from the 2002 test year (a $7.832 million decrease in Idaho). Tr. at 270-277; Tr. at 167-168.

Staff witness Sterling agrees that it is appropriate to pro form the normalized 2002 test year power supply expenses to the period of September 1, 2004 through August 1, 2005. Fifty-two of the adjustments are to test year expenses; 15 adjustments are to test year revenues. Exh. 128. Staff reviewed information related to the underlying contracts including some contracts and Company workpapers and excerpts. Sterling concludes that the power supply adjustments proposed by Avista are reasonably known and measurable. Sterling also concludes that the adjustments are based strictly on test year loads and are independent of future retail load conditions. Staff recommends approval of the Company's power supply adjustments. Tr. at 1194-1204.

The Commission has reviewed the record and is satisfied that the pro forma adjustments to power supply are proper.

***3. Class Revenue Allocations***

Accepting the Cost of Service results as a starting point, the Commission must determine the appropriate revenue requirement to be recovered in the rates of the different customer classes. In doing so we strive to achieve an equitable apportionment of the revenue requirement among the customer classes. The closer customer classes are moved to full cost of service the fairer the rates that are set. In this case Avista's COS study indicates that Schedule 1 residential customers and Schedule 25 Extra Large General Service customers are receiving substantial subsidies from all remaining customer classes. Tr. at 321.

Although cost of service studies are not precise, we find it is important that cross subsidies among customer classes be minimized. We find it reasonable in this case that all customer classes be moved to within 10% of full cost of service; no class less than 90%, no class greater than 110%. See Appendix E.

***4. Rate Design and Tariff Issues***

Avista proposes a number of changes to rate design for the customer classes, including increasing the fixed customer charge for residential customers. The Company proposes a declining tail block for Schedule 11 customers to preserve class identity and revenue responsibility and to discourage customer migration between classes. The Company also proposes to increase energy charges for every customer class in order to generate the authorized revenue requirement. This section of the Order addresses each customer class and the changes proposed.

*A. Residential Service (Schedule 1)*

Avista proposes to increase the basic customer or minimum monthly charge for residential customers from $4.00 to $5.00. The customer charge is a fixed component in rates that recovers a portion of the cost required to serve a customer. The Company recommends that the remaining revenue requirement be recovered through an equal increase to both energy blocks. Tr. at 782.

Staff recommends no increase in the $4.00 basic and minimum charges. Tr. at 1325. Citing a Commission ruling in a recent Idaho Power rate case, Order No. 29502 at 53, Staff witness Schunke testified that the basic charge should be based on the direct cost of meter reading and billing and should not include any fixed plant cost. The monthly cost associated with meter reading and billing for Avista is $2.62 for residential customers. The 25% increase in the basic charge recommended by the Company, Staff contends, would have a disproportionate affect on customers with low usage. Tr. at 1326-1327. Staff recommends that the two-block energy rate continue to be priced with a higher second block rate for usage in excess of 600 kWh (month). Staff recommends an average overall increase in base rates of 18.8% for Schedule 1. Tr. at 1325-1326.

On rebuttal Avista proposes a revised rate spread that would provide an identical increase in rates for each of the two energy blocks. If the proposed increase in the monthly basic charge is not approved, Avista proposes that a higher percentage increase be applied to the first block rate. The Company argues that an increase to the basic charge is appropriate to recover the costs associated with the plant that is on the customer's property and dedicated to serve that customer. Tr. at 818-819.

The Commission is unwilling to dampen the incentive for customers to conserve energy. For the residential customer that incentive is generally a price signal and the ability to control the total bill amount. We find that the present customer charge for residential customers is sufficient to provide the Company with recovery of those costs that are directly attributed to the customer taking service. We find that those charges are related to meter reading and customer billing costs, in this case approximately $2.62/residential customer. While we are not inclined to increase the charge; neither do we find a compelling reason to decrease it. We also approve an increase in the inverted block energy rates that recover the class revenue requirement and use the ratio between blocks proposed by Staff.

*B. General Service (Schedules 11 and 12)*

Avista proposes adding an additional energy usage block that would provide a lower energy rate for usage in excess of 3650 kWh per month than for usage below that amount because, under present rates, customers whose monthly peak demand exceeds 20 kW are billed at a higher average amount per kWh even though these high load factor customers cost less to serve on a per kWh basis. No increase to the customer or demand charge for monthly peak demand in excess of 20 kW is proposed. Tr. at 783-785.

Having both demand-metered and non-demand metered customers on a demand schedule, Staff contends, is the real problem that the Company is attempting to address with a declining tail-block. This is because higher use customers effectively pay more per kWh because Avista does not bill the first 20 kW. Although opposed to Avista's proposed declining block rates, Staff recommends acceptance in this case with the requirement that Avista be directed to gather additional information so that the Company can provide a proposal in its next rate case to: (1) divide Schedule 11 into two separate schedules, one demand metered and one not; (2) eliminate declining block rates in Schedules 11, 21 and 25; and (3) implement time of use (TOU) rates wherever practical. Staff recommends an average overall increase in base rates of 11.4% for General Service Schedules 11 and 12. Staff recommends no change in the basic charge, the minimum charge, or the demand charge. Tr. at 1319; 1327-1329.

On rebuttal the Company committed to conduct a study to split the schedule prior to its next general filing and to assess whether Staff's proposal should be implemented. Tr. at 819-820.

The Commission agrees with Staff that demand metered and non-demand metered customers should be separated to allow for a more appropriate billing of demand and energy. However, we recognize that the information necessary to make such a separation is currently unavailable. We therefore direct the Company to gather the required information and submit its findings to the Commission as part of its next general rate case. We accept the Company and Staff proposal to move to two block declining energy rates. Our rates recover the class revenue requirement and incorporate the ratio between blocks proposed by the Staff.

*C. Large General Service (Schedules 21 and 22)*

Avista proposes adding an energy usage rate block to Schedules 21 and 22 so that the larger customers would pay a lower incremental energy rate for usage beyond 250,000 kWh/month than for usage below that amount. The Company is proposing that the base tariff rates be the same for usage over 250,000 kWh under Schedule 21 and for usage under 500,000 kWh under Schedule 25. Approximately 1,800 customers take service under Schedule 21. Customers served under the schedule can have a monthly demand anywhere from 50 kW up to 2500 kW, the minimum level required for service under Schedule 25. Generally, larger use customers under the schedule are less costly to serve than smaller use customers on a per kWh basis. Several Schedule 21 customers have a higher load factor than many customers served under Schedule 25 – yet they pay an average energy rate under Schedule 21 that is presently up to 50% higher. Because of the present rate differential between Schedules 21 and 25, a customer switching from Schedule 21 to 25 can see a lower annual energy bill well in excess of $100,000, that represents a revenue/margin loss to the Company until corrected in a general rate case. The Company reports that two of the 15 customers presently served under Schedule 25 switched from Schedule 21 in 2003. The Company proposes to increase the minimum demand charge from $225 to $250, and increase the demand charge for kW over 50/month from $2.75 to $3.00. Tr. at 785-789.

Staff recommends that Avista's proposal for the second block energy rate and for increases to the demand charges be accepted. Staff recommends that Avista be directed to develop additional information before the next rate case assessing the economic impact of the second block and justifying the continued use of a declining block energy charge. Tr. at 1319; 1329-1330. Staff proposes an overall increase in base rates of 12.9% for Schedules 21 and 22.

The Commission accepts the demand charge as supported by both the Company and Staff. We also accept a second block energy rate with the caveat that the Company further justify a declining block rate before the next rate case. Finally, we establish the energy rates to achieve the allocated revenue requirements with the Staff proposed ratio between first and second block energy rates.

*D. Extra Large General Service (Schedule 25)*

The Company proposes a declining block energy charge whereby the Schedule's larger customers would pay a lower incremental energy rate for usage beyond 500,000 kWh/month, than for usage below that amount. The Company proposes to increase the minimum demand charge from $7,500 to $9,000, and to increase the demand charge for kva over 3,000/month from $2.25 to $2.75 per kva. Tr. at 788-789.

Avista includes Potlatch's Lewiston facility in this Schedule but proposes changes to the rate structure so that Potlatch will pay an average rate per kWh that is lower than the average rate(s) paid by other Schedule 25 customers. Tr. at 769; 780; 785-794.

Staff recommends that Avista's proposal for the declining second block energy rate and for increases to the demand charges be accepted. Staff recommends that Avista be directed to demonstrate in its next rate case that the Schedule 25 tail-block rate exceed the Company's variable costs and provides a contribution to the Company's fixed costs. Staff recommends an overall increase in base rates of 20% for Schedule 25, with Potlatch receiving a 14.9% increase. Tr. at 1319; 1330-1331.

Coeur Silver recommends that Schedule 25 customers be given the average jurisdictional increase. By way of critique, Coeur Silver recommends that Avista should be directly assigning as opposed to allocating distribution plant to Schedule 25 customers with identifiable primary plant. Coeur Silver also recommends that rates be established that better reflect load factor differences and thus cost causation. After Potlatch-Lewiston, Coeur Silver contends that it is the next largest customer in Schedule 25 and has a significantly higher load factor than the others. Those customers with a high load factor, it contends, should be rewarded with lower rates. Coeur Silver recommends that the Commission (1) increase the demand charge and lower the energy charge(s), or (2) develop a declining block energy rate that is load-factor dependent (i.e., the first so many kWh per kW are priced at one rate while usage above that level is priced at a lower rate). Although Coeur Silver has no preference as to which method should be adopted, it suggests that the Commission target a ratio of demand to energy charges of at least 120. Tr. at 500-501; 508-513.

Based on the significant increase in the present rate of return for Schedule 25 that results from the revised allocation of common and distribution costs, Avista on rebuttal proposes to reduce the original proposed rate increase. The first block energy rate would be decreased and the second block increased. The reduction in the proposed increase for Schedule 25 is offset by an additional increase to Residential Schedule 1. Tr. at 814-815; 818.

Coeur Silver is troubled by Staff comments regarding the declining block and though it welcomes the development of additional data, it does not believe that its intended purpose should be the elimination of the declining block rates. Tr. at 520. Coeur Silver dislikes Staff's rate design because in spite of the inclusion of a declining block energy rate, it reduces rates too little for higher load factor usage. Yankel proposes a rate design that better rewards high load factor customers. Instead of $9,000 for the first 3,000 kW and $2.75 per kW for each additional kW, Yankel proposes the initial 3000 kW be priced at $10,500 and that each additional kW be priced at $3.25 per kW – similar to Idaho Power's rate. Tr. at 520-523.

Potlatch on rebuttal expresses support in principle for Coeur Silver's proposal to directly assign primary facilities costs to Schedule 25 customers. Peseau is convinced that all cost of service models – including his own – significantly overstate Schedule 25's cost of service. Tr. at 962-963.

The Commission hereby adopts the increase in demand charges as proposed by the Company and accepted by Staff. We also approve the creation of a second block energy rate and establish energy rates that achieve the revenue requirement for the class while maintaining the Staff proposed first and second block rate differential ratios. However, we find the testimony of Potlatch and Coeur Silver persuasive regarding the make up of Schedule 25. We believe it is not appropriate to continue to include Potlatch as a customer in Schedule 25 and we therefore establish a separate stand alone schedule for Potlatch as discussed more fully in the following section.

*E. Potlatch's Lewiston Plant*

On January 15, 2004, in Order No. 29418, this Commission approved a new Power Purchase and Sale Agreement (Agreement) between Avista and Potlatch. The Agreement is for a 10-year term, beginning July 1, 2003 and ending June 30, 2013. As the sole purchaser of Potlatch's generation at the plant, Avista pays Potlatch $42.92 per megawatt-hour for up to 543,120 megawatt-hours (62 average megawatts) generated by Potlatch during each "Operating Year" (July 1 through June 30) of the Agreement. This amount is equivalent to 62 average megawatts and is referred to in the Agreement as the "Base Generation Amount." There are special provisions in the Agreement for the purchase of additional amounts generated by Potlatch in excess of the Base Generation Amount. Avista will serve Potlatch's entire load requirements at the Lewiston Plant, approximately 100 average megawatts, under its Extra

Large General Service Schedule 25 rates, including the present Power Cost Adjustment (PCA) surcharge and all other applicable rate adjustments, unless the Commission issues an Order in the future authorizing different billing rates. Nothing in the Agreement prejudices either Avista's or Potlatch's right to propose, or the Commission to order in future rate proceedings, that Avista's service to Potlatch should be priced at rates other than Schedule 25. Tr. at 790-791.

Avista is proposing that Potlatch continue to be served under Schedule 25, however, the Company is proposing changes to the present Schedule 25 rate structure that will result in Potlatch paying a lower average rate per kWh than the average rate(s) paid by other Schedule 25 customers. Tr. at 769; 785-794. The Company is proposing a two-tier declining block energy rate structure for Schedule 25, as compared to the present single energy rate for all usage under the Schedule. Tr. at 791. Because of the magnitude of Potlatch's load requirement, over 99% of their 2002 energy usage would be priced at the lower second block rate. For all other Schedule 25 customers in total, only 72% of their usage is priced at the lower second block rate. Additionally, Potlatch's load factor is substantially higher than other Schedule 25 customers. Tr. at 792.

Potlatch contends that the Avista and Potlatch power supply agreement is a unique contract that governs Avista's service to only one customer – the Potlatch Lewiston facility. In that agreement, the parties agreed to the temporary use of Schedule 25 rates for service to the facility, pending the next rate case. But Potlatch did not agree to become a Schedule 25 customer. It has always been a "special contract customer." Potlatch recommends rejection of Avista's proposal to include Potlatch's Lewiston facility in Schedule 25 because Potlatch is three times the size of the entire Schedule 25 class and should have its own tariff as a special contract customer. Tr. at 938-939.

Peseau's recommendation to create a separate rate schedule for Potlatch's Lewiston facility, the Company concedes on rebuttal, has merit, especially as rates are moved closer to the cost of providing service in the future. If the Commission creates a separate rate schedule for Potlatch, Avista proposes that the original proposed energy rates for Schedule 25 be reduced by a uniform percentage to yield the revised overall increase for the Schedule. Tr. at 821-822.

Coeur Silver on rebuttal contends that Potlatch-Lewiston should not be included in Schedule 25 rates because no other Schedule 25 customers have load characteristics that are remotely similar. Tr. at 520.

As indicated in our Schedule 25 discussion, the Commission finds it reasonable to establish a separate stand alone service schedule for Potlatch's Lewiston facility. As stated by witness Peseau, Potlatch is three times larger than all other Schedule 25 customers combined. We believe establishing a separate schedule for Potlatch will result in rates for Potlatch and Schedule 25 that more accurately reflect cost of service. The Commission hereby approves demand rates for Potlatch equal to those established in Schedule 25 but establishes a single block energy rate that generates the Potlatch revenue requirement.

*F. Pumping Service (Schedules 31 and 32)*

Avista proposed that an increase be applied to the present energy blocks of pumping service schedules on an equal cents per kWh basis. Tr. at 789-790. Staff agrees with the Company that all of the proposed increases to the pumping class should be applied to the energy rate. The basic charge under both Company and Staff proposals would remain at $6.00. Staff recommends that Schedule 31 and 32 base rates be increased by 13.5% Tr. at 1331.

The Commission agrees that the basic charge for service Schedules 31 and 32 should not be changed. We increase the declining block energy rates in the ratio proposed by Staff.

*G. Street and Area Lighting (Schedules 41-49)*

Avista proposes to increase all present street and area light rates on an equal percentage basis. Tr. at 790. Staff recommended a uniform increase to lighting customers and recommends that Schedule 41-49 base rates be increase by 17.2%. Tr. at 1332.

The Commission approves a uniform increase to Street and Area Lighting schedules and increases rates in the ratio proposed by Staff.

***Electric Rates***

The electric rates we approve as just and reasonable are set out in attached Appendix A. *Idaho Code* § 61-502. Base electric rates increase by $24,716,000 while PCA rates decrease by $20,337,000 and DSM rates decrease by $1,197,000. This results in a net increase of $3,182,459 or 1.9%. The authorized electric revenue to be recovered in rates including residential exchange credit, Centralia credit, PCA surcharge and DSM rider is $175,029,459 for a total average rate of 5.60 cents or 1.9% increase. The increase for an electric residential customer using an average of 941 kWhs per month is $4.01, or a 7.1% increase in their electric bill.

## POWER COST ADJUSTMENT (PCA) ISSUES

### *1. Deal "A" and Deal "B" (PCA issue)*

In Avista PCA Order No. 29377, Case No. AVU-E-03-6, the Commission deferred to this rate case a PCA recovery decision regarding the Company's acquisition and later sale at a loss of natural gas to fuel the Coyote Springs 2 (CS2) combined cycle combustion turbine or other less efficient Company generation resources. During the first half of 2001 Avista experienced a combination of low water conditions and high market prices. Tr. at 551. Avista entered into a series of contracts, purchases and financial swaps, beginning in March 2001 to secure gas and gas transportation, i.e., Deal A and Deal B. CS2 was initially scheduled for testing in early 2002 and was expected to be commercially available in July 2002.

The first gas supply contract (Deal A) was to be delivered November 1, 2001 through November 1, 2004. Deal A consists of two transactions of 10,000 dth/day each, for a 36-month delivery term, that were entered into for the purpose of hedging or fixing, the natural gas price for the period November 1, 2001 through October 31, 2004. Tr. at 564. One transaction was entered into on April 11, 2001 at a price of $6.75/dth and the second transaction was entered into on May 2, 2001 at a price of $6.50/dth. Tr. at 564. The price for October 2004 gas was locked-in for three and one-half years into the future. Exh. 139, p. 7. The system net loss attributed to Deal A gas is $47,936,000 through May 31, 2004.

The second gas supply contract (Deal B) was for delivery to begin June 1, 2002 and continue through October 31, 2003. Deal B consists of two hedge transactions of 10,000 dth/day each, for the 17-month delivery term June 2002 through October 2003. One transaction was entered into on April 10, 2001 and another transaction on May 10, 2001 at prices of $6.50/dth and $5.35/dth, respectively. Tr. at 565. The October 2003 price was locked-in two and one-half years into the future. Exh. 139, p. 7. The system net loss attributed to Deal B gas is $21,755,640 through May 31, 2004.

In March 2001, Avista Energy secured a physical supply of natural gas for CS2. Tr. at 572, 573; 609, 610. The purchase price, however, was not fixed but was index based. Avista maintains that the purchase of firm indexed based natural gas satisfied the fuel requirement for CS2 project financing. Tr. at 571.

The Deal A and Deal B transactions fixed the price for 84% of the gas purchased at index based prcies. Tr. at 574. The Deal A and B transactions were financial hedge transactions as opposed to physical transactions. A financial gas transaction as explained at hearing involves no actual exchange of physical gas. Instead, a financial deal is agreed upon by a buyer and seller who take "price positions." The buyer bets that future gas prices will rise, while the seller bets that future gas prices will fall. Depending upon the future monthly movement of gas prices; the loser, or the counter-party on the wrong side of the bet writes a monthly check or "settles" with the other party. BP and Mirant were the counter-parties on Deal A. Tr. at 909-910. Avista Energy was the counter-party on Deal B.

Avista argues that the purchases were necessary because Avista had an electric resource deficit, hedge prices compared favorably to forward prices, and that the purchases were reasonable given energy crisis market conditions. Tr. at 540-541; 564-591. It is also worth noting, the Company states, that prior to the acquisition of CS2, the Company's gas-fired units were all peaking units. The ownership of CS2, a base-load gas-fired project, brings with it a greater need to enter into hedge transactions. Tr. at 615. The Company maintains that at the time the natural gas was purchased, it was anticipated that when the gas was to be delivered CS2 would be operational and more economical to operate than making market energy purchases. However, as the Company states, as with all forward transactions the market conditions at the time of delivery will undoubtedly be different from what they were at the time the transactions were executed. Tr. at 585. As it turn out at the time the gas was scheduled for delivery CS2 was not operational nor was it economical to use the gas purchased for CS2 at the Company's other facilities. Instead Avista simply purchased its power needs on the electric market and sold the gas back into the gas market at a loss because gas prices had declined. Tr. at 1261.

Taking simultaneous and opposite positions on the same Deal B financial hedge transaction, Potlatch contends, cannot be deemed prudent. Tr. at 917. Potlatch contends the energy trader at Avista who was buying the fixed-price hedge on behalf of Avista Utilities was the same energy trader who was selling it on behalf of Avista Energy. The length of the Deal A and B hedges based on Potlatch's investigation appears to be unprecedented, outside the Company's normal business practice, and seemingly unmatched in the industry. Tr. at 918-919. Avista disputes Potlatch's contention that the Deal A and B transactions were of unprecedented length. Tr. at 615-616.

Potlatch contends that the only thing that made simultaneously taking opposite sides of the bet on the Deal B swap an attractive transaction for Avista Corp. was that the PCA mechanism insulated the shareholders of the parent company by passing through to ratepayers the excess of the locked in hedged natural gas prices over and above the actual market prices that existed at the time. Tr. at 910-911. Avista Energy's role as a broker for the utility division, Potlatch contends, placed it in a fiduciary position to disclose that it considered Deal B to be a bad deal for Avista Utilities. Tr. at 912. Speaking to the roles and responsibilities of Avista Utilities and Avista Energy in Deal A, Avista Utilities states that it requested that Avista Energy enter into the Deal B hedge transactions due to the non-standard 17-month term. Also there were limited counterparties willing to transact with Avista Utilities. Tr. at 618.

The high costs associated with Deals A and B, Potlatch contends, are the result of imprudent decisions and self-dealing between Avista Corp. and Avista Energy that resulted in more than $62 million in excess gas costs on a system-wide basis. These unprecedented long-term financial swaps were never "in the money" nor did they allow for physical delivery. Both deals ($62.4 million) should be disallowed for imprudence, Potlatch contends, but at a minimum, Deal B ($18.3 million) must be disallowed due to self-dealing. Tr. at 908-922.

Potlatch contends that the Company's normal practice (for its retail natural gas business) was to hedge for periods approximately six months prior to a season (November-March or April-October). For example, May 1, 2001 prices were used for the November 2001-March 2002 season. Exh. 203. If Avista had hedged for Deal A in the same manner it was hedging other natural gas purchases in the same time frame, Deal A gas costs would have been $30,365,240 lower. Tr. at 921; Exh. 203. Potlatch contends that should the Commission not disallow the entirety of the Deal A costs, it should disallow the $30.4 million of Deal A costs the Company would not have lost had it engaged in normal hedging practices, adjusted for both the Idaho jurisdiction allocation as well as PCA sharing. Tr. at 921-922. Avista responds that it is important that the purchasing practice and hedging strategies for the Company's natural gas distribution business not be confused with the purchasing practices and strategies of the vertically integrated electric utility. Tr. at 613. The Company's natural gas purchasing practices and hedging strategies, it states, were developed in consultation with the Commission Staffs in Idaho, Washington and Oregon, both through informal communications, through the natural gas IRP process and through the current Benchmark Mechanism. Tr. at 614.

Staff recommends that $6,496,669 of Idaho *net losses* from Deal "B" gas purchases to run Coyote Springs 2 should be denied because Avista violated risk policy provisions (in excess of the 150MW long limit) in the Company's Energy Resources Risk Policy and transacted with an unregulated affiliate without appropriate safeguards (a proper code of conduct or a requirement of lower-of-cost or market pricing). Tr. at 1262; Exh. 141; Tr. at 1274. Staff contends that its Deal B proposal amounts to giving the customer the better deal, cost or market. Tr. at 1270. Staff proposes to leave the $8,677,766 in Idaho Deal "A" losses in the PCA. Staff contends that Deal A hedges were not done with an Avista affiliate and that Deal A did not put Avista over the long limit contained in its Risk Management Policy. Tr. at 1270. Potlatch notes however that Deal A and B were both financial only – and not the physical index-priced gas purchases. Potlatch contends that its irrelevant that the physical purchases were, or were not, over some designated volumetric or long limit. Tr. at 955.

Both Deal A and B purchases, Staff states, were ongoing at the 18-month short-term risk policy transition point in October 2002. Tr. at 1264. In contrast to Staff's near term risk policy point of view, Avista analyzes this issue with a long-term (greater than 18 months) resource planning point of view. Staff argues the short-term risk policy should be used because the long-term IRP does not include gas acquisition criteria and the load balance was not consistent with the long-term acquisition process. Staff contends that the Company took unusual risks for both Avista Energy and its customers when hedging the price for the length of the Deal B contracts. Avista Energy's risk was that gas prices would go up and that when it needed gas for delivery it would be more costly. The utility was exposed to several types of risk. It had the risk that gas prices would both go down and gas would cost less when it was needed. The utility also had the risk that electric and gas prices would go down such that the gas could not be economically used to produce electricity. Because the deal with Avista Energy was not provided to Avista Utilities at cost, Avista Energy had the opportunity to profit by keeping the difference between the actual cost and fixed price of gas sold to the utility. In the end Avista Energy profited and the regulated utility is proposing that its customers pay 90% of the costs. Because Avista did not enter into similar long-term gas purchases for its gas customers, Staff contends that it was inconsistent and highly speculative to do so for electric customers. Tr. at 1260-1274; Exh. 140.

Avista maintains that the costs associated with the Deal A and Deal B contracts were prudent given the information and circumstances at the time and should ultimately be recoverable through the Idaho PCA mechanism. Tr. at 586. The Company maintains that the transactions were reasonable and consistent with the Company's long-term planning criteria and risk policy. The duration of these purchases was not of an unusual length to cover open power positions. It cannot be assumed Avista Energy profited by $18 million from the Deal B transactions as suggested by Peseau. If the Commission determines part of the Deal B transactions should be disallowed, the Company proposes two alternative methodologies to calculate disallowance ($2.7 million or $4 million v. Staff's $6.5 million). Tr. at 193-194; 602; 609-631.

Potlatch on rebuttal maintains that Staff should not have accepted the Deal A excess gas costs because Hessing's compelling argument to disallow Deal B gas costs applies to Deal A as well. Both transactions lack cost-benefit analyses, were irregular, and were speculative. Tr. at 953-957.

**Commission Findings**

Before the Commission can address the Deal A and B losses we must first consider a threshold issue, the propriety of the Avista Energy transactions themselves. Relevant to our consideration is the affiliate relationship that exists between Avista Energy and Avista Utilities. The Commission has authorized Avista Energy to act as an agent for Avista Utilities gas. As a condition of such approval a benchmark mechanism and agency agreement were put in place. We established some sideboards, a code of conduct and rules that established transparency and governed the transactions performed by Avista Energy on behalf of Avista Utilities. This operational infrastructure was put in place to provide an auditable paper trail and to insulate Avista Utilities and its customers from the risk associated with the Company's non-regulated subsidiary operations.

Avista Energy had authorization by this Commission to act on behalf of Avista Utilities-gas, not on behalf of Avista Utilities-electric. The record reflects that there was an understanding between the Company and Commission Staff that there would be no transactions between Avista Utilities-electric and Avista Energy. Tr. at 54, 55. A protocol had not been established for such transactions. When asked whether a similar protocol was followed for Avista Utilities–electric, the Company's policy witness Morris stated that Avista follows FERC guidelines with respect to its electric operations. Tr. at 54. He contends that the Company also follows its Risk Management Policy. Tr. at 58. During the time of these transactions the Company was in a severe liquidity crisis. Because of its financial troubles it was also having difficulty doing business with other counterparties. The Company made a choice at that time that it was in the best interest of its customers to be able to lock-in a $38 to $48 product. The Company preceded to hedge and lock-in a price at market. Tr. at 58.

Avista may have had the best intentions. The best intentions however cannot overcome the perception that it also had a divided loyalty, an obligation to shareholders to maximize profits and an obligation to treat its utility customers fairly. There was no protocol in place for electric side gas procurement. In choosing to act without regulatory approval the Company assumed the risk of loss. We have reviewed the documentation provided by the Company. Tr. at 590; Exh. 7. The paper trail that the Commission and our auditing Staff rely on for gas benchmark transactions was not present for Deal A and B. The appearance at hearing was that the justification for the transactions was cobbled together after the fact. Other than a notational entry that the financial hedges were required by lenders to obtain construction financing (financing that was ultimately not secured), there was no lender documentation to support such a requirement.

Regarding Deal B hedge losses, we find absolutely no justification for authorizing PCA recovery. Avista Energy assumed a financial position directly at odds with Avista Utilities. At a minimum it was highly irregular. Certainly it was speculative. The Company was operating outside its own risk management policy. When it chose to act without regulatory approval of an affiliate methodology, it was risking its own money, not its ratepayers'.

Regarding Deal A hedge losses, we find that many of the reasons justifying our disallowance of Deal B are also present for Deal A. However, there are differences that create a basis for different treatment. Among those differences are the counterparties themselves, neither of whom were affiliates of Avista Utilities, and Staff's analysis that demonstrates that these transactions, had an operating protocol been in place, would have been viewed by Staff to be within the Company's established risk management limits.

This Commission acts knowing that it's decisions may have financial repercussions in the lending community and on Wall Street. At the same time we send a signal to the regulated utility and its parent that affiliate transactions between regulated and unregulated entities must be guided by protocol. In failing to put such a protocol in place, the Company acted at its peril. We find that as to Deal A losses there should be a sharing of risk between ratepayers and shareholders. We find a reasonable disallowance to be one-third of the total losses.

As developed at hearing in Exhibit 141, Idaho PCA deferral balance at the end of May 2004 was $26,261,334. Deal A losses through May amounted to $47,936,010 on a system basis; $15,905,167 on an Idaho jurisdictional basis. With 90/10 PCA sharing the Idaho PCA amount related to Deal A losses is $14,314,651. Of that amount $5,636,885 was previously authorized for PCA recovery (July 1 – June 2002). Based on our consideration of the record and Deal A findings, the Commission finds it reasonable to exclude or disallow one-third of the Idaho system Deal A losses, or $4,771,550. Our mathematical calculation of the Idaho jurisdictional disallowance is based on the total Deal A losses through May 2004. This decision will also apply to Deal A losses after May 31, 2004 that otherwise may be in next year's PCA. We also direct Avista to work with Staff to make the appropriate interest adjustments to the PCA deferral account. The Commission disallows the losses associated with Deal B, in the amount of $6,496,669.

### *2. Updated PCA Components*

Avista's electric Schedule 66 Power Cost Adjustment (PCA) is a rate adjustment mechanism that annually adjusts a portion of customer rates to allow Avista to recover or refund 90% of the amount above or below the base power supply costs established in a general rate case and included in the revenue requirement and base rates for the customer classes.

The new authorized level of annual power supply expense proposed by the Company is $71,456,998. This is the sum of Accounts 555 (Purchased Power), 501 (Thermal Fuel), and 547 (Fuel) less Account 447 (Sale for Resale). Base power supply costs are updated in general rate cases for use in the PCA. The Company also proposes to update the load change revenue adjustment multiplier (average annual variable power supply cost of meeting new load as determined from the Company power supply model) from 21.23 $/MWh to 36.38 $/MWh. Tr. at 279-280.

Staff witness Hessing agrees with the Company's calculations and supports Avista's base power supply amounts and update to the load change revenue adjustment multiplier. Tr. at 1274-1276. The Commission approves these proposed updates.

*3. PCA Rate Recovery*

Avista's witness, Mr. Hirschkorn, proposes to reduce PCA rates in this case to recover one-half of the estimated Idaho PCA deferred balance each year for two years. Tr. at 767; 779; 820. Staff witness Hessing supports the Company's proposal to calculate rates to recover the remaining PCA balance over two years but recommends use of an actual known end of month balance instead of an estimated balance. Tr. at 1276-1277.

With respect to PCA issues deferred to this rate case in Order No. 29377 regarding Coyote Springs 2 (CS2), the Commission notes an audited PCA deferral account balance May 31, 2004 of $26,261,334 (reference Case No. AVU-E-04-3); disallows CS2 Deal B losses of $6,496,669; and disallows $4,771,550 of Deal A losses for a net PCA account balance total of $14,993,115. The Commission approves the Company proposal to recover the remaining PCA deferral balance over a two-year period. The resultant annual PCA recovery is $7,496,558, subject to annual PCA review and adjustment. The Commission authorizes changing in the future from the current uniform percentage recovery method to a recovery method based on energy consumption.

The Commission in this Order also approves the assignment and recovery from the residential class through the PCA of authorized CAPAI intervenor funding in the amount of $12,622.75.

*4. PCA Rate Design*

Avista witness Hirschkorn recommends recovery of the PCA surcharge by a uniform percentage allocation to each customer class and a single rate for all energy usage within the class (except for residential block rates). Tr. at 780.

Staff witness Hessing agreed with the Company proposal while there is a remaining deferral balance. However, he proposes that once the current PCA deferral balance is eliminated, PCA costs be recovered from ratepayers on a uniform cents per kWh basis rather than a uniform percentage of revenue by class. The PCA rate would then be the same for all schedules except lighting. Staff advocates this as a more appropriate way to collect variable energy costs. Tr. at 1277-1279.

Avista on rebuttal agrees that from a cost causation viewpoint, an equal cents per kWh application to all schedules is more appropriate than the present PCA methodology. The

Company also agrees that the change in methodology should not occur until the present deferral balance is fully recovered. Tr. at 821.

Potlatch witness Peseau opposes Staff's proposal on both theoretical and practical grounds and recommends that it be rejected or modified. Potlatch contends that power supply costs are not 100% energy or kWh-based and should not therefore be spread on an energy-only basis. There is both a fixed or capacity component and a seasonal differential cost component to power supply costs, he contends, that makes spreading balances on a flat, equal kWh basis inaccurate. A cents per kWh recovery method, Peseau contends, would expose high load factor customers to greater volatility because the surcharge and rebates will be greater than under the current system thus making business planning and management decisions more difficult. Rate increases can cause disruption and losses, he contends, that cannot be recovered by corresponding decreases in subsequent years. If Staff's proposal is adopted, Potlatch recommends that the Commission "seasonalize" the cents/kWh recovery on a monthly or quarterly basis in a manner similar to avoided costs rates. Tr. at 963-965.

The Commission finds that a cents per kWh recovery method for the PCA is superior to the percentage basis currently used. While we recognize the difficulties pointed out by Potlatch, we find the cents per kWh rate more equitable to all customers than the percentage allocation. We recognize that the variable cost of energy fluctuates from year to year based on the amount of energy consumed and should therefore be surcharged or credited on an equal cents per kWh basis. We authorize the change to an equal cents per kWh when the present deferral balance is eliminated. We reject Potlatch's proposal to seasonalize PCA recovery amounts on a monthly or quarterly basis as being administratively burdensome and unnecessary to achieve fairness and equity.

## OTHER ISSUES

### *1. After Hours Connection Fees*

Avista witness Hirschkorn proposes reconciling changes to non-recurring charges for reconnection rates so there is only one set of charges that applies to any reconnect or service turn-on situation. The proposed rate is $24 for reconnections occurring during normal business hours and $48 for after-hours, plus $4.00 for each additional service connected at the same time. Tr. at 811.

Staff witness Parker recommends approval of Avista's proposed changes for: (1) reconnection of seasonal gas customers, and (2) after-hours connection charges for both gas and electric customers. Staff recommends, however, that the tariff provision allowing an additional $4.00 charge to connect a second meter at the same location be eliminated. Tr. at 865.

Rebuttal witness Kopczynski was generally supportive of Staff positions while noting that several issues are concurrently being reviewed in the Staff-hosted Best Practices Task Force. Tr. at 258-264. The Company supports Staff's proposal to eliminate the $4.00 reconnection of additional meters at the same premises. Tr. at 826.

The Commission based on its review supports the changes in reconnection and after-hours connection fees agreed to by the Company and Staff. The Commission understands that there will not be a significant net change in revenue.

***2. Winter Payment Plan***

Staff witness Parker recommends that Avista take steps to resolve its computer programming issues so that a customer who has declared Moratorium eligibility can also participate in the Winter Payment Plan. Staff also recommends that the Company improve its communication with customers about the Winter Payment Plan and Moratorium. Tr. at 865.

On rebuttal Avista witness Kopczynski states that the Company's computer system does in fact allow customers to be set up on both the Winter Payment Plan and the Idaho Moratorium. The Company commits that all of its customer service representatives will be provided additional training by November 1, 2004. Tr. at 258-260.

***3. Telephone Call Center***

In a 2002 Edison Electric Institute/American Gas Association (EEI/AGA) study cited by Staff witness Parker, the average service level (the percentage of calls answered within a defined number of seconds) among the 62 reporting utility companies was 73.8% of calls answered in 32.3 seconds. Avista has recently set its internal service level goal at answering 70% of incoming calls within 60 seconds. Staff recommends that Avista be encouraged to answer 80% of calls within 30 seconds by January 2005 and significantly reduce the number of abandoned calls per month. Tr. at 865.

Avista witness Kopczynski on rebuttal notes that in the past 18 months, Avista has added 6.5 full time equivalent (FTE) positions to the Company's contact center and is improving its response time. To meet Staff's recommendations, however, Kopczynski states, an additional nine full-time positions would be required. The need for flexible staffing means that 9 FTE translates to approximately 13 new employees. Avista intends to add this additional contact center staff in the next year and establish 80% of incoming calls answered in 30 seconds as a target. This additional FTE complement would increase expense over that requested by the Company's Application by $162,735 for Idaho and Avista believes it is appropriate to reflect these additional costs in the Company's revenue requirement. Tr. at 260-263. As the Company moves to an 80% answered-calls-in-30-seconds standard, it believes the number of customers who hang up before they reach a contact representative (or abandoned calls) should be reduced.

Addressing Kopczynski's rebuttal testimony, Staff at hearing noted that the Company failed to indicate that they have five FTE positions in customer service that are currently vacant, and additionally, they have four FTE positions where the employees have been reassigned. Also in the last year or so the Company has filled 6.5 FTEs. And so, to the extent the Company has had all these positions vacant, Staff concludes that its not surprising that with the call volumes increasing, service levels and employee morale have declined. Even if the Company fills the vacant FTEs immediately, Staff contends that it will take some time for them to be trained. Staff recommends that the Company be given time to improve service and to explore some technology-based solutions designed to help improve service levels. Staff recommends that the Company be directed to file a report with the Commission in July 2005 reporting on the prior 12 months and indicating what progress it has made in improving the average service level. Tr. at 887, 888.

The Commission encourages the Company to improve its response time to customer calls and to reduce the number of abandoned calls. We find that this issue should be addressed by the Company and direct the Company to file a status and progress report with the Commission in July 2005 detailing the steps the Company has taken and implemented to improve the average service level. Until this issue is more fully explored, we find no basis for providing an increase in authorized revenue for additional Company FTEs.

***4. Prudency of DSM Expenditures***

When the Commission approved the Company's energy efficiency programs in 1995, Avista committed to demonstrate the prudence of program expenditures in future general rate cases. Avista witness Hirschkorn requests that the Company's electric DSM expenditures from January 1, 1999 through December 31, 2003 be found to have been prudently incurred and gas DSM prudent from March 13, 1995 through December 31, 2003. Tr. at 808-810. Since 1995, the Company calculates that over 286 million kWh (and 5.8 million therms) have been saved through its energy efficiency programs. Tr. at 809. A 15-year levelized utility cost per saved kWh of 1.4 cents per kWh has been achieved. The levelized avoided cost during this same period has been 4.7 cents per kWh. Hirschkorn also said the 15 year levelized cost per saved therm has averaged 14 cents per therm. Tr. at 809. Staff witness Anderson offered two corrections to Hirschkorn's testimony. Anderson said that the prudency review of both gas and electricity DSM for this case should have ended October 31, 2003. Tr. at 844. Anderson also said the average levelized cost of gas DSM savings was 25 cents per therm, not 14 cents per therm. Tr. at 845. Avista did not rebut these corrections.

Avista collects revenues for its DSM programs from surcharges. Currently tariff Schedule 91 electric surcharges amount to 1.95% of base revenues. The Company collected about $2.7 million in 2002. Staff witness Anderson finds Avista's DSM approach conscientious, cost-effective, and reasonable. Tr. at 844-845.

The Commission finds that the DSM programs of Avista have been demonstrated to be successful. Participating customers have benefited through lower bills and cost-effective energy efficiency measures. Non-participants benefit from the Company's acquisition of low cost resources. We find that the Company's DSM expenditures from January 1, 1999 through October 31, 2003 to have been prudently incurred.

***5. Advanced Meter Reading (AMR)***

Avista apprises the Commission in this case of its proposal to install AMR devices on all Idaho electric and natural gas meters over a four-year period commencing January 2005. The Company estimates that its annual electric net cost would increase $188,700. The Company estimates a $63,000 decrease in annual gas costs over a 15-year period. Avista requests that the estimated $16.3 million AMR project cost be capitalized as Construction Work in Progress (CWIP) until the entire project is completed and depreciation begins. Avista is <u>not</u> proposing a change in rates in this filing to pay for AMR. Tr. at 733-739; Tr. at 190.

Staff witness Anderson supports in principle the Company's proposal to install AMR facilities without specific time of use (TOU) pricing facilities at this time. He noted that the estimated $188,700 annual net cost increase equates to approximately a 7-cent increase on a $50 customer bill. He also noted that the estimated $63,000 annual net cost decrease to gas service equates to about a 7 cent decrease on a $57 customer bill. Although Avista will benefit from AMR before completion of the entire four-year installation, Staff wants to promote implementation and is not opposed to the requested deferred accounting treatment. Anderson anticipates critical peak TOU pricing will become cost-effective by about the time Avista completes its AMR project and that additional components necessary for such a pricing system should begin to be installed at that time. Tr. at 851-854.

The Commission supports the Company's plans to install AMR and authorizes the Company-requested deferral accounting treatment for its related investment. In doing so we acknowledge and support Staff's TOU comments.

***6. Intervenor Funding***

The Commission approves CAPAI's Petition for Intervenor Funding in the requested amount of $12,622.75. Reference *Idaho Code* § 61-617A. Our award is based on a finding that CAPAI's participation materially contributed to the Commission's decision, that the costs of intervention are reasonable and would be a significant financial hardship for CAPAI if no award is given, that the recommendations made by CAPAI differed materially from Staff's case, and that CAPAI's participation addressed issues of concern to residential and low income customers. The award is to be recovered from residential customers through the Company's electric PCA mechanism.

## AVISTA'S NATURAL GAS CASE

The Company in this general rate filing requested an overall Idaho natural gas base-rate increase of $4,754,000 or 9.16%. Avista contends that a rate increase is needed because of decreased therm usage and increased general business expenses. Tr. at 15-18; Tr. at 147; 180, Exh. 15, p. 2 of 8. From 1999 to 2002, Idaho residential and small commercial customers decreased their gas usage from an average of 82 therms per month to 73 therms per month, or about 11%. During this same time period the number of residential and small commercial customers served in Idaho increased by 11%, or about 5,800 customers. Tr. at 799.

Because Avista is a combined natural gas and electric utility many of the Commission's findings regarding the Company's utility operations are generic in scope and to the extent they have been discussed above will not be repeated in this section of the Order. To the extent they bear repeating for purposes of identifying the revenue requirement effect it will only be referenced below in brief fashion.

Specifically addressed above and not discussed below are the Commission's decisions regarding Test Year, Capital Structure, Cost of Debt, Return on Equity, and Rate of Return. Also not discussed are the Commission's decisions regarding Reconnections and After-Hours Connection Fees; Winter Payment Plan, LIWA Funding and Advanced Meter Reading.

***Adjustments to Gas Test Year Revenues, Expenses and Rate Base***

Once a test year is selected, adjustments are made to test year accounts and rate base to reflect known and measurable changes so that test year totals accurately reflect anticipated amounts for the future period when rates will be in effect. As indicated in our discussion of electric service, adjustments to test year accounts generally fall into three categories. 1) normalizing adjustments made for unusual occurrences, like one-time events or extreme weather conditions, so they do not unduly affect the test year; 2) annualizing adjustments made for events that occurred at some point in the test year to average their effect as if they had been in existence during the entire year; and 3) known and measurable adjustments made to include events that occur outside the test year but will continue in the future to affect Company income and expenses. Order No. 29505. This section of the Order addresses the proposed adjustment to test year revenues, expenses and rate base associated with natural gas service.

Staff witness Stockton and Harms accepted Avista's proposed Standard Commission Basis Adjustments except for the Company's gas inventory adjustment (Falkner Exh. 15, pp. 4-6, columns c through o) and also accepted the Company's Pro Forma Insurance Adjustment that decreases net operating income by $131,000 (Falkner Exh. 14, p. 7, column r). Tr. at 1097-1098, 1135-1136.

The Company on rebuttal agreed to and incorporated into its Rebuttal Exh. 27, pages 8-9 the following Staff proposed adjustments to net operating income and/or rate base:

| Adjustment | Reason | Net Operating Income after Taxes | Rate Base |
|---|---|---|---|
| Deferred Federal Income Tax | Appropriate deferred tax accounting treatment | | (2,639,000) |
| Labor (Exec.) | Update estimates to actuals | 2,000 | |
| Labor (Non-Exec.) | Update estimates to actuals | 6,000 | |
| Depreciation | Synchronize depreciation between states | 28,000 | |

| | | | |
|---|---|---|---|
| Corp. Fees | Similar treatment for Idaho utilities – split 50%/50% | 17,000 | |
| Misc. Exp. | Similar to prior Commission treatment, exclude contributions, dues, and expenses benefiting affiliates | 71,000 | |
| Ad. Exp. | Similar to prior Commission treatment, exclude charitable contributions and image advertising | 6,000 | |
| Avista Foundation | Correctly assigns expenses to affiliate | 1,000 | |
| Actual Therm Usage | Updated to actual | 15,000 | |
| Schedule M Allocator | Conforms to electric system treatment | 2,000 | |

By accepting these uncontested adjustments the Company revises its requested gas revenue increase to $4,061,000 or 7.82%. Avista Reb. Exh. 27, p. 2, Tr. at 218.

***A. Agreed Upon Adjustments***

After Avista filed its rebuttal testimony, Staff and Avista agreed to reduce Staff's originally proposed Gas Inventory and Accounts Receivable Sale Program Fees Adjustments by 50%. Tr. at 1142-1143. These revised adjustments increase net operating income after taxes by $29,000 and decrease rate base by $786,000. Tr. at 1142-1143.

*1. Gas Inventory*

Avista witness Falkner adjusts rate base for the average of monthly average value of gas stored at Jackson Prairie underground storage facility and the Plymouth LNG Plant. The Company adjustment increases Idaho rate base by $1,572,000. Tr. at 182.

Staff witness Stockton removed the Company's Pro Forma Gas Inventory adjustment from rate base because Avista has a negative cash working capital and thus Staff contends that it is not an appropriate rate base addition. Staff's adjustment decreases rate base by $1,572,000 and decreases total revenue requirement by $227,000. Tr. at 1116; 1137; Tr. at 1099.

Avista on rebuttal contends that Staff's interpretation of its working capital analysis is incorrect. The Company's working capital, it states, is actually positive, not negative. Also, Staff's classification of gas inventory in the working capital analysis excludes it from working capital. The Company notes that the Commission has historically allowed gas inventory to be included in rate base and recommends that it continue to do so in this case. Tr. at 219.

Staff on rejoinder represents that Staff and Avista have agreed to reduce Staff's adjustment by 50%. This amended adjustment decreases Idaho gas rate base by $786,000 and the total revenue requirement by $114,000. Tr. at 1142-1143.

*2. Accounts Receivable Program Fees*

As per Staff witness Stockton Rejoinder, the Company and Staff agreed to an amended adjustment increasing Idaho gas net operating income by $29,000 and decreasing the total revenue requirement by $45,000 for the same reasons as described in the electric section of this Order. Tr. at 1141-1142.

*3. Restate Debt Interest*

Adoption of Staff adjustment increases the Idaho gas federal tax accrual by $36,000 and increases revenue requirement by $56,000. Tr. at 1107; Rev. Exh. 107. For further detail regarding the nature of the adjustment, please refer to the electric section of this Order.

The following issues were discussed earlier in the electric rate section and are treated consistently with our findings there.

***B. Disputed Issues (Resolved in Electric)***

*1. Pension Expense*

Staff's proposed adjustment to gas pension expense to reflect the 2003 ERISA required minimum contribution increases Idaho gas net operating income by $137,000 and decreases the Company's Idaho gas revenue requirement by $214,000. Tr. at 1101-1102; 1171-1172. However, for the reasons discussed in the electric section of this Order, the Commission allows Avista recovery of $381,311 pension expense in its Idaho gas jurisdiction on the evidence presented in this case. This results in an adjustment increasing Idaho net operating income by $93,000.

*2. Legal Expense*

Adoption of Staff adjustment increases net operating income by $13,000 and reduces Avista's revenue requirement by $20,000. Tr. at 1102-1103; 1173.

***Summary of Adjustments to Gas Test Year Revenues, Expenses and Rate Base***

Considering all the evidence presented, and including all adjustments, the Commission finds just and reasonable Idaho jurisdictional expenses for the 2002 test year in the amount of $48,368,000, and Idaho jurisdictional operating revenues in the amount of $52,575,000 for an operating income before federal income tax of $4,207,000. The after tax

Idaho operating income is $3,402,000. After all adjustments, we find a 2002 total Idaho jurisdictional rate base amount of $59,653,000 to be just and reasonable. Appendix D to this Order summarizes the Commission's findings on rate base and operating results for the test year.

***Rate Base***

Avista in Exhibit 15, p. 2 proposed a pro forma rate base of $63,078,000 for the Idaho jurisdiction. As we indicated in our prior Amended Interlocutory Order No. 29588 the Commission approves as just and reasonable a gas pro forma rate base of $59,653,000. See Appendix D.

***Revenue Requirement***

Current revenue recovered in Idaho's gas base rates is $51,919,000. The Commission in this case approves a base revenue requirement of $55,230,000, an increase in gas base rates of $3,311,000 or 6.38%. The resultant average base rates for sales therms is 81 cents per therm.

***Calculation of Revenue Deficiency***

Having determined the Idaho gas rate base, net operating income requirement, and return on common equity, we proceed to determine the Idaho revenue deficiency with the following calculation:

| | |
|---|---|
| Rate Base | $59,653,000 |
| Rate of Return | 9.250% |
| Net Operating Income Requirement | $5,518,000 |
| Operating Income | $3,402,000 |
| Income Deficiency | $2,116,000 |
| Conversion Factor | .639 |
| Revenue Requirement Deficiency | $3,311,000 |

The Commission approves a pro forma rate base of $59,653,000. See attached Appendix D. The Commission approves additional natural gas revenues of $3,311,000 for a total revenue requirement of $55,230,000, a 6.38% revenue increase.

### ***Gas Jurisdictional Separations, Weather Normalization and Cost of Service***

*1. Gas Jurisdictional Separations*

Avista used the same jurisdictional separation methodology approved by the Commission in the Company's last natural gas rate case. This general methodology has been approved for the Company in all of its other operating jurisdictions. Staff witness Fuss accepts Avista's Gas Jurisdictional Separation Study using the four-factor methodology with one minor adjustment. He used the four-factor allocator for Schedule "M" accounts instead of "allocator 5-Actual Therms Purchased." Staff's adjustment reduces Idaho's share of taxes and increases the Idaho gas net operating income by $1,888. Tr. at 1238-1242; Revised Exh. 107, p. 2. The Commission accepts Avista's Gas Jurisdictional Separation Study using the four-factor methodology with Staff-proposed adjustments.

*2. Weather Normalization*

No change was made to the historical methodology used to calculate natural gas weather sensitivity. Tr. at 328-329. Staff witness Sterling accepts Avista's gas weather normalization performed as accurate and reasonable. Tr. at 1190; 1192-1194. The Commission accepts Avista's weather normalization as accurate and reasonable.

*3. Gas Cost of Service*

Avista used the same Base Case (aka "Peak Credit") Cost of Service methodology (with minor modifications) approved in the Company's last natural gas rate case. The proposed rate spread of the increase results in approximately a one-half movement to the cost of service for each schedule. Tr. at 329-334; Tr. at 801.

Staff witness Fuss accepts Avista's Gas Cost of Service Study (aka Washington Accepted Methodology) with two adjustments: (1) adjust usage within the pro forma revenue calculation resulting in a $23,000 revenue increase, and (2) allocate storage expenses and credits based on winter therm usage not annual usage as proposed by Avista to better allocate value received by each class. Staff's adjustments result in a net Idaho revenue requirement decrease of $23,414. Tr. at 1238; 1242-1249. The Commission accepts the Company's Gas Cost of Service Study (aka Washington accepted methodology) with Staff-proposed adjustments.

Avista on rebuttal accepts Staff's recommendation for allocation of underground storage costs and related capacity release revenues. Tr. at 335-337; Tr. at 826. The Commission finds Staff's proposed allocation of underground storage costs and related capacity release revenues to be reasonable.

*4. Cost of Gas in Base Rates*

Avista proposes adding the current PGA WACOG adjustment of $0.27186/therm to base rates to produce a total base rate gas cost of $0.44989/therm. Tr. at 1249.

Staff agrees with Avista's request and believes increasing the cost of gas in base rates to reflect the best estimate of future gas costs will reduce the overall magnitude of future PGA adjustments. Tr. at 1238-1239; 1249-1250.

The Commission adopts Avista's proposal to add the current PGA weighted average cost of gas (WACOG) adjustment of $0.27186/therm to base rates to produce a total base rate gas cost of $0.44989/therm.

***Natural Gas Rate Design and Tariff Issues***

Avista witness Hirschkorn contends that the rates for natural gas Schedules 101, 111 and 121 provide a clear distinction for customer placement as well as a reasonable classification of customers for analyzing the costs of providing service: customers who use less than 200 therms/month should be placed on Schedule 101; customers who use between 200 and 10,000 therms/month should be placed on Schedule 111; and only those customers who generally use over 10,000 therms/month should be placed on Schedule 121. Tr. at 805.

In calculating the revenue allocation between the natural gas customer classes, Staff witness Schunke balanced the objective to move each class customer closer to cost of service with the objective of achieving an equal contribution to the non-gas related costs (which is referred to the margin) from Schedules 121, 131 and 146. Staff's proposed revenue allocation between classes was achieved by starting with the cost of service results. Then Schedules 121, 131 and 146 were moved closer to an equal contribution to the margin in order to discourage switching between schedules and to protect against a revenue shortfall. Tr. at 1332, 1333.

The natural gas base rates the Commission approves as just and reasonable are those set forth in attached Appendix B. *Idaho Code* § 61-502. The base rates we approve in this case are the fixed base rates incorporated in the Company's PGA adjustment authorized in Order No. 29590, Case No. AVU-G-04-2. The resultant proposed increase for a natural gas residential customer using an average of 73 therms of gas per month will be $12.84 per month, or 21.39%.

With this Order the Commission approves an increase in all gas commodity rates maintaining the relationships between the classes as proposed by Staff to achieve the revenue requirement for each class. The increase for each class are those reflected in Appendix F. We reject an increase in customer charges for Schedule 101. We accept a customer charge of $200 for Transportation Schedule 146 and approve increases in first block minimum charges for Schedules 111 and 121. For Schedule 131 we approve an increase in the annual minimum deficiency charge to be reflective of the Company's margin rate.

*1. Residential (Schedule 101)*

Avista witness Hirschkorn proposes to increase the residential basic and minimum charges from $3.28 to $5.00 to recover one-half of the basic fixed costs of providing service. Tr. at 802-804. Staff witnesses Schunke and Parker recommend that the basic and minimum charges remain at $3.28. Staff contends that the customer charge should be based on the direct cost of meter reading and billing and should not include any fixed plant cost. The cost of meter reading and billing for Schedule 101 is $2.46. Staff also cites customer opposition to this type of charge. See discussion in electric. Tr. at 1319; 1333-1334; Tr. at 866. Staff recommends an average overall increase in base rates of 6.97% to Schedule 101.

Avista on rebuttal states that the cost of providing service to residential customers has increased over the 15 years since the $3.28 basic charge was last set. The basic charge, Avista contends, should recover not only meter reading and billing, but also the cost associated with providing a meter and service line. Avista contends that the average cost associated with these expenses is well over $9.00 per customer per month. Avista believes that Staff's minimum charge proposal incorporates current PGA gas costs under Schedule 150, regardless of the customer's usage. Avista believes it is more reasonable to increase the fixed minimum charge under this schedule by the increase in margin and bill the present Schedule 150 rate only for those therms used by the customer. Tr. at 824-825.

The Commission rejects an increase in the customer charge for Schedule 101 and approves an increase in the commodity rate as reflected in Appendix F.

*2. Large General Service (Schedule 111)*

Schedule 111 is a three tier declining block rate structure. Avista proposes a $12.75 increase to the monthly minimum charge for Schedule 111 customers. Tr. at 802; 805. Staff recommends an increase in the basic or minimum charges to reflect the overall base rate increase for the first block. Tr. at 1334-1335. Staff recommends an average overall increase in base rates of 2.78% to Schedule 111. Tr. at 1319.

On rebuttal Avista recommends increasing the fixed minimum charge under this Schedule by the increase in margin and billing the present Schedule 150 rate only for those therms used by the customer. The Company's proposed rates, it states, incorporate the present Schedule 150 rate in the block usage rates under this Schedule and as an additional variable charge to the monthly minimum charge. The monthly minimum charge would increase from $97.30/month to $108.26/month, plus a 27.186¢/therm charge under the present Schedule 150 (WACOG adjustment). Tr. at 825.

The Commission approves an increase in the commodity rates for Schedule 111 as reflected in Appendix F and approves an increase in the minimum charge to reflect the resultant increase in first block rates.

*3. Extra Large General Service (Schedule 121)*

Schedule 121 has a four-tier declining block rate structure. The $267.63 monthly minimum charge is in addition to a 27.186¢/therm charge under the present Schedule 150 (WACOG adjustment). Avista proposes a $29.30 increase to the monthly minimum charge. There is also a minimum annual load factor requirement of approximately 58%. The Company proposes adding an annual minimum usage requirement of 60,000 therms for service under this schedule. Tr. at 802-803; 805-806. Staff recommends an increase in basic or minimum charges to reflect the overall base rate increase for the first block. Staff recommends an average overall increase in base rates of 1.86% to Schedule 121. Tr. at 1319; 1335.

Avista on rebuttal recommends increasing the fixed minimum charge under this schedule by the increase in margin and billing the present Schedule 150 rate only for those therms used by the customer. The Company's proposed rates incorporate the present Schedule 150 rate in the block usage rates under this schedule and as an additional variable charge to the monthly minimum charge. The monthly minimum charge would be $265.74/month plus a 27.186¢/therm charge under the present Schedule 150 (WACOG adjustment). Tr. at 825.

The Commission approves an increase in the commodity rates for Schedule 121 as reflected in Appendix F and approves an increase in the minimum charge to reflect the resultant increase in first block rates.

*4. Interruptible Service (Schedule 131)*

Schedule 131 is a single rate tariff. The present annual minimum charge is based on a usage requirement of 250,000 therms per year. Avista recommends revising the annual minimum charge to an annual minimum deficiency charge based on margin as it appears unreasonable to charge the customer for gas costs when the gas was not used. The annual deficiency charge will be determined by subtracting the customer's annual usage from 250,000 therms. Any resulting usage deficiencies will be multiplied by the present margin (revenue less gas costs) per therm under the Schedule, with the proposed margin level being 10.739 cents/therm. Tr. at 803; 806.

Staff to be reflective of the Company's margin rate recommends an increase in the annual minimum deficiency charges. Tr. at 1319; 1335-1336.

The Commission accepts an increase in the annual minimum deficiency charge to reflect the margin rate for Schedule 131 and approves an increase in the commodity rates as reflected in Appendix F. The Company is directed to calculate and file tariffs reflective of their margin rate as of September 9, 2004.

*5. Transportation Service (Schedule 146)*

Schedule 146 is a single rate tariff for all volumes transported on the Company's distribution system and includes an annual minimum charge based on 250,000 therms per year. The Company is proposing to add a $200 monthly customer/basic charge reflective of the administrative costs associated with gas scheduling, balancing and billing transportation customers. Tr. at 769; 801; 803; 807.

Staff recommends an average overall increase in base rates of 6.94% to Schedule 146. The proposed increase for transportation Schedule 146 excludes gas costs. If gas costs were included the resulting increase would be approximately 1.5%. Staff recommends that the Company-proposed basic charge of $200/month be approved. Tr. at 1317-1318; 1336; 1320.

The Commission approves the $200/month basic charge for Schedule 146 agreed to by the Company and Staff and approves an increase in the energy rate as reflected in Appendix F.

*6. Special Contracts*

Avista included all expenses associated with providing service to Idaho's Gas Special Contract customers in the general rate filing. The Company has three transportation service customers under special contract (Potlatch-Lewiston, Lignetics and IMCO formerly IMSAMET). All three of the contracts were negotiated, executed and approved based on the customers' close proximity to an interstate pipeline and their reasonable ability to by-pass the Company's distribution system. Tr. at 798-799.

Staff recommends acceptance of Avista's treatment of Idaho gas special contracts within the Gas COS study without changes. Tr. at 1239; 1250-1252.

The Commission acknowledges the Company's special contracts with Potlatch-Lewiston, Lignetics and IMCO. The terms and conditions of those contracts have been previously approved by this Commission.

***Other Issues***

*1. Prudency of DSM Expenditures*

The Commission finds Avista gas DSM expenditures from March 13, 1995 through October 31, 2003 to be prudently incurred.

*2. Tariff Summary Sheet*

Staff recommends that Avista be required to add a tariff summary sheet (sheet D) to its gas tariff schedules because it will provide clarity for customers without being administratively burdensome. Tr. at 1239; 1252; Tr. at 884.

Avista on rebuttal agrees to file the tariff summary sheet each time rates change. Tr. at 826.

The Commission directs the Company to prepare and file a tariff summary sheet for natural gas rates.

## CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over this Application and Avista Corporation dba Avista Utilities, an electric and natural gas utility, pursuant to the authority and power granted under Title 61 of the Idaho Code and the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq*.

The Commission has jurisdiction and authority pursuant to the above identified statute and rules to authorize and require Avista to re-allocate its revenues among the customer classes to change its rate components within the customer classes, to award intervenor funding and to address the other issues in the manner set forth in the text of this Order.

## ORDER

In consideration of the foregoing and as more particularly described above and reflected in Amended Interlocutory Order No. 29588 issued September 9, 2004, IT IS HEREBY ORDERED and the Commission hereby authorizes Avista Corporation dba Avista Utilities to increase its net electric revenues by $3,182,000 or approximately 1.9%. This increase incorporates the base revenue increase approved by the Commission, a two year recovery of the adjusted PCA deferral balance, and a decrease in DSM rates. We approve for rates and charges in compliance with the terms of this Order the amended tariff sheets filed by Avista in compliance with Order No. 29588 and for service rendered on and after September 9, 2004.

IT IS FURTHER ORDERED and the Commission hereby authorizes Avista Corporation dba Avista Utilities to increase its net gas revenues by $3,311,000 or approximately 6.38%. We approve for rates and charges in compliance with the terms of this Order the amended tariff sheets filed by Avista in compliance with Order No. 29588 and for service rendered on and after September 9, 2004.

IT IS FURTHER ORDERED that Avista Corporation dba Avista Utilities comply with all other directives of the text of this Order.

IT IS FURTHER ORDERED that Community Action Partnership Association of Idaho is awarded intervenor funding in the amount of $12,622.75. Avista Utilities is directed to pay this amount within 28 days of the date of this Order.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) or in interlocutory Orders previously issued in this Case Nos. AVU-E-04-1 and AVU-G-04-1 may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order or in interlocutory Orders previously issued in this Case Nos. AVU-E-04-1 and AVU-G-04-1. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 8th day of October 2004.

PAUL KJELLANDER, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

bls/O:AVUE0401_AVUG0401_sw7

**AVISTA UTILITIES**
**AVU-E-04-1**
**Present and Commission Ordered Electric Rates**

## Residential Service - Schedule 1

| Present Rates | | Commission Ordered Rates | |
|---|---|---|---|
| Basic Charge | $4.00 | Basic Charge | $4.00 |
| First 600 kWhs | 4.555 ¢/kWh | First 600 kWhs | 5.717 ¢/kWh |
| All over 600 kWhs | 5.303 ¢/kWh | All over 600 kWhs | 6.487 ¢/kWh |
| PCA Rate 0 - 600 kWh | 0.939 ¢/kWh | PCA Rate | 0.286 ¢/kWh |
| All over 600 kWh | 1.092 ¢/kWh | | |
| Energy Efficiency Rider | 0.104 ¢/kWh | Energy Efficiency Rider | 0.081 ¢/kWh |

## General Service - Schedule 11

| Present Rates | | Commission Ordered Rates | |
|---|---|---|---|
| Basic Charge | $6.00 | Basic Charge | $6.00 |
| Energy Charge | 6.564 ¢/kWh | First 3650 kWh | 7.148 ¢/kWh |
| | | All Over 3650 kWh | 6.076 ¢/kWh |
| Demand Charge: | | Demand Charge: | |
| 20 kW or less | no charge | 20 kW or less | no charge |
| Over 20 kW | $3.50/kW | Over 20 kW | $3.50/kW |
| PCA Rate | 1.391 ¢/kWh | PCA Rate | 0.335 ¢/kWh |
| Energy Efficiency Rider | 0.140 ¢/kWh | Energy Efficiency Rider | 0.095 ¢/kWh |

## Large General Service - Schedule 21

| Present Rates | | Commission Ordered Rates | |
|---|---|---|---|
| Energy Charge | 3.996 ¢/kWh | First 250,000 kWh | 4.688 ¢/kWh |
| | | All Over 250,000 kWh | 3.985 ¢/kWh |
| Demand Charge: | | Demand Charge: | |
| 50 kW or less | $225.00 | 50 kW or less | $250.00 |
| Over 50 kW | $2.75/kW | Over 50 kW | $3.00/kW |
| Primary Voltage Discount | 20¢/kW | Primary Voltage Discount | 20¢/kW |
| PCA Rate | 1.011 ¢/kWh | PCA Rate | 0.256 ¢/kWh |
| Energy Efficiency Rider | 0.100 ¢/kWh | Energy Efficiency Rider | 0.073 ¢/kWh |

## Extra Large General Service - Schedule 25

| Present Rates | | Commission Ordered Rates | |
|---|---|---|---|
| Energy Charge | 2.874 ¢/kWh | First 500,000 kWh | 3.862 ¢/kWh |
| | | All Over 500,000 kWh | 3.259 ¢/kWh |
| Demand Charge: | | Demand Charge: | |
| 3,000 kva or less | $7,500.00 | 3,000 kva or less | $9,000.00 |
| Over 3,000 kva | $2.25/kva | Over 3,000 kva | $2.75/kva |
| Primary Voltage Discount | 20¢/kva | Primary Voltage Discount | 20¢/kva |
| Annual Minimum | $406,140 | Annual Minimum | $502,670 |
| PCA Rate | 0.607 ¢/kWh | PCA Rate | 0.181 ¢/kWh |
| Energy Efficiency Rider | 0.068 ¢/kWh | Energy Efficiency Rider | 0.052 ¢/kWh |



Rates Exhibit 9/9/2004 KDH

**AVISTA UTILITIES**
**AVU-E-04-1**
**Present and Commission Ordered Electric Rates**

**Potlatch - Schedule 25P**

| Present Rates | | First 3650 kWh | |
|---|---|---|---|
| Energy Charge | 2.874 ¢/kWh | Energy Charge | 3.333 ¢/kWh |
| Demand Charge: | | Demand Charge: | |
| 3,000 kva or less | $7,500.00 | 3,000 kva or less | $9,000.00 |
| Over 3,000 kva | $2.25/kva | Over 3,000 kva | $2.75/kva |
| Primary Voltage Discount | 20¢/kva | Primary Voltage Discount | 20¢/kva |
| Annual Minimum | $406,140 | Annual Minimum | $474,630 |
| PCA Rate | 0.607 ¢/kWh | PCA Rate | 0.163 ¢/kWh |
| Energy Efficiency Rider | 0.068 ¢/kWh | Energy Efficiency Rider | 0.046 ¢/kWh |

**Pumping Service - Schedule 31**

| Present Rates | | Commission Ordered Rates | |
|---|---|---|---|
| Basic Charge | $6.00 | Basic Charge | $6.00 |
| First 85 kWh/kW | 5.716 ¢/kWh | First 85 kWh/kW | 6.440 ¢/kWh |
| Next 80 kWh/kW | 5.716 ¢/kWh | Next 80 kWh/kW | 6.440 ¢/kWh |
| All additional kWhs | 4.548 ¢/kWh | All additional kWhs | 5.474 ¢/kWh |
| PCA Rate | 0.888 ¢/kWh | PCA Rate | 0.265 ¢/kWh |
| Energy Efficiency Rider | 0.102 ¢/kWh | Energy Efficiency Rider | 0.076 ¢/kWh |

**Street and Area Lights - Schedules 41-49**

| Present Rates | | Commission Ordered Rates | |
|---|---|---|---|
| Base Rates | Various | Base Rate Increase | 20.19% |
| PCA Surcharge | 19.37% | PCA Surcharge | 4.385% |
| Energy Efficiency Rider | 1.95% | Energy Efficiency Rider | 1.25% |

**AVISTA UTILITIES**
**AVU-G-04-1**
**Present and Commission Ordered Natural Gas Rates**

**General Service - Schedule 101**

| Present Rates[1] | | Commission Ordered Rates[2] | |
|---|---|---|---|
| Basic Charge | $3.28 | Basic Charge | $3.28 |
| All Therms | 74.197 ¢/Therm | All Therms | 80.050 ¢/Therm |

**Large General Service - Schedule 111**

| Present Rates[1] | | Commission Ordered Rates[2] | |
|---|---|---|---|
| 1st 200 Therms | 75.836¢/Therm* | 1st 200 Therms | 78.301¢/Therm* |
| Next 800 Therms | 74.197¢/Therm | Next 800 Therms | 76.481¢/Therm |
| Over 1,000 Therms | 64.975¢/Therm | Over 1,000 Therms | 66.239¢/Therm |
| *Minimum - $97.30/Month plus 27.186¢/Therm | | *Minimum - $156.60/Month | |

**Large General Service - Schedule 121**

| Present Rates[1] | | Commission Ordered Rates[2] | |
|---|---|---|---|
| 1st 500 Therms | 74.852¢/Therm* | 1st 500 Therms | 77.209¢/Therm* |
| Next 500 Therms | 74.197¢/Therm | Next 500 Therms | 76.481¢/Therm |
| Next 9,000 Therms | 64.975¢/Therm | Next 9,000 Therms | 66.239¢/Therm |
| Over 10,000 Therms | 63.284¢/Therm | Over 10,000 Therms | 64.361¢/Therm |
| *Minimum - $238.33/Month plus 27.186¢/Therm | | *Minimum - $386.05/Month | |

**Interruptible Service - Schedule 131**

| Present Rates[1] | | Commission Ordered Rates[2] | |
|---|---|---|---|
| All Therms | 55.724¢/Therm* | All Therms | 56.586¢/Therm* |
| *Annual Minimum $78,385 | | *Annual Minimum[3] | |

**Transportation Service - Schedule 146**

| Present Rates[1] | | Commission Ordered Rates[2] | |
|---|---|---|---|
| Basic Charge | $0.00 | Basic Charge | $200 / Month |
| All Therms | 10.574¢/Therm | All Therms | 10.960¢/Therm |

[1] Includes Purchase Gas Adjustment Schedule 150/Excludes all other rate adjustments

[2] Does not include Schedule 150 or any other rate adjustment.

[3] Annual Minimum: Each Customer shall be subject to an Annual Minimum Deficiency Charge if their gas usage during the prior year did not equal or exceed 250,000 therms. Such annual Minimum Deficiency Charge shall be determined by subtracting the Customer's actual usage for the twelve-month period ending each August from 250,000 therms multiplied by 11.597¢ per therm.

Rates Exhibit tabRate Exh
MJF

APPENDIX B
Order No. 29602
Case Nos. AVU-E-04-1
AVU-G-04-1

AVISTA UTILITIES
CALCULATION OF GENERAL REVENUE REQUIREMENT
IDAHO ELECTRIC SYSTEM
TEST YEAR 2002
(000'S OF DOLLARS)

| Line No. | Description | Commission Decision |
|---|---|---|
| 1 | Pro Forma Rate Base | $424,114 |
| 2 | Proposed Rate of Return | 9.250% |
| 3 | Net Operating Income Requirement (Line 1 x Line 2) | $39,231 |
| 4 | Pro Forma Net Operating Income | $23,121 |
| 5 | Net Operating Income Deficiency (Line 3 - Line 4) | $16,110 |
| 6 | Conversion Factor | 0.63926135 |
| 7 | Revenue Requirement Deficiency (Line 5/Line 6) | $25,201 |
| 8 | Levelized Deferred Return on Coyote Springs 2 | (485) |
| 9 | Revised Revenue Requirement Deficiency (Line 7 + Line 8) | $24,716 |
| 10 | Total General Business Revenues | $146,248 |
| 11 | Percentage Revenue Increase (Line 9/Line 10) | 16.90% |

AVISTA UTILITIES
CALCULATION OF GENERAL REVENUE REQUIREMENT
IDAHO GAS
TEST YEAR 2002
(000'S OF DOLLARS)

| Line No. | Description | Commission Decision |
|---|---|---|
| 1 | Pro Forma Rate Base | $59,653 |
| 2 | Proposed Rate of Return | 9.250% |
| 3 | Net Operating Income Requirement (Line 1 x Line 2) | $5,518 |
| 4 | Pro Forma Net Operating Income | $3,402 |
| 5 | Net Operating Income Deficiency (Line 3 - Line 4) | $2,116 |
| 6 | Conversion Factor | 0.639 |
| 7 | Revenue Requirement Deficiency (Line 5/Line 6) | $3,311 |
| 8 | Total General Business Revenues | $51,919 |
| 9 | Percentage Revenue Increase (Line 7/Line 8) | 6.38% |

APPENDIX E
Order No. 29602
Case Nos. AVU-E-04-1

# Commission Decision
## AVU-E-04-1
## Avista Utilities - Electric
## State of Idaho
## 20% Cost of Service with Caps
## Normalized 12-Months Ending December 31, 2002

Base Rate, PCA and DSM Changes

| Line No | Type of Service | (1) Rate Sch. No. | (2) Average Number of Customers | (3) Sales Normalized (MWh) | (4) Current Revenue* | (5) Ordered General Increase | (6) Ordered PCA Decrease** | (7) Ordered DSM Decrease | (8) Net Revenue Adjustments | (9) Ordered Revenue | (10) Average Rate ¢/kWh | (11) Percent Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential | 1 | 87,494 | 988,380 | 60,102,000 | 11,583,193 | (7,146,416) | (449,618) | 3,987,159 | 64,089,159 | 6.48 | 6.6% |
| 2 | General Service | 11 | 16,051 | 225,328 | 19,436,000 | 995,000 | (2,379,808) | (120,449) | (1,505,257) | 17,930,743 | 7.96 | -7.7% |
| 3 | Large General Service | 21 | 1,789 | 674,177 | 41,682,000 | 4,631,000 | (5,086,756) | (276,045) | (731,801) | 40,950,199 | 6.07 | -1.8% |
| 4 | Extra Large General Service | 25 | 14 | 303,707 | 12,346,000 | 2,070,781 | (1,293,385) | (87,820) | 689,575 | 13,035,575 | 4.29 | 5.6% |
| 6 | Potlatch | 25 | 1 | 870,086 | 33,056,000 | 4,650,170 | (3,863,085) | (226,423) | 560,662 | 33,616,662 | 3.86 | 1.7% |
| 7 | Pumping Service | 31 | 1,043 | 48,922 | 2,997,000 | 409,789 | (304,688) | (20,712) | 84,389 | 3,081,389 | 6.30 | 2.8% |
| 8 | Street and Area Lights | 41-49 | - | 12,983 | 2,228,000 | 376,263 | (262,849) | (15,682) | 97,731 | 2,325,731 | 17.91 | 4.4% |
| 9 | Total/Average | | | 3,123,583 | 171,847,000 | 24,716,195 | (20,336,987) | (1,196,749) | 3,182,459 | 175,029,459 | 5.60 | 1.9% |

* Includes all present rate adjustments; Residential Exchange Credit, Centralia Credit, PCA Surcharge, DSM Rider

** Residential includes $12,623 of intervenor funding

AVISTA UTILITIES
COMMISSION APPROVED REVENUE INCREASE BY SCHEDULE
IDAHO - GAS
12 MONTHS ENDED DECEMBER 31, 2002
(000s of Dollars)

| Line No | Type of Service | Schedule Number | Revenue Under Present Rates (1) | Proposed Increase | Revenue Under Approved Rates (2) | Therms (000s) | Revenue Increase Per Therm | Percent Increase | COS Index | Company Increase |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | ( c) | (d) | (e) | (f) | (g) | (h) | (I) | (j) |
| 1 | General Service | 101 | $40,114 | $2,984 | $43,097 | 50978 | 5.853¢ | 7.44% | 99.58% | 10.0% |
| 2 | Large General Service | 111 | $8,955 | $259 | $9,213 | 12930 | 2.000¢ | 2.89% | 100.91% | 6.6% |
| 3 | High Annual Load Factor LGS | 121 | $1,522 | $30 | $1,551 | 2357 | 1.253¢ | 1.94% | 101.26% | 3.8% |
| 4 | Interruptible Service | 131 | $385 | $6 | $391 | 691 | 0.862¢ | 1.55% | 102.63% | 3.4% |
| 5 | Transportation Service | 146 | $444 | $33 | $477 | 4200 | 0.786¢ | 7.43% | 117.43% | 18.2% |
| 6 | Special Contracts | | $500 | $0 | $500 | 58852 | 0.000¢ | 0.00% | 100.00% | 0.0% |
| 7 | Total | | $51,919 | $3,311 | $55,230 | 130007 | 2.547¢ | 6.38% | 100.00% | 9.2% |

(1) Includes Purchase Adjustment Schedule 150 / Excludes other rate adjustments
(2) Does not include Purchase Gas Adjustment Schedule 150 or other rate adjustments